Indianapolis Power & Light Company

2016 Integrated Resource Plan

Public Version

Volume 1 of 3

November 1, 2016

Table of Contents

Page

Table of Figures

Page

Integrated Resource Plan Acronyms

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
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
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
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
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
PRMucap	Planning Reserve Margin on UCAP (Unforced Capacity)
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
RIM	Rate Payer Impact Measure (see EM&V)

RRaR	Revenue Requirement at Risk
RTO	Regional Transmission Organization (Independent System Operator)

S

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 (the amount of Installed Capacity that is actually available)
UCT	Utility Cost Test
Ultra SCPC	Ultra Super Critical Pulverized Coal

V

VAR	Volt Ampere Reactive, Variance, or Value at Risk

W

WQBEL	Water Quality Based Effluent Limits

Rule Reference Table

170 IAC 4-7 (Proposed 10/4/12)		
Regulatory Requirement	**Rule Reference Link**	**Section and/or Attachment in Indianapolis Power and Light's 2016 IRP Document**
0.1 -Applicability	-	No Response Required
1 - Definitions	-	No Response Required
2 - Procedures and Effects of Filing Integrated Resource Plans	-	No Response Required
2.1 - Public Advisory Process	-	No Response Required
2.2 - Contemporary Issues Tech Conference	-	No Response Required
3 -Waiver or Variance Requests	-	No Response Required
4 - Methodology and Documentation		
(a) IRP Summary Document	170 IAC 4-7-4(a)	Attachment 1.1
(b)(1) inputs, methods, definitions	170 IAC 4-7-4(b)(1)	Sections 7, 7.3.1
(b)(2) forecast datasets	170 IAC 4-7-4(b)(2)	Section 4, Confidential Attachment 4.8, Attachments 4.9, 4.10, 4.11, 4.12
(b)(3) electric consumption patterns, load research	170 IAC 4-7-4(b)(3)	Attachment 4.1, 4.2, 4.12
(b)(4) customer surveys on end use penetration	170 IAC 4-7-4(b)(4)	Sections 4.3, 5.6.2, Confidential Attachment 4.4, Attachment 4.5, 5.6
(b)(5) customer self-generation	170 IAC 4-7-4(b)(5)	Section 3.2.4, 5.4
(b)(6) alternative forecast scenarios	170 IAC 4-7-4(b)(6)	Sections 4.2, 4.5.4
(b)(7) fuel inventory and procurement	170 IAC 4-7-4(b)(7)	Sections 2.2, 6
(b)(8) emissions allowance inventory and procurement	170 IAC 4-7-4(b)(8)	Section 7.3.1
(b)(9) expansion planning criteria	170 IAC 4-7-4(b)(9)	Sections 7.6, 8.4.1
(b)(10)(A) power flow study	170 IAC 4-7-4(b)(10)(A)	Section 2.5
(b)(10)(B) dynamic stability study	170 IAC 4-7-4(b)(10)(B)	Section 2.5
(b)(10)(C) transmission reliability criteria	170 IAC 4-7-4(b)(10)(C)	Section 2.4
(b)(10)(D) joint transmission system	170 IAC 4-7-4(b)(10)(D)	Section 2.5
(b)(11)(A) model structure and reasoning	170 IAC 4-7-4(b)(11)(A)	Section 7.2
(b)(11)(B)(i) forecast	170 IAC 4-7-4 (b)(11)(B)(i)	Section 4
(b)(11)(B)(ii) cost estimates	170 IAC 4-7-4 (b)(11)(B)(ii)	Section 7.3, Attachment 2.1, Confidential Attachment 2.2
(b)(11)(B)(iii) treatment of risk and uncertainty	170 IAC 4-7-4 (b)(11)(B)(iii)	Section 6
(b)(11)(B)(iv) transmission & generation reliability	170 IAC 4-7-4 (b)(11)(B)(iv)	Section 2.3.1
(b)(12) avoided cost calculation	170 IAC 4-7-4(b)(12)	Section 5.6.4, Confidential Attachment 5.10
(b)(13) system actual demand	170 IAC 4-7-4(b)(13)	Attachment 4.12
(b)(14) public advisory process	170 IAC 4-7-4(b)(14)	Section 1.4, Attachment 1.2
5 - Energy and Demand Forecasts		
(a)(1) analysis of load shapes	170 IAC 4-7-5(a)(1)	Attachment 4.2
(a)(2) disaggregated load shapes	170 IAC 4-7-5(a)(2)	Attachments 4.2, Confidential Attachment 4.8
(a)(3) disaggregated data & forecasts	170 IAC 4-7-5(a)(3)	Confidential Attachment 4.8
(a)(4) energy and demand levels	170 IAC 4-7-5(a)(4)	Section 4
(a)(5) weather normalization methods	170 IAC 4-7-5(a)(5)	Section 4.3, 4.6
(a)(6) energy and demand forecasts	170 IAC 4-7-5(a)(6)	Confidential Attachment 4.8, Attachment 4.12
(a)(7) forecast performance	170 IAC 4-7-5(a)(7)	Attachment 4.13
(a)(8) end-use forecast methodology	170 IAC 4-7-5(a)(8)	Attachments 4.4, 4.5
(a)(9) data sets	170 IAC 4-7-5(a)(9)	Attachments 4.6, 4.7, 4.8, 4.9, 4.10, 4.11
(b) alternative peak/energy forecasts	170 IAC 4-7-5(b)	Section 4
6 - Resource Assessment**		
(a)(1) net dependable capacity	170 IAC 4-7-6(a)(1)	Section 5.1
(a)(2) expected capacity changes	170 IAC 4-7-6(a)(2)	Sections 8.1, Section 8.1.1
(a)(3) fuel price forecast	170 IAC 4-7-6(a)(3)	Section 2.2.1
(a)(4) significant environmental effects	170 IAC 4-7-6(a)(4)	Section 6.4, 6.5
(a)(5) transmission system analysis	170 IAC 4-7-6(a)(5)	Sections 2.4.2, 2.7.1
(a)(6) demand-side programs	170 IAC 4-7-6(a)(6)	Sections 5.1.2, 5.5, 8.1.2
(b)(1) DSM program description	170 IAC 4-7-6(b)(1)	Attachment 5.5
(b)(2) DSM avoided cost projections	170 IAC 4-7-6(b)(2)	Confidential Attachment 5.10
(b)(3) DSM customer class affected	170 IAC 4-7-6(b)(3)*	Attachment 5.6, Confidential Attachment 8.2
(b)(4) DSM impact projections	170 IAC 4-7-6(b)(4)*	Attachment 5.6, Confidential Attachment 8.2
(b)(5) DSM program cost projections	170 IAC 4-7-6(b)(5)*	Attachment 5.6, Confidential Attachment 8.2
(b)(6) DSM energy/demand savings	170 IAC 4-7-6(b)(6)*	Attachment 5.6, Confidential Attachment 8.2
(b)(7) DSM program penetration	170 IAC 4-7-6(b)(7)*	Attachment 5.6, Confidential Attachment 8.2
(b)(8) DSM impact on systems	170 IAC 4-7-6(b)(8)*	Attachment 5.6, Confidential Attachment 8.2
(c)(1) supply-side resource description	170 IAC 4-7-6(c)(1)	Section 5.3
(c)(2) utility coordinated cost reduction	170 IAC 4-7-6(c)(2)	Section 5.3, 5.3.2

(d)(1) transmission expansion	170 IAC 4-7-6(d)(1)	Section 2.6
(d)(2) transmission expansion costs	170 IAC 4-7-6(d)(2)	Section 2.7
(d)(3) power transfer	170 IAC 4-7-6(d)(3)	Sections 2.4.2, 2.7, 2.7.1
(d)(4) RTO planning and implementation	170 IAC 4-7-6(d)(4)	Section 2
7 - Selection of Future Resources		
(a) resource alternative screening	170 IAC 4-7-7(a)	Section 5.3, 7.3, Section 8.1
(a)(1) environmental effects	170 IAC 4-7-7(a)(1)	Sections 6, 6.4, 6.5
(a)(2) environmental regulation	170 IAC 4-7-7(a)(2)	Section 6
(b) DSM tests	170 IAC 4-7-7(b)*	Section 5.6.5
(c) life cycle NPV impacts	170 IAC 4-7-7(c)*	Confidential Attachment 8.1
(d)(1) cost/benefit components	170 IAC 4-7-7(d)(1)	Attachments 5.7, 5.8
(d)(2) cost/benefit equation	170 IAC 4-7-7(d)(2)	Attachments 5.7, 5.8
(e) DSM test exception	170 IAC 4-7-7(e)	No Response Required
(f) load build directions	170 IAC 4-7-7(d)	No Response Required
8 - Resource Integration		
(a) candidate resource portfolios process	170 IAC 4-7-8(a)	Sections 7, 8.1
(b)(1) preferred resource portfolio description	170 IAC 4-7-8(b)(1)	Section 8.4
(b)(2) significant factors	170 IAC 4-7-8(b)(2)	Section 8.3, 8.4.1
(b)(3) supply-side and demand side comparable treatment	170 IAC 4-7-8(b)(3)	Sections 5.5, 5.6, 7.33
(b)(4) utilization of all resources	170 IAC 4-7-8(b)(4)	Section 8.4.2
(b)(5) DSM utilization	170 IAC 4-7-8(b)(5)	Section 5.6.4
(b)(6)(A) operating and capital costs of preferred resource portfolio	170 IAC 4-7-8(b)(6)(A)	Section 8.1.4, Confidential
(b)(6)(B) average cost per kWh	170 IAC 4-7-8(b)(6)(B)	Section 8.1.4
(b)(6)(C) annual avoided cost of the preferred resource portfolio	170 IAC 4-7-8(b)(6)(C)	Confidential Attachment 5.10
(b)(6)(D) plan resource financing	170 IAC 4-7-8(b)(6)(D)	Section 6.2
(b)(7)(A) explanation of assumptions	170 IAC 4-7-8(b)(7)(A)	Section 7
(b)(7)(B) risk management	170 IAC 4-7-8(b)(7)(B)	Section 6.1
(b)(7)(C) potential futures	170 IAC 4-7-8(b)(7)(C)	Section 7.1
(b)(7)(D) PVRR of resource plan	170 IAC 4-7-8(b)(7)(D)	Section 8.1.4
(b)(7)(E) assessment of robustness	170 IAC 4-7-8(b)(7)(E)	Section 9.2
(b)(8) strategy for unexpected changes	170 IAC 4-7-8(b)(8)	Section 9.2
9 - Short Term Action Plan		
(1)(A) description/objective	170 IAC 4-7-9(1)(A)	Section 9.1
(1)(B) progress measurement criteria	170 IAC 4-7-9(1)(B)	Section 9.1.1
(2) implementation schedule	170 IAC 4-7-9(2)	Section 9.1.2
(3) plan budget	170 IAC 4-7-9(3)	Section 9.1.2
(4) prior STIP vs actual	170 IAC 4-7-9(4)	Section 9.1.1

Note: The reference(s) listed is the most pertinent Section(s). The topic may be addressed in other Sections not referenced.
*High level customer costs and incentives were utilized in the DSM MPS evaluation. However, programs will be developed and filed in subsequent DSM proceedings based on the results of the IRP.
**The DSM as a selectable resource section in this IRP cites the proposed draft red-lined strawman rulemaking dated 03/02/2016, pg. 20,170 IAC 4-7-6(b).

Executive Summary

Vision

Indianapolis Power & Light Company (“IPL”) is committed to improving lives by providing safe, reliable, and sustainable energy solutions to customers. Effective planning is integral to fulfill this mission, including anticipating and preparing for changes in technology, public policy, and public perception.

A particular section of planning results in an Integrated Resource Plan (“IRP”), which is the subject of this document. Seasoned resource planners looked for a robust portfolio to serve customers’ future needs, that is, a plan that performs well under a variety of circumstances. In the parlance of today, IPL is planning to be antifragile - preparing to meet customers’ needs in multiple potential future outcomes. This IRP evaluates resource plans through multiple scenarios, which were developed through a public advisory process to cover a broad range of potential futures.

IPL has been a leader in Indiana in taking steps to change its portfolio, moving toward cleaner resource options through offering Demand Side Management (“DSM”) programs, replacing coal-fired generation with natural gas-fired generation, securing wind and solar long-term contracts known as Purchased Power Agreements (“PPAs”), and building the first battery energy storage system in the Midcontinent Independent System Operator’s (“MISOs”) region. IPL plans to continue this transition proactively while simultaneously maintaining high reliability and affordable rates.

IPL was among the first utilities in Indiana to offer DSM programs in 1993, now known as IPL PowerTools®. IPL offered solar net metering in 2000, which pre-dated the Commission's net metering requirement. IPL offered a feed-in tariff in 2010 to support local renewable generation, better understand the operating characteristics of solar and successfully integrate distributed generation on its grid. IPL also entered into wind purchase power agreements in 2008 to mitigate future carbon impacts. IPL installed and is operating the first battery energy storage system in the MISO footprint. While this battery currently provides primary frequency response services, this is, it automatically responds if system frequency deviates significantly from the 60 hertz standard, to meet customers’ needs, batteries are a rapidly emerging technology that can also address a variety of resource needs. This flexibility will allow that energy storage system to efficiently provide additional services as those needs evolve.

More recently, IPL retired 260 MW of coal-fired generation, converted 630 MW of coal-fired generation to gas and will bring on line a 671 MW clean, efficient Combined-Cycle Gas Turbine (CCGT) power station in spring 2017. These projects, which are helping IPL move towards a cleaner resource mix, are also the reasonable least-cost option to serve customers.

IPL continues to research new ways to optimize existing assets to benefit customers, such as reducing minimum generation limits and related emissions while providing capacity value during the expected movement toward cleaner, affordable, and reliable resources. "Optionality will take us many places, but at its core, an option is what makes you antifragile and allows you to benefit from the positive side of uncertainty, without a corresponding serious harm from the negative side."[1]

IPL continues to invest in its existing coal-fired generation to the extent it makes economic sense for customers. However, these investment will be focused on maintaining the underlying value of those generation units while, at the same time, preparing for the evolving role of coal generation in the future generation mix.

IPL and its parent company, AES, recognize the public appetite for and declining costs of cleaner resources and focus on sustainability. As stated in the 2015 AES Annual Report, "Our development efforts are increasingly focused on natural gas, energy storage, solar and hydroelectric opportunities. We expect the global electric sector to reduce the carbon intensity of electric generation by retiring older, inefficient units and replacing them with new, natural gas and renewable capacity. We seek to maintain and strengthen our leadership position during this transformation." [2]

IPL's recent significant resource portfolio changes move in this direction, which positions IPL well to continue to adapt to changes.

Company Overview

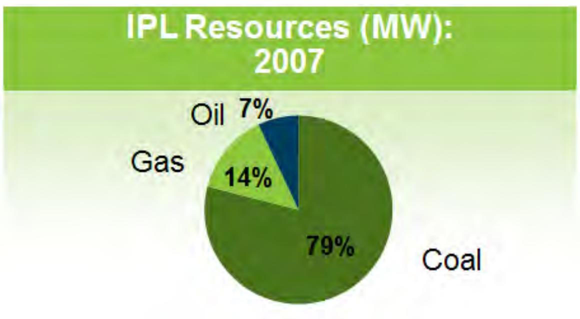
IPL provides retail electric service to more than 480,000 residential, commercial and industrial customers in Indianapolis and surrounding central Indiana communities and fully participates in the electricity markets managed by MISO.

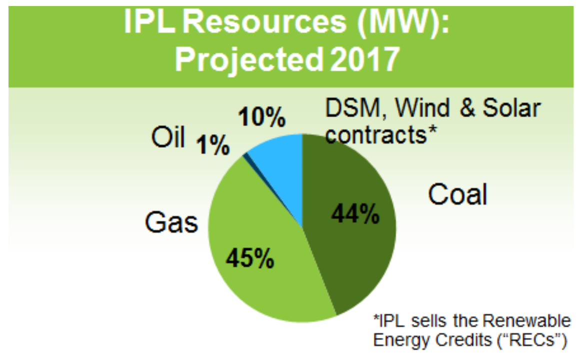
IPL owns and efficiently operates approximately 2700 MW of generation, including 1100 MW natural gas fired and 1700 MW of coal, is in the process of constructing 671 MW CCGT, supports 58 MW of DSM resources, and secured PPAs for approximately 96 MW of solar generation and approximately 300 MW of wind generation. Under the terms of the PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") associated with the wind and solar PPAs which it currently sells to offset the cost of this energy to customers.[3] However, IPL

[1] As stated in *Antifragile: Things That Gain From Disorder* by Nassim Nicholas Taleb.
[2] See 2015 AES Annual Report on page 3.
[3] The null energy of the Wind PPAs is used to supply the load for IPL customers, and in the absence of any Renewable Portfolio Standards (RPS) mandates, IPL is currently selling the associated RECS, but reserves the right to use RECs from the Wind PPAs to meet any future RPS requirement. The Wind PPAs were approved by the IURC and if IPL chooses to monetize the RECs that result from the agreements, IPL shall use the revenues to first offset the cost of the Wind PPAs and next to credit IPL customers through its fuel adjustment clause proceedings. The Green-e Dictionary (http://green-e.org/learn_dictionary.shtml) defines null power as, "Electricity that is stripped

reserves the right to use RECs to meet any future environmental requirement, such as the EPA's Clean Power Plan ("CPP"). This results in a significantly different portfolio than 10 years ago as shown in Figure A below.

Figure A – Changing Resource Mix

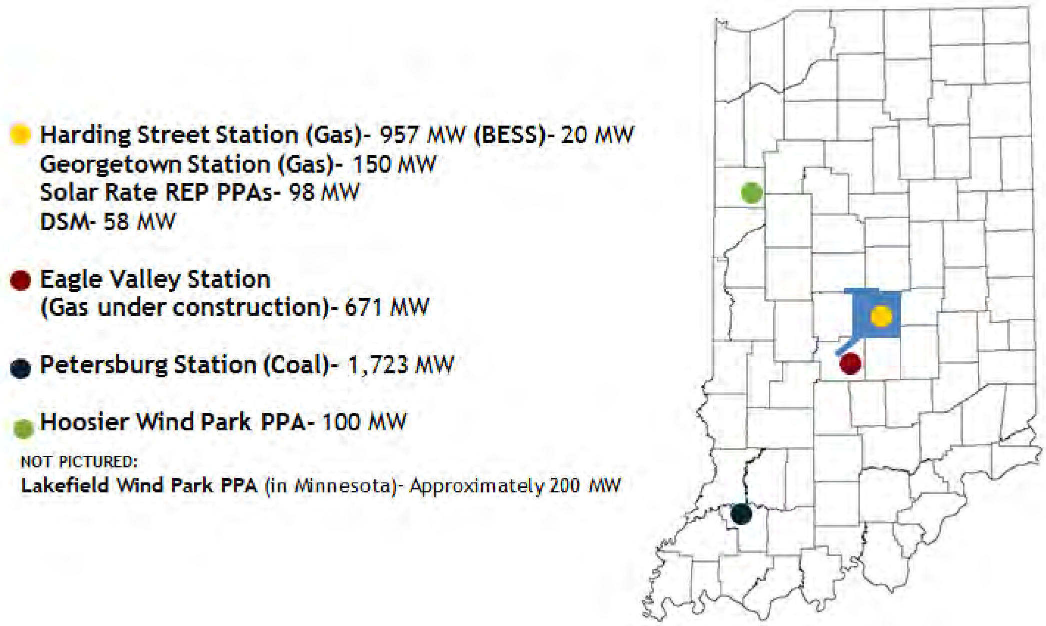




IPL prepared for Environmental Protection Agency ("EPA") regulations to improve air emissions and water quality by investing $1.4 billion in environmental controls and new generation. This investment program is expected to reduce SO2, NOx, mercury and particulate matter by over 50 percent in 2017 compared to 2013. Investments include retiring approximately 260 MW of coal-fired generation, refueling 630 MW of coal-fired units to natural gas at Harding Street, upgrading controls at Petersburg to comply with the Mercury and Air Toxics Standard ("MATS") Rule and the National Pollutant Discharge Elimination System ("NPDES") rules and construction of the new 671 MW Eagle Valley Combined Cycle Gas Turbine ("CCGT"). Figure B shows the relative location and capacity contributions of IPL's resources.

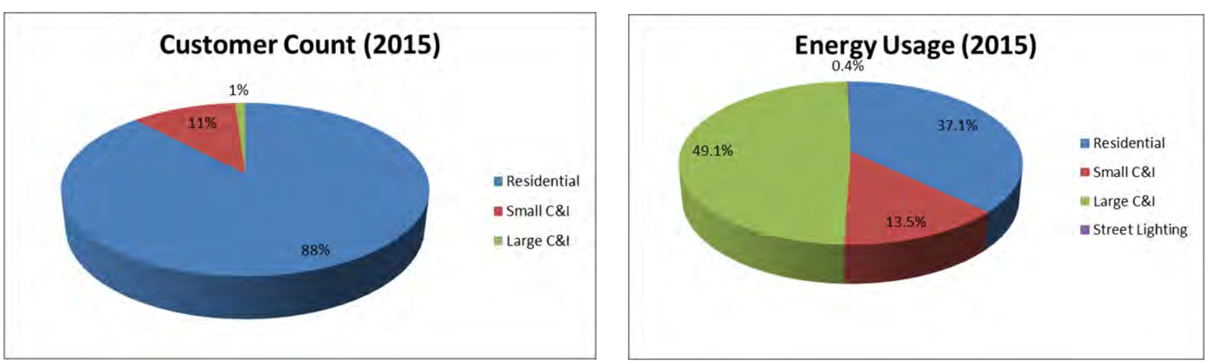
of its attributes and undifferentiated. No specific rights to claim fuel source or environmental impacts are allowed for null electricity. Also referred to as commodity or system electricity."

Figure B – IPL 2017 Resources



IPL serves its residential, commercial and industrial ("C&I") customers through an interconnected grid of transmission and distribution circuits as a vertically integrated investor-owned utility. IPL's customer mix and their respective energy usage are shown in Figure C.

Figure C – IPL Customer Mix



The Company prepares an IRP as required by the Indiana Administrative Code ("IAC") on a biennial basis to identify a resource plan to reliably serve IPL customers for a forward looking twenty (20) year period.[4] In this cycle, IPL built upon the Public Advisory Process as required by

[4] The IURC is reviewing the IRP rules and may change to the filing requirement from a 2 year to a 3 year cycle.

the proposed IAC for the 2014 IRP and incorporated stakeholder feedback in the development of this IRP. There were four specific IPL public meetings with an average of 25 stakeholder attendees at each one to share information and seek feedback throughout this process.

The IRP analyzes a combination of projected customer load, existing resources, projected operating costs, anticipated environmental and other regulatory requirements, and potential supply and demand side resources within the context of risks of uncertain future landscapes to plan to provide electricity service in the most cost-effective way possible. In this IRP, IPL is forecasting relatively flat load growth due to energy efficiency impacts in all customer sectors and smaller square footage new "homes" in multi-family developments.

The IRP results indicate potential candidate future resource portfolios in light of uncertainties and risk factors identified to date. "Unknown unknowns", such as customer use of technologies or public policy changes not yet proposed or unexpected future environmental regulations are not included, which could affect future implementation plans. Subsequent specific resource changes are based upon competitive processes with detailed regulatory filings such as DSM or Certificate of Public Convenience and Necessity ("CPCN") proceedings before the Commission.

IPL documented guiding principles and key assumptions such as assuring compliance with all regulatory and reliability requirements, modeling DSM as a selectable resource and consistency with current regulatory frameworks which are more fully described in Section 1. This IRP includes risk analysis to quantify potential changes in model input costs such as construction, fuel, market prices, and carbon as well as load forecast variances, customer adoption of distributed generation.

Through the IRP process, IPL defined multiple scenarios which were modeled to derive candidate resource portfolios with stakeholder input. The scenarios include the risks of uncertain future landscapes such as economics affecting load requirements, natural gas and market prices, EPA's Clean Power Plan ("CPP") and environmental costs, and varying levels of customer distributed generation adoption.

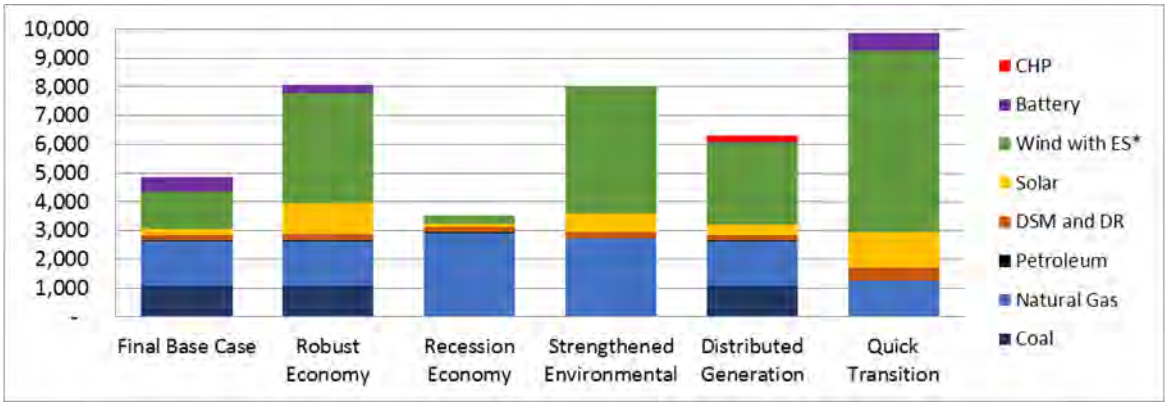
A base case was defined to only reflect a continuation of the status quo without significant changes in resources, regulations or customer use. Specific base case assumptions were modified to create the six scenarios in this IRP shown in Figure D below.

Figure D - IPL IRP Scenario Variables

	Scenario Name	Load Forecast	Natural Gas and Market Prices	Clean Power Plan (CPP) and Environment	Distributed Generation (DG)
1	**Base Case**	Use current load growth methodology	Prices derived from a ABB Mass-based CPP Scenario	ABB Mass-based CPP scenario starting in 2022. Low cost environmental regulations: ozone, 316b, and CCR	Expected moderate decreases in technology costs for wind, storage, and solar
2	**Robust Economy**	**High**	**High**	Base Case	Base Case
3	**Recession Economy**	**Low**	**Low**	Base Case	Base Case
4	**Strengthened Environmental Rules**	Base Case	Base Case	**20% RPS, High carbon and environmental costs: ozone, 316b, OSM**	Base Case
5	**Distributed Generation**	Base Case	Base Case	Base Case	**Base case with fixed additions of 150 MW in 2022, 2025, and 2032**
6	**Quick Transition (Stakeholder inspired)**	Base Case	Base Case	Base Case	**Fixed portfolio to retire coal, add max DSM, minimum baseload (NG), plus solar, wind and storage**

The candidate resource portfolios resulting from each scenario at the end of the 20 year IRP study period are shown in Figure E below.

Figure E - Candidate Resource Portfolios (MW in 2036)



IPL has traditionally relied primarily upon costs to customers in terms of PVRR to select its preferred resource portfolio. The "Preferred Resource Portfolio" based upon the lowest cost to customers in terms of the Present Value Revenue Requirement ("PVRR") would be the Base Case scenario.

In addition to PVRR analyses, IPL developed metrics related to environmental stewardship, financial risk, resiliency, and rate impact metrics to compare the portfolios derived from multiple scenarios which are summarized in Figure F.

Figure F - Metrics Summary

Scenarios	Cost		Financial Risk	Environmental Stewardship				Resiliency			
	20 yr PVRR ($ MN)	Rate Impact, 20 yr average (real cents/kWh)	Risk Exposure ($)	Average annual CO2 emissions (tons)	Average annual NOx emissions (tons)	Average annual SO2 emissions (tons)	Total CO2 intensity (tons/MWh)	Planning Reserves (lowest amount over 20 yrs)*	Distributed Generation (Max DG as percent of capacity over 20 yr)	Market Reliance for Energy (Max over 20 yrs)	Market Reliance for Capacity (Max MW over 20 yrs)
Base	$ 10,309	3.53	$1,324,989,546	12,883,603	13,181	11,808	0.79	15%	3%	9%	150
Robust Econ	$ 10,550	3.62	$1,303,754,944	12,883,183	13,181	11,808	0.70	27%	15%	9%	200
Recession Econ	$ 11,042	3.78	$1,463,842,563	3,334,067	1,925	593	0.44	3%	3%	58%	0
Streng Enviro	$ 11,990	4.11	$1,126,983,327	3,309,326	1,910	629	0.28	15%	10%	52%	50
Adopt of DG	$ 11,092	3.80	$1,294,337,690	13,219,942	12,910	10,874	0.78	15%	11%	9%	50
Quick Transition	$ 11,988	4.20	$1,311,247,113	5,403,645	4,320	3,243	0.32	15%	35%	57%	0

Hybrid Preferred Resource Portfolio

These metric results spurred discussions about how best to meet the future needs of customers. In the fourth public advisory meeting, IPL shared the Base Case as the preferred resource portfolio. However, subsequent review and stakeholder discussions, as well as recent evidence of declining technology cost trends for solar and energy storage since the beginning of the IRP modeling process in January 2016, prompted further developments leading IPL to believe the ultimate preferred resource portfolio, designed to meet the broad mix of customer and societal needs, will likely be a hybrid of multiple model scenario results.

IPL recognizes the challenge of balancing affordability with environmental risk uncertainty and costs. As stated in the 2014 IRP Director's report at pg. 4, "This preferred Plan might be the base case. The base case should describe the utility's best judgment (with input from stakeholders) as to what the world might look like in 20 to resources or laws/policies affecting customer uses and resources." [5]

Following a review and analysis of metric results and scenario assumptions, as well as industry trends, IPL believes future resource mixes are likely to vary. While the Base Case has the lowest PVRR, it also has the highest collective environmental emission results and least amount of DG penetration. The economic variables used to model environmental and DG costs reflect what is measurable today, for example, potential costs for future National Ambient Air Quality Standards ("NAAQS") ozone regulations and an estimate of Combined Heat and Power ("CHP") costs. The model does not include estimated costs for regulations not yet proposed, public policy changes which may occur in the study period or specific customer benefits of DG adoption such as avoided plant operational losses, grid independence or cyber security advantages.

[5] http://www.in.gov/iurc/files/Directors_Final_Report_IRP_20142015_June_10_at_1035_AM.pdf.

IPL recognizes that dynamic conditions across the electric utility industry have driven rapid change in many areas, and IPL believes additional changes may occur even more rapidly than the scenarios modeled. By comparison, the 2014 IRP analysis indicated less than 50 percent of the wind resources selected in this IRP, no solar additions and did not even include energy storage as a selectable option.

Given that a blend of variables from the base case, strengthened environmental and DG scenarios appear likely to come to fruition (such as public pressure to reduce emissions, higher customer adoption of DG, and some additional environmental costs), IPL contends that, at this point, a hybrid preferred resource portfolio is a more appropriate solution. In addition, technology costs may decrease more quickly than the modeled inputs which would likely drive changes in renewable and distributed generation penetration.

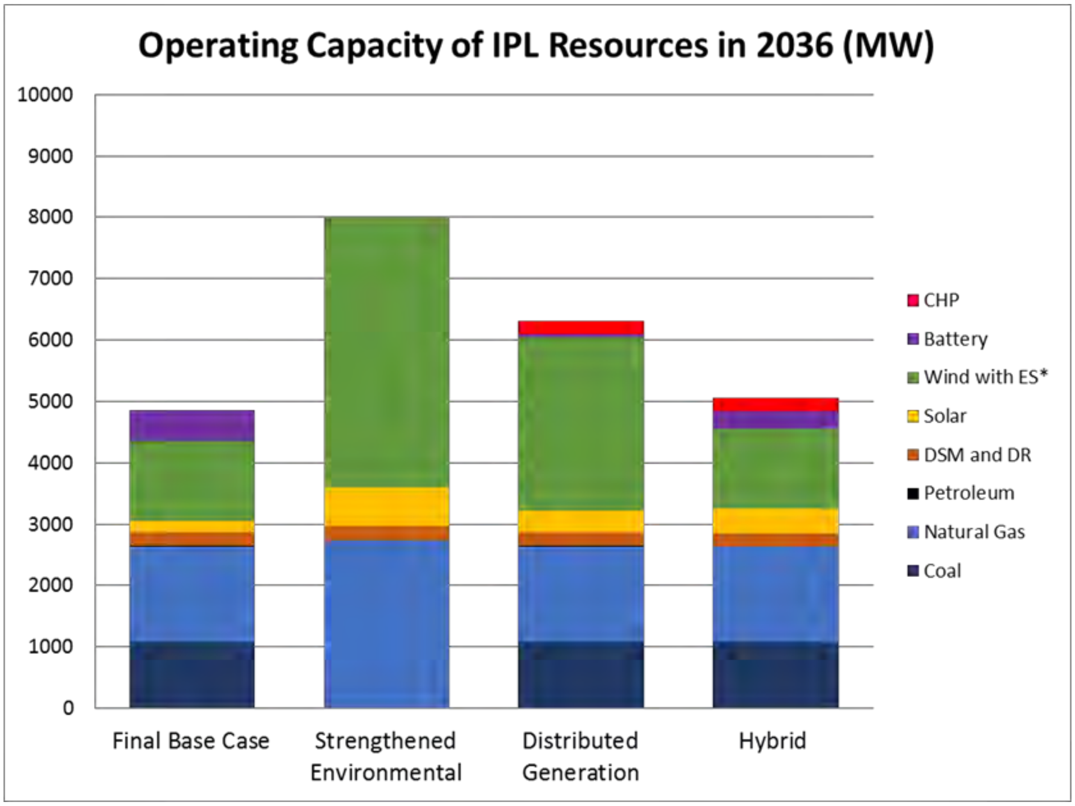
Under this scenario, a hybrid portfolio in 2036 could include two Pete coal units (although these units would not necessarily serve as baseload generation but could be utilized more as a capacity resource), natural gas generation focused on local system reliability, wind to serve load during non-peak periods, and an average of DSM, solar, energy storage levels from the three scenarios as summarized in Figures G and H below.

Figure G - Summary of Resources (cumulative changes 2017-2036)

	Final Base Case	Strengthened Environmental	Distributed Generation	Hybrid
Coal	1078	0	1078	1078
Natural Gas	1565	2732	1565	1565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1300	4400	2830	1300
Battery	500	0	50	283
CHP	0	0	225	225
totals	4858	8006	6319	5060

*Wind resources include small batteries for energy storage ("ES").

Figure H – Candidate Resource Portfolios including Hybrid Option



Although the model selects specific resources in each scenario based upon current market conditions and what IPL knows today, other, as yet unidentified, cost effective resources may exist in the future. IPL will evaluate these resource options in subsequent IRPs to develop the best Preferred Portfolio based on updates to market and fuel price outlooks, future environmental regulations, relative costs of technologies, load forecasts and public policy changes.

Results of subsequent IRPs will likely vary from these IRP results. During this interim time period, IPL does not anticipate significant changes to the resource mix aside from DSM program expenditures and welcomes discussion with stakeholders. IPL invites continued stakeholder dialog and feedback following the filing of this IRP and anticipates scheduling an additional public advisory meeting to facilitate this in early 2017.

Section 1: Introduction

Indianapolis Power & Light Company ("IPL") provides retail electric service to more than 480,000 residential, commercial and industrial customers in Indianapolis and surrounding central Indiana communities. The compact service area measures approximately 528 square miles. The Company, headquartered in Indianapolis, 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 Operating ("MISO").

IPL continually assesses how to best meet customers' needs to accomplish its mission: "Improving lives by providing safe, reliable and affordable energy solutions in the communities we serve." [6]

Every two 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 proposed resource portfolio represents what IPL believes to be the most likely based on factors known at the time of the IRP filing. It does not represent a planning play book, specific commitment or approval request to take any specific actions. The IRP forms a foundation for future regulatory requests based upon a holistic view of IPL's resource needs and portfolio options.

1.1. IRP Objective

The objective of IPL's IRP is to identify a portfolio to provide safe, reliable, sustainable, reasonable least cost energy service to IPL customers from 2017-2036, giving due consideration to potential risks and stakeholder input.

IPL incorporates potential risks quantitatively and qualitatively in IRP scenarios. For example, possible future environmental regulations are described with estimated compliance cost ranges, customer adoption of distributed generation is incorporated, and economic growth opportunities are described. In this IRP, environmental stewardship, financial risk, resiliency, and rate impact metrics were developed to compare the portfolios derived from multiple scenarios in addition to

[6] IPL is a part of The AES Corporation. The AES Corporation (NYSE: AES) is a Fortune 200 global power company. We provide affordable, sustainable energy to 17 countries through a diverse portfolio of distribution businesses as well as thermal and renewable generation facilities. Its workforce of 21,000 people is committed to operational excellence and meeting the world's changing power needs.

the traditional total cost metric of Present Value Revenue Requirement ("PVRR"). In this IRP a more robust probabilistic modeling approach is utilized than in the previous IRP.

1.2. Guiding Principles

IPL documented guiding principles to describe more fully its decision analysis process.

1. IPL will comply with IURC Orders, IAC requirements, North American Electric Reliability Council ("NERC") reliability standards and FERC approved MISO tariffs.
2. Costs estimates for demand and supply-side resources are based upon local economics and recent market experiences.
3. The modeling is indifferent to the resource mix comprising portfolio plans. Since resources are selected compared to forecasted market prices for capacity and energy, resource biases are eliminated from the results.
4. Demand Side Management ("DSM") is modeled as selectable resources in this IRP, representing a change from previous IRPs which reduced load forecasts by the market potential volumes.
5. IPL plans to offer cost-effective DSM programs that are inclusive for customers in all rate classes and appropriate for our market and customer base, modify customer behavior and provide continuity from year to year.

1.3. IRP Assumptions

IPL assumed the following parameters remain constant in the IRP study period of 2017-2036. Should these change in the future, the analyses subsequent to the IRP may vary.

- Regulatory framework remains – This IRP assumes current regulatory frameworks IPL based on the IURC and FERC scopes of influence. Specifically, retail choice does not exist in Indiana and the IURC is responsible for resource adequacy.
- MISO Capacity construct – While IPL is aware of MISO's plans to propose tariff changes to its capacity construct with FERC for the 2018-2019 planning year by the end of 2016, the details are not yet known. 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.
- Natural gas/market price correlations – While IPL recognizes potential influences of resource mix changes on market prices, in this IRP correlations between fuel and market prices do not change significantly from recent historic trends.
- 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 he 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.
- Pending elections – Policy changes may follow pending national and local elections scheduled to occur just days after the IRP is filed. IPL will stay abreast of subsequent implications and adjust planning accordingly.
- 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 IRP includes scenarios and modeling inputs to evaluate impacts of regulations proposed to date with a range of potential outcomes. There will be likely outcomes that vary from what is known today and additional regulations in the study period which will be modeled in future IRPs.

IPL will monitor these realities and incorporate changes in subsequent IRP analysis.

1.4. IRP Process

170 IAC 4-7-4(b) (14)

The most current revision of the proposed rule 170 IAC 4-7, which describes the Indiana IRP process and requirements, was issued on October 4, 2012. While this rule has not yet been finalized, since 2013 IPL and other Indiana electric utilities have voluntarily complied with the proposed requirements including amended documentation requirements, implementing a public advisory process, and including a non-technical summary posted on the utility's website, which comprises Attachment 1.1.

IPL has incorporated changes in its 2016 IRP based on stakeholder feedback from its 2014 IRP including the following:

1. The risk analysis is less constrained with more robust scenarios with a wider range of input assumptions.
2. Probabilistic methods were incorporated through stochastic analysis.
3. A more robust load forecast was developed by Itron, as the primary consultant with IPL staff input, to review all correlation assumptions and fully assess organic energy efficiency.
4. Demand Side Management ("DSM") resources including energy efficiency and demand response measures were modeled as selectable resources in the Capacity Expansion Model instead of as a direct impact on the load forecast as an input. Potential DSM is

still based upon an IPL specific Market Potential Study ("MPS") and cost-benefit test screening.

5. Distributed Generation ("DG") was incorporated through Combined Heat and Power ("CHP"), Community solar (1 MW) and utility scale solar (10 MW) resources as model inputs. In addition, IPL created a scenario to reflect high customer adoption of DG. The DG assets may be owned by customers or IPL.
6. IPL worked to enhance the public advisory stakeholder process by adding an educational meeting jointly hosted by Indiana electric utilities, a fourth IPL-specific meeting, inviting stakeholders to formally present individual points of view, and more interactive exercises throughout this IRP process. IPL also met with large commercial and industrial customers to seek their input in the scenario and metrics development process.

The IRP results indicate potential candidate future resource portfolios in light of uncertainties and risk factors identified to date. Unknowns, such as public policy changes or future environmental regulations are not included, which could affect implementation plans. 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, such as DSM or Certificate of Public Convenience and Necessity ("CPCN") proceedings, before the IURC.

1.5. Stakeholder Engagement

The 2016 meeting series included discussions of the IRP process, modeling assumptions, data inputs, modeling DSM as a selectable resource in 2018 and beyond, scenario development, sensitivity analysis, results and using metrics to compare portfolios. IPL incorporated stakeholder suggestions throughout the process including adding an additional meeting in the schedule, inviting stakeholders to present their points of view, developing metrics to compare scenario results, engaging in small group discussions about environmental concerns, creating a "Quick transition" scenario to retire coal units early, and modifying formatting and data presentation.

This IRP included declining technology costs which prompted significant amounts of renewables to be selected in most portfolios. Discussion related to sustainability goals and societal impacts of environmental emissions prevailed at multiple meetings. IPL engaged in discussions with individual stakeholders and its Advisory Board. Stakeholders acknowledged IPL's efforts to reduce reliance on coal by refueling the Harding Street Station units to natural gas in the timeframe 2015-2016 and challenged IPL to prioritize energy conservation and alternative sources. In addition, stakeholders suggested IPL consider: Climate change holistically as described in Pope Francis' 2015 environmental encyclical, "Laudato Sì"[7], the health impacts on local communities of burning coal, reducing carbon dioxide ("CO_2") emissions in overly-

[7] http://w2.vatican.va/content/francesco/en/encyclicals/documents/papa-francesco_20150524_enciclica-laudato-si.html.

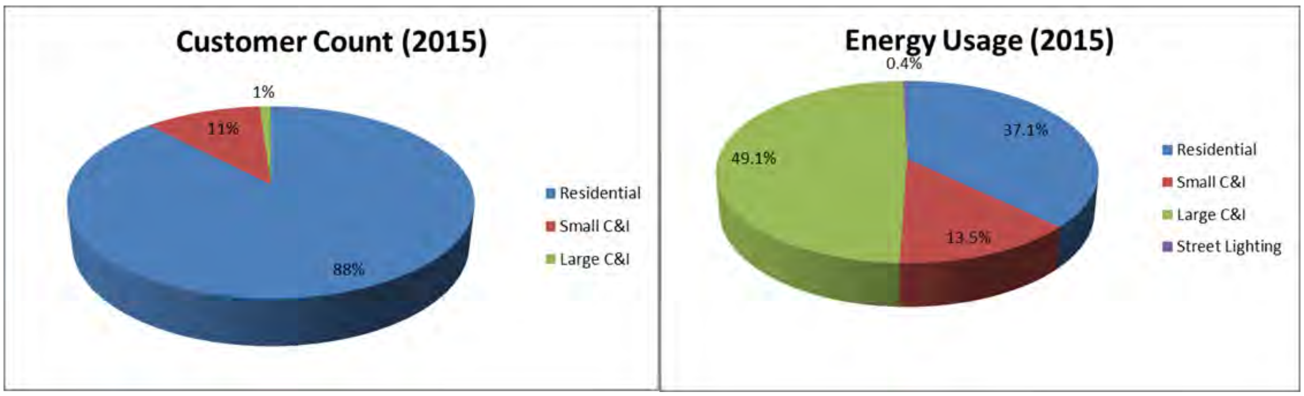
burdened communities, and use of an economic equity analysis to determine costs versus benefits.

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.

1.6. Existing Customers

IPL's customer mix and their respective energy usage split between residential and small and large Commercial and Industrial ("C&I") are shown in Figure 1.1.

Figure 1.1 – IPL Customer Mix



1.7. Existing Resource Portfolio

IPL provides energy service to these customers through its own generating assets, purchase power agreements for solar and wind generation, MISO market purchases, and DSM resources which include energy efficiency, demand response and Conservation Voltage Reduction ("CVR") programs. IPL owns and operates approximately 800 miles of transmission lines, and 11,600 miles of distribution lines to deliver energy as a vertically integrated investor owned utility.

IPL has made great strides to diversify its portfolio by changing the fuel mix from 79% coal, 14% natural gas and 7% oil in 2007 to the projected mix of 44% coal, 45% natural gas, 1% DSM, and 10% wind and solar resources to IPL's portfolio through Purchase Power Agreements ("PPAs") in 2017. In addition, IPL refueled Harding Street units 5 through 7 from coal to natural gas and is constructing the new 671 MW Eagle Valley CCGT and the to ensure compliance with new environmental regulations and otherwise support the need for electricity in IPL's service area.

1.7.1. Thermal Resources

IPL currently owns and operates the following assets:

(1) The Petersburg Generating Station ("Pete") in Petersburg, Indiana includes four coal fired units located in close proximity to its Indiana fuel supply to provide low cost energy to IPL's customers. This plant is being retrofitted with environmental compliance equipment in accordance with regulatory requirements.

(2) The Harding Street Generating Station ("HSS") in Indianapolis, Indiana, includes seven natural gas fired units. Three of these are steam units recently converted from coal and four are combustion turbines.[8] Because HSS is directly connected to the IPL load zone through its 138 kV transmission system, it provides an important capacity resource at the center of IPL's service territory, thus reducing transmission costs and service interruption risk. In addition, the IPL Advancion Energy Storage Array is located at the Harding Street Station. This transmission asset is a 20 MW lithium ion battery providing frequency control services to maintain grid stability.

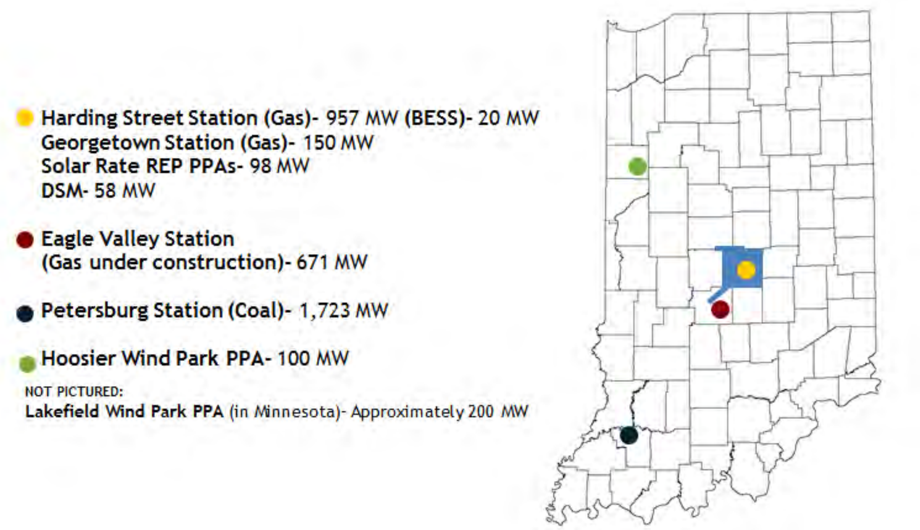
(3) The Georgetown Generating Station in Indianapolis, Indiana, includes two natural gas fired combustion turbines.

(4) The Eagle Valley Generating Station in Martinsville, Indiana, is the location where IPL is constructing a 671 MW Combined Cycle Gas Turbine ("CCGT") which is scheduled to be operational in spring 2017.[9] Coal fired generation was recently retired at this location; however, transmission and substation assets are in the process of being upgraded to accommodate the new generation.

Figure 1.2 shows the relative location and nameplate capacity of IPL's resources.

[8] The coal conversions were approved by the Commission in Cause No. 44339 and 44540.
[9] The CCGT construction was approved by the Commission in Cause No. 44339.

Figure 1.2 – IPL Resources



1.7.2. Renewable Resources

IPL has secured energy output from approximately 300 MW of wind generation under long term Power Purchase Agreements ("PPAs"). Additionally, IPL purchases the energy from approximately 96 MW of solar projects through IPL's Rate Renewable Energy Portfolio ("REP") program. IPL's Rate REP is a pilot renewable energy feed-in tariff offering approved by the IURC that went into effect on March 30, 2010. According to Environment America Research & Policy Center, IPL has the 2nd largest per capita concentration of solar among U.S. cities to date.[10] Under the terms of the PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") associated with the wind and solar PPAs which it currently sells to offset the cost of this energy to customers.[11] However, IPL reserves the right to use RECs to meet any future environmental requirement, such as the EPA's Clean Power Plan ("CPP").

[10] http://www.environmentamerica.org/reports/ame/shining-cities-2016

[11] The null energy of the Wind PPAs is used to supply the load for IPL customers, and in the absence of any Renewable Portfolio Standards (RPS) mandates, IPL is currently selling the associated RECS, but reserves the right to use RECs from the Wind PPAs to meet any future RPS requirement. The Wind PPAs were approved by the IURC and if IPL chooses to monetize the RECs that result from the agreements, IPL shall use the revenues to first offset the cost of the Wind PPAs and next to credit IPL customers through its fuel adjustment clause proceedings. The Green-e Dictionary (http://green-e.org/learn_dictionary.shtml) defines null power as, "Electricity that is stripped of its attributes and undifferentiated. No specific rights to claim fuel source or environmental impacts are allowed for null electricity. Also referred to as commodity or system electricity."

1.7.3. Demand Side Resources

Demand Side Management ("DSM") is comprised of demand response and energy efficiency. IPL currently utilizes approximately 58.1 MW of demand response resources, including 21.8 MW associated with its Conservation Voltage Reduction ("CVR") program, 35.4 MW from its Air Conditioning Load Management ("ACLM") program and 0.9 kW from Standard Contract Rider No. 17 Interruptible load as further described in Section 5.

In addition, IPL sponsors cost-effective energy efficiency programs which have contributed an estimated 144,795 MWh of energy savings benefits and approximately 21.5 MWs of demand savings benefits through the first eight months of 2016.[12] See Figure 1.3 – Current DSM Programs below.

Figure 1.3 – Current DSM Programs

2016 DSM Programs
Residential Lighting
Residential Income Qualified Weatherization
Residential ACLM
Residential Multi Family Direct Install
Residential Home Energy Assessment
Residential School Kit
Residential Online Energy Assessment
Residential Appliance Recycling
Residential Peer Comparison Reports
Business Energy Incentives – Prescriptive
Business Energy Incentives – Custom
Small Business Direct Install
Business ACLM

[12] YTD gross savings from the August, 2016 Scorecard as provided to the IPL OSB. Results are subject to EM&V which will be completed after the program year.

Section 2: Operating and Planning Within MISO

170-IAC 4-7-4(b) (10)(C) 170 IAC 4-7-6(d)(4)

Executive Summary

This section describes the framework in which IPL performs planning activities and operates its resources. MISO interactions, fuel procurement, IPL resource adequacy requirements, transmission planning activities are presented.

2.1. Business framework and daily operations

As a MISO market participant and transmission owner, IPL engages in resource adequacy planning activity aligned with MISO requirements and daily operational practices to serve customers reliably and optimize resources for wholesale opportunities to benefit stakeholders. The IPL Commercial Operations group offers IPL resources including generation, wind PPAs and demand response assets and bids for IPL's retail customer demand within the MISO Day-Ahead ("DA") and Real-Time ("RT") Energy and Operating Reserves Markets. MISO dispatches the IPL resources in response to RT needs. The IRP modeling incorporates the MISO dispatch methodology and recommends resource expansion and production costs through comparison to market purchases. In addition, IPL's Transmission Operations Control Center ("TOCC") interfaces with MISO to operate the transmission system and substation assets. This section describes operational practices and resource adequacy planning within the MISO framework and relates them to the IRP process.

2.1.1. MISO Energy and Operating Reserves Market

IPL participates in the MISO Energy and Operating Reserve Market (the "MISO Market"). IPL offers the electricity produced by its generation facilities and power purchase agreements and buys the electricity necessary to serve its retail customers from the MISO Market on a day-ahead and real-time basis. The day-ahead market is a forward market in which energy and operating reserve are cleared on a simultaneously co-optimized basis for each hour of the next operating day using Security-Constrained Unit Commitment ("SCUC") and Security-Constrained Economic Dispatch ("SCED") models to satisfy the energy demand bids and operating reserve requirements of the day-ahead energy and operating reserve market. The results of the day-ahead energy and operating reserve market clearing include hourly locational marginal price ("LMP") values for energy demand and supply, hourly market clearing price ("MCP") values for operating reserves, hourly energy demand schedules, hourly energy supply schedules for each resource, and hourly operating reserve supply schedules for each qualified resource. The real-time market is a physical market in which energy and operating reserve are cleared on a simultaneously co-optimized basis every five minutes using SCED to satisfy the forecasted energy demand and operating reserve requirements of the real-time market based on actual system operating conditions, as described by MISO's state estimator.[13] The results of the real-time market clearing include five-minute ex-ante LMPs for energy demand and supply, five-minute ex-ante MCP values for operating reserves, and five-minute dispatch targets for each resource for energy and operating reserves. The real-time market dispatch is supported by a Reliability Assessment Commitment ("RAC") process to ensure sufficient capacity is on line to meet real-time operating conditions.

Per the MISO tariff, all IPL generation is offered into the MISO Market. IPL retains all rights and obligation for the generation equipment as well as ownership of the output of the generators. MISO does not take title to the energy produced. IPL continues to be responsible for maintenance of the generation as well as all reliability requirements. IPL submits planned outages for generation maintenance to MISO for approval. MISO studies the impact of the proposed outage on system reliability and then approves the outage schedule. If a reliability issue requires mitigation as a result, MISO will work with IPL to either reschedule the outage or develop another solution. MISO can only deny an outage that causes a transmission reliability issue.

Demand Response for IPL and its customers is governed by its specific tariffs approved by the IURC, not the MISO Tariff.[14] Demand Response resources may be used as Load Modifying Resources "LMRs" to satisfy IPL's resource adequacy requirements with MISO or utilized by IPL to serve a system need per the customer's demand response agreement. IPL's demand response resources are retail assets and as such do not directly participate in the wholesale markets.

2.1.2. Transmission Operations

IPL is responsible for the operation and maintenance of its transmission assets. This includes transmission lines and substations operated at the 345 kV and 138 kV voltage levels. The IPL Transmission Operations Control Center ("TOCC") is staffed around the clock to monitor the status of equipment, system conditions, and to react to events that may occur on the system. The IPL TOCC is in direct communications with the MISO Control Center and they work closely together to assure safe and reliable operation of the transmission system. IPL uses a computerized Energy Control System ("ECS") to operate and monitor the equipment that makes up the transmission system. Equipment status and loadings on equipment are displayed to the IPL TOCC operators in real-time. This data is also shared with the MISO Control Centers in real-time.

As a transmission owner of MISO, IPL along with the other MISO transmission owners have transferred functional control of their transmission assets to MISO. MISO reviews and approves

[13] MISO's state estimator is a system that analyzes the real-time condition of the transmission system. Its data is used by the SCED tool to balance generation and load.
[14] Standard Contract Riders No.13, 14, 15, 17, 18 and 23. Refer to iplpower.com for more information.

scheduled equipment outages. MISO's role in this process to study all requested equipment outages and to make sure that the system can be safely operated under normal and contingency conditions during those outages. MISO and the transmission owner work together to coordinate outages to minimize the risk to the transmission system. IPL and the other MISO transmission owners have the final operating authority over their respective transmission assets. MISO is also the designated NERC Reliability Coordinator (RC) for IPL and the MISO operating footprint. IPL works with MISO as the RC to assure compliance with real-time and day ahead operating requirements.

The IPL transmission system is interconnected at multiple points with its four neighboring utilities, Duke Energy Midwest, American Electric Power, Hoosier Energy Cooperative, and Southern Indiana Gas & Electric (dba Vectren). The transmission control centers of each utility are in direct communications with each other, and work closely together along with MISO to operate the transmission system in Indiana safely and reliably.

2.2. Fuel Procurement

170 IAC 4-7-4(b)(7)

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 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 through the use of the solicitation and negotiation process. 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 targets 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 units. IPL maintains firm pipeline transportation contracts which provide access to liquid supply zones to supply the Harding Street generating units and the EV CCGT. The pipeline contracts include no-notice service and park/loan services which are used for unexpected unit starts & stops to mitigate fuel availability risks. Since the Georgetown 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.

2.2.1. Fuel Price Forecasting and Methodology

170-IAC 4-7-4(b)(2) 170-IAC 4-7-6(a)(3)

The fuel forecasts used in the IPL 2016 IRP modeling are based on ABB's "Midwest Fall 2015 Power Reference Case, Electricity and Fuel Price Outlook," including base case, high and low ranges for natural gas and an expected coal price forecast. The IPL contracts for 2017 to 2019 are used as starting points followed by ABB expected annual escalation factors. Both NG and coal forecasts are lower in the 2014 IRP due to market conditions and are aligned with the EIA data shown in Confidential Attachment 2.2.

For the non-confidential gas and coal forecasts, see Figure 7.4 and Figure 7.8 in Section 7. These fuel forecasts and their related explanations also appear in Attachment 2.1, ABB's "2016 Integrated Resource Plan Modeling Summary", included in this document.

A forecast of average annual fuel costs by IPL generating unit is found in Confidential Attachment 2.2. Individual unit natural gas prices will vary slightly due to differing delivery charges.

2.3. Resource Adequacy

The IRP process focuses on the developing potential resource portfolios needed to meet two different types of customer needs: energy use and peak demand. Annual energy use is measured in MWHs to reflect the accumulation of electricity used over time. Annual peak demand is the instantaneous measure of the highest usage for the year and is measured in MWs. As an example, IPL's 2017 forecasted retail energy use is near 14,000,000 MWhs and peak demand of ~2,900 MWs. The Resource Adequacy analysis serves as the foundation the IRP process to create 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 determined based upon potential future world and related risks described in Section 6, such as commodity and electricity market pricing. The scenarios are described in section 7 of this IRP.

2.3.1. Reserve Margin Criteria

170 IAC 4-7-4 (b)(11)(B)(iv)

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

For this IRP, IPL used an approximate 15% Planning Reserve Margin ("PRM") as its target to calculate its Planning Reserve Margin Requirement ("PRMR") in terms of MW throughout the study period. The 15% PRM is based on Loss of Load Expectation ("LOLE") Studies performed annually by MISO and applied across the footprint.[15] 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 generating units and other resources, and the transmission system configuration. MISO uses load forecast information from Load Serving Entities ("LSEs") coupled with previous calendar year actual system peak to determine coincidence factors for subsequent year planning purposes in the LOLE process. IPL uses previous calendar year actual MISO system peaks and corresponding IPL data to determine coincidence factors for the subsequent year. For 2017, the IPL coincidence factor is 97.74% which is used throughout the IRP study period. IPL multiplies the peak load times 0.9774 to establish the foundation upon which the PRMR is based.

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. In other words, if all utilities in the MISO footprint carried an average of 15% 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.

The Resource Adequacy planning process is based upon forecasted annual peak demand. In other words the forecast is for the maximum use at any one time as opposed to the average or total use over the course of the year. MISO defines a Planning Year in seasonal terms of June 1 through May 31.

---

[15] While the specific percentage varies annually, historic experience indicates values between 14 and 15%. MISO's most recent LOLE study may be found at this link:
https://www.misoenergy.org/Library/Repository/Study/LOLE/2015%20LOLE%20Study%20Report.pdf

2.3.2. Planning for Resources

IPL's coincident peak load forecast is multiplied by 1 plus the PRM to establish the resource portfolio capacity requirement. When considering the portfolio needed to meet the peak demand plus the reserve margin, the maximum allowable capacity credit of each resource is used as an input. The Capacity Expansion Model assumes there are no scheduled outages for any resources. The 15% PRM is used to cover uncertainty related to both unavailability of traditional resources (thermal units and demand response programs) (about 7.5%) and forecast error (about 7.5%). Resource capacity credits are based upon MISO business practices in terms of Installed Capacity ("ICAP") and Unforced Capacity ("UCAP").[16] 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 Equivalent Forced Outage Rate Demand ("xEFORd"). The production from renewable resources at the time of peak load is much lower than the production from traditional thermal units. For example, the wind does not blow as hard on a very hot day, especially compared to a cold winter night, so the wind units do not produce as much power on very hot days. MISO only allows entities to include credit for wind capacity with firm transmission service at this time. IPL did not secure firm transmission service when their wind PPAs were executed; therefore its existing wind resources receive no capacity credit. Each year MISO performs a detailed analysis of wind unit performance during peak load hours and incorporates analysis results in stakeholder guidance. MISO recently published values for specific zones including Zone 6 for Indiana at 9.6% and an expected capacity credit near 10% as wind penetration approaches 25,000 to 30,000 MW in the most recent version of the Resource Adequacy BPM-11.[17] See Section 5 of this IRP for further discussion about modeling wind resources.

Similarly, productions from solar units at time of peak load have proven to be less than traditional thermal unit production. MISO updated its allowable capacity credit to 50% for planning year 2016-2017. IPL has studied the performance of the 96 MW of solar generation under contract in IPL's service territory and has found that the expected production from solar units at time of peak is about 45% of nameplate ratings and applied this value in the IRP. The contracted solar is connected to the IPL distribution system and reduces its load requirements and associated PRMR rather than being offered as resources in the MISO market.

Demand response resource capacity credit is based upon the capability of the resource to contribute to reduced peak demand for a minimum of four hours based on engineering estimates

[16] For more detail see MISO Business Practices Manual (BPM-11) at this link:
https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx
[17] Ibid. See page 117. For more detail, see also "Planning Year 2016-2017 Wind Capacity Credit" December 2015, at misoenergy.org.

or field testing. For example, IPL's Air Conditioning Load Management ("ACLM") program contributes approximately 38 MW and its Conservation Voltage Reduction ("CVR") program contributes approximately 20 MW. These assets are considered Load Modifying Resources ("LMRs") in MISO. IPL includes capacity credit for its existing Battery Energy Storage System ("BESS") and future BESS options in this IRP as well. Please see the Resources section of this IRP for more discussion. Market purchases may be implemented to address capacity shortfalls prior to adding resources. In this IRP, IPL limits market purchases to less than 200 MW as a way to mitigate customers' price and capacity availability risk.

IPL's reserve margins are expected to exceed 15% following the commercial operation date of the CCGT under construction in the spring of 2017. This long capacity position is expected to be reduced as other IPL units are retired. The resource portfolios in this IRP target maintaining approximately 15% reserves throughout the study period. The Results section of this IRP indicates IPL meeting its PRMR throughout the study period.

2.3.3. 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. 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 not plans for resources in the future.

Each November each LSE provides MISO with a peak demand forecast for the next twelve months. MISO adds a reserve margin, based on its most recent LOLE Study, and adds MWs to cover expected transmission losses to produce each LSE's Planning Reserve Margin Requirement (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 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.

The volume of capacity resources in each LSE's MISO capacity accounts are a function of test results and availability. Each year, prior to the summer, resource owners in MISO conduct GVTC tests for each resource and report the test results to MISO. MISO logs these GVTC test results in their capacity accounting system as Installed Capacity MWs (ICAP MWs).

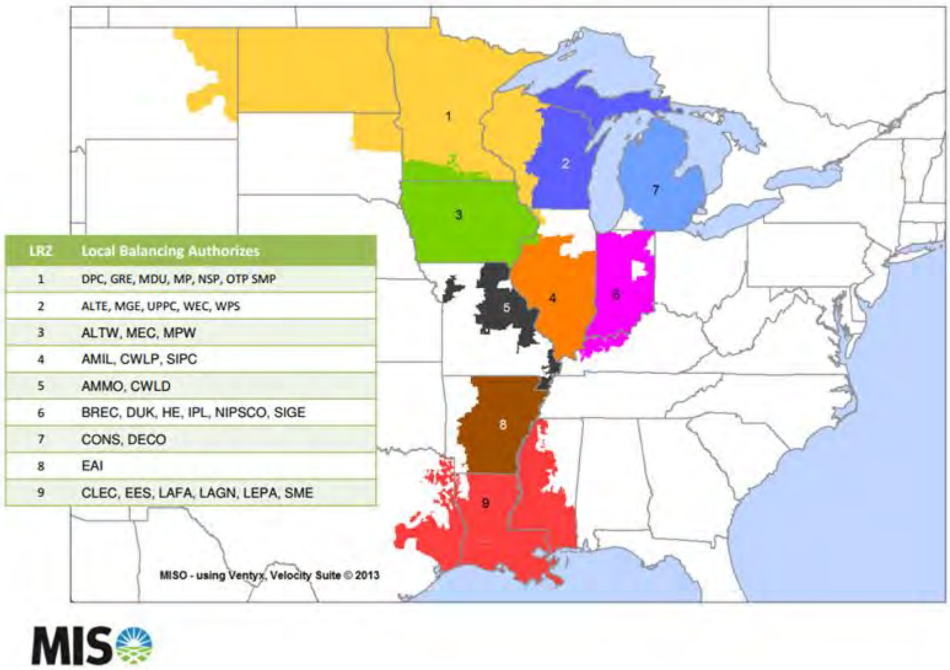
Because units with favorable availability are more likely to contribute more MWs during peak load periods than units with historically less favorable availability the ICAP MWs are adjusted based on their 3 year xEFORd ratings. ICAP MWs are multiplied by one minus the 3 year historic xEFORd rating to produce an Unforced Capacity MW rating (UCAP). MISO logs each unit's UCAP MWs in their capacity accounting system. A similar system is used to register UCAP MWs for demand response resources.

The volume of capacity resources in each LSE's MISO capacity accounts are also a function of bilateral capacity purchases and sales prior to the auction. 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 or 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. In other words, sometimes it is more efficient for an LSE to purchase capacity credits from a resource owner that has extra resources, than it would be for that LSE to build a new unit or implement a new Demand Response program. Sometimes it is more economic for an LSE to build a unit that may provide more MWs than is necessary to exactly meet its Targeted Reserve Margin, and then sell its extra capacity credits to an LSE that is short of meeting its PRMR without capacity credit purchases.

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 Loss of Load study.

MISO established zones for it auction framework as shown in Figure 2.1 below.

Figure 2.1 – MISO Zones



If all LSE's 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 in the process of preparing to file proposals with FERC for changes to its capacity construct to include a forward capacity construct for retail choice states and a two season construct for the entire footprint. IPL did not model these potential changes in the 2016 IRP, because the details of the proposals have not yet been finalized. The current Planning Resource Auction ("PRA") occurs each April for the Planning Year ("PY") that runs from the following June 1 to May 31.

The proposed changes are complex and have not been fully vetted in the MISO stakeholder process. As currently anticipated by IPL, the proposed changes may not provide any economic or resource adequacy benefits to Illinois or Michigan, and may increase costs to customers in Indiana and the rest of MISO.

2.3.4. Transmission Planning in MISO

IPL provides electric power to the City of Indianapolis and portions of the surrounding counties as a member of MISO. 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 American Electric Power ("AEP"), which ties to the PJM footprint and Duke Energy Midwest ("DEM"), and 138 kV interconnections with DEM, Hoosier Energy, and Vectren within the MISO footprint. In the Indianapolis area, IPL has 345 kV interconnections with AEP and DEM and 138kV interconnections with DEM and Hoosier Energy. 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 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.

2.4. Transmission Planning Criteria

170 IAC 4-7-4(b)(10)(C)

IPL transmission plans are 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, ANSI/IEEE standards,[18] 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.
- Provide adequate dynamic reactive capacity to support transmission voltages under contingency outage or other abnormal operating conditions.

[18] American National Standards Institute (ANSI)
Institute of Electrical and Electronics Engineers (IEEE)

- 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 North American Electric Reliability Council ("NERC") standards in which the use of Blackstart Resources are 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 ("RF"). 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/Library/Repository/Study/TO%20Planning%20Criteria/IPL%20TO%20Planning%20Criteria.pdf.
- There is no measure of system wide reliability that covers the reliability of the entire system that includes transmission and generation.

2.4.1. IPL Blackstart Capability

In the event of a shutdown to all or part of the Bulk Electric System, Blackstart is the process of restoring the electric grid to operation. Normally, the electric power used within a generating plant is provided from the plant's own generators, or if the plant is shut down, station power is drawn from the grid. However, during a wide-area outage such as a black out, grid power is not available. In this case, power is required from another source to bring generators back on line.

NERC standards require IPL to secure Blackstart capability through its own resources or agreement with neighboring utilities. IPL prefers to control this service internally as a risk mitigation strategy and owns Blackstart resources at its Harding Street Station facility. Historically, Blackstart units have included small diesel generators and small simple cycle gas generators that can be used to start larger generators. Blackstart power cannot be provided over designated tie lines serving more than one generator or positioned nearby a larger generator that can then be used to start another in a controlled series.

In a large grid such as MISO, Blackstart restoration events will often involve starting multiple "islands" of generation (each supplying local load areas), and then synchronizing and reconnecting these islands to form a complete grid. The power stations involved have to be able to accept large step changes in load as the grid is reconnected.

There is no common set of procedures for all networks. Different systems require different approaches considering how the system went down, the type of generation, cost, system complexity, interconnectivity with other systems, and response time requirements. In MISO, each Local Balancing Authority ("LBA") has a Blackstart Plan that is reviewed and approved by MISO as the NERC Reliability Coordinator. The restoration plans are coordinated and shared with each of the neighboring utilities. Should a system restoration event requiring a Blackstart occur, MISO is the coordinator to assure appropriate sequencing and safety. IPL is an LBA and has received MISO's approval of its Blackstart Plan.

Blackstart needs are one of the considerations analyzed before retiring existing generation. As stated above, while there is no NERC requirement for an individual entity to hold Blackstart units, MISO is responsible to ensure Blackstart capability per NERC standard EOP-001. IPL believes it is a critical component of providing reliable service to its customers and registers its Blackstart resources with NERC. Any changes to the Blackstart plans must be approved by MISO. IPL is considering the use of batteries for Blackstart prior to retiring the HSS Blackstart units.

2.4.2. Assessment Summary

170 IAC 4-7-6(a)(5)

As a Transmission Owner ("TO") member of MISO, IPL actively participates in the MISO annual coordinated seasonal assessments ("CSA") of the transmission system performance for the upcoming spring, summer, fall, and winter peaks. The CSAs are performed to provide guidance to system operators as to possible acute system conditions that would warrant close observation to ensure system reliability. Planned and unplanned outages are modeled to determine system impacts.

As a TO member of MISO, IPL actively participates in the Midwest Transmission Expansion Plan ("MTEP") process. MISO annually performs rigorous studies to facilitate a reliable and economic transmission planning process annually. The MTEP study process includes identification of transmission issues, optional proposals and selects efficient solutions. Costs and benefits are assessed to assure that costs allocated are commensurate with benefits received. Cost allocation is further discussed below. 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.

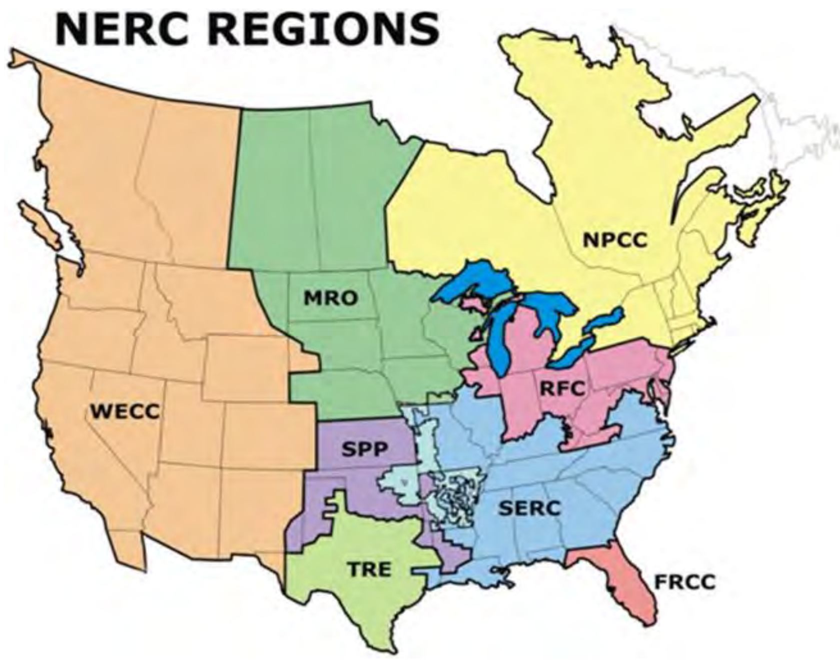
System congestion is analyzed through the MISO MTEP process. As part of the process, a Top Congested Flowgate Analysis is performed by MISO to identify near-term system congestion. A Congestion Relief Analysis is also performed to explore longer-term economic opportunities. The Market Efficiency Planning Study process, also performed as part of the MTEP, builds on the study methodologies of both analyses and further improves them by appropriately linking the two processes to identify both transmission issues and economic opportunities. The study results are discussed among MISO members throughout the process, as well as reported in the MTEP study report provided by MISO.

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

https://www.misoenergy.org/Planning/SeasonalAssessments/Pages/SeasonalAssessments.aspx
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

ReliabilityFirst ("RF") also performs annual assessments of transmission system performance for the upcoming summer and winter peak seasons, for near-term and long-term shoulder peak load conditions, and from time to time will perform near long-term transmission assessments for off-peak load 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. Figure 2.2 below is a map of the NERC Regions of the United States. (Note: RF was previously named ReliabilityFirst Corporation ("RFC") which is still noted on this map.)

Figure 2.2 – NERC Regions Map



RF develops a series of power flow cases and performance assessments with expected power transfers and long term power purchases and sales. RF also performs First Contingency Incremental Transfer Capability ("FCITC") analysis. This analysis shows adequate power transfer capability to support load growth and long term power purchases and sales. FCITC cannot be used as an absolute indicator of the capability of a power system; FCITC is only determined for specific system conditions represented in the study case. Any changes to study case specific conditions, such as: variations in generation dispatch, system configuration, load, or other transfers not modeled in the study case, can significantly affect the level of determined transfer capability.

These assessments may be found on the RF website at URL:
https://www.rfirst.org/reliability/Pages/default.aspx

The IPL assessment of transmission system performance is performed annually in conjunction with the RF and MISO assessments. The IPL assessment follows the NERC TPL standards to assess transmission performance in peak near-term and long-term conditions and other sensitivity conditions as described below.

- 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.

2.5. Key Results

170 IAC 4-7-4(b)(10)(A) 170 IAC 4-7-4(b)(10)(B) 170 IAC 4-7-4(b)(10)(D)

- IPL operates its transmission system efficiently with strong ties to interconnecting companies.

- IPL does not jointly own or operate any transmission facilities.

- The transmission facility outages with the greatest impact on IPL facility loadings are those internal to IPL.

- The transmission facility outages with the greatest impact on IPL area voltages are those in neighboring utilities. In particular, these are the AEP Rockport-Jefferson 765kV line and the Duke Cayuga-Nucor 345kV line. IPL will continue to review the impact on voltage resulting from these facility outages, and will monitor available reactive resources to help mitigate this impact and for general voltage support.

- The import capability into the IPL 138 kV system for different NERC contingency categories is summarized in Figure 2.4 – Import Capability Summary.

The 138 kV transmission system is supplied by external generation and internal. External generation is supplied by seven 345 kV transmission lines connected to a 345 kV loop around the load pocket and one 138 kV line. 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.

Individually and combined, these transmission performance assessments demonstrate that IPL meets the system performance requirements of NERC TPL-001-4 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.

- NERC TPL-001-4:
    - System performance under normal (no contingency) conditions. (Category P0)
    - System performance of the Bulk Electric System for the loss of the one of the following elements: Generator, transmission circuit, transformer, shunt, or single pole of a DC line. (Category P1)
    - 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 P2)
    - System performance of the Bulk Electric System for loss of multiple elements: Generator and a generator, transmission circuit, transformer, shut, or single pole of a DC line. (Category P3)
    - System performance 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 P4)
    - System performance 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 P5)
    - System performance of the Bulk Electric System for loss of multiple elements: Transmission circuit, transformer, shunt, or single pole of a DC line. (Category P6)
    - System performance of the Bulk Electric System for loss of multiple elements for circuits on common structure or loss of a bipolar DC line. (Category P7)

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 15 studies which contain the most recent power flow study available to IPL including interconnections. In MTEP 15, MISO conducted regional studies using models for 2017 Light Load, 2017 Summer Peak, 2020 Light Load, 2020 Summer Peak, 2020 Shoulder Load, 2020 Winter Peak and 2025 Summer Peak. The MTEP 15 dynamic simulations identified no system stability needs and meet the NERC standards.

2.6. Transmission Short Term Action Plan

170 IAC 4-7-6(d)(1)

For the forecast period of 2017-2019, IPL currently plans to add or modify the following transmission facilities. The estimated cost for all facilities is in Attachment 2.3, Transmission and Distribution Estimated Costs.

Upgrade the Guion to Westlane Line - 2017

- Upgrade of the IPL Guion to Westlane 138 kV line to at least 298 MVA. The upgrade is needed to increase the line capacity during contingency loading conditions and meet NERC reliability standards.

Replace the Stout 345-138 kV Auto Transformer - 2017

- The replacement is needed due to transformer health.

Upgrade the Rockville Substation - 2018

- The upgrade of the Rockville substation includes two new 345 kV breakers and one 138 kV breaker. The project increases import capability into the IPL 138 kV transmission system, improves reliability and allows for better operational flexibility.

Upgrade the Stout CT to Southwest Line - 2018

- Upgrade of the IPL Stout CT to Southwest 138 kV line to at least 345 MVA. The upgrade is needed to increase the line during contingency loading conditions and meet NERC reliability standards.

Upgrade the Stout CT to Stout North Line - 2018

- The upgrade of the IPL Stout CT to Stout North 138 kV line to at least 345 MVA. The upgrade is needed to increase the line during contingency loading conditions to meet NERC reliability standards.

Upgrade the Georgetown to Westlane Line - 2018

- The upgrade of the IPL Georgetown to Westlane 138 kV line to at least 333 MVA. The upgrade is needed to increase the line during contingency loading conditions to meet NERC reliability standards.

Upgrade the Guion Substation - 2018

- The upgrade of the Guion Substation includes two new 345 kV breakers. The project increases import capability into the IPL 138 kV transmission system, improves reliability and allows for better operational flexibility.

Replace Parker Substation breakers - 2018

- The Parker Substation project includes replacement of three 138 kV breakers. The replacement is needed to increase interrupting capability and meet NERC reliability standards.

Replace River Road Substation breaker - 2018

- The River Road Substation project includes replacement of one 138 kV breaker. The replacement is needed to increase interrupting capability and meet NERC reliability standards.

Rehab Center Substation - 2018

- The Center Substation project includes new 138 kV breakers, disconnects and relay equipment.

2.7. Transmission Expansion Cost Sharing

170 IAC 4-7-6(d)(2) 170 IAC 4-7-6(d)(3)

The methodology for the socialization of transmission expansion costs has been one of the significant drivers of uncertainty in the past several years. MISO and the transmission owners began development of a methodology for the sharing of costs for reliability projects in 1994, and shortly thereafter launched into development of a methodology for the sharing of costs of projects deemed to be "economic." Economic projects are those projects that are not needed to meet NERC criteria for reliability, but for which there may be an economic benefit. In 2010, MISO filed and FERC accepted a cost sharing methodology for transmission projects built to meet the renewable mandates of states within the footprint. These projects are called Multi-Value Projects ("MVP"). The costs of these projects are socialized across the footprint regardless of the load need. Included in the MVP filing was a renaming of "Economic" projects; they are now called Market Efficiency Projects ("MEP").

2.7.1 FERC Order 1000

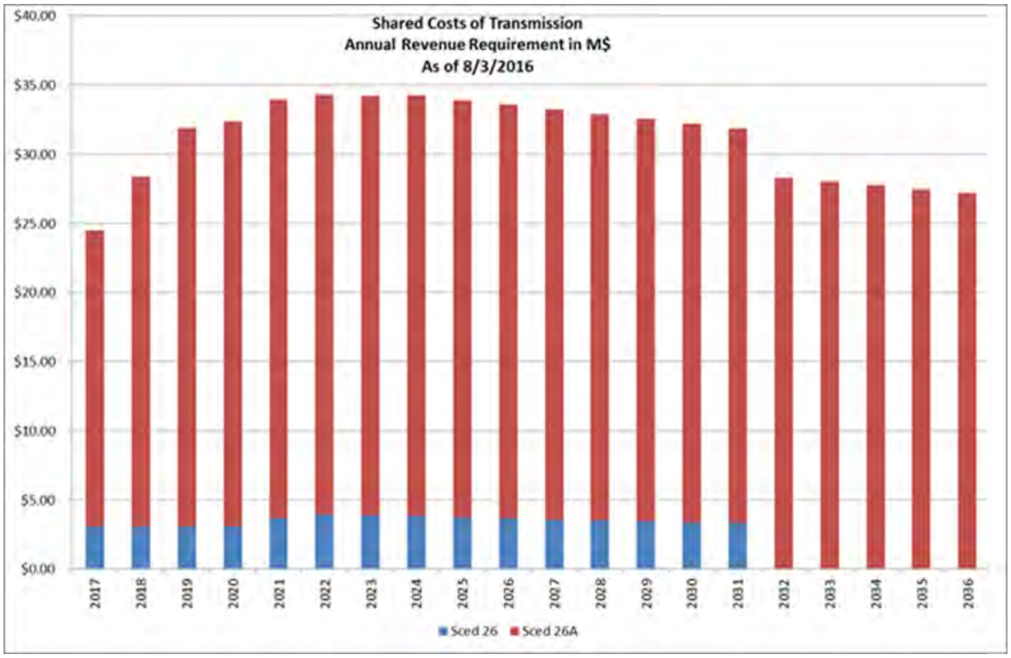
170 IAC 4-7-6(a)(5) 170 IAC 4-7-6(d)(3)

Both at the state level and in the MISO tariff, the right of first refusal for transmission projects needed for baseline reliability projects have been preserved. Effective with the 2015 planning cycle, due to the implementation of FERC Order 1000, the right to develop Market Efficiency and Multi-Value transmission projects has opened up to third party transmission developers. This event necessitates a process to qualify transmission developers and to select a developer to build the project. This will add three or more years to the process of placing transmission enhancements in service. FERC demands that incumbent utilities who wish to bid on projects not directly connected to their own transmission systems compete with third parties for the right to build, and therefore must submit a developer application to MISO for evaluation. If the project is directly connected to the incumbent's transmission system and is a baseline reliability project, no application is required; however the incumbent still must compete for the right to build MEPs or MVPs. To preserve its right to develop transmission projects of all types and locations, IPL completed the application process dictated by the MISO tariff and is a Qualified Transmission Developer. IPL submitted its first application on August 4, 2014, and resubmits annually to preserve its status as a Qualified Transmission Developer. Due to the integration of Entergy into the MISO system at the end of 2013, changes to the 100kV "bright line" for cost sharing of MEPs and MVPs are proposed for implementation before the next MTEP process begins. As a result, IPL will be required to pay a greater portion of the shared costs of transmission in the now much larger footprint.

Figure 2.3 below indicates IPL's portion of the MISO Shared Costs of Transmission Forecast as of August 2016.[19] The blue bar represents the cost from Schedule 26 projects which are designed to improve "market efficiency." The red bar represents the cost from Schedule 26A projects which are primarily designed to deliver wind requirements of other states in the MISO footprint.

[19] For the data sources of this graph see https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=259 and select the most recent Attachment O.

Figure 2.3 – IPL's Estimated Portion of MISO Transmission Expansion Costs



As part of FERC Order 1000, MISO is required to coordinate transmission plans with neighboring RTOs and Transmission Providers. Since the Order was issued, the RTOs, neighboring Transmission Providers and their Stakeholders have been developing potential projects and cost sharing mechanisms for Transmission Projects that cross between RTOs. The first of such projects went out for bid in early 2016. The developer that is chosen for this project will be announced in December of 2016.

2.7.1. 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.

Applicable resources connected to the distribution system such as solar facilities reduce the requirements of generation serving the IPL load pocket through the transmission grid. If future resource plans remove generation that is interconnected directly to the 138 kV transmission system and all other parameters remain in a steady state, 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 2,004 to 2,402 MW. The limit based on a double element failure ranges from 1,200-1,800 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			
2016	Guion North 345-138 kV XFMR	2,203	Guion South 345-138 kV XFMR
2018		2,402	
Breaker Failure			
2016	Guion North 345-138 kV XFMR	2,004	Guion South 345-138 kV XFMR & Guion to Rockville 345 kV line
2018		2,203	
Double Element			
2016	Guion North 345-138 kV XFMR	1,218	Guion South 345-138 kV XFMR & Whitestown to Hortonville 345 kV line
2018	Hanna East 345-138 kV XFMR	1,806	Stout to Hanna 345 kV line & Hanna to Sunnyside 345 kV line
* Import capability can vary based on external factors			

For this IRP, IPL used a 2,000 MW limit as the criterion to fine tune the base case resource portfolio. Further transmission analysis is expected for multiple scenarios prior to the next IRP.

Section 3: Distribution & Smart Grid

Executive Summary

Distribution system operations and benefits are described as part of this IRP. Specifically, IPL's Smart Grid assets provide demand side resource opportunities and enable distributed generation as described below.

3.1. Distribution System Planning

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 on the basis of known customer additions, distributed generation 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 scheduled when projected area loads cannot be served from existing substations or if existing substation facilities reach their design limits. Circuit construction is scheduled to utilize newly installed substation capacity, to provide relief to circuits projected to exceed design capacity or to improve reliability or operational performance. Short-term operating remedies are used to delay construction only with the agreement of the Distribution Operations Department.

A 4.16 kV to 13.2 kV conversion plan 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. The conversion schedule is developed to complete the proposed plan with minimum capital expenditures and to maintain system continuity.

Industrial substation expansion is scheduled to provide capacity for known industrial load additions and to relieve 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.

IPL maintains a capacitor program to provide sufficient reactive power (known as Volt Amperes Reactive or "VARs") to maintain adequate distribution voltage under all probable operating conditions and to economically reduce facility loading. Through its Smart Grid Initiative, funded in part through an U.S. Department of Energy ("DOE") Smart Grid Investment Grant ("SGIG"), IPL upgraded its capacitor control system to improve the operators' remote monitoring and control capability with two-way verifications from each location. Please see the following section for more details about smart grid efforts.

3.2. Smart Grid Technologies and Opportunities

IPL deployed advanced technologies beginning in 2010 as part of its DOE-funded Smart Energy Project to accomplish the following functions:

- Strategically automate distribution equipment to improve reliability.
- Build upon equipment and systems which are in place to minimize undepreciated assets and minimize costs.
- Utilize Advanced Metering Infrastructure ("AMI") for approximately 10,000 customers to accomplish 100% automated meter reading, and integrate interactive system outage and voltage information.
- Upgrade communications infrastructure to support long-term requirements.

IPL's distribution system includes the following features:

- Supervisory Control and Data Acquisition ("SCADA") functionality enables remote device monitoring and control for 90% of the distribution customers.
- Automated controls are used in 100% of the 1,300 switched capacitor banks.
- Nearly 225 automated reclosers with microprocessor-based programmable remote controls and 50 automatic distribution line switches are in use to reduce customer exposure to outages.
- SCADA functionality was extended to the Central Business District ("CBD") network in downtown Indianapolis through network protector relays and fault indicators on the network.
- A Distribution SCADA ("dSCADA") software system has been implemented on the radial distribution network throughout the service territory to link new devices.
- Upgraded microprocessor-based distribution feeder relays have been installed for approximately 300 circuits to enable remote configuration and estimated fault location data to operators.
- An automated Conservation Voltage Reduction ("CVR") program has been implemented through the deployment of smart microprocessor-based Transformer Load-Tap Changer

("LTC") controllers and upgrading capacitor controls from one-way to two-way functionality as described below.

The use of the Smart Grid technologies has become a part of the normal daily operations at IPL. IPL's operations personnel utilize Smart Grid technologies in the following ways:

- Distribution Operations leverages fault locations from relays to dispatch trouble crews more effectively and reduce service restoration times.
- Asset Management uses the Optimized CVR on distribution circuits to maximize peak load reductions and minimize substation transformers load tap changer operations.
- Asset Management uses CBD SCADA operations as a catalyst for network protector maintenance frequency.
- CBD Network Operations uses the CBD fault indicators for faster cable fault locating, reducing repair time and facilitating the return of the system back to a normal status much quicker.
- Power Quality Technicians refer to capacitor control and AMI meter voltage information to help assess power quality issues.
- The majority of new substation, transmission and distribution equipment is Smart Grid enabled.

IPL is using a common communication system for the AMI and DA systems to form a robust foundation for additional deployment of "advanced technology" components.

3.2.1. Advanced Metering Systems

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 as designed to acquire 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. Approximately 6,000 single phase AMR meters were replaced with AMI meters as well, to pilot this technology. There have continued to be additional single phase meter replacements since that time. In 2016, all advanced metering was transitioned to a single system. IPL has 34,000 AMI meters with remote connect/disconnect capability located in areas of high customer turnover. In total, there are approximately 40,000 AMI meters currently serving IPL customers. 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).

3.2.2. Smart Grid Benefits

Smart Grid, or 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 operations capability of feeder relays, reclosers and verification of capacitor functionality.

AMI benefits include 15-minute interval usage data, avoided truck rolls for service disconnection and 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.

As described in the Smart Grid 2015 Annual Report filed in Cause No. 43623 in February 2016, IPL experienced over 91,000 avoided truck rolls associated with its Smart Grid assets last year. Please see Attachment 3.1 for more details.

A CVR program enabled by Smart Grid assets allows IPL to reduce system peak demand during peak hours of the year. This voltage reduction through interactive operations monitoring on the 13.2 kV distribution system is planned through multiple circuit devices, two-way communications, and a distribution SCADA control software system. Essentially, IPL can operate the system at slightly lower voltages at the substation bus, but still within industry standard limits defined by ANSI. Load tap changers at substations are controlled by Transmission Operations Control Center personnel to reduce voltages on the 13 kV circuits. Real time voltage readings from two-way communicating capacitor controls and AMI meters are collected to verify compliance with the service requirement of 120 v +/- 5% at the meter base. Partial system tests in 2012 through 2015 indicated positive results with the largest test reducing demand by 7 MW per hour based on an average voltage reduction at each substation bus of 1%. IPL may also avoid purchasing power from the market during those times when demand and prices are highest. IPL successfully achieved the ability to modify the MISO business practices to "count" this capacity as a Load Modifying Resource ("LMR") within the context of the MISO market. IPL estimates achieving up to 20MW of peak load reductions through CVR if voltage is reduced by 2.5% at each substation bus. IPL registers 20 MWs for CVR with MISO annually and included this resource, including the associated avoided 7.5 % Planning Reserve Margin, which increases the CVR capacity benefit to 22 MW in this IRP.

IPL's Smart Grid communication network has enabled distributed generation.

3.2.3. Cyber Security and Interoperability Standards

IPL recognizes interoperability and strong cyber security practices are essential to advanced technology deployment. IPL employs specific cyber security business practices and procedures and is working closely with vendors to assure that current and proposed Smart Grid standards and procedures are employed. IPL has a dedicated staff, including a Certified Information Systems Security Professional ("CISSP") to ensure that cyber security is maintained at each stage of system deployment. IPL tests and updates its security plan to mitigate any foreseen threats to key infrastructure components. IPL monitors and protects its network on a 24/7 basis with intrusion prevention systems to identify any malicious activity targeting or originating from corporate assets, including outside attempts to gain access to the system.

IPL vendors who may affect cyber security risk undergo a screening process which includes a thorough questionnaire and interview process to identify risks and mitigation plans.

IPL also seeks vendors who can commit to physical equipment security and utilize open protocols and standards to support interoperable system components wherever possible. While some customization is required to interface to legacy systems, IPL prefers vendors that utilize standards-based security features of application servers versus proprietary methods to quickly adapt through configuration to new requirements as they unfold and become adopted standards.

The Smart Grid system has been designed with security best practices incorporated from an architectural standpoint to facilitate security from the beginning of a project. Implementation of security best practices at each system junction point ensures authenticity and reliability of data transport.

IPL believes these are potential ways to minimize centralized cyber security risks through DG.

3.2.4. Distribution Generation Enabled

170 IAC 4-7-4(b)(5)

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 distributed generation ("DG") since 2012 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 3.3 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 kV, and establish the engineering criteria for a maximum of 10 MW connected per substation transformer. IPL is not aware of any occurrence of backfeed on its transmission system including during non-peak hours.

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 which 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 allowed IPL to interface to DG resources and gather and monitor output in real time.

As further described in Section 5, IPL has 95 net metered customers. They are smaller facilities than Rate REP and do not provide real time data to IPL dispatchers.

3.2.5. Electric Vehicle

IPL initiated an electric vehicle ("EV") pilot program as part of its Smart Energy Project, which included the deployment of one hundred sixty two (162) chargers and special EV rates for home, business and public use. Minimal impacts to the distribution grid have been identified by the monitoring that is enabled by separate meters for each charger location. Transformer loading analysis has been completed for each site with no transformer replacements necessary.

IPL's 2013 Electric Vehicle Program Report which contains information about this pilot was filed with the IURC.[20] In addition, since 2013 IPL is coordinating the implementation of the first EV car sharing program in the U.S. known as BlueIndy.

IPL continues to support the growth of EVs in its service area through these programs. 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 facilitate the development of potential future demand response programs to release battery energy to the grid during peak periods.

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 in this IRP.

[20] https://www.iplpower.com/Business/Programs_and_Services/Electric_Vehicle_Charging_and_Rates/

3.2.6. Future Smart Grid Expectations

IPL will continue to leverage smart grid investments to provide capacity value, realize operational efficiencies, increase the understanding of equipment performance, and to develop asset lifecycle plans. Detailed analysis of field device data being collected through the two-way communications systems will enhance these capabilities.

- IPL is incrementally investing in smart grid assets. Standard equipment specifications include smart grid enabled communication device, such as relays, reclosers, load tap changers, and capacitor controls.
- IPL has deployed a 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 1 meter increments. There are plans to install an additional 30,000 feet of fiber optic cable for this program starting in late 2016.
- IPL is in process of upgrading telecommunication equipment to new platforms to increase bandwidth and efficiencies for smart grid assets.
- As part of the IPL's ACLM program, new air conditioning control devices are compatible with the AMI communications network provided by the same vendor, Landis + Gyr.

Transmission and distribution assets will likely play a larger role in future resource planning as distributed resources including DG, DR, and smart grid initiatives increase to provide capacity and energy benefits. IPL plans to optimize operations of these interrelated efforts. IPL recognizes the potential for smart grid networks to enable customers to interact in new ways including customer energy management systems and distributed generation opportunities. IPL anticipates continuing to investigate ways to enable additional smart grid benefits.

Section 4: Load Research, Forecast and Load Forecasting Methodology

170 IAC 4-7-4(b)(2) 170 IAC 4-7-4 (b)(11)(B)(i) 170 IAC 4-7-5(a)(4) 170 IAC 4-7-5(b)

Executive Summary

IPL forecasts flat load growth primarily due to energy efficiency. Average use per customer continues to decrease and GDP is no longer correlated with load. This section describes the forecast as well as the forecasting research and methodology applied in this IRP.

4.1. Load Research

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

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 is not a direct input to the forecast at this time. See Attachment 4.1 for Load Research description and Attachment 4.2 for 2015 Hourly Load Shapes. IPL anticipates using AMI more fully for load research and load forecasting as an improvement in the next IRP.

4.2. Forecasting Overview

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

In this IRP, IPL chose to review the forecast holistically to reassess the landscape given the unique challenges in capturing the impacts of organic efficiency on customer load. IPL hired Itron to create the energy and peak load forecasts for the IRP and its budget. IPL uses Itron's MetrixND regression modeling software for internal forecasting and weather models and has had an excellent working relationship with Itron for over 10 years. The 10 Year Energy and Peak Forecast is available electronically as Attachment 4.6. The 20 Year Base, High and Low Forecast is available electronically as Attachment 4.7. In prior years, forecasting has been performed by IPL staff with the Itron review and support.

The input data for energy by sector may be found in Attachment 4.9, 4.10 and 4.11.

This section will provide an overview of the IRP forecast results, discuss the forecasting methodology, note the key forecasting challenges and review the key forecast drivers by sector. Itron's detailed report comprises Attachment 4.3.

In 2015, residential sales represented 37% of sales, Small Commercial & Industrial 13%, Large Commercial & Industrial 49%, and Street Lighting 1% of sales. Figure 4.1 shows 2015 class-level sales distribution.

Figure 4.1 – IPL 2015 Sales Distribution by Customer Sector

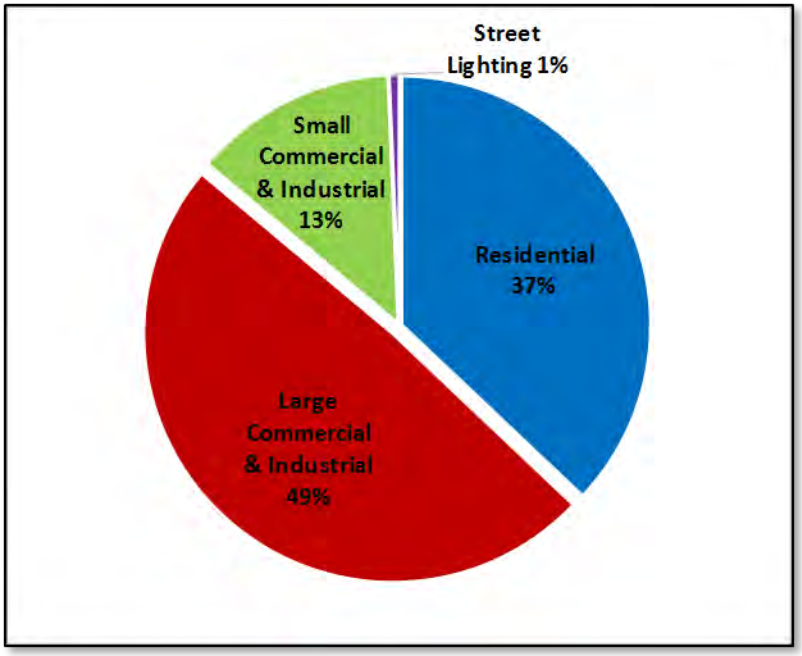
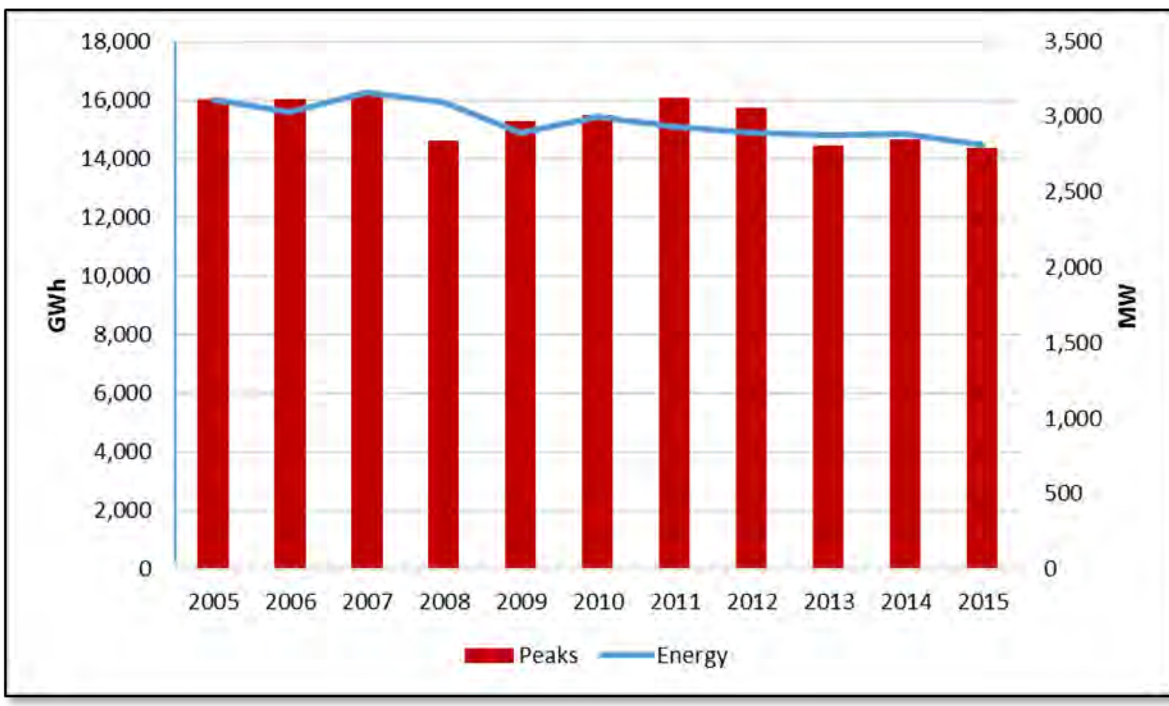


Figure 4.2 – IPL Historic System Energy Requirements 2005 – 2015

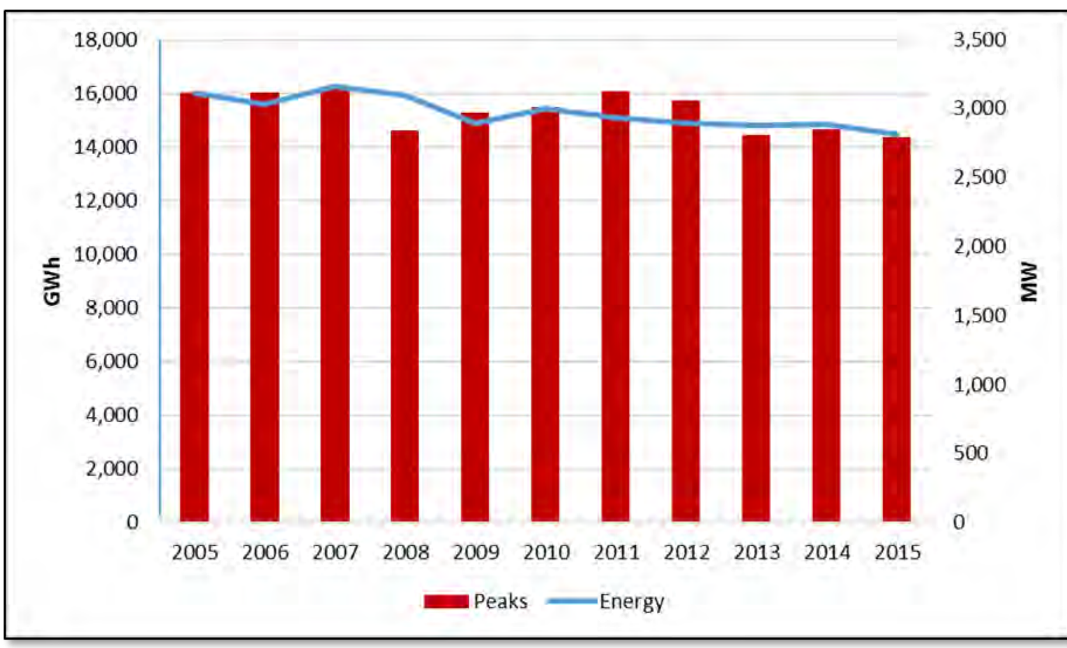


According to Itron's 2016 Long-Term electric Energy and Demand Forecast Report for IPL, "Since 2005, total system energy requirements have been trending down. System energy requirements in 2015 were 14,471 GWh compared with system energy requirements of 16,006 GWh in 2005. Energy requirements on average have declined 1.0% annually over this period." Figure 4.2 below exhibits decline in the historic energy and peak requirements from 2005-2015. The system summer peak in 2015 was July 29th at 14:00 and the system winter peak in 2015 was February 20th at 8:00. The system peaks and the Hourly Load data is available in Attachment 4.2.

According to Itron, "The primary contributing factor to this decline in customer usage is significant improvements in lighting, appliance and business equipment efficiency. Efficiency improvements have largely been driven by new end-use efficiency standards and IPL's DSM program activity. Additionally, part of the decline can be contributed to the 2008 recession and the slow economic recovery. Between 2007 and 2011 customer growth actually declined 0.1% per year. Since 2011, customer growth bounced back with residential customer growth averaging 0.8% per year and non-residential customer growth averaging 0.4% per year. But despite increase in customer growth and business activity, sales have still been falling 1.0% per year."

"Over the next twenty years, energy requirements are expected to increase 0.5% annually and system peak demand 0.4% annually, before adjusting for future DSM program savings."[21] Figure 4.3 shows annual energy and demand forecast before DSM program savings.

Figure 4.3 – Energy and Demand Forecast (Excluding Future DSM Program Savings)



[21] Future DSM program savings refers to the amount of DSM that the Capacity Expansion Model selects.

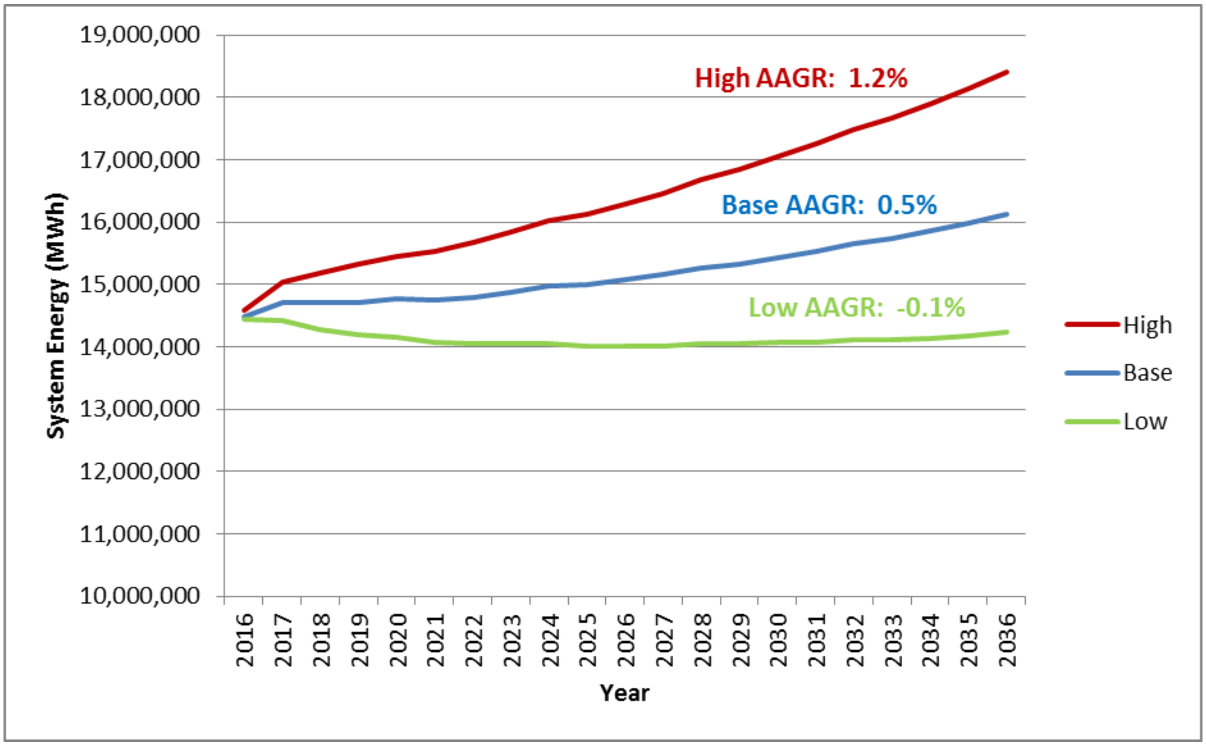
Figure 4.4 – Base Energy and Peak Forecast (2016-2037)

Year	Energy (GWh)	Percent Change	Peaks (MW)	Percent Change
2016	14,487		2,863	
2017	14,707	1.5%	2,866	0.1%
2018	14,713	0.0%	2,864	-0.1%
2019	14,717	0.0%	2,862	-0.1%
2020	14,761	0.3%	2,870	0.3%
2021	14,751	-0.1%	2,868	-0.1%
2022	14,797	0.3%	2,875	0.2%
2023	14,870	0.5%	2,885	0.4%
2024	14,967	0.7%	2,900	0.5%
2025	15,005	0.3%	2,907	0.3%
2026	15,074	0.5%	2,920	0.4%
2027	15,152	0.5%	2,933	0.5%
2028	15,268	0.8%	2,952	0.7%
2029	15,332	0.4%	2,965	0.4%
2030	15,423	0.6%	2,983	0.6%
2031	15,520	0.6%	3,002	0.6%
2032	15,651	0.8%	3,026	0.8%
2033	15,731	0.5%	3,042	0.5%
2034	15,853	0.8%	3,065	0.7%
2035	15,979	0.8%	3,088	0.8%
2036	16,135	1.0%	3,116	0.9%
2037	16,223	0.5%	3,134	0.6%
16-37		0.5%		0.4%

Itron included IPL-sponsored DSM since 2010 as an independent variable input in the forecast models. Including prior DSM allowed Itron to determine the volume of historic DSM that is embedded the forecast going forward. This embedding occurs because prior IPL-sponsored DSM savings are included in the sales data used for the forecast. Through this process, Itron determined that roughly 50% of prior IPL-sponsored DSM is included in the forecasts used in this IRP. The Base Energy and Peak Forecast is presented in Figure 4.4 above.

High and low sales, energy, and demand forecasts were developed for respective economic growth scenarios for this IRP. Figure 4.5 below displays the high and low system energy forecasts compared to the base forecast. **Future DSM program savings as selected by the Capacity Expansion Model in this IRP are not included in these forecasts.** Annual system energy growth is expected to be 1.2% on average in the high forecast versus -0.1% on average in the low forecast. The methodology section provides additional information regarding high and low forecast development.

Figure 4.5 – Base, High and Low System Energy Forecasts (Excluding Future DSM Program Savings*) with Average Annual Growth Rates ("AARG")



*Future DSM program savings as selected by the Capacity Expansion Model in this IRP are not included in these forecasts.

4.3. Forecast Methodology

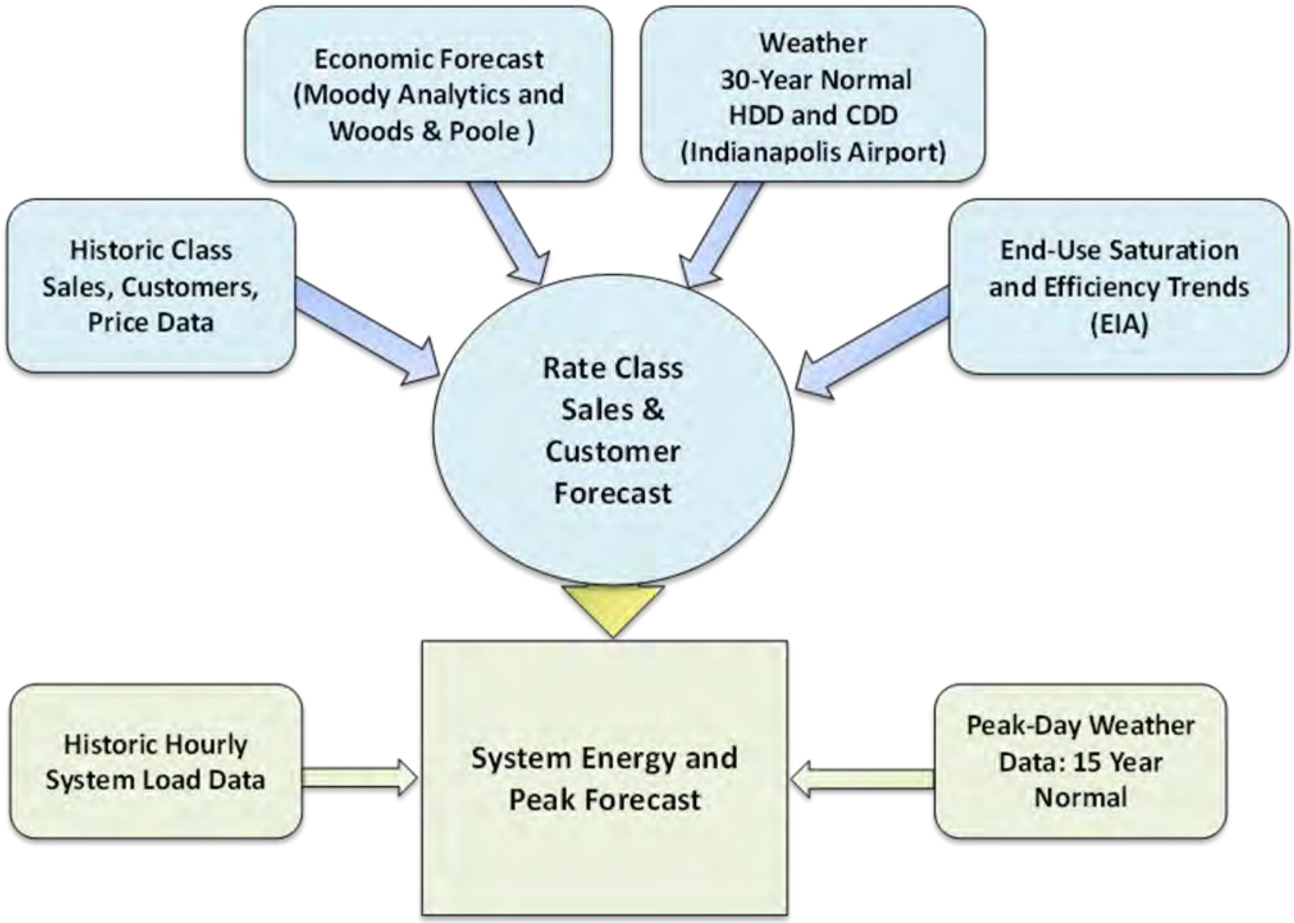
170 IAC 4-7-4(b)(4) 170 IAC 4-7-4(b)(11) 170 IAC 4-7-5(a)(5)

Itron employs an econometric model that makes use of Statistically Adjusted End-use ("SAE") impacts in order to estimate the effects of efficiency measures, appliance saturation and new technology penetration. Figure 4.6 below provides an overview of the model illustrating the independent variable inputs. 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") 2015 Annual Energy Outlook ("AEO") for the East North Central Census Division. The EIA End Use Data is available in Confidential Attachment 4.4. 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. Due to insufficient data from the EIA, saturation and efficiency trends were not developed for the industrial sector. In future years, IPL may conduct additional research using the interval AMI data from the industrial sector and customer surveys to gain a better understanding of efficiency in this sector. For more information regarding end use modeling techniques, see Attachment 4.5.

- *Economic data* – Economic projections are from Moody Analytics and Woods & Poole. IPL has traditionally used Moody Analytics' economic forecast. This year, however, the Moody Analytics' near-term forecast seemed unreasonably high: Moody's December 2015 forecast showed Indianapolis real GDP growth over 5.0% for 2017, yet actual GDP growth has averaged a little over 2.0% for the past few years. Woods & Poole projects more reasonable near-term economic growth with GDP growth of a little over 2.0%. IPL adjusted Moody's economic forecast through 2020 down to reflect Woods & Poole's more reasonable near-term forecast and continued with Moody's forecast beyond 2020. This adjustment using the Woods & Poole data was only made to the base forecast. The high and low forecasts use different Moody's scenarios described later.
- *Historical class sales and customers* – IPL tracked and provided historical sales and customer data for each discrete rate code.
- *IPL price forecast* – Historical prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars.
- *Weather data* – Historical and normal monthly heating degree days ("HDD") and cooling degree days ("CDD") are derived from daily temperature data for the Indianapolis Airport. A temperature base of 60 degrees is used in calculating HDD and a temperature base of 65 degrees are used in calculating CDD. The base temperature selection is determined by evaluating the sales/weather relationship and determining the temperature at which heating and cooling loads begin. There is no heating or cooling between 60 degrees and 65 degrees. Normal degree-days are calculated over a 30-year period (15-year period for the peak forecast) from 1986 to 2015, by averaging the historical monthly HDD and CDD for each month.
- Future IPL DSM was <u>not</u> included in the base, high or low energy and peak forecasts that were used as inputs into the IRP. This DSM was selected in the IRP alongside other supply-side capacity options based on IPL's resource needs in the Capacity Expansion Model. See Section 8 for more detail on DSM selection for the IRP.

Figure 4.6 – Forecasting Methodology Process



As Figure 4.6 demonstrates, these independent variables are used to predict sales (by rate code) and peak and energy forecasts. The sales forecasting methodology varies slightly for the residential and non-residential (commercial and industrial) sectors. Please refer to Itron's report in Attachment 4.4 for a more detailed discussion of the regression modeling and forecasting methodology.

Itron estimated the volume of IPL sponsored DSM inherently embedded in the forecast to be around 50%. Note that this reflects DSM that IPL has been offering at a quantifiable level since 2010. It is unavoidably captured in the historic sales data which drives the forecast. To quantify this impact, Itron loaded IPL's annual DSM savings since 2010 into the model as an independent variable. IPL and Itron did not adjust the forecasts used in the IRP for this DSM since it is a very rough estimate with low statistical significance.

The system energy and peak forecasts, represented at the bottom of Figure 4.6, are used as inputs into the IRP to determine the resource requirements in the study period.

According to Itron, “System energy forecasts are derived by summing monthly rate schedule sales forecast and adjusting sales upwards for line losses. The adjustment factor is based on the historical ratio of monthly energy to sales for the last four years as an indication of system losses. Adjustment factors are calculated for each month. The annual forecast adjustment factor is 1.059 to adjust for line loss of 5.9%.”

“The system peak forecasts are driven by heating, cooling, and base-use energy requirements derived from the sales forecast models. Cooling and heating requirements are interact with peak-day CDD and HDD. The peak regression model is estimated using monthly peak demand (the highest peak that occurred in the month) and the CDD and HDD that occurred on that day.”

As previously noted, high and low sales, energy and demand forecasts were developed in addition to the base forecast to represent alternative economic growth scenarios.

Based on Itron’s development of the base, high and low forecasts, “The base case forecast assumes relatively modest regional demographic and economic growth. Households are projected to average 0.8% annual growth through the forecast period, output 2.4% annual growth, and employment 0.8% annual growth. The economic forecast is consistent with recent economic activity. Between 2005 and 2015, the number of households has averaged 0.7% annual growth, output has averaged 1.4% annual growth, and employment 0.9% average annual growth.”

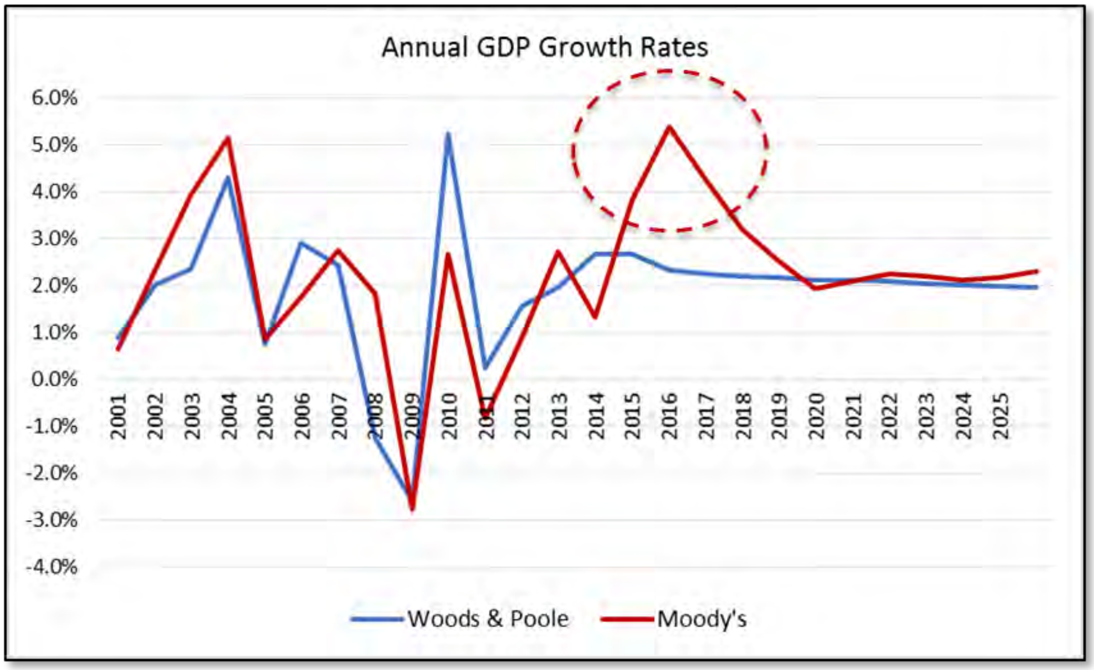
“The high case forecast is based on Moody Analytics “stronger near-term rebound” scenario for the Indianapolis MSA. In this scenario output is projected to average 3.5% annual growth through the forecast period. The low case is based on Moody Analytics “protracted slump” scenario.” In “slump” scenario output is projected to average 1.1% annual growth through the forecast period. In both scenarios we assume that the relationship between GPD growth and other economic drivers (including employment, number of households, and real income) is the same as it is in the base case.”

4.4. Forecasting Challenges

IPL and Itron encountered a few challenges during the development of the IRP load forecast.

The first challenge was finding an appropriate GDP forecast. Moody’s economic forecast contained an unusual jump in GDP in 2017 of over 5% as shown in Figure 4.7. Projecting an accurate near-term forecast is critical for IPL’s internal budget in addition to the IRP, thus IPL and Itron purchased a second set of economic data from Woods & Poole. The new dataset contained a more reasonable GDP growth of 2% for 2017, consistent with growth in prior years. Itron adjusted Moody’s dataset down to the Woods & Poole growth rates for 2017–2020 to reflect a more probable near-term GDP forecast. For 2021 and beyond, the forecast resumed using Moody’s growth rates.

Figure 4.7 – Moody's and Woods & Poole Annual GDP Growth Rates

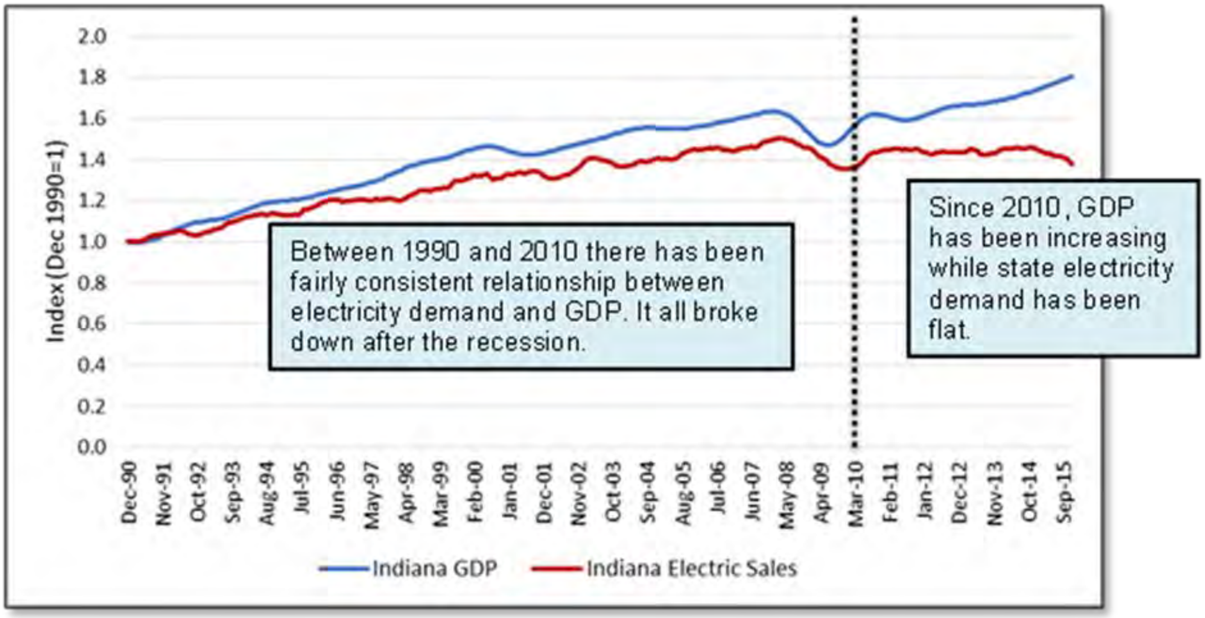


Another challenge for IPL and Itron was the need to reassess the relationship between GDP and energy consumption. Consistent with trends identified in the EIA's 2015 Annual Energy Outlook, Itron has found that GDP is no longer a strong predictor for electric sales.[22] Figure 4.8 below shows that before 2010, GDP could fairly reliably predict utility sales. In fact, most forecasters used GDP as the key driver for electric sales. Since the conclusion of the economic downturn, GDP has grown while electric sales have remained flat.

---

[22] 2015 Annual Energy Outlook Report. http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf. See pgs. 16 &17.

Figure 4.8 – Indiana GDP and Electric Sales

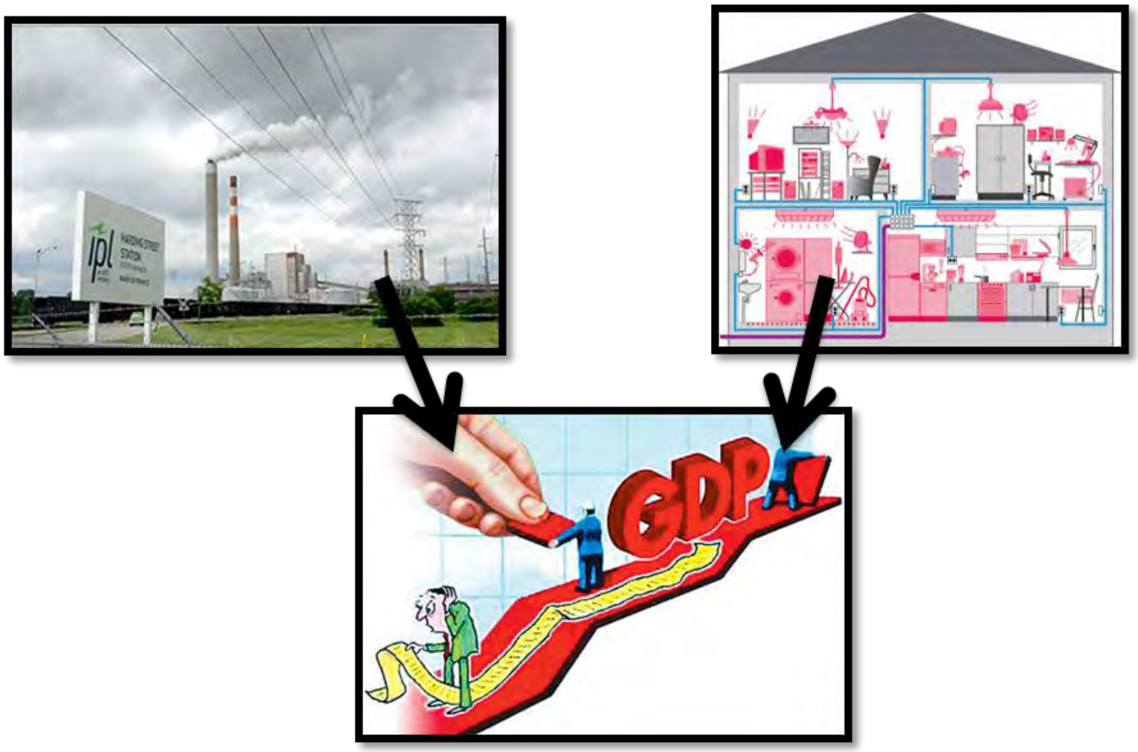


As illustrated in Figure 4.8 above, the relationship between GDP and electric sales is correlative and not causal. Electric sales act as an input into calculating GDP in addition to the products that we buy and use in our homes. While customers are buying more of these products than ever before, the products are becoming substantially more efficient due to technological advancements and federal codes and standards. As a result, IPL is seeing flat electric sales while GDP continues to grow.

To address this challenge, Itron utilized an economic variable that is more heavily weighted towards employment than previous forecasts which is a better predictor of sales for the commercial and industrial sectors. For the commercial rate codes, the variable was weighted 80% nonmanufacturing employment / 20% nonmanufacturing GDP. For the industrial HL1 rate code the variable was weighted 80% manufacturing employment / 20% manufacturing GDP; the HL2 rate code was weighted 90% manufacturing employment / 10% manufacturing GDP.

Additionally, to more accurately capture energy efficiency impacts, the Itron forecast used the most recent 2015 end-use equipment data from Energy Information Administration Annual Energy Outlook.

Figure 4.9 – Utility sales and consumer products as inputs into GDP



4.5. Key Forecast Drivers by Sector

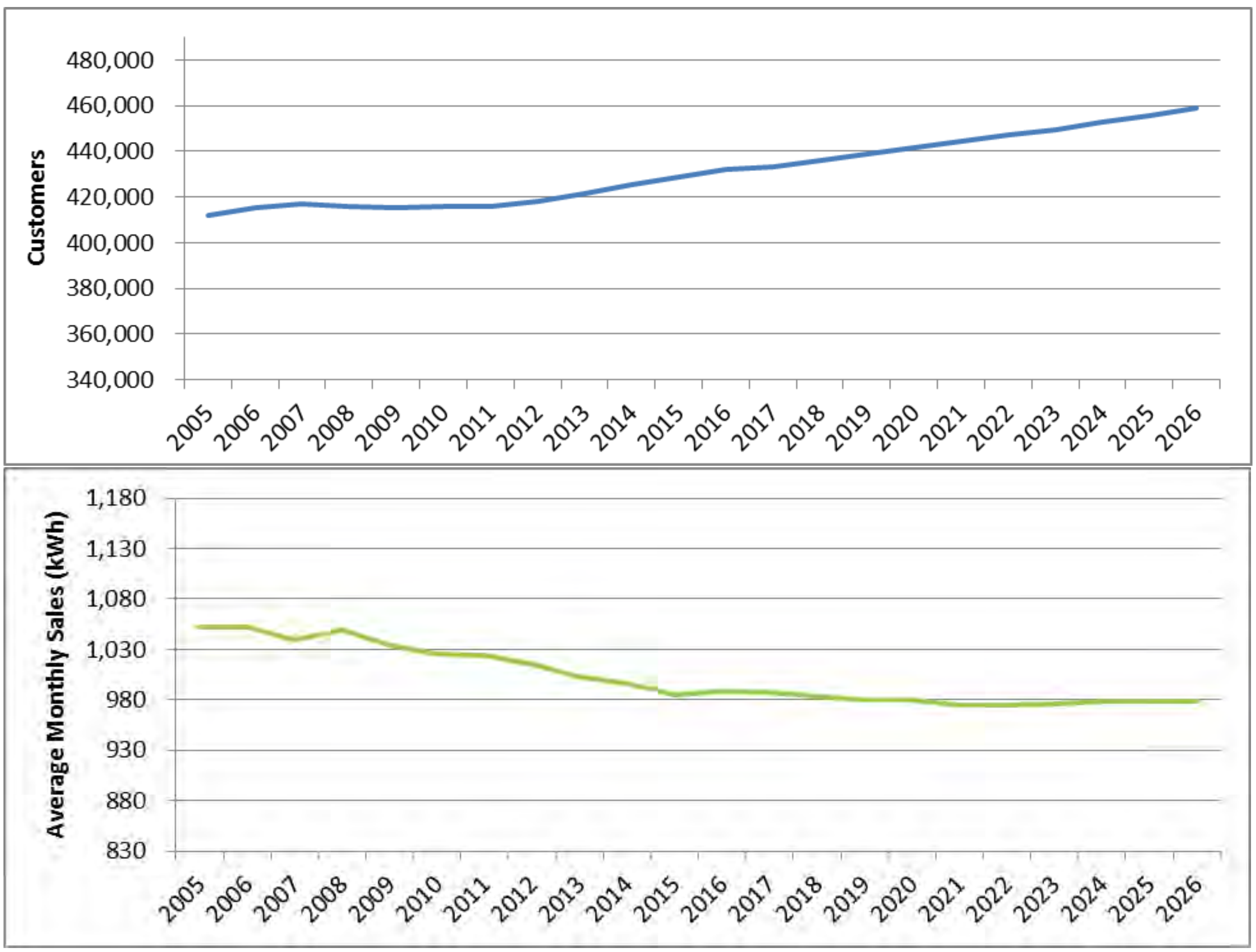
This section provides an overview of the drivers and trends in each of the three IPL customer sectors – Residential, Small C&I and Large C&I. The forecast summaries and charts have been adjusted downward to demonstrate the impacts of the DSM selected by the Capacity Expansion Model in the IRP Base Case scenario.

4.5.1. Residential

The key residential forecast drivers are Marion County housing starts, Marion County household income and electricity prices. Over the next 20 years, the numbers of housing starts are projected to grow at an average annual rate of 1.7% while household income is projected to grow at an average annual rate of 0.8%. Both will increase customer volume and total usage. . IPL electricity prices are projected to increase at an average annual growth rate of 1.6%, which is expected to drive down usage due to the effects of price elasticity.

Figure 4.10 displays the average projected trends in customer count and average electricity use across the Residential Sector. New customers are projected to increase at an average annual rate of 0.65% while average use is expected to decline at an average annual rate of 0.1%.

Figure 4.10 – Customer and Average Use Projections in the Residential Sector



The shift in the Residential sector to a higher percentage of multifamily homes in combination with organic and IPL sponsored DSM will contribute to the forecasted flat-to-declining average use per customer.

Customer growth is expected to come primarily through additional multifamily apartment; a trend that is demonstrated in Figure 4.11. Between 2012 and 2015, 60% of the new IPL residential accounts have been multifamily apartment units which on average are smaller in conditioned square footage than a single family home.

Figure 4.11 – New Residential Accounts (2012 – 2015)

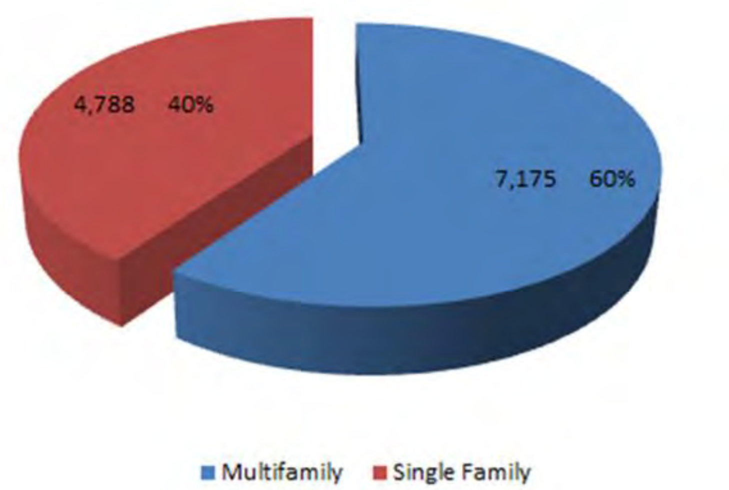
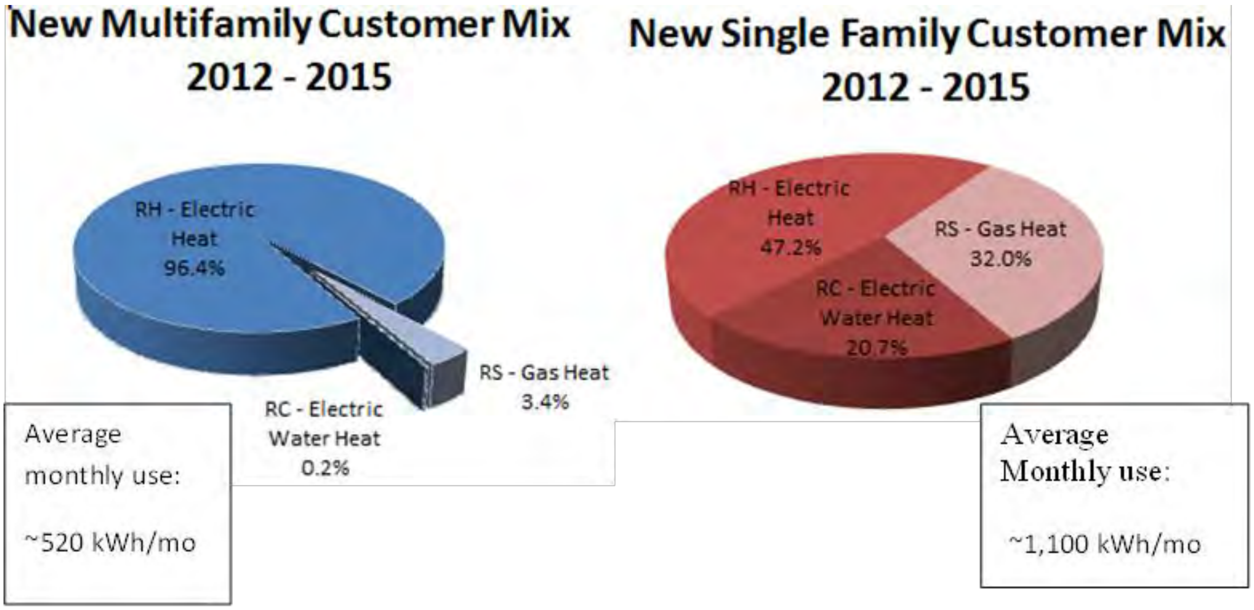


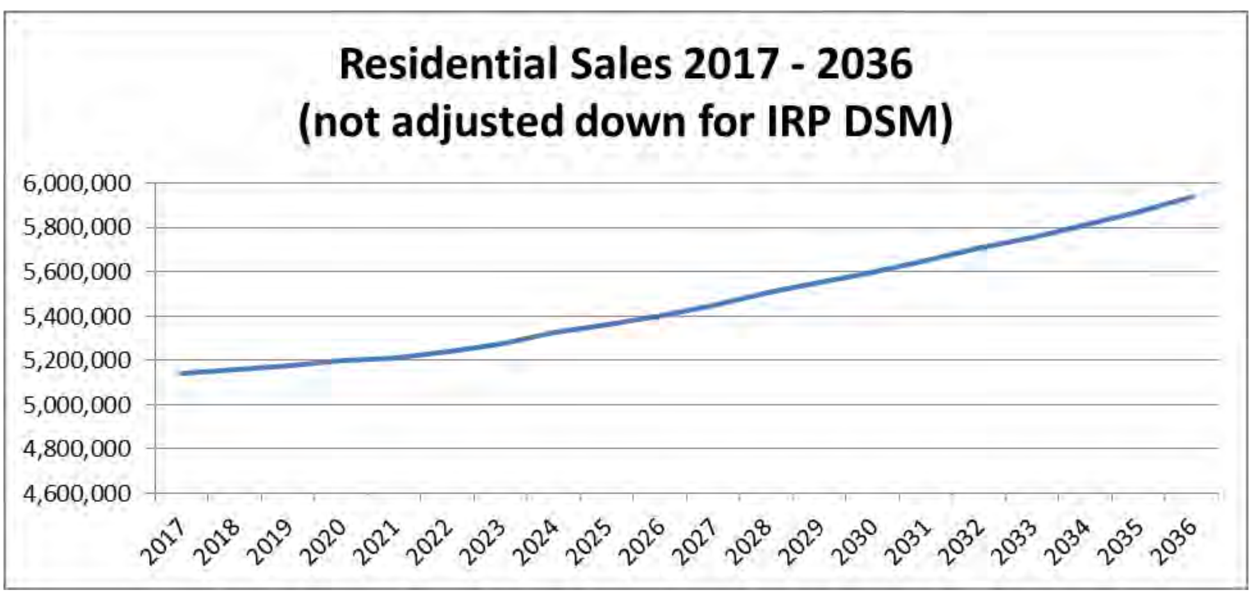
Figure 4.12 presents the mix of heating types from these new multifamily and single family customers. Because the majority of the new multifamily construction is occurring in downtown Indianapolis where gas service connections are more costly due to working around existing infrastructure, 96% of the new multifamily units are electrically heated. Based on consumption data from 2012-2015, the average multifamily unit uses approximately half as much electricity as the average single family home.

Figure 4.12 – Customer Mix by Heating Type



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 0.3%, as shown in Figure 4.13.

Figure 4.13 – Residential Sales

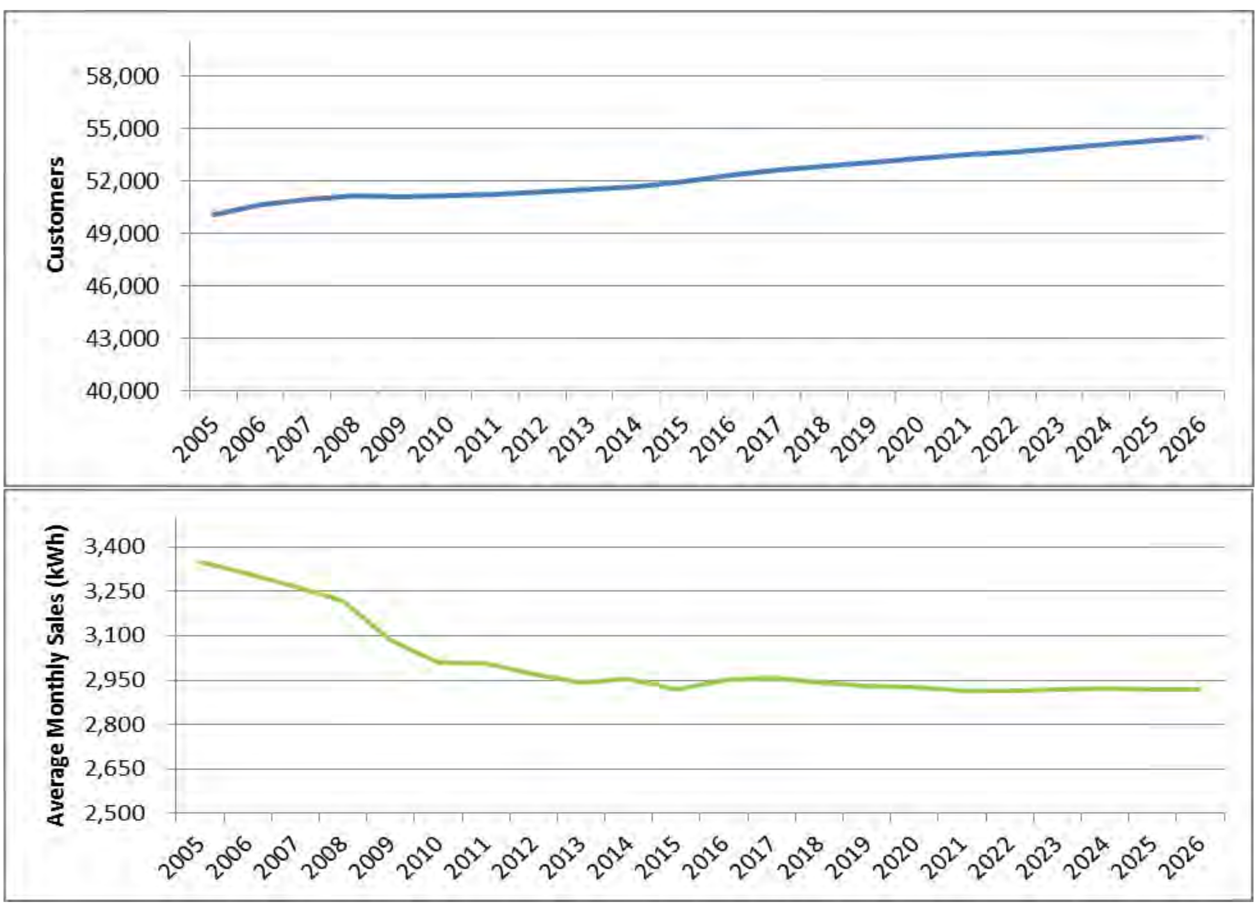


4.5.2. Small C&I

The key drivers to the Small C&I forecast are Marion County nonmanufacturing employment and Marion County nonmanufacturing GDP. As mentioned previously, Itron created an economic variable that was 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 0.9% and nonmanufacturing GDP at a rate of 2.4%. The combined variable used in the forecast had an average annual growth rate of 1.2%. This growth is evident anecdotally by the volume of new businesses opening to cater to the new multifamily residents in the downtown metropolitan area.

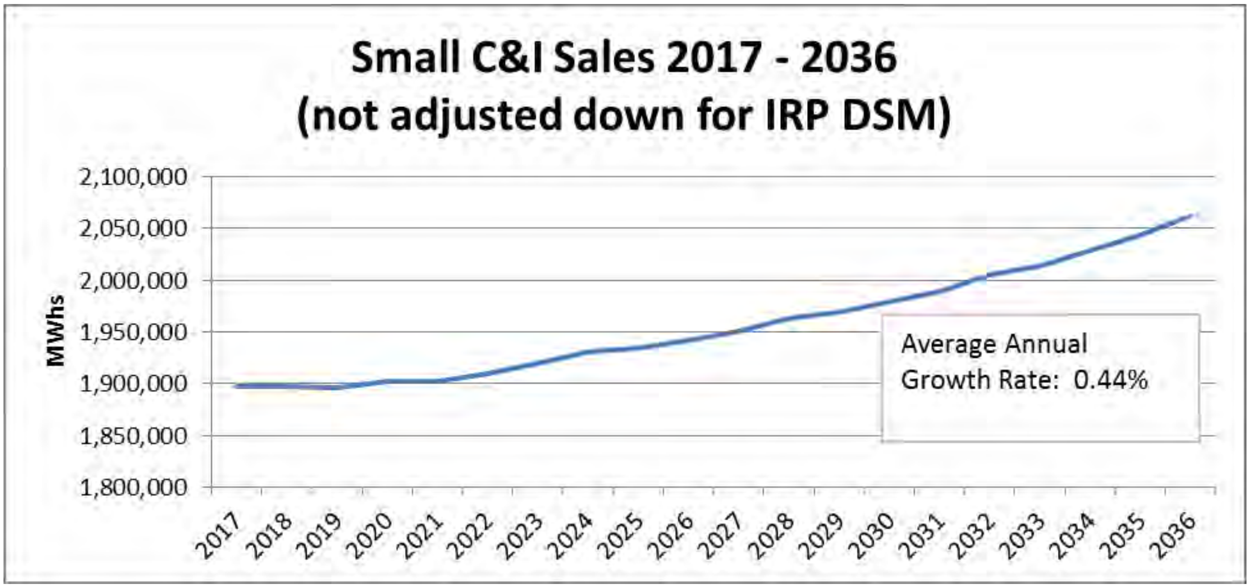
Figure 4.14 displays the projected customer count growth and average electricity use for the Small C&I sector. The numbers of new customers are projected to grow at an average annual rate of 0.4%; however, the average use per customer is anticipated to decline at an average annual rate of -0.1%. With generally favorable projections in employment and GDP, organic and IPL-sponsored energy efficiency is the primary driver for the decline in average use per customer.

Figure 4.14 – Customers and Average Use Projections in the Small C&I Sector.



Before removing the IPL sponsored DSM selected in this IRP, Small C&I sale are projected to grow at an average annual rate of 0.44% as demonstrated in Figure 4.15.

Figure 4.15 – Small C&I Sales

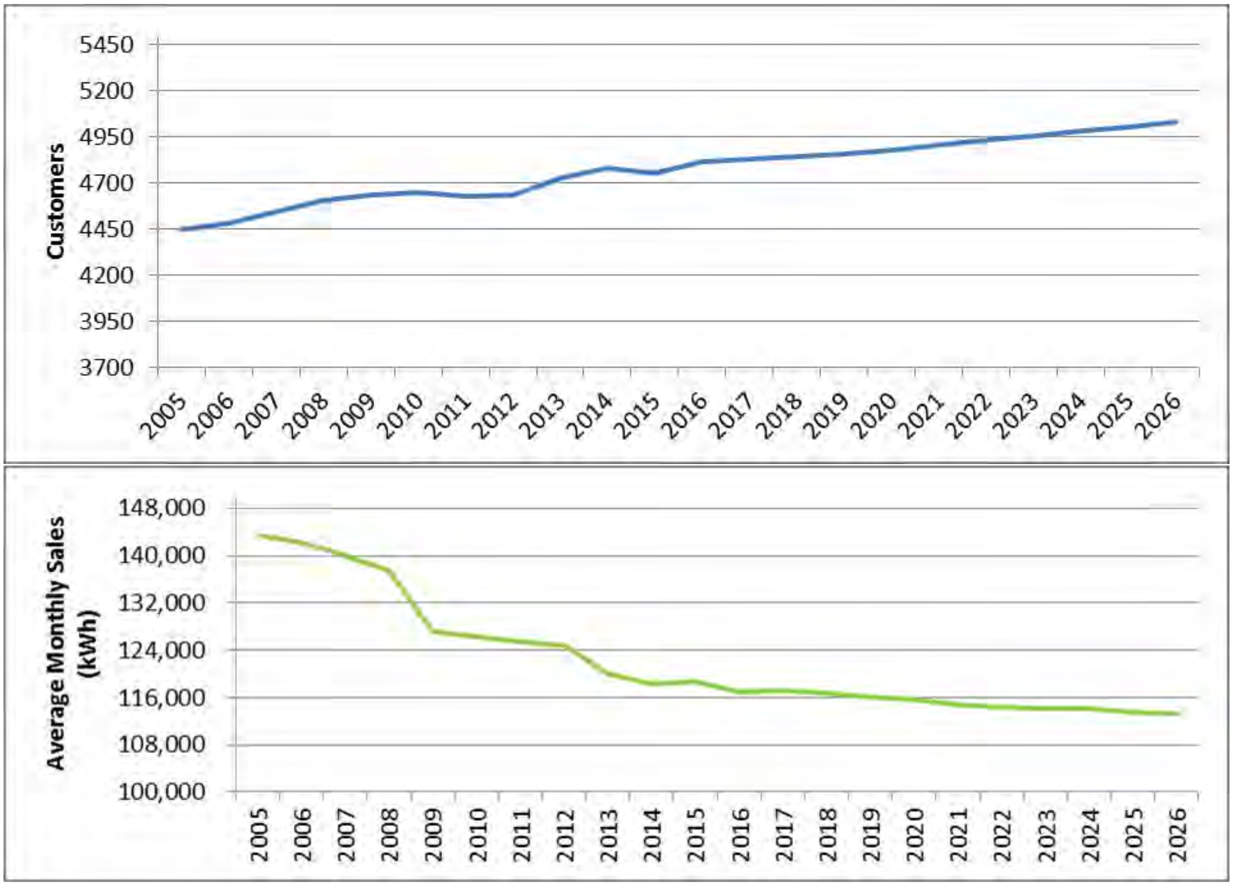


4.5.3. Large C&I

The primary driver for the Large C&I forecast are Marion County manufacturing GDP and Marion County manufacturing employment. Over the IRP period, manufacturing GDP is anticipated to increase at an average annual growth rate of 2.1% while employment is anticipated to decline at a rate of -0.4% annually. Based on these trends, it appears that the manufacturing sector will continue to grow production using fewer workers possibly driven by advancements in technology. Itron weighted the economic variable used for the forecast more heavily to employment resulting in a variable with an average annual growth rate of 0.1%.

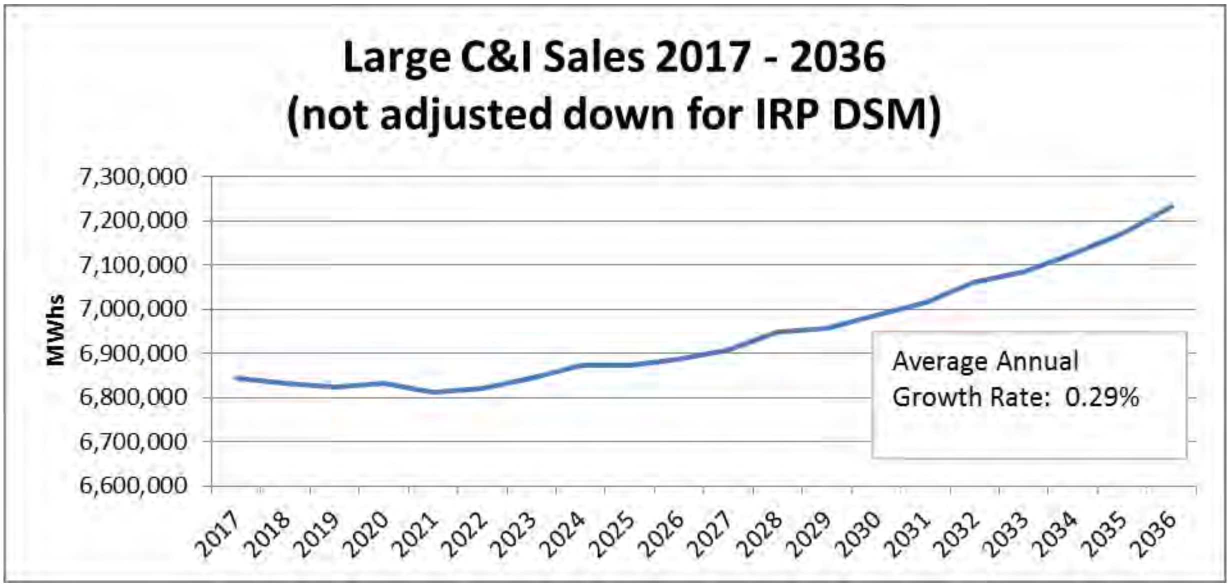
Figure 4.16 displays the projected customer count growth and average use per customer for the Large C&I sector. As with the Small C&I Sector, the number of new customers is expected to grow at an average annual rate of 0.4%, while average use is anticipated to decline at a rate of -0.3% annually. Customer growth is expected to come primarily from the Secondary Load ("SL") rate code which typically includes large grocers and fast food restaurants. The decline in average use is due to a shift to less energy intensive industries and energy efficiency impacts.

Figure 4.16 – Customer and Average Use Projections in the Large C&I Sector



Before removing IPL sponsored energy efficiency, the Large C&I sector sales are projected to increase eat an average annual rate of 0.29% over the IRP period as demonstrated in Figure 4.17.

Figure 4.17 – Large C&I Sales



See Attachment 4.4 for Itron's full report which includes additional information on their forecasting modeling and methodology.

Confidential Attachment 4.8 provides the energy forecast drivers and Attachment 4.12 provide the peak forecast drivers and input data.

4.5.4. Electric Vehicles

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

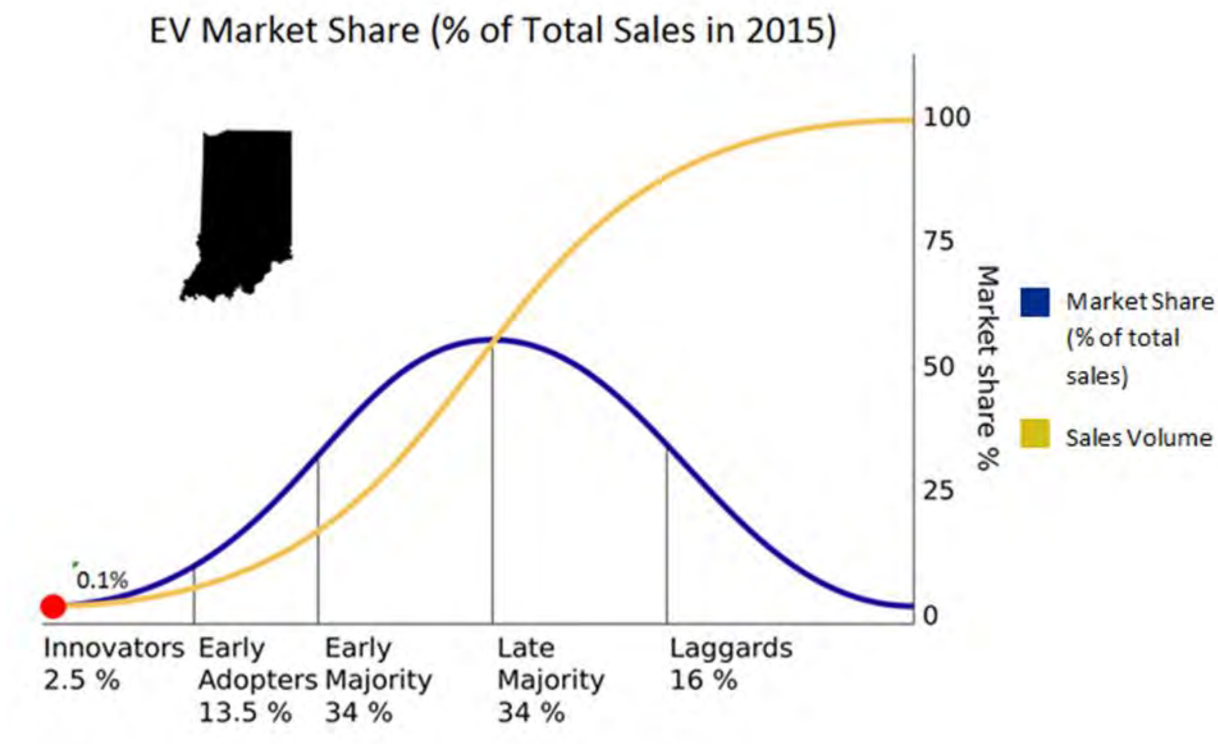
Electric Vehicle ("EV") adoption has the potential to result in measurable future grid impacts. Excluding fleet vehicles, there are approximately 1,700 EVs registered in the State of Indiana as of late 2015, with approximately 300 registered in the greater Indianapolis area. Given the low EV penetration to date, IPL has experienced no material distribution system impacts, but will continue to monitor and assess necessary infrastructure upgrades as EV market share increases.

For purposes of the IRP, IPL undertook research to understand EV market share[23] and penetration[24] rates in its serving area. Current market share and penetration rates were plotted on the Diffusion of Innovations[25] curve. The Diffusion of Innovations theory defines categories of "adopters", and attempts to explain how innovative technologies are perceived and ultimately accepted by consumers in each adopter category. As can been seen in Figure 4.18 below, EVs represented approximately 0.1% of new vehicle sales (registrations) in 2015. EV penetration – the percentage of vehicles on the road represented by EVs – is even smaller, at approximately

[23] Market Share, meaning the percentage of new vehicles sales represented by Electric Vehicles
[24] Penetration, meaning the percentage of vehicles on the road represented by Electric Vehicles
[25] Diffusion of Innovations (Everett Rogers, Diffusion of Innovations, 1962)

0.04% of all vehicles on the road. Per IPL's research, Indiana's EV penetration is approximately 78% less than the national average. IPL customers that are in the market for EVs are considered to be "Innovators" according to the Diffusion of Innovation theory.

Figure 4.18 – EV Market Share



In order to better understand EV impacts and provide innovative solutions for customers, IPL has implemented an Electric Vehicle ("EV") program since 2011. This program resulted in integrated charging infrastructure in homes, business and public parking facilities, with partial Smart Grid Investment Grand ("SGIG") funding support from the U.S. Department of Energy ("DOE") and the State of Indiana Office of Energy Development. IPL received authority to defer the non-grant funded portion of this project in Cause No. 43960 for future rate recovery. Approximately 162 of the 200 planned charging stations have been installed in homes and businesses. IPL received approval for both a Time of Use ("TOU") EVX rate for customer premises and a public EVP rate. To date, approximately 100 customers participate in Rate EVX shown in Figure 4.19.

Figure 4.19 – 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

IPL found that approximately 76% of the electricity used for Rate EVX charging occurred during off-peak periods, an additional 4% occurred during mid-peak, and the remaining 20% occurred during peak periods in 2013. While the impacts of the total 2013 Rate EVX usage are modest, IPL believes that the results demonstrate customers' willingness to charge off-peak in recognition of the TOU rate structure. 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 deployed at eight (8) locations as a result of the pilot. The public systems may be used by any customer or visitor to Indianapolis enabled by a key fob and credit card based system. While public charging is less robust than expected, it mitigates range anxiety for EV drivers.

Please see IPL's 2013 Electric Vehicle Program Report for more information at: https://www.iplpower.com/Business/Programs_and_Services/Electric_Vehicle_Charging_and_Rates/.

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. To date, 74 of the 200 proposed locations have been installed. See Attachment 3.1 for a summary of activity which was filed in Cause No. 44478. In a settlement approved by the IURC regarding this initiative, the practice of utilizing EV batteries to feed a distribution system was referred to as Vehicle to Grid integration ("V2G"). IPL reported on this initiative in accordance with the IURC Order in Cause No. 44478, see Attachment 3.2 for this report.

To quantify the impacts of electric vehicles ("EVs") on the system over the IRP period, IPL reviewed various EV forecasts from numerous sources and found considerable variability. Using the current EV impacts described in the paragraphs above as a baseline, IPL decided to apply growth rates from the Energy Information Administration's ("EIA") EV market share projections to compile the Base EV Forecast for the IRP period. Using these rates, EVs are only forecasted to encompass 1.19% of the light vehicle market share by 2036. As shown in Figure 4.20, cumulative EVs on the road go from 1,092 in 2017, to 4,421 in 2036. This equates to an increase from 1,610 MWhs in respective total electric sales to 1,961 MWhs. In IPL's High EV Forecast which assumes an average annual market share growth rate of 15% after 2020, electric sales attributable to EVs are projected to be 32,765 MWhs by 2036 – equivalent to 13,652 EVs on the road as presented in Figure 4.21. The incremental new vehicles added over the IRP period would be equivalent to adding roughly 895 new residential customers based on average consumption of 1,100 kWh per month in the base EV forecast, and roughly 2,765 new residential customers in the high EV forecast. The base and high load forecasts are assumed to include the energy consumption impacts from EV growth.

Figure 4.20 – Forecasted volume of Electric Vehicles served by IPL – Base Scenario

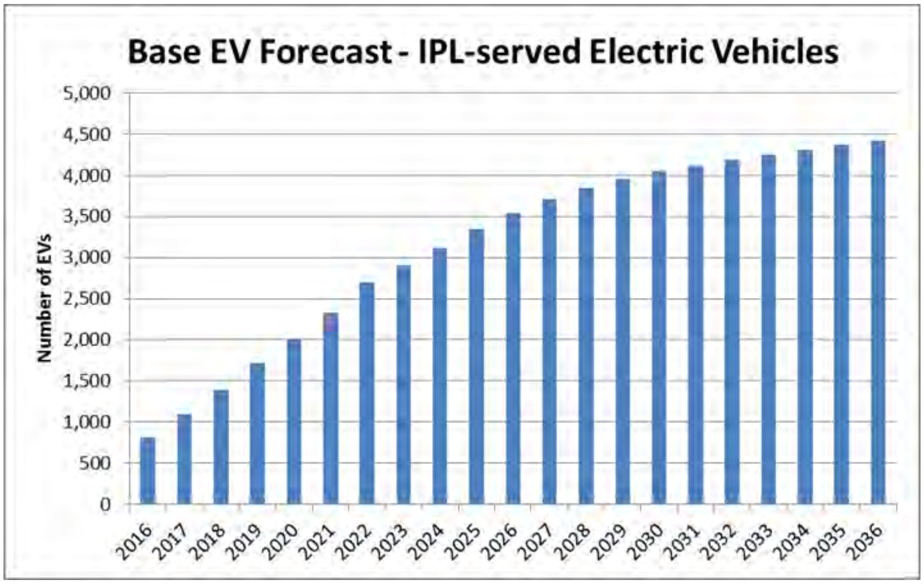
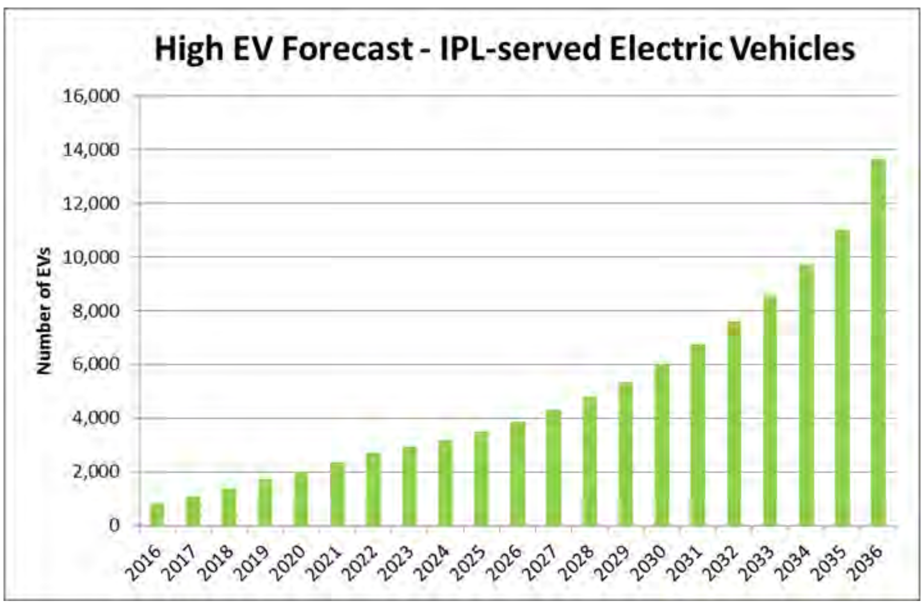


Figure 4.21 – Forecasted volume of Electric Vehicles served by IPL – High Scenario



4.6. Load Model Performance and Analysis

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

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. Additional discussion of model statistics and other statistical measures is available in Itron's 2016 Long-term Electric Energy and Demand Forecast Report, Attachment 4.3.

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. As long as 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 4.22 and Figure 4.23 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 4.13.

Figure 4.22 – Forecast Error Analysis: Weather-Adjusted Energy Sales vs. Forecasts

ANNUAL "INDIANAPOLIS ONLY" GWH SALES
Actual & Forecasted

For	Actual Sales *	Forecast Made: One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago
2006	14,715.865	15,221.281 3.4%	15,164.506 3.0%	14,996.604 1.9%	15,153.834 3.0%	15,938.745 8.3%
2007	15,368.392	15,255.687 -0.7%	15,452.281 0.5%	15,408.373 0.3%	15,157.356 -1.4%	15,364.855 0.0%
2008	15,003.127	15,264.979 1.7%	15,427.470 2.8%	15,702.410 4.7%	15,620.741 4.1%	15,334.846 2.2%
2009	14,085.841	15,208.790 8.0%	15,472.539 9.8%	15,612.025 10.8%	15,932.337 13.1%	15,838.873 12.4%
2010	14,609.153	14,287.148 -2.2%	15,356.932 5.1%	15,702.517 7.5%	15,817.438 8.3%	16,173.497 10.7%
2011	14,229.012	14,172.293 -0.4%	14,420.894 1.3%	15,520.059 9.1%	15,914.802 11.8%	16,020.434 12.6%
2012	14,023.717	14,268.134 1.7%	14,391.694 2.6%	14,717.444 4.9%	15,705.912 12.0%	16,149.633 15.2%
2013	14,028.502	14,118.020 0.6%	14,263.240 1.7%	14,491.940 3.3%	14,783.227 5.4%	15,691.466 11.9%
2014	13,995.697	13,999.408 0.03%	14,241.352 1.8%	14,411.550 3.0%	14,627.775 4.5%	14,917.986 6.6%
2015	13,701.544	14,085.083 2.8%	14,141.772 3.2%	14,409.551 5.2%	14,526.255 6.0%	14,700.724 7.3%

Mean % Error	1.5%	3.2%	5.1%	6.7%	8.7%

Figure 4.23 – Forecast Error Analysis: Summer Peak Demands vs. Forecasts

SUMMER PEAK DEMANDS
Actual & Forecasted

For	Actual Peak Demand	Forecast Made: 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
2006	3162	3110 -1.6%	3203 1.3%	3132 -0.9%	3191 0.9%	3376 6.8%	3297 4.3%	3275 3.6%	3267 3.3%	3259 3.1%	3288 4.0%
2007	3206	3195 -0.3%	3156 -1.6%	3243 1.2%	3173 -1.0%	3233 0.8%	3430 7.0%	3348 4.4%	3322 3.6%	3322 3.6%	3319 3.5%
2008	2813	3197 13.7%	3231 14.9%	3190 13.4%	3264 16.0%	3215 14.3%	3277 16.5%	3483 23.8%	3402 20.9%	3370 19.8%	3379 20.1%
2009	2843	3218 13.2%	3236 13.8%	3293 15.8%	3236 13.8%	3313 16.5%	3257 14.6%	3321 16.8%	3536 24.4%	3457 21.6%	3419 20.3%
2010	3013	3117 3.5%	3253 8.0%	3274 8.7%	3343 10.9%	3281 8.9%	3354 11.3%	3300 9.5%	3364 11.6%	3590 19.2%	3514 16.6%
2011	3100	2943 -5.1%	3173 2.4%	3287 6.0%	3312 6.8%	3391 9.4%	3327 7.3%	3395 9.5%	3344 7.9%	3408 9.9%	3645 17.6%
2012	3061	2938.3 -4.0%	3001 -2.0%	3253 6.3%	3320 8.5%	3350 9.4%	3445 12.5%	3372 10.2%	3429 12.0%	3388 10.7%	3453 12.8%
2013	2807	2928.4 4.3%	2974.6 6.0%	3047 8.5%	3311 18.0%	3352 19.4%	3388 20.7%	3489 24.3%	3418 21.8%	3484 24.1%	3432 22.3%
2014	2698	2937 8.9%	2981 10.5%	3004 11.3%	3064 13.6%	3355 24.4%	3385 25.5%	3426 27.0%	3536 31.1%	3463 28.4%	3533 30.9%
2015	2757	2945 6.8%	2984 8.2%	3031 9.9%	3003 8.9%	3073 11.4%	3400 23.3%	3418 24.0%	3464 25.7%	3584 30.0%	3509 27.3%

Mean % Error	3.9%	6.1%	8.0%	9.6%	12.1%	14.3%	15.3%	16.2%	17.0%	17.5%

Section 5: Resource Options

Executive Summary

The electric utility industry will continue to experience changes in technology, regulations, policies and customer expectations. Meeting customer needs in this environment presents opportunities to change the future resource mix. World events and trends play a big role in planning for future resources. This section describes efforts to identify, characterize and evaluate a broad selection of demand side, renewable and supply options to meet customer requirements during the study period.

5.1. Existing IPL Resources

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

Existing IPL supply and demand side resources are included in the IRP modeling process to meet customer energy and demand needs and are described fully in this section.

5.1.1. Existing Supply-Side Resources

IPL's resource portfolio has changed dramatically over the last several years. Coal made up 79% of the IPL fleet in 2007, but will be represent only 44% of the nameplate capacity in 2017. 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. Four coal and six oil-fired units have been permanently retired. Another three coal units have been converted to firing natural gas at the Harding Street Station. Contracts to purchase 300 MW of wind energy and 96 MW of solar have been executed. IPL also added a new 300 MVAR Static VAR Compensator and 20 MW Battery Energy Storage System ("BESS") to support grid services.. The Eagle Valley CCGT will begin commercial operations in spring 2017. It will be the largest natural gas fired power station ever constructed by IPL, and is part of a significant change in the company's generating portfolio.

Figure 5.1 shows the Installed Capacity ("ICAP")[26] value of IPL's resources . ICAP values are based on annual unit testing. Figure 5.1 also shows the date of unit retirement based on the unit's expected useful life., IPL has registered the Battery Energy Storage System ("BESS")as a Load Modifying Resource ("LMR") like Demand Response ("DR") resources through the MISO Module E process.

[26] IPL Installed Capacity ("ICAP") (Equivalent of ICAP listed in 2016 Organization of MISO States Survey)

Figure 5.1 – IPL Resources Installed Capacity Credit

Unit Name	Fuel	ICAP Value (MW)	Estimated end of useful life
Eagle Valley Combined Cycle Gas Turbine (CCGT)*	Natural Gas	671	2055
Harding Street Gas Turbines 1&2	Petroleum/NG	37	2023
Harding Street Gas Turbine 4	Natural Gas	73	2044
Harding Street Gas Turbine 5	Natural Gas	75	2045
Harding Street Gas Turbine 6	Natural Gas	146	2052
Harding Street Unit 5	Natural Gas	100	2031
Harding Street Unit 6	Natural Gas	102	2031
Harding Street Unit 7	Natural Gas	438	2033
Harding Street Battery Energy Storage System**	N/A	5	2036
Georgetown Gas Turbine 1	Natural Gas	74	2050
Georgetown Gas Turbine 4	Natural Gas	75	2052
Petersburg Unit 1	Coal	234	2032
Petersburg Unit 2	Coal	417	2034
Petersburg Unit 3	Coal	547	2042
Petersburg Unit 4	Coal	531	2042
Pete Internal Combustion Engines 1-3	Petroleum	8	2042

*Construction of the CCGT is underway and on schedule to be completed in the spring of 2017.
** The 20-year life includes planned augmentation of batteries.

As requested by stakeholders in the fourth Public Advisory meeting, IPL prepared this unit by unit snapshot comparison of the Eagle Valley CCGT under construction and the Petersburg units based on 2017 budgeted coal prices and a range of natural gas prices as shown in Figure 5.2 and Figure 5.3.

Figure 5.2 compares the range of average cost of fuel and variable O&M of the four Petersburg units (shown in the horizontal blue bar) with estimated costs at the Eagle Valley CCGT (shown on solid red line) with varying natural gas prices. Fixed costs for these units are not included in this analysis. For the Petersburg units, IPL used forecasted 2017 average heat rate and variable O&M values as well as the 2017 contracted fuel price to calculate average costs of each unit. For Eagle Valley, IPL rounded an estimated 6.7 MMBtu/MWh heat rate to 7.0 MMBtu/MWh heat rate and forecasted variable O&M. The fuel price for the CCGT was increased in equal increments from \$3.00/MMBtu to \$4.00/MMBtu.

This comparison of costs gives an estimate for the price of natural gas at which the CCGT will be at parity with the Petersburg units on an average cost basis. The "average cost breakeven range" in Figure 5.2 shows that in terms of average cost, the CCGT is at parity with the

Petersburg units with natural gas prices in the $3.50/MMBtu to $3.70/MMBtu range. All costs are subject to change over time, so this figure is intended to provide an approximate cost comparison, not an exact indication of dispatch or operation of these units.

Figure 5.2 – Unit Variable Cost Comparison

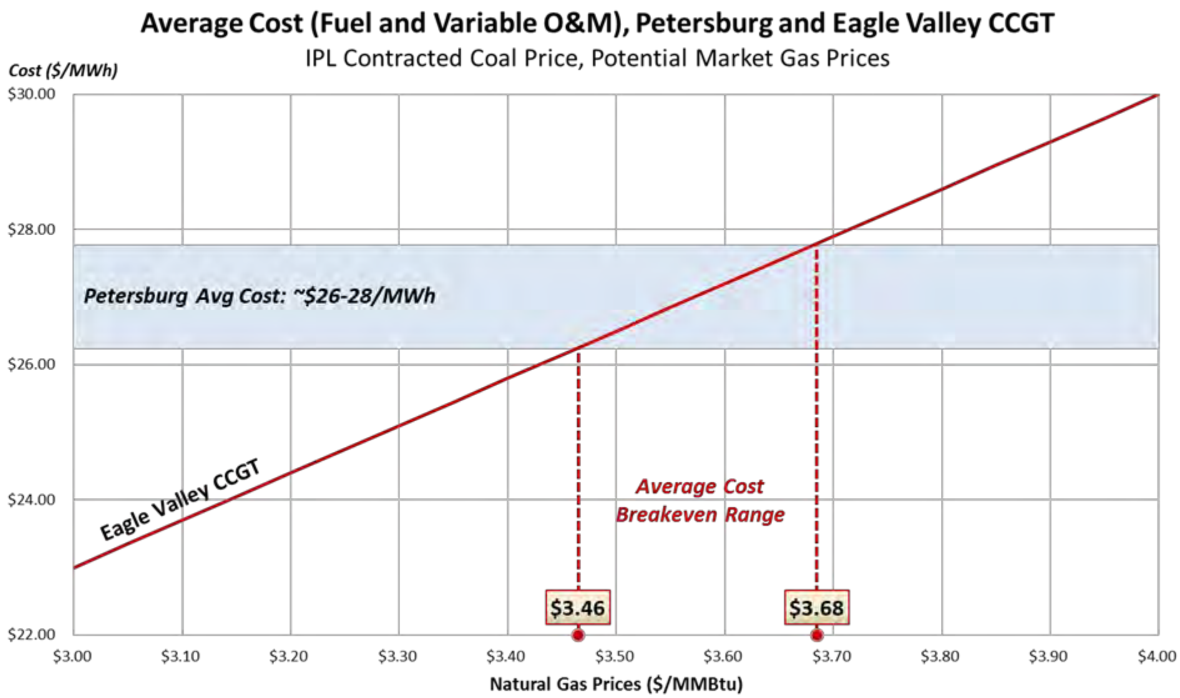


Figure 5.3 utilizes the same data for Petersburg and wider range of natural gas prices from $2/MMBtu to $6/MMBTU for Eagle Valley to show a different graphical representation of the relative costs of the Petersburg units and the CCGT.

Figure 5.3 – Unit Graphical Comparison

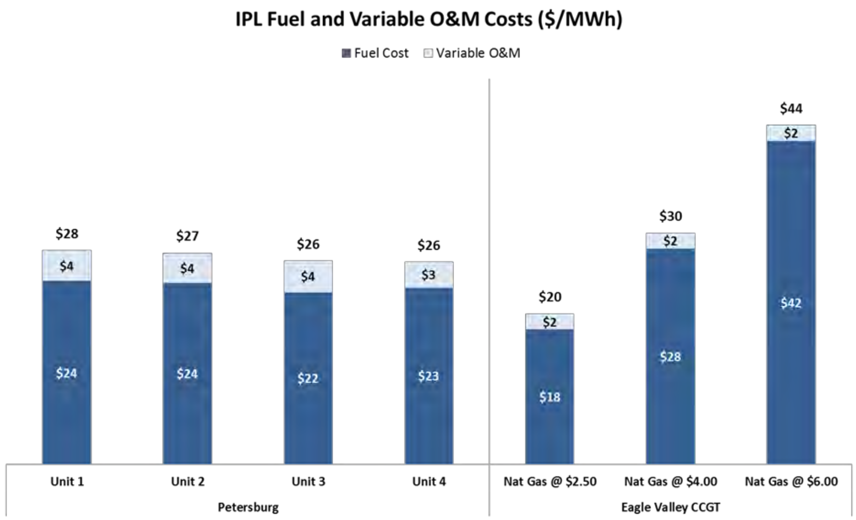


Figure 5.4 shows both the nameplate capacity and ICAP value for IPL's wind and solar PPAs. MISO gives IPL zero capacity credit for wind and solar, yet IPL subtracts 43 MW of solar from its load forecast for MISO planning purposes.

Figure 5.4 – Summary of IPL PPAs

Unit Name	Nameplate Capacity	ICAP Value (MW)	Contract Expiration or Retirement Date
Solar REP*	96	43	2021-2030
Lakefield Wind Park	200	0	2031
Hoosier Wind Park	100	0	2029

*IPL does not offer solar PPA generation directly into the MISO market; however, solar energy reduces it's the IPL peak load by 43 MW based on 2015 experience.

Figure 5.5 summarizes the growth of net metered customers in the IPL Service territory. IPL has experienced modest growth in PV net metered customers. With the exception of a federally funded 1 MW project, most net metered projects are relatively small solar installations. Residential projects average approximately 5.3 kW in nameplate capacity and commercial projects average 8.0 kW.[27] Net metered capacity reduces IPL load requirements in terms of energy and does not materially affect capacity.

Figure 5.5 – Summary of IPL Net Metering Participation

Customer Types	2013		2014		2015		2016 thru September	
	Participants	kW	Participants	kW	Participants	kW	Participants	kW
Residential	31	111	52	209	68	349	81	429
Commercial	6	17	8	45	10	1,053	14	1,104
Total	37	128	60	254	78	1,402	95	1,533

5.1.2. Existing Demand Side Resources

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

IPL's current portfolio of DSM resources consists of the programs for 2015 and 2016, approved in December 2014, in Cause No. 44497. This comprehensive set of programs provides energy efficiency opportunities for all IPL customers.

5.1.2.1 *Current DSM Programs*

The 2016 programs with estimated 2015 contributions are listed in the Figure 5.6 below. The 2016 contributions are estimated to be approximately net 122,000 MWh and will be quantified based on actual customer participation in 2017. In some cases, these programs have been successfully offered by IPL for several years (i.e., Income Qualified Weatherization and Air Conditioning Load Management ["ACLM"]). Figure 5.6 provides the current DSM programs.

[27] All the Indiana IOUs file an annual net metering report with the IURC. The 2015 report published March 2016, is available at http://www.in.gov/iurc/files/2015_Net_Metering_Required_Reporting_Summary.pdf.

Figure 5.6 – 2015 DSM program contributions

DSM Program	Evaluated 2015 Program Achievement (Ex Post Net kWh)[28]
Residential Lighting	9,379,491
Residential Income Qualified Weatherization	1,148,697
Residential ACLM	31,192
Residential Multi Family Direct Install	4,114,637
Residential Home Energy Assessment	4,327,927
Residential School Kit	4,475,194
Residential Online Energy Assessment	2,041,030
Residential Appliance Recycling	1,615,065
Residential Peer Comparison Reports	32,216,315
Business Energy Incentives – Prescriptive	32,158,502
Business Energy Incentives – Custom	9,284,478
Small Business Direct Install	4,883,004
Business ACLM	1,095

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 2015, IPL has deployed approximately 43,000 residential switches and has 82 participating Commercial and Industrial ("C&I") customers, which in total contribute approximately 35.4 MW of demand reduction opportunity.[29]

Of current offerings, the most significant DSM programs in terms of energy efficiency savings in 2016 are expected to be the C&I Prescriptive Program (approximately 72,000 gross MWh through August 31, 2016) and the Residential Peer Comparison Report (with approximately 23,000 MWh through August 31, 2016).

5.1.2.2 *Current Demand Response Programs*

In addition to the energy efficiency DSM programs and the ACLM demand response program described above, IPL also has a number of Load Curtailment/Interruptible programs that are tariff offerings targeted to C&I customers. Since 2014 these programs have seen a significant decrease in participation and the amount of capacity that is being provided. The programs have been targeted primarily at customers that have emergency back-up generation. Customers are called upon from time to time to operate the emergency generation equipment on IPL's behalf to

[28]Ex Post Net reflects the net impact of DSM programs following annual third party evaluation.
[29] 2015 Demand Side Management Evaluation Report, Indianapolis Power & Light Company, June 30, 2016, Table 7, p. 10.

reduce load. However, with the recent National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines ("RICE/NESHAP") rulemaking most customer generation is no longer available to participate in utility sponsored programs due to air emission constraints.

At the end of 2014, IPL had less than 1MW of demand response programs under contract with C&I customers. This is a decrease from the 45 MW that was available in 2014, largely as a result of departures by participating customers and due to EPA restrictions on emissions from diesel generators. In most cases, the incentives offered are adjusted annually to reflect changes in power market conditions. The currently approved programs are described below. In most cases, the incentives offered are adjusted annually to reflect changes in power market conditions. The currently approved programs are described below. As a result of these EPA restrictions, the current level of participation is just under 1 MW as shown below.

Figure 5.7 shows the demand response resources for which IPL receives capacity credit from MISO totaling 58.1 MW in 2016. 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 5.7 – Existing DR program Contributions

Demand Response Type	ICAP Value (MW)
Air Conditioning Load Management	35.4
Rider 17: Curtailment Energy	0.9
Conservation Voltage Reduction	21.8
Total	58.1

5.2. United States Resource Trends

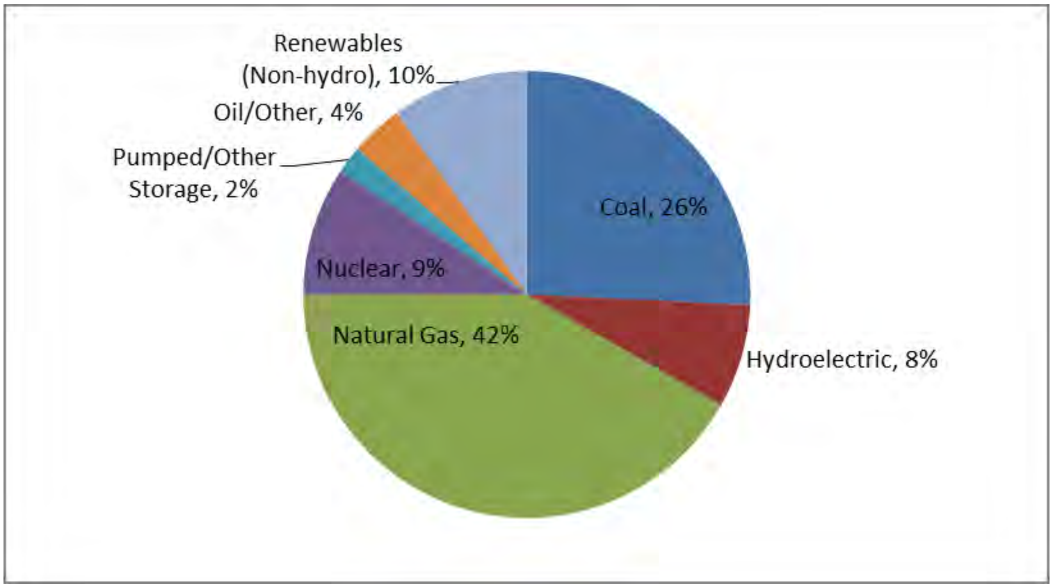
The resource mix throughout the United States ("U.S.") and within the MISO footprint continues to change each year with a heavier prevalence of renewables and natural gas fired generation than historic reliance on coal-fired generation as described below.

5.2.1. National Resource Mix

The U.S. domestic generation mix is shown in terms of capacity in Figure 5.8, and in terms of energy in Figure 5.9.[30] The two sets of data vary for a number of reasons, including the relative price of fuel and the variability of some resources such as renewables.

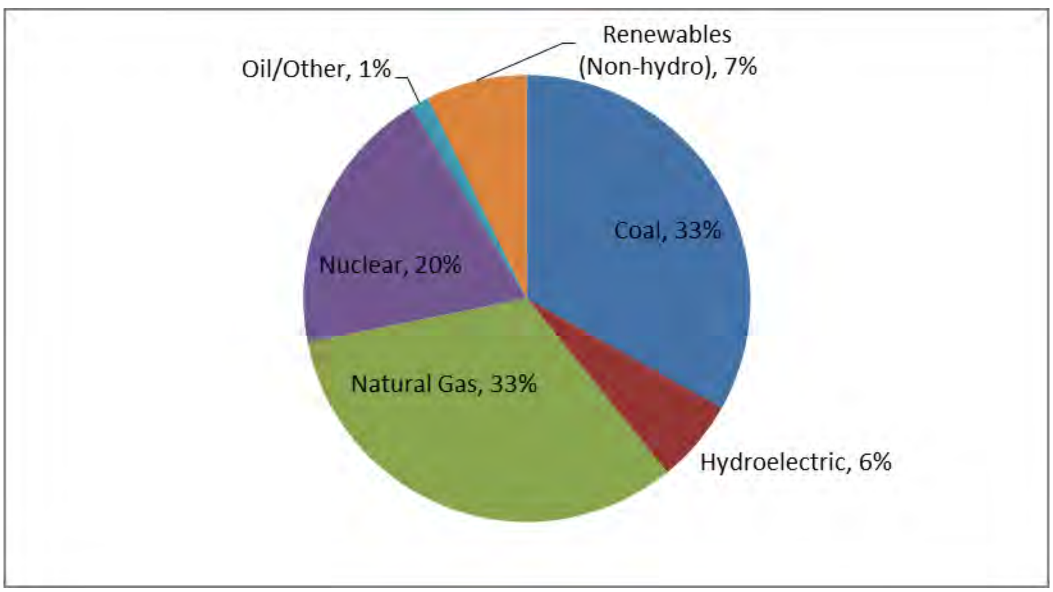
[30] The source for all resource mix comments in this section is *Electricity & Fuel Price Outlook*, *Midwest Spring 2015*, ABB, unless otherwise noted.

Figure 5.8 – U.S. Generating Capacity by Fuel Type (2015)



Source: EIA

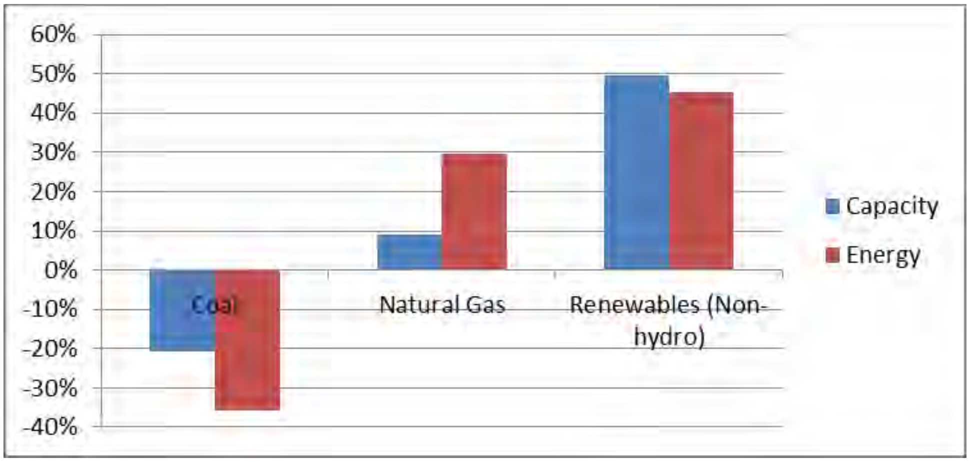
Figure 5.9 – U.S. Electric Power – Electricity Energy Production (2015)



Source: EIA

Compared to similar data in 2009 as shown in Figure 5.10, the trend is for natural gas and renewables to play a larger role in the generation mix, both for energy and capacity, and for the role of coal to decline. The change for renewables is the most pronounced, although it is also true that this category started from a small base which tends to magnify the change on a percentage basis. Nonetheless, renewable energy technologies will clearly play an increasingly important role in the U.S. generation portfolio.

Figure 5.10 – Variation of Resources (2015 compared to 2009)



Source: EIA

It is worth noting that the changes in capacity and energy include two different drivers for coal and natural gas: Coal capacity was retired due in large part to increasing environmental regulation costs and new natural gas capacity was built over this period. This in turn has led to some of the changes in energy production. Energy production from coal and natural gas has also responded to the decreased cost of natural gas which has led to increased utilization of natural gas capacity and decreased use of coal capacity.

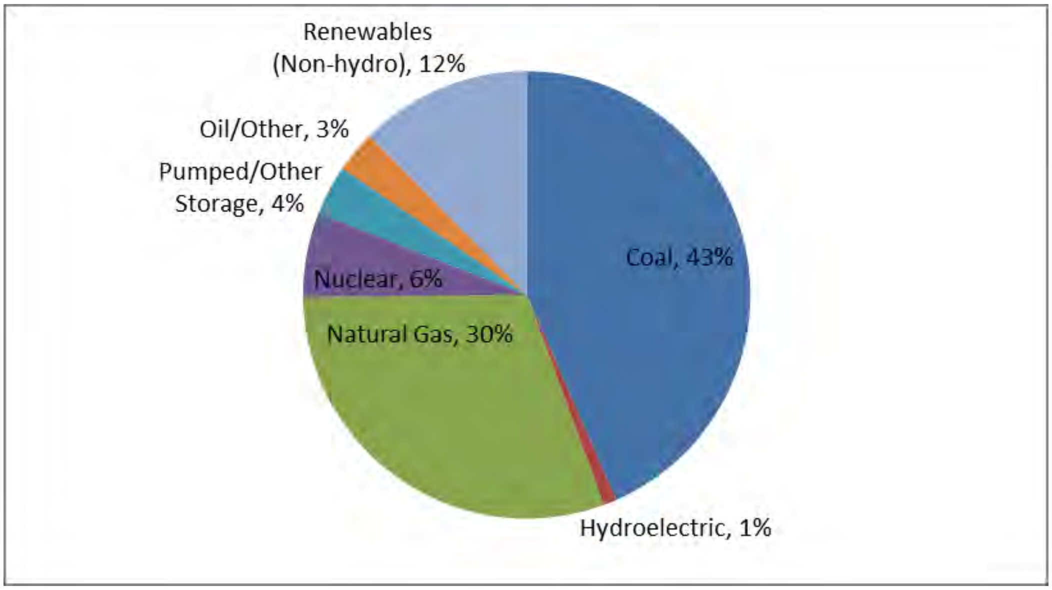
Recent trends suggest that natural gas and renewables will continue to increase their role in the U.S. generation mix, but the sheer size of the installed coal generating resources will continue to make it an important contributor. Nuclear and hydroelectric resources will likely continue to remain flat or decline on a relative basis as fewer new resources are constructed primarily due to higher costs.

5.2.2. MISO Resource Mix

As a market participant in the MISO markets as described in Section 2, IPL customers benefit from the diverse resources found in the 15 states and part of the Province of Manitoba that make up the MISO Footprint.

IPL is located in the North Region of MISO. The generating mix for the 11 state North Region is fairly distinct from the four states which make up the MISO South Region. As shown in Figure 5.11, the MISO North Region relies heavily on coal-fired generating resources for capacity, although this percentage has decreased 18% from 2010, when coal was 53% of the MISO North generating mix.

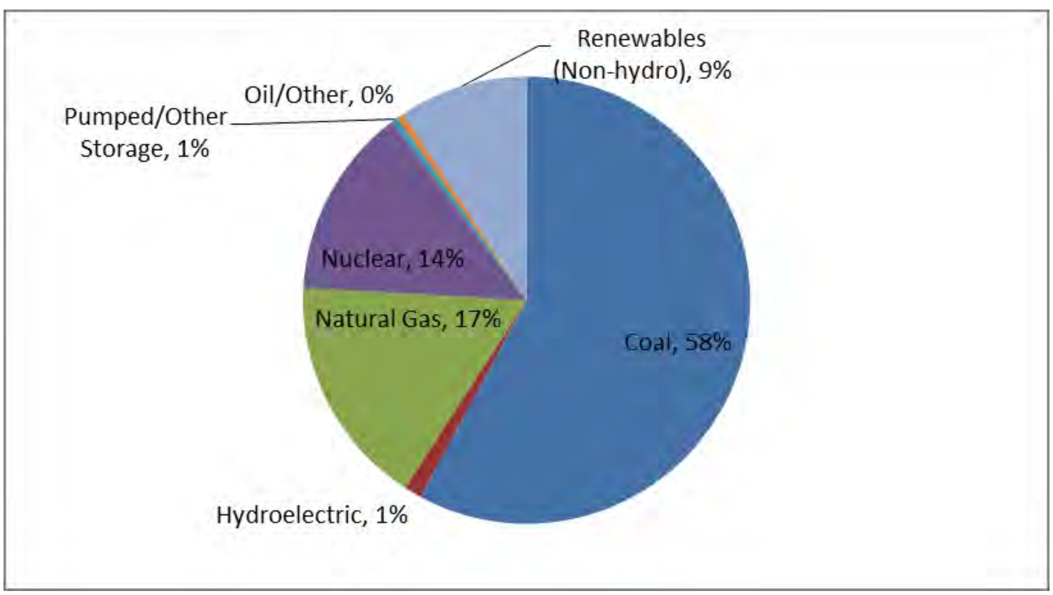
Figure 5.11 – MISO-North Generating Capacity by Fuel Type (2016)



Source: Data provided by MISO to IPL in an email on September 6, 2016.

As an energy source, coal plays an even larger role in the production of electrical energy, where it has a 58% share in Figure 5.12. Here too, however, there has been a decline; in 2010 coal was responsible for 75% of the energy production in MISO. This is driven by the same trends noted above for the U.S. as a whole. From 2000, until April 2016, approximately 9.1 GW of coal-fired capacity has retired within MISO, according to data supplied by SNL.[31]

Figure 5.12 – MISO-North Generating – Electricity Production (YTD through 9/1/2016)



Source: Data provided by MISO to IPL in an email on September 6, 2016.

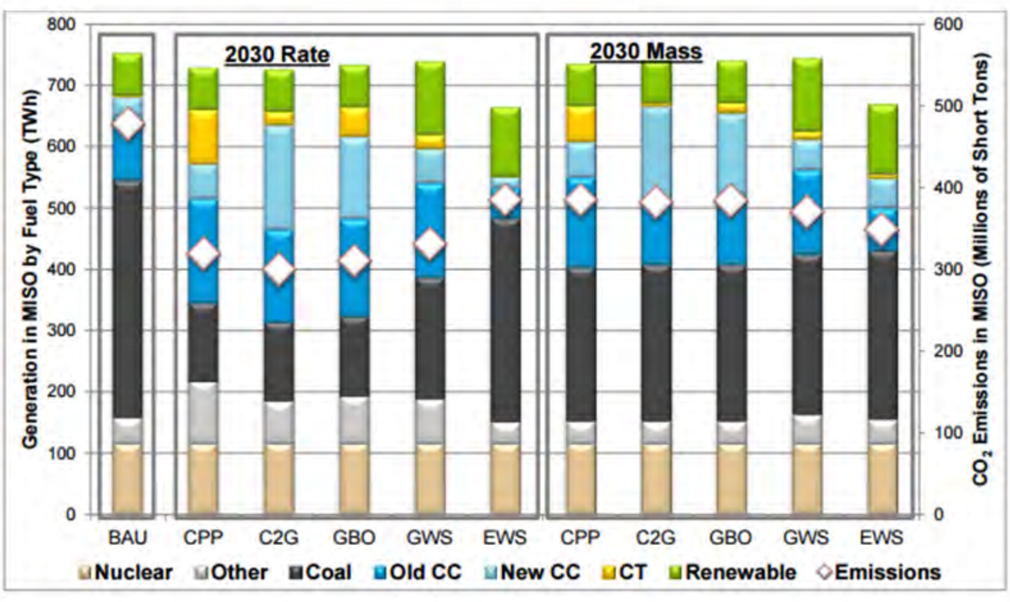
[31] Analysis by author of data listed on coal retirements at https://www.snl.com (subscription required).

The next most prevalent fuel-type after coal is natural gas fired generation, which accounts for almost 30% of the generating capacity in the MISO North Region as shown in Figure 5.11. Natural gas resources produce 17% of the energy in the region, which represents a 6% increase since 2010 as shown in Figure 5.12. Natural gas capacity frequently sets the price in MISO for many hours. Energy production from natural gas is expected to increase within the MISO North Region.

The mix of generation is relatively homogeneous across the sub-regions within the MISO North Region; however, the north and west sub-regions host most of the wind resources, while the east has the largest quantity of nuclear resources.

However despite these negative headwinds, however, coal is projected to continue to play a significant role in the U.S. generation mix. MISO's *Mid-Term Analysis of the Clean Power Plan* projects that coal will continue to remain part of the MISO portfolio for each of the scenarios that MISO considered. MISO considered the following scenarios under both rate-based and mass-based implementation plans for CPP.[32] Business as Usual ("BAU"), CPP Constraints ("CPP"), Coal-to-Gas Conversions ("C2G"), Gas Build-Out ("GBO"), Gas, Wind, and Solar Build-Out ("GWS"), and Increases Energy Efficiency with Wind and Solar Build-Out ("EWS") as shown in Figure 5.13.[33]

Figure 5.13 – 2030 Generation in MISO by Fuel Type across MISO CPP Scenarios



[32] A rate-based implementation plan for CPP will set and measure goals in pounds of CO_2 per megawatt hour (lbs/MWh) while a mass-based implementation plan will set and measure goals in total tons of CO_2 emissions.
[33] *MISO Analysis of EPA's Final Clean Power Plan Study Report.* MISO. July 2016.

5.3. Supply-Side Resource Options

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

For planning purposes in this IRP, IPL selected a group of reference units that represent proven and commercially available technologies, as well as emerging technologies considered viable in the next five to 10 years. The reference units represent four natural gas-fired options (including one natural-gas fired Combined Heat & Power option), one nuclear case, and three renewable choices. Two Battery Energy Storage System ("BESS") options were also included and are described separately.

Coal options were not considered since Supercritical Pulverized Coal ("SCPC") no longer appears to be a viable option due to EPA Section 111(b) regulations on greenhouse gas emissions for new sources. Likewise, IPL has not considered Integrated Gasification Combined Cycle ("IGCC") since this technology has yet to become widely adopted.

In the IPL 2011 IRP, the Company determined hydroelectric power was not a viable resource. There have been no significant changes since that analysis; hence, hydroelectric power has not been included in this IRP.

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 – F-Class ("F-Class")
- Combined Cycle Gas Turbine – H-Class ("H-Class")
- Combined Heat and Power ("CHP")

Nuclear and Renewables

- Nuclear ("Nuclear")
- Utility Scale Photovoltaic ("PV")
- Community Solar ("CS")
- Wind

Battery Energy Storage Systems ("BESS")

- Battery – Large BESS
- Battery – Medium BESS
- Battery – Small BESS (a ½ MW battery to support wind resources as described below)

Please note that all the capital costs used in the IRP model reflect "overnight costs". As the name implies, overnight costs represent pricing the costs of a unit as if it could be built in one day. Separate assumptions on commodity and labor-price escalation are included in the ABB modeling to adjust these costs to the year a unit is brought online. IPL assumed significant cost decreases for renewable and battery technologies. In addition, Allowance for Funds Used during Construction ("AFUDC") cost is also included in the model runs.

The Supply-Side Resources considered in IPL's IRP modeling are listed below in Figure 5.14 along with MW capacity and installed costs. The installed costs in the table below are indicative prices and are not the actual modeled prices, since those prices are confidential. A more detailed chart with the resource option cost information is available in Attachment 5.1 and Confidential Attachment 5.1.

Figure 5.14 – Public Data Sources, Supply-Side Resource Cost Chart

IRP Resource Technology Options		
	MW Capacity	**Representative Overnight Cost per Installed kW**
Simple Cycle Gas Turbine[1]	210	$700 (2012$)
Combined Cycle Gas Turbine – H-Class	400	$1,000 (2012$)
CHP – industrial site (steam turbine)[6]	10	Ranges from $670 - $1,110 (real$)
Nuclear[1]	200	$5,500 (2012$)
Solar[4]	> 5	$2,120 (2015$)
Wind[2,3]	100	$1,980 (2014$)
Energy Storage – Medium BESS	20	$1,000 (real$)

[1] These costs, from *EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants Report* (published April 2013), are shared as proxies for IPL's confidential costs. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

[2] Excludes transmission costs.

[3] U.S. Energy Information Administration | *Assumptions to the Annual Energy Outlook 2015*.

[4] 2015 SunShot National Renewable Energy Laboratory ("NREL") Solar Report, *Photovoltaic System Pricing Trends*, normalized and converted from DC to AC, utility scale defined as greater than 5MW. Retrieved from: https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf.

[5] AES Energy Storage Website http://www.aesenergystorage.com/choosestorage/.

[6] EPA Combined Heat and Power Partnership. Retrieved from: https://www.wbdg.org/resources/chp.php.

In addition to traditional generating units, transmission projects, efficiency improvements and Smart Grid resources are considered part of IPL's portfolio on an on-going basis. IPL submits transmission expansion and improvement projects to MISO as part of its transmission planning process. MISO determines the benefits of such projects and includes those that are cost-effective in its MISO Transmission Expansion Plan ("MTEP") on an annual basis as further described in Section 2.

IPL considers efficiency improvements that may provide additional generating capacity on an on-going basis. IPL has secured a permit for potential addition of a Continuous Emissions Monitoring System ("CEMS") at its Georgetown Station to allow increased utilization of those units if it becomes economically reasonable in the future. This may result in higher capacity factors but no additional MWs.

The technology and size of units selected for capacity additions will depend on a number of factors including, among others, load and energy demand growth and best available technologies at time of construction. In the write-up on technology below, IPL indicates the size in megawatts of each unit under consideration, and the size of an IPL portion of the plant. So as to not skew the results, IPL is using a "common size" of 200 MW for the CCGT and Nuclear options, for example, to represent a portion of those plant outputs and costs.

This analysis is neutral on whether the underlying resource would be built by IPL using competitive bidding, jointly owned by IPL and another utility, or owned by a third party and contracted through a Power Purchase Agreement ("PPA") or similar arrangement. Given the sophisticated market in the U.S. for engineering, procurement and construction services, the underlying costs of either option are likely to be similar at the level of analysis being conducted in this IRP. IPL has used both options in the past to secure new generation capacity, and will obtain specific project cost information through competitive processes and perform in-depth analysis on the "build versus buy" decision to ensure the reasonable least cost option is determined before proposing any plan to the IURC for approval.

A brief description of each of the technology alternatives currently or potentially available to IPL to meet future capacity needs follows.

5.3.1. Natural Gas

IPL evaluated four types of natural gas-fired generation in the IRP analysis. Natural gas-fired units have historically had low dispatch rates in the Midwest due to a cost-competitive installed coal-fired fleet. However, natural gas-fired generation in the Midwest has increased significantly in recent years due to increasing regulation of coal generation coupled with increased natural gas supply and low natural gas prices. An Indiana example is the Sugar Creek CCGT plant owned by NIPSCO. It is a 561MW, 2x1 F-Class CCGT. According to publically available data, it operated in the 20% capacity range in 2010, but the capacity factors have increased in subsequent years to 90% and above by 2015.

5.3.1.1 *Simple-Cycle Combustion Turbine*

For purposes of the IRP analysis, IPL assumed the incremental addition of a 160 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. However, one disadvantage of CTs is the relatively high average heat rate which increases the amount of fuel needed to produce a MWh of electricity and resulting high operation costs at low capacity factors.

IPL has substantial experience in both the construction and operation of simple-cycle CTs. IPL’s existing units include Georgetown Generating Station (“Georgetown”) Unit 1 added in 2000, and Harding Street Generating Station (“HSS”) CT 6 added in 2002. IPL also purchased Georgetown Unit 4 in 2007. IPL monitor developments in CT technology and will continue to consider CTs as a generation option due to their flexibility in adding small increments of capacity within a relatively short time frame. Please also refer to the discussion below in BESS for using energy storage as an alternative to CT technology.

5.3.1.2 *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. IPL is constructing a 671MW F-class CCGT at Eagle Valley, which is projected to come on line in spring 2017.

It is anticipated that by the commercial operation date of any new CCGT, both F- or H-class machines will be widely in-service at other North American utilities and will represent a proven choice for IPL. For all technology choices described in this IRP, IPL modeling is based on the most current information. But IPL is also aware that more advanced choices are likely to be available at the time an actual project is bid and constructed.

IPL has modeled both the F- class and H-class machines in its analysis. Additionally, the units have low pollutant emissions, low water consumption levels, reduced space considerations and modular construction. IPL continues to monitor developments in CCGT technology and will evaluate CCGT alternatives in any decision for future capacity additions.

5.3.1.3 *Combined Heat & Power (CHP)*

As the name implies, a Combined Heat & Power ("CHP") unit is capable of the simultaneous generation of electricity and useful heating, cooling or process steam from the combustion of one energy input. For this analysis, the combustion fuel is natural-gas, although coal could also be used as a fuel. CHP is a thermodynamically efficient use of fuel.

CHP is sometimes also called Cogeneration. Although the terms CHP and Cogeneration are used interchangeably, CHP is more often used to describe units capable of the simultaneous generation of electricity and useful heating and/or cooling, whereas Cogeneration is used to refer to the simultaneous generation of electricity and process steam. The former is often located in government buildings, hospitals, universities or similar campuses, and the latter is generally found in manufacturing plants, including food processing facilities.

Because CHP cost and performance assumptions were not included in ABB's Fall 2015 Reference Case, IPL commissioned the engineering firm of Burns & McDonnell to prepare a report for this information, which is included as Attachment 5.2 and Confidential Attachment 5.2, "Modeling Parameters – Generic CHP," May 20, 2016.

Indiana currently has 42 separate CHP/cogeneration plants totaling 2,300 MW,[34] putting the state in the top 10 for CHP capacity in the United States.[35] An IPL customer, MacAllister has publically identified a new 0.6 MW CHP being constructed at its new facility on the southeast side of Indianapolis.[36] However, one factor working against the siting of CHP within Indianapolis is the significant district heating and cooling system owned and operated by Citizens Energy. This system is the second largest of its type in the U.S., and is already providing process steam for many facilities which might otherwise benefit from CHP.

Note that CHP and CCGT technologies are very similar. In the case of a CCGT, there is the simultaneous generation of electricity through one or more combustion turbines, the capture of waste heat to create steam, and the use of the steam to produce electricity through a steam turbine generator. CHP systems are normally much smaller than CCGTs and cited for individual customers connected at distribution circuit or sub transmission voltage level.

[34] Presentation by the Indiana Electric Association to the Indiana General Assembly Interim Study Committee on Energy, Utilities and Telecommunications, "Customer Owned Generation: Tools and Transitions." September 2, 2015.
[35] "Combined Heat and Power (CHP) Technical Potential in the United States." U.S. Department of Energy, March 2016.
[36] "Combined Heat & Power, A Case Study in the Design & Development of a CHP Project in Indiana," September 18, 2016.

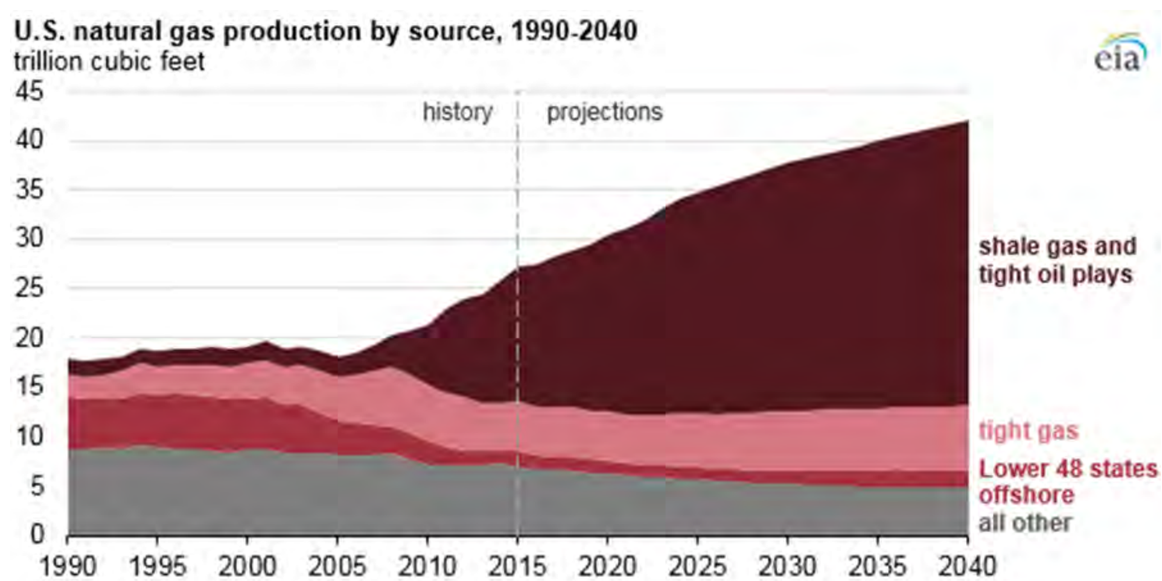
5.3.1.4 *Shale and the New Gas Supply Paradigm*

Natural gas technologies are important in the 2016 IPL IRP analysis of new supply options because environmental regulations are pushing U.S. utilities to retire existing coal assets. As important, however, is the emergence of shale gas and the significant increase in available U.S. natural gas resources.

Geologists have long known that shale formations contained significant amount of natural gas, the formations are not porous, and the gas cannot flow freely when wells are drilled. Combining the practice of horizontal drilling with hydraulic fracturing caused a breakthrough in commercial drilling in shale formations. Hydraulic fracturing (sometimes called “Fracking”) is the process of using high pressure liquids to create cracks in the shale, which then allows the gas to flow.[37]

Between 2005 and today, the rate and range of shale gas development from fracking expanded in many parts of the county, as noted in Figure 5.15 below from the EIA “Annual Energy Outlook 2016.” EIA notes in that report that the “growth in total U.S. dry natural gas production projected . . . results mostly from increased development of shale gas and tight oil plays. Natural gas resources in tight sandstone and carbonate formations (often referred to as “tight gas”) also contribute to the growth to a lesser extent, while production from other sources of natural gas such as offshore, Alaska, and coalbed methane remains relatively steady or declines.”[38]

Figure 5.15 – Projected Domestic Gas Supply



[37] *Task Force on Ensuring Stable Natural Gas Markets*, 2011 Report, Bipartisan Policy Center and American Clean Skies Foundation, pp. 35-36.

[38] http://www.eia.gov/todayinenergy/detail.cfm?id=26552.

With traditional domestic U.S. gas drilling, most operations are in relatively unpopulated areas. Shale gas operations include more populated areas, leading to more chance of public opposition and possible water pollution. The natural gas industry and environmental officials have begun paying more attention to these issues and must take the steps necessary to avoid any significant environmental degradation. Furthermore, potential future environmental regulations on fracking may impact the cost and usage of natural gas for power production.

5.3.2. Nuclear

170 IAC 4-7-6(c)(2)

Improved technology and declining costs are causing solar, wind, and battery energy storage to become major players in the U.S. energy sector, and nuclear is seeing a small renaissance in the southern U.S.

Although IPL chose to include a nuclear option within this analysis, it is not anticipated that IPL will build or buy a greenfield nuclear plant. Rather, due to permitting and other issues, IPL could procure a minority interest in the development of a new nuclear plant at an existing site. Recent nuclear projects in the U.S. have experienced both cost overruns and time delays.

At one point, generator owners with a total of 23 new reactors requested Construction and Operating Licenses ("COLs") from the Nuclear Regulatory Commission ("NRC"). Due to uncertainty about construction costs and financing issues, most of these projects have now been delayed or cancelled, although several projects are moving forward in the southern U.S..

The Tennessee Valley Authority's ("TVA") Watts Bar Unit 2 nuclear plant was connected to the power grid on June 3, 2016, becoming the first nuclear power plant to come online in the U.S. in twenty years. According to EIA, "construction on Watts Bar Unit 2 originally began in 1973, but construction was halted in 1985 after the NRC identified weaknesses in TVA's nuclear program. In August 2007, the TVA board of directors authorized the completion of Watts Bar Unit 2, and construction started in October 2007. At that time, a study found Unit 2 to be effectively 60% complete with $1.7 billion invested. The study said the plant could be finished in five years at an additional cost of $2.5 billion. However, both the timeline and cost estimate developed in 2007 proved to be overly optimistic, as construction was not completed until 2015, and costs ultimately totaled $4.7 billion."[39]

In its description, EIA further noted that "four other reactors are currently under construction and are expected to join the nuclear fleet within the next four years. Vogtle Electric Generating Plant Units 3 and 4 in Georgia and Virgil C. Summer Nuclear Generating Station Units 2 and 3 in South Carolina are scheduled to become operational in 2019–2020, adding 4,540 MW of generation capacity." Both projects have experienced delays in schedule and increases in cost.

[39] https://www.eia.gov/todayinenergy/detail.cfm?id=26652.

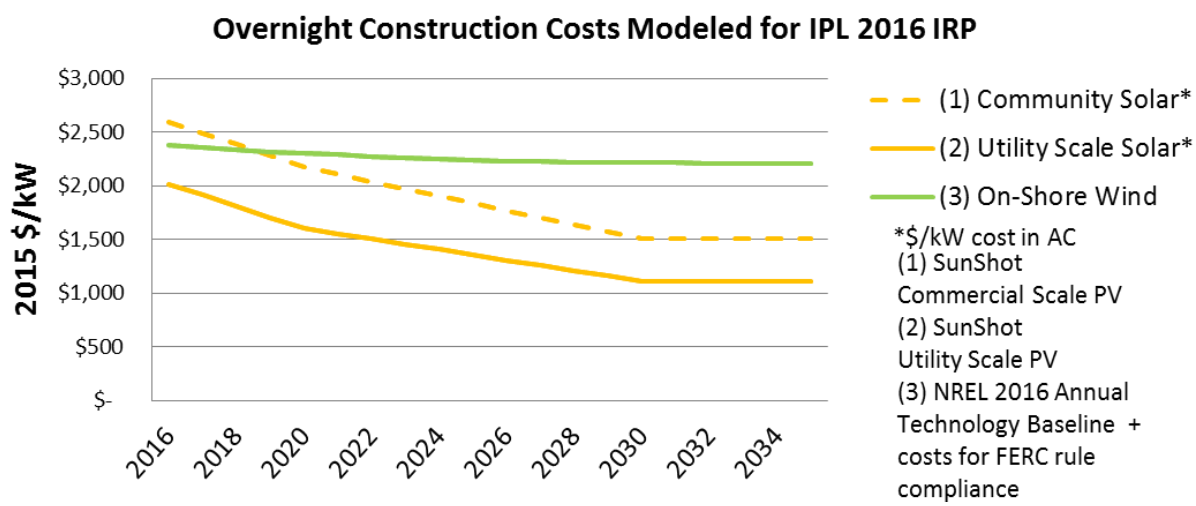
IPL continues to monitor developments in nuclear and renewable energy technology and will consider nuclear alternatives in any decision for future capacity additions.

5.3.3. Renewables

Renewable energy is an increasingly important part of the U.S. energy mix, as noted above; this is being driven by favorable public policy, interest-group activity, and falling costs. The installed cost of solar fell 54% from 2009 to 2015, according to the U.S. Department of Energy.[40] The national average PPA price for wind projects reported to the Lawrence Berkeley National Laboratory ("LBL") fell 70% from 2009 to 2015.[41] The same study found that the average PPA price for wind in the Great Lakes Region, which includes Indiana, fell 50% from 2009 to 2015. According to IHS Inc., the cost of Lithium-ion batteries fell 53% from 2012 to 2015.[42]

As Figure 5.16 shows, the cost of wind parks and solar farms are projected to keep falling throughout the IRP study period.

Figure 5.16 – Wind and Solar Cost Curves



This IRP makes reference to IPL existing and potential future wind and solar projects. It should be noted that in the absence of any mandatory federal or state Renewable Portfolio Standard ("RPS"), IPL is currently selling the associated Renewable Energy Credits ("RECs"), but reserves the right to use RECs from existing PPAs to meet any future RPS or similar such requirements, such as a carbon tax or carbon cap and trade legislation.

[40] http://energy.gov/eere/sunshot/photovoltaics.
[41] Wiser, Ryan H., and Mark Bolinger. *2015 Wind Technologies Market Report*. U.S. Department of Energy. August 2016. https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.
[42] http://press.ihs.com/press-release/technology/price-declines-expected-broaden-energy-storage-market-ihs-says.

With the sale of the RECs, the null energy[43] is used to supply the load for IPL customers, As approved by the IURC, if IPL chooses to monetize the RECs that result from the agreements, IPL shall use the revenues to first offset the cost of the PPAs and next to credit IPL customers through its fuel adjustment clause proceedings. When the RECs associated with the production of null energy from the wind PPAs are sold to a third party, IPL does not claim that energy as renewable energy on behalf of its retail customers.

5.3.3.1 *Solar*

For this IRP, IPL reviewed Utility Scale Photovoltaic ("PV") and Community Solar ("CS") information. According to the Solar Energy Industries Association, the "U.S. installed 1,665 megawatts ("MW") of solar PV in Q1 2016 to reach 29.3 gigawatts ("GW") of total installed capacity, enough to power 5.7 million American homes. With more than 1 million individual solar installations nationwide, the industry is on pace to nearly double in size in 2016. The residential solar market remained strong, with a fourth consecutive quarter with more than 500 MW of capacity brought online."[44]

IPL is a leader in encouraging the growth of solar energy. IPL has 96 MW of utility-scale PV operating, with another 2 MW in development; these are contracted through PPAs under IPL's Rate Renewable Energy Production ("REP"). According to the report, "Shining Cities 2016: How Smart Local Policies Are Expanding Solar Power in America," Indianapolis is ranked number two in the entire United States in per capita installation of solar photovoltaic. First on the list is Honolulu, Hawaii.[45]

IPL supporting net metering prior the IURC expanding the Net Metering rules to include all customers and increased the maximum nameplate rating to 1 MW in the early 2000s. As previously discussed in this section, IPL net metered customers collectively contribute 1.5 MW, primarily from residential customers on a volume basis. The increase residential participation has been influenced by the decline in PV panel costs and extension of the Investment Tax Credit. Commercial customers continue to have limited participation.

IPL continues to monitor developments in PV technology and will consider PV alternatives in any decision for future capacity additions. IPL consulted with colleagues from the AES Distributed Energy team which develops solar projects internationally to review construction cost forecasts. IPL modeled production data 8760 hours per year from its Rate REP experience in the IRP. The two illustrations in Figure 5.17 below show two sample days from IPL's Rate REP and the load for those days.

---

[43] The Green-e Dictionary (http://www.green-e.org/learn_dictionary.shtml) defines null power as, "Electricity that is stripped of its attributes and undifferentiated. No specific rights to claim fuel source or environmental impacts are allowed for null electricity. Also referred to as commodity or system electricity."

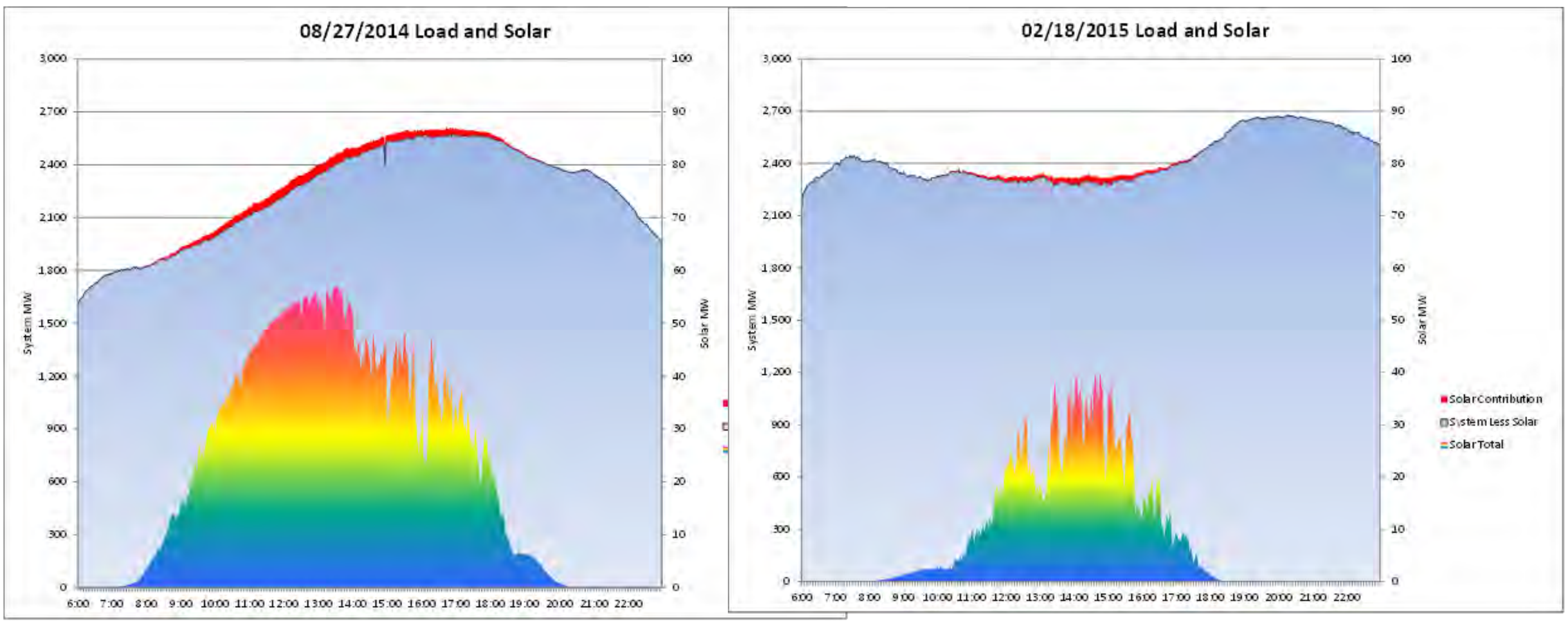
[44] http://www.seia.org/research-resources/us-solar-market-insight.

[45] "Shining Cities 2016: How Smart Local Policies Are Expanding Solar Power in America," by Kim Norman, Frontier Group and Rob Sargent and Bret Fanshaw, Environment America Research & Policy Center. April 2016.

These charts both show the intermittent nature of solar production and to what extent solar helps IPL meet peak energy needs. As shown below, solar production in the summer somewhat helps meet peak energy needs. However, because peak energy needs in the winter take place in the evening after the sun has gone down, solar production in the winter does not help meet peak energy needs. Due to intermittent solar production throughout the day, as well as lower solar production in the winter, MISO gives solar resources capacity credit of 50%.[46] This means that for every 100 MW of solar that an entity installs, MISO will allocate capacity credit of 50 MW. Therefore if an entity needs 100 MW of new capacity to comply with reserve margin requirements, it would need to secure 200 MW of solar PV.

Figure 5.17 – Solar Production and Load in the Summer versus the Winter

Summer Winter



IPL's model allowed additional PV to be selected in 10 MW blocks and CS to be selected in 1 MW increments.

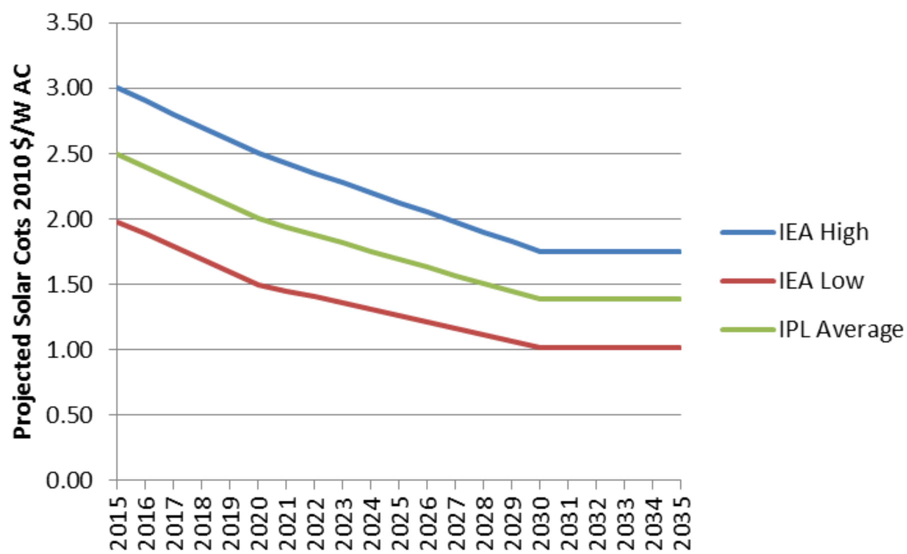
IPL used a declining cost curve for modeling solar installed costs with PV solar (10 MW) costs less than smaller scale CS (1 MW) in the IRP model. IPL calculated forecasts starting from the U.S. DOE 2015 SunShot Initiative Photovoltaic System Pricing Trends report.[47] The cost graphs presented in the SunShot report are high and low projections from the International Energy Administration ("IEA"). IPL assumed PV and CS costs as an average of the high and low IEA numbers as shown in Figure 5.18 below. The ABB Fall Reference Case included higher solar

[46] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf page 141

[47] https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf.

costs which IPL believes are less realistic based on discussions with stakeholders including the AES Distributed Energy team and recent industry reports of downward trends. Real dollar costs are converted to nominal costs in the IRP model.

Figure 5.18 – IPL Developed Solar Construction Cost Curve (2010 $/W AC)



Costs are in dollars per watt ($/W) AC. This was then converted to 2015 $/W and then to nominal dollars for the final IPL input into the model. Alternating Current ("AC")is electric charge, or current, that flows directionally and changes direction periodically. Conversely, Direct Current ("DC") is electric charge that is one directional. The inverters installed with the solar installation convert the current from AC to DC. An industry rule of thumb to convert estimated DC costs to AC costs is 80%.[48]

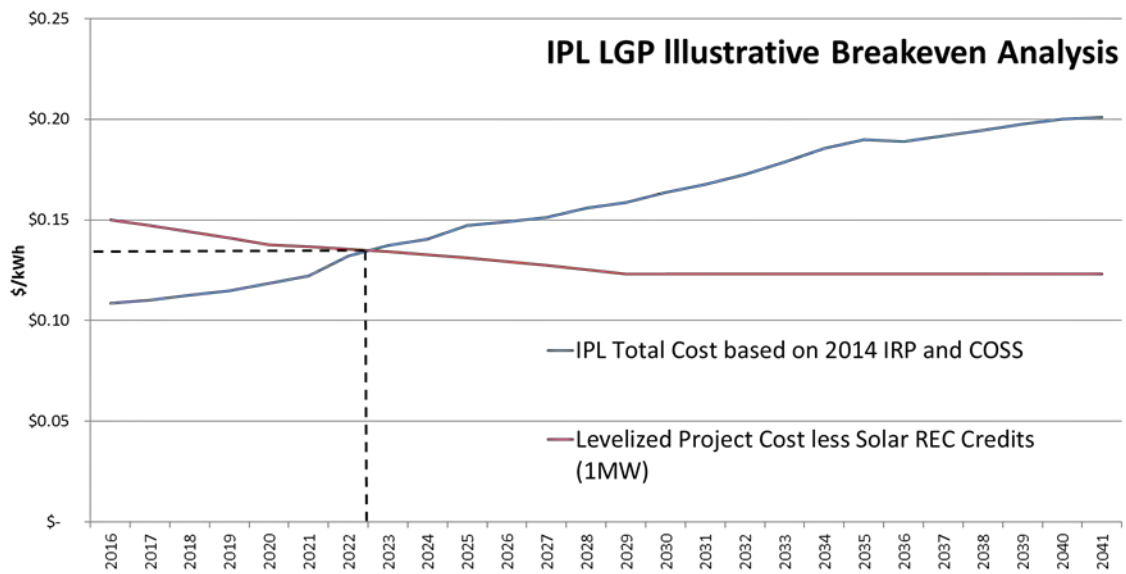
5.3.3.2 *Community Solar*

A solar option that is increasing throughout the U.S. is Community Solar ("CS"). Community Solar, sometimes referred to as Shared Solar, allows program participants to pay for their share of a local renewable generation project. This generation provides electricity to the grid, then program participants are credited their portion of the energy produced. As of late 2015, there were approximately 68 active CS programs throughout the country. Of the active programs, over 80% are under 1MW in size.[49] CS programs provide customer and utility benefits. Many customers may not live in an owner occupied home, so private solar is not an option for them. CS also provides a tool for customer engagement for the utility sponsoring the program.

[48] http://understandsolar.com/calculating-kilowatt-hours-solar-panels-produce/.
[49] https://www.solarelectricpower.org/media/422095/community-solar-design-plan_web.pdf.

In Q1 2016, IPL formed a Local Green Power Advisory ("LGP") Committee of stakeholders to discuss the possibility of increasing local opportunity for renewables through an enhanced green power program. Attachment 5.4 contains LGP Committee information. IPL led open discussions about potential benefits of facilitating additional renewable development, performed cost analyses of a potential Community Solar project and presented the analysis and findings to the committee members. This analysis showed the current prohibitive cost to create such a program at this time, but IPL modeled CS in the IRP as a potential selectable resource. As part of the LGP Committee Advisory Process, IPL calculated an illustrative break-even analysis to determine at what cost an IPL sponsored CS project may compete with future retail electric rates based on historic IRP and Cost of Service Study ("COSS") data which is presented in Figure 5.19 below.

Figure 5.19 – IPL Breakeven Analysis for Community Solar



5.3.3.3 *Wind*

Continued improvement of large-scale, utility-grade wind turbine generators ("WTG") into the marketplace has made wind energy a commercially viable technology in Indiana and the U.S. Increases in turbine heights and blade lengths have significantly lowered the cost of wind per installed kW and allowed the WTG to reach higher wind speeds.[50] Advances in wind technology coupled with high wind speeds in Northern Indiana made Indiana a hot spot for wind development starting in 2008. An 80 meter turbine height was common in Benton County for some of the early Indiana wind projects. From 2012-2015, 67% of WTGs installed in the Great

[50] Wiser, Ryan H., and Mark Bolinger. *2015 Wind Technologies Market Report*. U.S. Department of Energy. August 2016. https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.

Lakes Region, which includes Indiana, have a hub height above 90 meters, which further increases the potential for wind energy potential in Indiana.[51] Likewise, the Midwest is favored with several very good wind basins, allowing generation to be diversified and take advantage of metrological variances.

Wind speeds are important in determining WTG performance. The power available to drive WTG is proportional to the cube of the speed of the wind. In other words, a doubling in wind speed leads to an eight-fold increase in power output. Higher wind speeds are not only important for generation; they also tend to lower the cost per kWh of the electricity produced. Wind parks generally have very high fixed costs (i.e., most of the cost of operating a wind park is the initial capital and financing costs), yet the availability to spread this fixed cost over more hours of production per year reduces the hourly cost of electricity.

Currently, IPL's resource portfolio has two long-term Wind Power Purchase Agreements ("PPAs") for a total of 300 MW. The Lakefield Wind Farm is located in Minnesota and has a nameplate capacity of 200 MW. The Hoosier Wind Farm is located in Benton County, Indiana and has a nameplate capacity of 100 MW. Under the terms of the Wind PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") from the two wind farms.

As shown in Figure 5.20, IPL has seen mixed performance of Hoosier and Lakefield wind parks.[52] The capacity factors of the Hoosier and Lakefield wind parks have varied from year to year, due to a combination of variations in annual wind speeds and transmission line congestion.

Figure 5.20 – Capacity Factors of IPL Wind PPAs

	Hoosier Wind Park	Lakefield Wind Park
2012	21%	25%
2013	13%	23%
2014	13%	24%
2015	21%	30%

Transmission line congestion can result in curtailments of wind. MISO estimates that 5.4% of potential wind generation in its footprint was curtailed in 2015. For the 2016 IRP, IPL modeled the Hoosier and Lakefield wind parks with an annual average capacity factor of 16% and 25% respectively, through the end of their contracts. IPL assumed that the both PPA contracts will be renewed, at which point the wind farms would see 35% capacity factors due to an improved transmission system. IPL models new wind as having capacity factors of 35%, with the

[51] Wiser, Ryan H., and Mark Bolinger. *2015 Wind Technologies Market Report*. U.S. Department of Energy. August 2016. https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.
[52] The capacity factors are calculated with the assumption that Hoosier Wind Farm has a nameplate capacity of 100 MW and Lakefield Wind Farm has a nameplate capacity of 200 MW.

expectation that transmission projects to accommodate additional wind will be completed through the MISO Transmission Expansion Planning ("MTEP") process.

Good wind sites usually are located far from the main load centers; therefore, transmission system expansion may be required to connect the load centers with the wind-rich sites. Opposition to siting new transmission lines is a common occurrence and can slow down such projects.[53]

IPL currently does not receive any capacity credit from MISO for its Hoosier and Lakefield wind parks. In other words, IPL cannot count Hoosier or Lakefield Wind Parks towards its capacity for State or MISO planning reserve requirements. For this IRP, IPL monitored new wind farms at a 10% capacity credit starting in 2030. This means that if IPL enters into another PPA for a 100 MW wind farm, IPL can count 10 MW of that wind towards its capacity.[54] IPL continues to monitor developments in wind technology and will consider wind alternatives in any decision for future capacity additions.

IPL used NREL's public 2016 projections for wind costs, which align with ABB's cost assumptions.[55] IPL applied NREL's declining costs which were more aggressive than the ABB forecast. Additionally, IPL added cost assumptions for 1) frequency response (via a Small BESS) per proposed order in FERC docket RM16-6, and 2) reactive power (via Static VAR Compensator) provisions per recent final FERC Order 827.[56] More information on the Small BESS is provided in the next section.

FERC released RM16-6-000 on February 18, 2016, and FERC Order 827 on June 16, 2016. As baseload, synchronous units retire across the U.S.; fewer generation units are providing reliability services for the U.S. bulk power system. These two FERC orders are meant to address the decline across the U.S. of resources that provide primary frequency response or reactive power.

[53] http://www.southbendtribune.com/news/local/rural-land-targeted-for-new-power-line/article_4d796166-29ba-50bb-ab4f-0b438be51b60.html.

[54] IPL acknowledges the discussion around wind capacity credit in the fourth public advisory meeting. For reference material on wind capacity credit, please see the following resources:

(1) MISO SAWG Presentation Material, specifically see slide 5.
Retrieved from :
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2015/20151202/20151202%20LOLEWG-SAWG%20Joint%20Meeting%20Item%2004%20Wind%20Capacity%20Credit%20Presentation.pdf

(2) Planning Year 2016-2017 Wind Capacity Credit December 2015 – MISO Report,
Retrieved from:
https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf.

[55] NREL 2016 Annual Technology Baseline, April 2016. http://www.nrel.gov/analysis/data_tech_baseline.html

[56] http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf.

FERC docket RM16-6 explains that the following:

> *Reliably operating an Interconnection requires maintaining balance between generation and load so that frequency remains within predetermined boundaries around a scheduled value (60 Hz in the United States). […]Frequency response is a measure of an Interconnection's ability to arrest and stabilize frequency deviations within pre-determined limits following the sudden loss of generation or load. Frequency response is affected by the collective responses of generation and load resources throughout the entire Interconnection.*[57]

IPL modeled RM16-6 as a Small BESS paired with WTGs for frequency response. The energy storage paired with WTGs is meant to control system frequency and maintain grid reliability, and *not* to provide capacity or store energy at times of low demand and then dispatch it at times of high demand. Therefore, IPL did not model the energy or capacity values of the energy storage paired with the wind. Additionally, energy storage, as a tool for frequency response, is not expected to increase the capacity factors of the wind turbines.

FERC Order 827 explains that the transmission "providers require reactive power to control system voltage for efficient and reliable operation of an alternating current transmission system. At times, transmission providers need generators to either supply or consume reactive power."[58] FERC Order 827 states that wind generators are no longer exempt from the uniform requirement for non-synchronous generators to meet the dynamic reactive power requirement, due to the following:

> *Due to technological advancements, the cost of providing reactive power no longer presents an obstacle to the development of wind generation. The resulting decline in the cost to wind generators of providing reactive power renders the current absolute exemptions unjust, unreasonable, and unduly discriminatory and preferential. Further, the growing penetration of wind generators on some systems increases the potential for a deficiency in reactive power.*

FERC Order 827 states that both capacitors and Static VAR Compensators can meet this requirement for reactive power, and IPL modeled this requirement by pairing Static VAR Compensators with WTGs.

IPL will continue to monitor the impact of the new proposed and final FERC rules on the cost of future wind resources.

[57] FERC Docket No. RM16-6-000, February 18 2016. https://www.ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf.

[58] FERC Order No. 827, June 16 2016. http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf

5.3.4. Energy Storage Resources

The category of Energy Storage includes various technologies including but not limited to Fly Wheels, Pumped Storage, Compressed Air Energy Systems ("CAES"), and Batteries. The DOE Global Energy Storage Database lists 570 MW of electro-chemical battery projects as operational in July 2016,[59] with the predominate technology being lithium ion. Battery Energy Storage Systems ("BESS") can be located in many different locations (unlike Pumped Storage and CAES) and can provide a range of attributes which provide benefits to the electric grid (unlike Fly Wheels). Lithium ion batteries as part of a BESS are the leading battery technology today and for the foreseeable future.[60]

Lithium ion storage systems do not generate electricity, but instead store energy generated by other resources. These BESS projects have a unique set of attributes which provide benefits to the electrical grid. Lithium ion batteries can be designed to provide essential reliability services (frequency and voltage control), or they can be configured to provide reliability and peaking services more efficiently than a generating station. As battery costs continue to decline, energy storage will become even more competitive in the future.

Today, lithium ion batteries are providing frequency and voltage control services in the Netherlands, UK, Philippines, Chile, and the U.S. They respond to mitigate deviations in voltage or system frequency or peak energy needs in less than a second whereas generators require materially more time. In California, BESS units have been selected instead of thermal-fired peaking generators in competitive procurements. Their ability to provide multiple services, switch from one to another nearly instantaneously and be continuously available makes lithium ion batteries an economically efficient choice.

One advantage this technology has over generators providing essential reliability services is that generators can only provide service if the generator is dispatched. Lithium ion battery systems can move from a neutral state to full discharge/withdraw nearly instantaneously – like flipping a light switch. It does not have to already be operating or "spinning." It manages its state of charge so that it is continuously available and continuously providing essential services.

This section describes IPL's efforts in the area of lithium ion battery storage. The first part describes the new energy storage project constructed at IPL's Harding Street Station. The second part describes the energy storage resources modeled in this IRP.

---

[59] http://www.energystorageexchange.org/.

[60] IPL appreciates input from stakeholders at the fourth IRP public advisory meeting about vanadium flow batteries; however, these appear to have significantly higher costs at this time. See http://www.sandia.gov/ess/tools/es-select-tool/ for detailed technology cost information.

5.3.4.1 *IPL Advancion® Energy Storage Array*

IPL recently constructed a state-of-the-art facility to serve its customers with 20 MW of battery-based energy storage known as the IPL Advancion Energy Storage Array, which is also known as the Harding Street Station Battery Energy Storage System ("Array" or "HSS BESS"). The Array provides 40 MW of reliability services[61] automatically and continuously with no downtime. The Array responds to deviations in grid frequency by either injecting or withdrawing energy as needed in less than a second. It is the first grid-scale energy storage system in the 15-state Midcontinent Independent System Operator ("MISO") system, and achieved commercial operation on May 20, 2016.

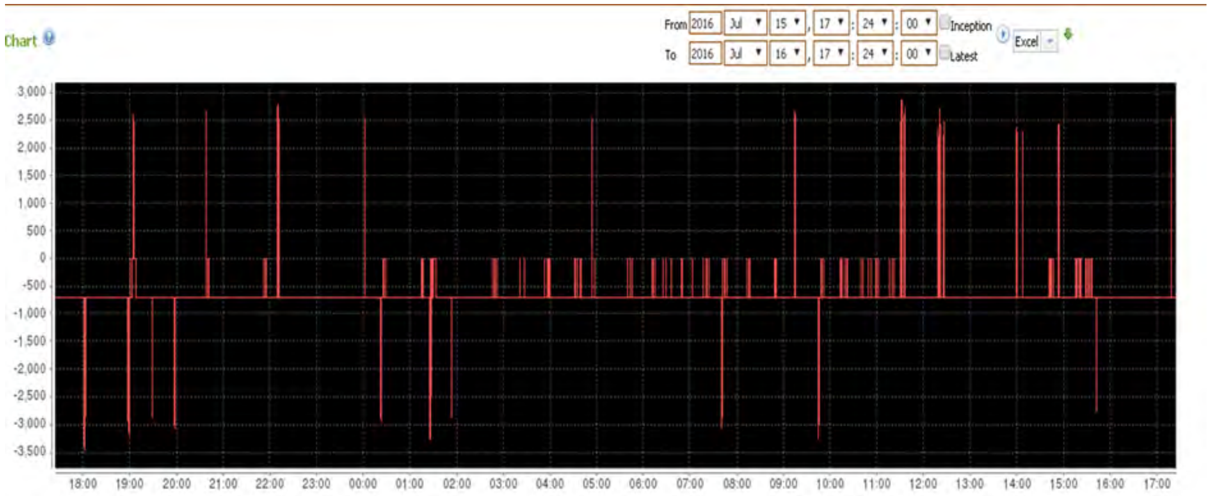
The Array provides the reliability service of frequency control automatically without the need for dispatch or other human intervention. This includes Regulation and Primary Frequency Response ("PFR"), both of which mitigate deviations from the standard of ±60 Hertz. Regulation mitigates the normal and anticipated deviations resulting from real time changes in generation and load. Primary Frequency Response mitigates unanticipated deviations caused by such events as a generator suddenly shutting down or an unexpected significant change in load.

The screen shot in Figure 5.21 below provides an example of the response of the Array on July 15th and 16th earlier this year. The upward bars represent times when the Array added energy to the system in response to dips, whereas the downward bars indicate when energy was removed from the grid.[62] System frequency is generally 60 Hertz.

[61] All figures listed for BESS systems are nameplate MW. Since batteries can be fully either a source for energy or a demand for energy (recharging), batteries can provide grid management services up to twice their stated nameplate rating. Thus a 20MW BESS project can provide +20MW to the grid when energy is needed but also provide 20MW when there is excess power on the grid which can be stored for later use. So a 20MW BESS application provides 40MW of value to the grid unlike a traditional power plant.

[62] The system has a target frequency. There is a tolerance, on both the positive and negative side of the target frequency, where the system does not actively inject or withdraw power based on frequency. This range of non-action is the dead band. When outside of the deadband, the system injects or withdraws power as a function of the frequency it is seeing. As the frequency gets further from the edge of the dead band, the system injects/withdraws more power. The slope of this response is determined by the droop percentage. In this example, the Array has a dead band of 0.036 Hertz.

Figure 5.21 – Battery Array Response



Controlling system frequency is essential for maintaining grid reliability and is an inherent necessity for continued provision of reliable electricity service for customers. When grid frequency varies too far away from 60 Hertz, businesses and households may experience issues with computers, lighting and electric motors. If deviations from the standard are prolonged and of sufficient magnitude additional power plants may trip-off and lead to brownouts or blackouts. A recent study performed by NERC showed PFR in the entire U.S. Eastern Interconnection is declining as increased levels of renewable generation, and decreased levels of traditional generation plants, have led to less inertia to supply the necessary system response.[63]

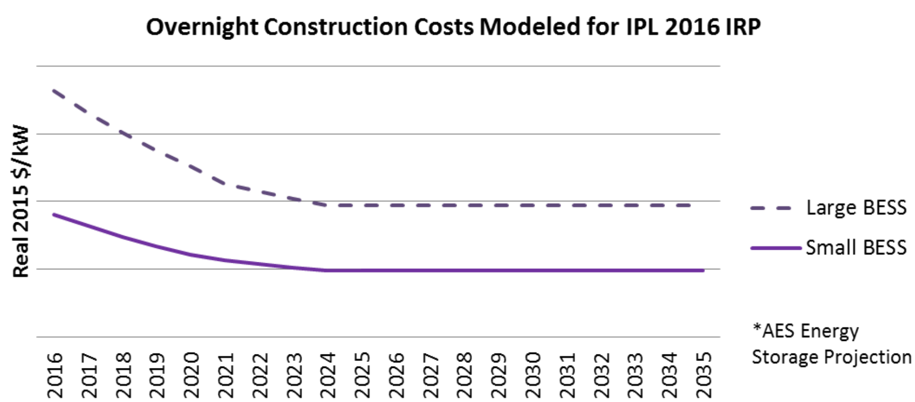
The IPL Array is also a given credit in MISO as a source of capacity to meet IPL's resource adequacy requirements as an LMR. It was successfully tested to provide 5 MW of energy continuously over the four hours of the peak as designed. The Array can switch from providing frequency control to providing energy during peak conditions and back to providing frequency control nearly instantaneously. IPL has tested successfully to provide capacity and given the array's operating characteristics it also has the capability to provide all the ancillary services defined in the MISO tariff. MISO business practices and tariffs currently do not allow the facility to provide such services through the commercial market. All services being provided by the battery are currently being performed "behind-the-meter." IPL continues to work with MISO, its stakeholders and interested parties to develop appropriate business and tariff rules to facilitate the use of these state of the art economically efficient devices in the MISO footprint.

[63]http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

5.3.4.2 *BESS Modeled in the IRP*

Building upon the experience with the HSS BESS, consultation with the AES Energy Storage team and industry research, this IRP includes three sizes of BESS projects as possible resources to provide capacity and energy. Figure 5.22 below shows the declining cost curve projection for BESS resources. For the confidential version of this graph see Confidential Attachment 5.3 shows the AES proprietary costs for battery energy storage. The benefits of a battery provided including system reliability and revenues derived from participation in the RTO administered markets will accrue to IPL's customers. Because the MISO tariff, business practice rules, and dispatch scenarios are not yet developed for battery based energy storage provision of multiple services we are unable at this time to discretely model incremental benefits.

Figure 5.22 - BESS Cost Curves



In future IRPs IPL expects to include detailed analyses.

The three sizes of BESS resources modeled are:

- **Large BESS** – the unit modeled has 50 MW of capacity and 200 MWh of energy; in other words, it can provide up to 50 MW of energy for a minimum of four consecutive hours at peak output, or longer at lower levels of output. It is anticipated that this sized unit would be used for peaking capacity, as is described more fully below.

- **Medium BESS –** the medium sized unit is a 20 MW/ 20 MWh battery. It can either provide the full 20 MW in one hour or provide 5 MW for a four hour period. This battery could be used as a peak resource, also, but its primary use would more likely be for reliability and transmission support. The existing HSS BESS is an example of this type of battery system.

- **Small BESS** – this small sized unit is a 500 kW battery as support to provide frequency response for potential future wind assets. This support is embedded by increasing the cost of the future wind asset to account for the battery as a proxy as proposed by FERC in its rule regarding frequency response in FERC docket RM 16-6. See the Wind discussion in this Section 5.

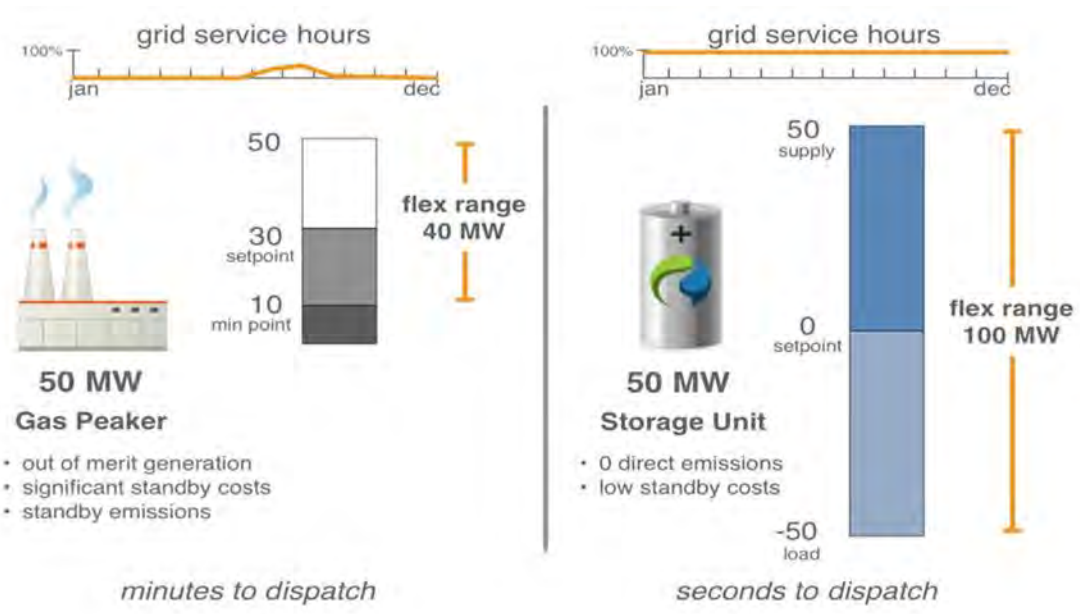
5.3.4.3 *Comparison to a Simple Cycle CT*

The IRP model includes several resource types in addition to batteries such as thermal generating units, renewable energy, and demand response. One of the thermal units is a Simple Cycle Combustion Turbine ("CT"). Although they can produce energy, electric utilities primarily source CT units for their capacity value and operating hours are often limited to periods of peak demand (hence CT units are often called "peakers"). Natural Gas-fired peaker CT units are also operated to help the grid balance short-term variations in load and demand. The IRP model chooses the most appropriate cost-effective resource.

In recent years, Large and Medium BESS units have emerged as an alternative to building new CT peaking units. There are several reasons why a battery/energy storage system is superior to a CT for providing peak energy including a larger flexible operating range, continuous availability, quick ramp rate, scalability, mobility, and customizable design options.

The larger flexible range of a battery is demonstrated in the diagram Figure 5.23 below.

Figure 5.23 – Flexible Range of a Battery



The above diagram shows a gas-fired peaking CT and a storage unit, both of which have a 50 MW nameplate capacity. As a peaker, the goal of either unit is to be able to help the grid operator provide energy when needed, and balance load and generation by rapidly adding or removing electricity from the grid. The process of adding or removing power is described as the flexible range of the unit.

The CT gas peaker has a flexible range of only 40 MW since it has a minimum generation of 10 MW in this example. Operation of this unit might see it dispatched to operate at a 30 MW set point, and thus be available to move up to generating 50 MW or down to generating 10 MW and thus helping to quickly add or remove electricity from the grid.

The Large BESS 50 MW has the ability to add a full 50 MW to the grid and subsequently remove 50 MW from the grid. This is particularly true in a day ahead-type market such as exists in the MISO footprint. For example, if the day-ahead market expects large demand for the next day, then the battery could be fully charged to be used to provide electricity over a four hour period. Alternatively, if the forecast was for over-generation of renewable resources, then the battery could be fully discharged to accept power (over-generation occurs when solar or wind resources generate more power than is needed for load at that time).

In addition to the larger flexible range, the battery has several other advantages over a gas-fired CT, including the ability to be "always on," and the ability to respond in less than a second. These features help to avoid the high costs of out of merit generation dispatch and lower standby emissions. Natural gas peaking plants also incur start-up related costs and associated emissions; battery energy storage facilities do not have any of these costs.

CT Peakers operate for a limited number of hours per year and then stand by in an idle mode. In fact, some CT Peakers are restricted to only operate a set number of hours by their air permit. There is no similar limiting factors for BESS units and they can operate around the clock providing a variety of services. As described above, a Large BESS can provide the grid with 50 MW of peaking energy over four hours and then later help store over-generation of renewable energy of 50 MW for four hours (for a total of 200 MWh). For the remaining 16 hours of a given day, the Large BESS can provide other ancillary services to the grid such as frequency control.

The Large BESS can move from neutral to full output in less than a second as opposed to the minutes it takes a CT to respond. This super quick reaction to grid needs surpasses slower "ramp rates" of CTs. The battery can reduce out-of-merit generation dispatch since it only needs to be dispatched when needed by the grid as opposed to a thermal peaker which may need to be dispatched and held at a minimum generation level which leads to higher costs. Being dispatched only when needed also minimizes air emissions and, in fact, the battery can be charged with lower emitting resources such as renewable energy in the example above.

Energy storage systems are scalable to meet incremental needs, in as small as 100 kW blocks, are more easily permitted than CTs and may be designed to be mobile. There are no emissions or water use related to permitting an energy storage facility. Thus BESS units may be sited close to load in areas where thermal-fired power plants would likely not be welcomed. As noted before, BESS units can provide multiple services. A Small or Medium BESS might be located in a high load growth area instead of building new substation equipment or upgrading individual distribution circuits.

Specific energy storage system designs are customizable based upon the needs of the owner and electricity market in which it is operated. Decreasing costs and flexible hardware and software configurations are expected to continue to result in customized and creative uses of battery technology in the future.

A challenge to deploying Energy storage systems compared to a gas-fired CT is the lack of flexibility in current electricity market tariffs to accommodate them. IPL is working closely with MISO, FERC and stakeholders to update tariffs effectively. A second challenge is that the economics of Large BESS units depends upon whether future MISO rules for batteries are designed to allow flexibility for battery design. MISO rules that do not take into account the differences between various battery technologies or that treat batteries the same way as more "traditional" resources may result in the battery being dispatched in a way that is inefficient. However, MISO rules for CTs are currently fairly established.

The Large and Medium BESS systems were modeled in this IRP with a four hour discharge and recharge cycle to support current MISO rules which require a peak demand resource to be dispatchable for a minimum four hour period. While this is sufficient in most circumstances, a CT unit can be available for as long as needed once called upon, as long as fuel is available.

All battery based energy storage devices in service today rely upon the grid for energy to store for future use as well as the energy required to maintain the array's state of charge. IPL anticipates that some battery designs in the future will also be able to charge using solar cells. For the battery based energy storage in service today, most designs can provide continuous energy for 4 or potentially 6 hours, making them valuable for use in emergency events as well as for extra energy in peak periods. IPL expects the duration of the ability to continuously provide stored energy to increase as technology advances.

5.3.4.4 *Ancillary Service Modeling Limitations*

Whereas the Large BESS is a 50 MW/200 MWh, the Medium BESS is a 20 MW/ 20 MWh battery. The Medium BESS can either provide the full 20 MW in one hour or provide 5 MW over four hours. This battery could be used as a peak resource, similar to the Large BESS or a CT, but it is primarily designed to provide ancillary services which have need for a shorter duration of energy production. Such ancillary services could include the frequency control and primary frequency regulation like the new HSS BESS. Other ancillary services could be the management of renewable energy over-generation, time-shifting renewable energy, spinning/non-spinning reserves, voltage support, and blackstart. At this time, the ancillary service benefits of the Medium BESS cannot adequately be modeled within this IRP. As the

MISO market rules and tariffs are changed, and as new modeling tools are developed, it is likely that the full ancillary service benefits of battery systems will be captured.

When modeling both the Large and Medium BESS units, IPL utilized a declining capital cost curve over the 20 year modeling period. Each year costs decline by approximately 5% to 10% based on AES Energy Storage expertise. The IRP Capacity Expansion Model selects the batteries for peak and energy contributions based on incremental requirements of either 50 or 20 MW respectively. See [Section 8] for a description of the Capacity Expansion Model.

5.3.4.5 *Distributed Energy Storage (DES) Pilot*

In addition to the three utility scale BESS project described above, IPL is also completing a pilot to test small scale battery or distributed energy storage ("DES") systems (approximately 8 kWh of capacity per battery pack) that may be suitable for a residential or small business customer to provide back-up power and reduce peak demand as a Load Modifying Resource ("LMR"). IPL engaged a local electrical contracting firm to design, develop and test an electric demand response system that will have the capability to regulate, monitor and control individual circuits in an electrical panel and remotely calling upon the battery sources. IPL has not explicitly modeled DES in this IRP but will apply lessons learned from the pilot to future planning efforts.

5.4. Distributed Generation

170-IAC 4-7-4(b)(5)

Distributed Generation ("DG") is connected to distribution circuits and theoretically may be owned by customers or a utility, for example the Rate REP solar facilities are DG resources. In this IRP, future solar additions and CHP are considered DG. The modeling reflects attributes of these resource regardless of ownership. IPL has received requests to analyze Combined Heat and Power ("CHP") with individual customers; however, these have not proven to be cost-effective to date. See Section 3 for discussion of IPL's DG integration experience. In this IRP, IPL calculated DG penetration as a metric for each candidate resource portfolio as shown in Section 8.

5.5. Demand Side Resource Options

170-IAC 4-7-6(a)(6) 170 IAC 4-7-8(b)(3)

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).

In this IRP, IPL modeled DSM as selectable resource with similar characteristics as generation resources. Figure 5.24 below lists the DSM "bundles" that were developed for this IRP.

Figure 5.24 – DSM "Bundles" developed for IRP

	Levelized Utility Cost per MWh		
Sector and Technology	**(up to $30/MWh)**	**($30-60/MWh)**	**($60+ /MWh)**
EE Residential HVAC	x	x	x
EE Residential Lighting	x	N/A	N/A
EE Residential Other	x	x	x
EE C&I HVAC	x	x	x
EE C&I Lighting	x	x	x
EE C&I Other	x	x	x
EE C&I Process	x	x	N/A
	Levelized Utility Cost per MW/MWh without tiers		
EE Residential Behavioral	x		
DR Water Heating DLC	x		
DR Smart Thermostats	x		
DR Emerging Tech	x		
DR Curtail Agreements	x		
DR Battery Storage	x		
DR Air Conditioning Load Mgmt	x		
*N/A indicates that a bundle was not needed; all measures fell within lower cost bundles.			

The process employed by IPL to derive these bundles as selectable resources is based upon historic experience, guiding principles, national and local legislation, market potential, baseline projections, avoided costs, and DSM screening tests is described below.

5.5.1. 2017 DSM Resources

Due to overlapping schedules in the filing of regulatory proceedings for this IRP, and IPL seeking approval to continue DSM programs in 2017, IPL decided to input DSM in the IRP for the year 2017 as an existing resource and allow the IRP model to select DSM resources beginning in 2018 as described below.

IPL updated its 2017 DSM Action Plan from 2014 as the third and final year of the 2015-2017 DSM Action Plan that was filed in Cause No. 44497.[64] In Cause No. 44497, IPL sought and received approval for delivery of DSM programs for the first two years of the 2015-2017 DSM Action Plan. The 44792 filing for approval of the 2017 DSM Action Plan is a request for a one

[64] IPL filed the Petition and Direct in Cause No. 44497 on June 2, 2014. An Order approving the 2015-2016 DSM Plan was issued on December 17, 2014.

year extension to continue offering the current DSM programs.[65] The requested one year program extension for 2017 also represents the first year of IPL's 2017-2019 Short Term Action Plan for the 2016 IRP.

5.5.2. IPL's DSM Guiding Principles

IPL has continuously offered DSM programs to benefit customers and optimize demand side resources since 1993, and developed this list of guiding principles that characterize DSM offerings. These guiding principles were presented for stakeholder feedback at the 2016 IRP public advisory meetings.

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.

5.5.3. Indiana Legislation

Two relatively recent Indiana legislative changes have prompted changes in utility sponsored DSM offerings: Senate Enrolled Act 340 ("SEA 340") (codified at Ind. Code § 8-1-8.5-9) created a large customer opt-out provision, and more recently Senate Enrolled Act 412 (codified at Ind. Code § 8-1-8.5-10) and the IURC related rulemaking established a framework for the IURC to evaluate utility-sponsored EE. These impacts are described below. Both enactments focus primarily on Energy Efficiency ("EE") programs. IPL considers EE as one part of its DSM resources along with demand response ("DR") programs.

In 2014, SEA 340 provided industrial customers with electrical demand at a single site greater than one MW the opportunity to opt-out of participation in utility sponsored energy efficiency programs. Industrial customers that meet the definition of a "Qualifying Customer" may opt-out by providing notice to its electricity supplier. Once a Qualifying Customer has opted out, the utility may not charge the customer rates that include energy efficiency program costs. The enactment, codified at Ind. Code § 8-1-8.5-9, defines "energy efficiency program costs" as

[65] The 2017 Action Plan is shown in Attachment 5.5. In Cause No. 44792 - IPL filed the Petition and Direct Testimony in this case on May 27, 2016. The Public Hearing on this case was conducted on September 8, 2016. The case is pending before the Commission.

including: "(1) program costs; (2) lost revenues; and (3) incentives approved by the commission."

SEA 340 also allows customers to opt back in to participation and payment for utility-sponsored energy efficiency programs. A customer who opts back in must participate in the energy efficiency program for at least 3 years (and must pay energy efficiency program rates for such 3-year period). IPL has included estimated impacts of this large customer opt-out in this IRP.

In addition, SEA 340 suspended the Statewide Energizing Indiana program and the EE targets previously established by the IURC Generic Order in Cause No. 43623. Since then, IPL continued DSM program delivery and expects to continue to rely on DSM as a valuable resource. IPL has the responsibility for delivery of all DSM programs to customers directly and coordinates planning and implementation efforts with the IPL DSM Oversight Board ("IPL OSB").[66]

In 2015, SEA 412 added a new section (codified at Ind. Code § 8-1-8.5-10 (Section 10)) to the existing law that outlines specific factors the IURC should consider when examining a utility's energy efficiency proposal. SEA 412 requires utilities, beginning not later than 2017, to petition the IURC at least one time every three years for approval of a plan that includes energy efficiency goals; programs to achieve those goals and program budgets and costs. SEA 412 also requires that evaluation, measurement and verification ("EM&V") of energy efficiency programs be completed by an independent third party. SEA 412 provides assurance for the recovery of DSM costs (direct and indirect program operating costs, lost revenues, and financial incentives) if the energy efficiency plan is determined to be reasonable and approved by the IURC.

In this IRP, IPL is satisfying the updated requirements for the evaluation of DSM as provided for in Section 10.[67] IPL is accomplishing the selection of future DSM as a resource in this IRP in the Capacity Expansion Modeling process. This approach to DSM selection also is consistent with recent stakeholder input and comments provided in the most recent 2014-2015 IRP Director's Report issued by the IURC.[68]

[66] IPLDSM OSB members are the Citizens Action Coalition (CAC) and the Indiana Office of Utility Consumer Counselor (OUCC).
[67] These Section 10 provisions are also included in the current IURC rulemaking (proposed 170 IAC 4-7 and 4-8).
[68] http://www.in.gov/iurc/files/Directors_Final_Report_IRP_20142015_June_10_at_1035_AM.pdf

5.5.4. Federal Regulation

A significant national development regarding energy efficiency is the rule that recently was proposed by the EPA to regulate CO_2 named the Clean Power Plan ("CPP"), which was issued pursuant to Section 111(d) of the Clean Air Act as discussed in Section 6 of this IRP. The EPA initially identified four specific building blocks on which compliance with the target state CO_2 emission rates can be achieved including EE, heat rate improvements at existing power plants, additional generation by renewable energy resources and nuclear energy. Energy efficiency, while no longer considered to be a "building block" in the current iteration of the rule is still expected to be one of the key compliance approach options. Each state is invited to develop a CPP State Implementation Plan ("SIP") or adopt the Federal Implementation Plan ("FIP"). The State of Indiana and stakeholders, including IPL, have continued to evaluate and comment on the proposal and seek to understand the role that energy efficiency ("EE") will play in compliance.

Due to the evolving nature of the rulemaking and legal challenges,[69] it is unknown whether the CPP will go into effect as proposed. However, it is prudent for IPL to include a range of assumptions of carbon costs and potential mitigation methods in the IRP planning process.

Although the specific level of EE that might be necessary for Indiana to achieve compliance with the Clean Power Plan is not known at this time, the EPA has assumed that at some point Indiana capable of achieving an incremental annual energy efficiency amount of 1.5% per year, which IPL believes would be difficult to achieve. If Indiana eventually is required to comply with the Clean Power Plan, EE will have a significant role in the compliance plan.

The CPP FIP includes a provision known as the Clean Energy Incentive Program ("CEIP"). The CEIP is a program "designed to help states and tribes with affected sources meet their goals under the plan by removing barriers to investment in energy efficiency and solar measures in low-income communities and encouraging early investments in zero-emitting renewable energy generation. States may, but are not required to, implement this incentive program for early action."[70]

Earlier in 2016, the EPA proposed certain design details for the optional Clean Energy Incentive Program ("CEIP"). Once finalized, the design elements in this proposal will help guide states and tribes that choose to participate in the CEIP when the CPP becomes effective. In summary, it is expected that the EPA will provide matching allowances or Emission Rate Credits ("ERCs") to states that participate in the CEIP, up to an amount equal to the equivalent of 300 million short tons of CO_2 emissions. Wind or solar projects will receive 1 credit for 1 MWh of generation (i.e., half early action credit from the state and half matching credit from the EPA). Demand-side EE projects implemented in low-income communities will receive 2 credits for 1 MWh of avoided generation (i.e., a full early action credit from the state and a full matching credit from

[69] On February 9, 2016, the Supreme Court stayed implementation of the Clean Power Plan pending judicial review.
[70] https://www.epa.gov/cleanpowerplan/clean-energy-incentive-program

the EPA). IPL notes the proposed/draft status of the CEIP and will continue to monitor developments to determine how IPL may participate in such a program to benefit customers and include developments in future proceedings.

Beyond the implications of the CPP for EE in the future, there has continued to be an uptick in the scale and scope of energy efficiency nationally as well as locally. Data shows that the significant increase in DSM efforts in Indiana has continued to be in synch with national developments. According to the 2015 State Energy Efficiency Scorecard report from the American Council for an Energy Efficient Economy ("ACEEE"),[71] total spending on utility-sponsored energy efficiency programs has increased from approximately $2.5 billion in 2007, to more than $7.3 billion in 2014.

In spite of the lack of recent new federal legislation, there is a continued tightening of the federal EE standards are incorporated in the IPL load forecast and described in Section 4.

5.6. DSM as a Selectable Resource

170 IAC 4-7-8(b)(3) Section 10 170 IAC4-7-6(b), dated 03/02/2016, p. 20

Traditionally, IPL conducted a Market Potential Study ("MPS") which narrowed the universe of potential DSM measures down to a cost-effective and achievable level suitable for IPL's service territory. As a best practice, cost tests referenced in the California Standard Practice Manual were considered in the economic screening portion of the study which included the Utility Cost Test ("UCT"), Total Resource Cost Test ("TRC"), Participant Cost Test ("PCT") and Rate Impact Measurement ("RIM"). The Achievable Potential results were further grouped into cost-effective programs or Program Potential to be delivered as part of a 3-year Short Term Action Plan and estimated through the 20-year IRP period. The savings from these programs were reduced from the customer load requirements used in the IRP analysis. The IRP analysis had no bearing on future DSM; the MPS provided all of the DSM guidance.

In this IRP, IPL has modeled DSM, including EE and DR, as a resource that can be selected alongside other supply-side options in the Capacity Expansion Model.[72]

DSM in the model is compared to building new generation or purchasing power to meet retail load requirements. This is achieved by giving supply-side characteristics including a load reduction potential or load shape and levelized cost in $/MWH and $/MW to DSM. Rather than loading all potential DSM into the Capacity Expansion Model as one big resource, the DSM is separated out into "bundles" based upon similar characteristics or costs which were developed based on the process described below.

---

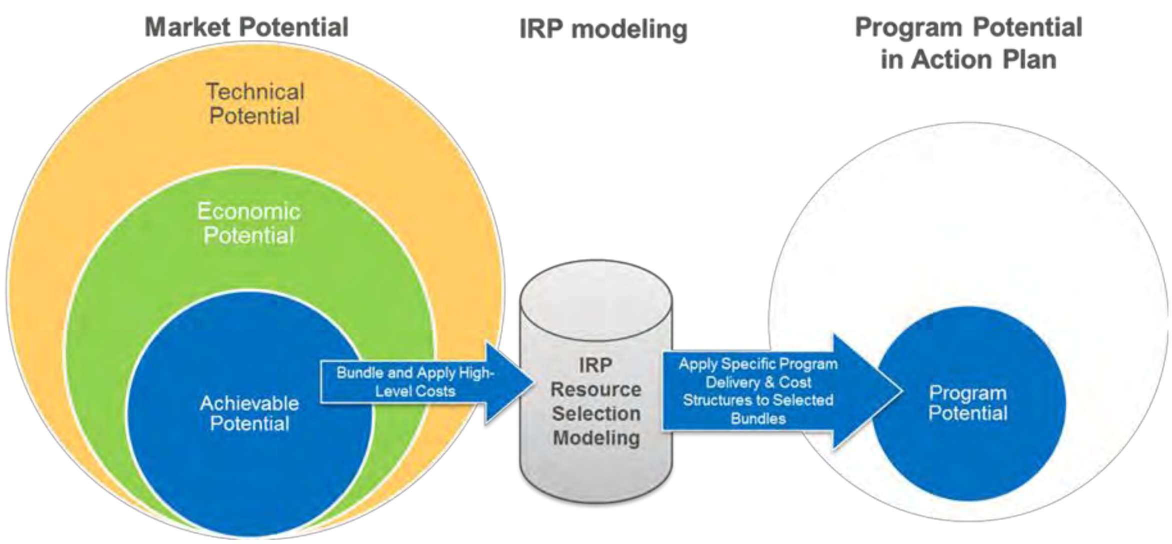
[71] "The 2015 State Energy Efficiency Scorecard", American Council for an Energy-Efficient Economy by Annie Gilleo, Seth Nowak, Megan Kelly, Shruti Vaidyanathan, Mary Shoemaker, Anna Chittum and Tyler Bailey, October 2015, Figure 2, page 23.

[72] See Section 8 for the model results and Section 9 will summarize the Short-term DSM Action Plan which was constructed using the IRP results.

Figure 5.25 provides a visual representation of the overall process IPL used to model DSM as a selectable resource. The process begins with a market potential analysis to determine an achievable level of DSM. Next, the achievable level of DSM is placed into "bundles" that will be used as inputs into the IRP Capacity Expansion Model. The Capacity Expansion Model compares and (potentially) selects DSM as an alternative to traditional capacity options or market purchases to meet load requirements. DSM selections then are refined into programs which go into a Short Term DSM Action Plan: The Market Potential and DSM "bundling" steps.

IPL collaborated with experts in the field and other utilities in working through this process. For the DSM Market Potential Study and DSM bundling, IPL partnered with Applied Energy Group ("AEG") and Morgan Marketing Partners. Additionally, the IPL Resource Planning team attended several IRP workshops and held meetings with utilities in Indiana and across the country to understand the process of modeling DSM as a selectable resource.

Figure 5.25 – DSM Planning Process



5.6.1. Market Potential

In order to estimate the appropriate level of achievable and cost-effective DSM suitable for IPL's service territory, IPL partnered with AEG to prepare a MPS based on AEG's familiarity with IPL customers' characteristics, experience and reputation among other utilities in the state and quality work product.

The development of the MPS paralleled historic processes to identify local DSM potential with additional steps to bundle selectable resources with energy and demand components for IRP modeling. While the IRP covered the study period of 2017-2036, the MPS started in 2018 and covers DSM opportunities through 2037.

The key objectives of the MPS study were to:

- Develop credible and transparent electric energy efficiency and demand response potential estimates by customer class for the time period of 2018 through 2037 within the IPL service territory.
- Account for current baseline conditions, future codes and standards, naturally occurring energy efficiency, and the Indiana legislative provision which allows large C&I customers to opt-out of energy efficiency program participation.
- Develop inputs to represent DSM as a resource in IPL's integrated resource plan ("IRP") for 2018 through 2037. The available DSM savings potential was bundled into resources that are interpretable and selectable by the IRP Capacity Expansion Model.
- Inform the development of IPL's detailed DSM Action Plan for the time period of 2018-2020, including estimates of savings, budgets, and program implementation strategies.

The study assesses various tiers of energy efficiency potential including technical, economic, maximum achievable, and realistic achievable potential. The study developed updated baseline estimates with the latest information on federal, state, local codes and standards, including the consideration of the current Indiana Technical Resource Manual ("TRM"). The study consisted of two primary components: a full energy efficiency potential analysis at the measure level and a separate analysis of the potential for demand response.

The DSM Market Potential Study (Attachment 5.6) involves a few key steps in working towards the objective of determining the DSM market potential and then bundling that market potential into inputs to be considered as a selectable resource in the IRP modeling. These steps include: a) Market Characterization, b) Baseline Projections, and c) DSM Potentials.

In the Market Characterization and Baseline Projections steps, all customers <u>including</u> opt-out industrial customers are modeled. IPL identifies the portion of opt-out load, based on opt-out letters received as of 2016, and makes adjustments to the market potential where appropriate in the DSM Potentials step.

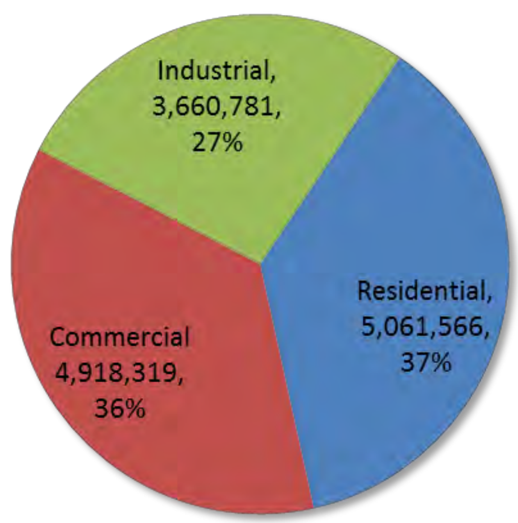
5.6.2. Market Characterization

170 IAC 4-7-4(b)(4)

The goal of the Market Characterization step is to determine how IPL customers use energy in the base year. The results from this analysis are used to determine the potential by sector for particular technologies, e.g., lighting, cooling, water heating, and to build a load forecast that acts a Baseline Projection for DSM.

The planning team begins by splitting IPL's customers into three sectors – residential, commercial and industrial – using IPL load data. Figure 5.26 provides the results for IPL's service territory based on 2015 load. Note that AEG's sale by sector differs from the sales by sector summarized in the Load Forecasting section. This is because AEG aggregates commercial and industrial sectors into distinct commercial and industrial groups in order to accurately categorize end-uses and market potential. In the load forecast, customers are aggregated into the traditional IPL sectors (residential, Small C&I and Large C&I) where there is a mix of what would be considered commercial and industrial customers in the Small C&I and Large C&I sectors.

Figure 5.26 – Sales by Sector



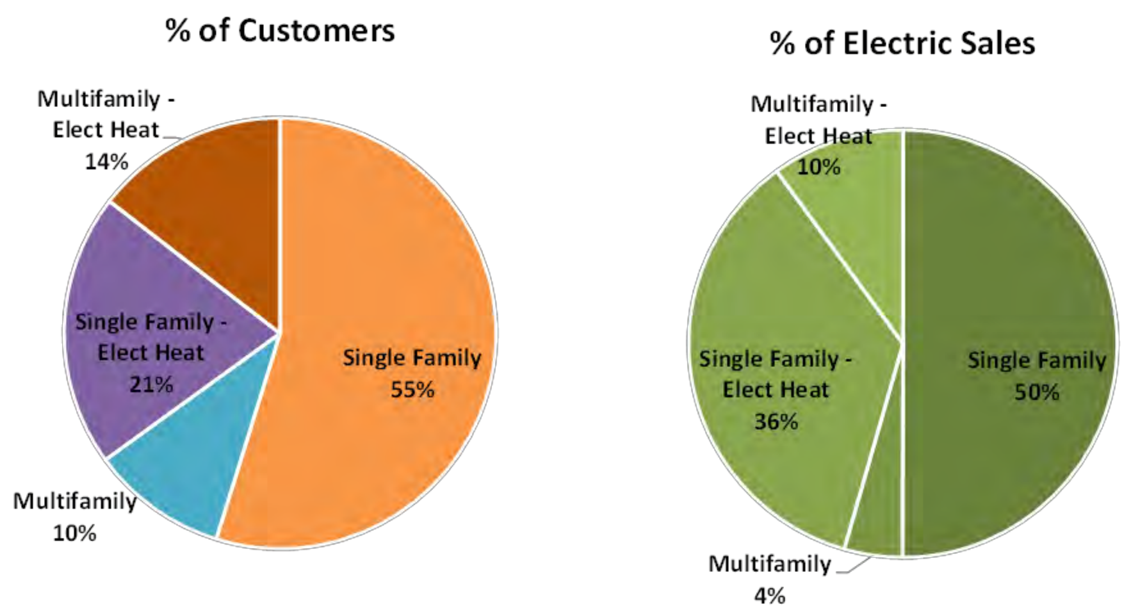
Each customer sector is then further disaggregated using load data into segments as follows –

- Residential: single family, multifamily, single family electric heat, and multifamily electric heat;

- Commercial: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous;
- Industrial: chemicals and pharmaceutical, food products, transportation, and other industrial.

Figure 5.27 below provides the residential sector segments disaggregated by customers and electric sales.

Figure 5.27 – Residential Customers and Corresponding Percentage of Electric Sales



Finally, to complete the Market Characterization step, AEG develops an energy market profile for each of the segments defined above. Energy market profiles characterize electricity use in terms of end use and technology for the base year. The elements in a market profile include:[73]

- **Market size** represents the number of customers in the segment;
- **Saturation** identifies the saturation of appliances or equipment;
- **Unit energy consumption** ("UEC") describes the amount of electricity consumed annually by a specific technology;
- **Intensity** represents the average use for the technology or end use across all homes, businesses or facilities;

[73] Please refer to the IPL 2016 IPL Market Potential Study as Attachment 5.6 for additional methodology and source information.

- **Total energy use** ("GWh") is the total energy used by a technology or end use in the segment.

As an example, Figure 5.28, represents the combined average market profile for all residential segments.

Figure 5.28 – Residential Market Profile Segmentation

Residential :	Total
Total Households:	429,245
GWh:	5,082.5

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	62.8%	2,084	1,308	561.6
Cooling	Room AC	19.9%	702	140	59.9
Cooling	Air-Source Heat Pump	6.4%	1,987	127	54.6
Cooling	Geothermal Heat Pump	0.9%	1,448	13	5.5
Heating	Electric Room Heat	13.5%	2,231	301	129.3
Heating	Electric Furnace	14.2%	10,098	1,434	615.7
Heating	Air-Source Heat Pump	6.4%	5,028	322	138.1
Heating	Geothermal Heat Pump	0.9%	3,139	28	12.0
Water Heating	Water Heater <= 55 Gal	28.2%	2,946	831	356.5
Water Heating	Water Heater > 55 Gal	13.1%	3,044	398	170.9
Interior Lighting	General Service Screw-In	100.0%	954	954	409.3
Interior Lighting	Linear Lighting	100.0%	83	83	35.6
Interior Lighting	Exempted Screw-In	100.0%	283	283	121.7
Exterior Lighting	Screw-in	100.0%	341	341	146.3
Appliances	Clothes Washer	86.1%	87	75	32.0
Appliances	Clothes Dryer	77.3%	778	601	258.0
Appliances	Dishwasher	58.5%	392	229	98.3
Appliances	Refrigerator	100.0%	732	732	314.2
Appliances	Freezer	37.2%	590	219	94.1
Appliances	Second Refrigerator	29.8%	1,062	316	135.6
Appliances	Stove	61.6%	424	261	112.2
Appliances	Microwave	104.5%	128	134	57.6
Appliances	Dehumidifier	27.9%	612	171	73.3
Appliances	Air Purifier	12.6%	1,091	137	58.8
Electronics	Personal Computers	58.9%	175	103	44.2
Electronics	Monitor	69.8%	74	51	22.1
Electronics	Laptops	161.5%	46	74	31.7
Electronics	TVs	292.5%	157	460	197.3
Electronics	Printer/Fax/Copier	102.1%	60	61	26.4
Electronics	Set top Boxes/DVRs	313.8%	109	341	146.4
Electronics	Devices and Gadgets	100.0%	104	104	44.8
Miscellaneous	Pool Pump	4.8%	1,393	66	28.5
Miscellaneous	Pool Heater	0.3%	1,416	5	2.1
Miscellaneous	Furnace Fan	68.7%	739	508	217.9
Miscellaneous	Bathroom Exhaust Fan	32.6%	144	47	20.1
Miscellaneous	Well pump	9.4%	574	54	23.1
Miscellaneous	Miscellaneous	100.0%	529	529	226.9
	Total			11,841	5,082.5

5.6.3. Baseline Projections

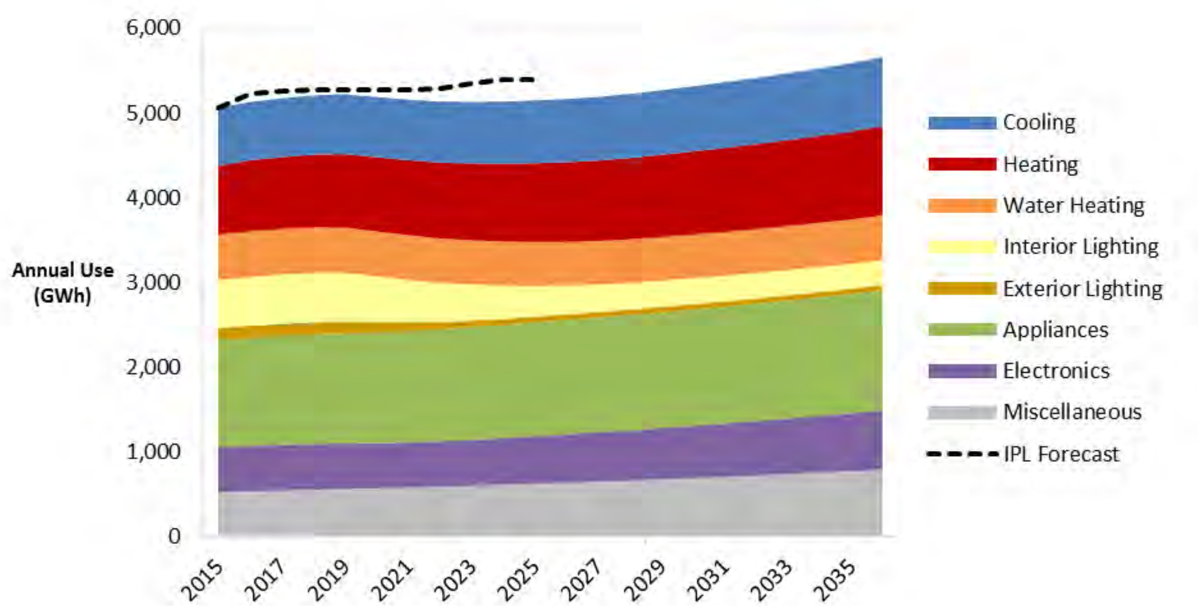
The base-year Market Characterization profiles are used to develop a forecast of annual energy use by customer segment and end use from 2017 to 2036 which serve as the baseline projections. These projections include relatively certain impacts of codes and standards that will unfold over the study timeframe. Ultimately, these baseline projections will serve as the foundation for future DSM efforts and the DSM potential analysis.

Inputs to the baseline projections include:

- Current economic growth forecasts (i.e., customer growth, income growth, employment);
- Electricity price forecasts;
- Trends in fuel shares and equipment saturations;
- Existing and approved changes to building codes and equipment standards;
- Does not include future IPL sponsored DSM.

Figure 5.29 provides the Residential Baseline Projections as an example.

Figure 5.29 – Residential Baseline Projections



*Dotted line is from IPL's 2015 forecast. Note – this is not the same forecast used for the IRP.

Note that in developing the Baseline Projections (forecast) and Itron's IRP load forecast, AEG and Itron collaborated regarding methodologies and end results to ensure the two forecasts were relatively consistent.

5.6.4. Avoided Cost Calculation

170 IAC 4-7-4(b)(12) 170 IAC 4-7-8(b)(5)

Avoided cost is defined in the IAC as “the incremental 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”.

IPL calculated the avoided cost in the IRP to reflect generation, transmission and distribution components as shown in Confidential Attachment 5.10. Generation or production components include the cost of energy and capacity. The energy costs are based on the ABB 2015 Fall Reference Case which accounts for fuel, variable operating and maintenance costs and quantifiable emissions costs. The generation capacity costs are forecasted as a blend of short-term bilateral transactions and the ABB 2015 Fall Reference 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 mitigate 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 GCS filing. The sum of these costs were 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 AEG to calculate the NPV of DSM lifetime benefits.

5.6.5. DSM Screening Process

170 IAC 4-7-7(b)*

The objective of this step is to define an "Achievable Potential" for DSM that will be used to create the DSM "bundles" for IRP modeling. The process starts with all technically possible efficiency measures or Technical Potential. A cost-effectiveness screen is then applied to determine the Economic Potential and, finally, market barriers and customer adoption rates are considered to determine the Achievable Potential.

To develop the Technical Potential, AEG established a list of available efficiency measures using IPL's current programs, the Indiana Technical Reference Manual ("TRM") v2.2 and AEG's Database of Energy Efficiency Measures ("DEEM"). To ensure that all new and emerging technologies were considered, AEG is constantly monitoring the trends and feasibility of technologies that are available on the market as well as those expected to be on the market in the coming years (e.g., super-efficient air conditioners, cutting-edge LED lighting technologies, heat pump water heaters, heat pump clothes dryers, behavioral programs, combined heat and power initiatives, the effects of codes and standards, electric vehicles, etc.). DEEM is updated continually to reflect the most recent source material and state-of-the-art technological advancements. Each database entry is meticulously referenced to document the original source containing the measure information. Measure characteristics (energy and demand savings, measure life, incremental measure costs, etc.) are added to the measures using algorithms and assumptions in the Indiana TRM or DEEM.

AEG applies a cost-effectiveness screen using the TRC as the primary metric to reach the Economic Potential. See Attachments 5.7 & 5.8 for explanation and summary DSM cost-effectiveness tests and Confidential Attachment 5.9 for measure-level cost-effectiveness results. This test selects any measure which, if installed in a given year, has a TRC NPV of lifetime benefits that exceed the NPV of lifetime costs, i.e., a TRC benefit-to-cost ratio greater than 1.0.

IPL applied a more liberal cost-effectiveness screen (i.e., with an avoided cost including capacity benefits as described above) in the MPS in order to determine the Technical Potential and, in turn, Achievable Potential., This analysis helped minimize complexity and runtime within the Capacity Expansion Model.

AEG estimates two levels of Achievable Potential from the Economic Potential: Maximum Achievable Potential ("MAP") and Realistic Achievable Potential ("RAP").

MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be well established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. MAP establishes a maximum target for the savings that an administrator can hope to achieve through its DSM programs and involves incentives that represent a substantial portion of measure costs combined with high administrative and marketing costs.

RAP reflects expected program participation given DSM programs under more typical market conditions and barriers to customer acceptance, non-ideal implementation channels, and constrained program budgets. The delivery environment in this analysis projects the current state of the DSM market in IPL's service territory and projects typical levels of expansion and increased awareness over time.

A downward adjustment was applied to the MAP and RAP savings in an amount proportional to the percentage of load that has elected to opt out of efficiency programs.

Note: The narrative above is intended to provide a high level account of the MPS process. Please refer to the final IPL 2016 Market Potential Study in Attachment 5.6 for additional information on methodology, data sources or results that have not been addressed.

5.6.6. DSM "Bundles"

IPL considered three different DSM bundling options as shown in Figure 5.30, Figure 5.31 and Figure 5.32 below. Option A consisted of creating the Program Potential or actual programs - each program would represent a DSM bundle. Option B involved creating end use bundles with similar load shapes that are further disaggregated into cost tiers. Option C used MAP to create bundles based on similar load shape end uses. IPL decided to bundle using Option B (with different cost tiers) because the approach allowed for more creativity in program creation using the IRP results. With this approach, the buckets of like measures could be portioned out into different program concepts for the DSM Action Plan. Additionally, the cost tiers prevent cost-effective measures from being eliminated because they are bundled in with high cost measures which could result in Option C.

Figure 5.30 – DSM "Bundling" Option A – DSM "Bundles" defined by Programs (MPS Program Potential) and Sectors

OPTION A: 13 Blocks (13 programs)

hypothetical numbers

	Residential	**GWh Savings**
1	AC Load Mgmt	0
2	Appliance Recycling	5
3	HEA	13
4	IQW	12
5	Lighting	34
6	Multifamily DI	12
7	Online Kit	6
8	Peer Comparison	27
9	School Education	6
	Business	
10	AC Load Mgmt	0
11	Custom	33
12	Prescriptive	39
13	Small Bus Direct Install	14
	TOTAL	**201**

Figure 5.31 – DSM "Bundling" Option B – DSM "Bundles" by Measure Categories with Similar Load Shapes; Cost Tiers Applied

OPTION B: 16 Blocks (8 end uses X 2 cost tiers)

hypothetical numbers

		GWh Savings		
	Levelized cost of energy tiers:	**under $60/MWh**	**above $60/MWh**	**Total**
1	Res Lighting	9	5	14
2	Res HVAC	13	53	66
3	Res Other	14	7	21
4	C&I Lighting	23	8	31
5	C&I HVAC	18	21	39
6	C&I Process	8	13	21
7	C&I Other	6	3	9
	Levelized cost of capacity tiers:	**Under $75/kW**	**Above $75/kW**	**Total**
8	Demand Response	0	0	0
	TOTAL	**91**	**110**	**201**

Figure 5.32 – DSM "Bundling" Option C – DSM "Bundles" by Measure Categories with Similar Load Shapes; Cost Tiers not Applied

OPTION C: 16 Blocks (8 end uses X 2 participation tiers)

hypothetical numbers

		GWh Savings		
	Participation tiers:	**Realistic Achievable Potential**	**Maximum Achievable (Delta from RAP, or MAP minus RAP)**	**Total**
1	Res Lighting	12	7	19
2	Res HVAC	39	10	49
3	Res Other	18	14	32
4	C&I Lighting	27	10	37
5	C&I HVAC	29	9	38
6	C&I Process	14	3	17
7	C&I Other	7	2	9
8	Demand Response	0	0	0
	TOTAL	**146**	**55**	**201**

***Note that IPL used $30/MWH, $30 - $60/MWH and Over $60/MWh for the final cost tiers.**

MAP (or all of the Achievable Potential) was used to construct the DSM "bundle" inputs into the IRP as opposed to Technical or Economic Potential. IPL considered this decision carefully and decided to use MAP in order to accurately capture the customer adoption rate in our service territory. If customer adoption rates are not considered in the potential used for DSM "bundling" and IRP modeling, then the possibility exists for DSM to get selected at a level that is unachievable in the market.

Some utilities have taken the approach of creating energy efficiency "bundles" by surpassing the cost-effectiveness screen and using the Technical Potential with a customer adoption rate applied. IPL considered this approach but realized that it would increase the complexity and runtime within the Capacity Expansion Model, yet yield approximately the same results. This approach would require that additional high-cost/MWh "bundles" be developed that would ultimately get filtered out during the Capacity Expansion Modeling step. Most emerging technologies included in the Technical Potential fall within the high-cost "bundles." A more "liberal" MPS cost-effectiveness screen (described earlier) as compared to the Capacity Expansion Model screen is used to filter out measures that end up in these additional high cost "bundles." These bundles ultimately would have been eliminated in the Capacity Expansion Modeling step. It's important to note that the cost-effective emerging technologies still make it into the lower cost/MWh "bundles."

IPL worked with AEG and Morgan Marketing Partners to create the DSM "bundles" using the DSMore cost-effectiveness model.

5.6.6.1 *Energy Efficiency Bundles*

Energy efficiency measures within the MAP were bundled by sector and technology in order to take advantage of load shape similarities among like measures. Except for the Residential Behavioral Program, “bundles” were further disaggregated by the ‘direct cost to implement’ per MWh –

- *up to $30/MWh,*
- *$30-60 /MWh,*
- *$60+ /MWh.*

Creating cost tiers addresses the issue of having highly cost-effective measures lumped into a bundle with marginally cost-effective measures. Such a structure could result in these cost-effective measures not getting selected. IPL decided to use $30/MWh as the top-end of the low cost tier because this is roughly the delivery cost for the 2016 DSM portfolio. While ideally bundles would be created for every IRP year, taking this approach would result in an unmanageable number of bundles for the Capacity Expansion runs. ABB determined the maximum number of bundles that the Capacity Expansion Model could reasonably handle to be between around 45. Thus, IPL decided to split the IRP timeframe into a *Near-term* period that is consistent with our next DSM filing period of 2018–2020 and a *Long-term* period of 2021-2036.

Note that many of the emerging technologies would have fallen in the higher cost tiers had a cost-effectiveness screen not been applied during the MPS and Technical Potential. As presented below, these higher cost tiers would not have been selected by the Capacity Expansion Model.

Also, certain technology cost tiers were null sets or empty. These tiers are labeled N/A in the table below.

5.6.6.2 *Demand Response Bundles*

For the DR analysis, all measures in the MAP case were bundled into groupings. Unlike the EE resources, however, the economic screen was not considered for the DR IRP input bundles.

Six DR program input bundles were identified as outlined in the table below, each of which was also separated into the same years of installation categories as the EE resources described above (2018-2020 and 2021-2037) creating 12 possible bundles. These 12 bundles were translated into the appropriate format for the Capacity Expansion Modeling using DSMore.

Figure 5.33 – DR "Bundles"

Program Option	Segment	Rationale for modeling in the IRP	Name of DR Program Input Block for IRP
DLC Central AC	Residential	Clearly cost-effective in potential study	**DR Air Conditioning Load Mgmt**
DLC Central AC	Small C&I		
DLC Water Heating	Residential	Clearly cost-effective in potential study	**DR Water Heating DLC**
DLC Water Heating	Small C&I	Nearly cost-effective; Bundle with similar Res resource; Strategic interest in applying more detailed economic analysis in DSMore and IRP	
DLC Smart Thermostats	Residential	Nearly cost-effective; Unique savings load shape with DR & EE contributions; Strategic interest in applying more detailed economic analysis in DSMore and IRP	**DR Smart Thermostats**
Curtail Agreements	Large C&I	Clearly cost-effective in potential study	**DR Curtail Agreements**
Battery Energy Storage	Large C&I	Not cost-effective, but Strategic interest in applying more detailed economic analysis in DSMore and IRP.	**DR Battery Storage**
Battery Energy Storage	Residential		
Battery Energy Storage	Small C&I		
DLC Space Heating	Residential	Not cost-effective, but Strategic interest in applying more detailed economic analysis in DSMore and IRP.	**DR Emerging Tech**
DLC Space Heating	Small C&I		
DLC Smart Appliances	Residential		
DLC Room AC	Residential		
DLC Elec Vehicle Charging	Residential		
Ice Energy Storage	Small C&I		

Section 6: Risks and Environmental Considerations

170 IAC 4-7-4(b)(7) 170 IAC 4-7-4 (b)(11)(B)(iii) 170-IAC 4-7-7(a)(1) 170-IAC 4-7-7(a)(2)

Executive Summary

IPL identifies and quantifies risk as part of normal business operations. The risks highlighted below were considered in this IRP. The most significant risks identified include existing and pending environmental regulations.

6.1. Planning Risks

170 IAC 4-7-4(b)(11) 170 IAC 4-7-8(b)(7)(B)

IPL regularly evaluates risks to its business and identifies means to mitigate these risks. As part of our normal business practices and for the IRP process, the risks and mitigation methods in Figure 6.1 are reviewed. The key risks listed below are discussed qualitatively and measured quantitatively where appropriate for inclusion in this IRP as they impact resource planning. Operating risks are generally mitigated through robust business practices and contingency planning.

Figure 6.1 – IPL Risks and Mitigation Methods

Risk	Description	Mitigating Measure
Environmental Regulations	As described fully in Section 3 of this IRP, a wide variety of regulations related to water, air, and waste continue to impact the electric utility industry and will do so in the near future.	To mitigate these risks, IPL carefully evaluates potential impacts and actively participates in the rulemaking processes that include working with various industry trade groups and government agencies.
Natural gas "fracking" regulations	Natural gas "fracking" has raised concerns about potential environmental impacts on water quality and stability. Many states have enacted stringent regulations to reduce fracking. Should this prevail nationally, NG supply is expected to reduce which may lead to price increases.	In this IRP, IPL modeled this potential outcome with high natural gas as an input.
Load Variation	Loads may vary based on consumer energy consumption choices, energy efficiency adoption and weather. In addition, economic drivers and customer adoption of alternative energy sources described below affect IPL loads.	Planning reserve margins determined by MISO, above annual load forecasts, serve as mitigating measures to address increased load. IPL regularly and proactively manages costs to mitigate the impacts of variable costs and revenues.

Risk	Description	Mitigating Measure
Economics	National, state and local economics drive energy usage and related market prices. Gross Domestic Product ("GDP") has less impact on energy usage than it has historically; thus more emphasis was placed on employment in the forecast modeling.	IPL has modeled a base, high and low load forecasts using three different economic datasets that reflect different economic outlooks. A low load forecast included a dip in the economic data in 2017 to reflect potential impacts of a recession.
Customer Adoption of Distributed Generation	Interest in distributed generation has increased since the last IRP cycle. Developers and customers have inquired about interconnection requirements and discussed benefits with IPL contacts. Should a significant amount of customers choose to deploy DG assets, existing generation assets may not be fully utilized in the future.	In this IRP, a scenario was developed to model impacts of DG selected for reasons other than economics. A hypothetical value of 15% of the peak load was chosen in 3 different blocks.
Social concerns	Stakeholders challenge the status quo and seek cleaner sources of energy. Environmental advocates and investors have raised concerns about carbon emissions and future impacts.	IPL created metrics to show environmental impacts of each portfolio.
Power Market Prices	Market prices vary based on fuel costs, resource availability and customer demand.	The IRP includes low, base and high market prices used in multiple scenarios and stochastic analyses.
Fuel Costs	Fuel pricing varies based on supply, demand, and source.	IPL contracts include fixed costs and market based fuel prices with variable escalation factors for multiple components and years.
Fuel Supply	Fuel availability directly influences IPL's ability to run its generating units efficiently. Coal or natural gas shortages may occur during high volume periods including seasonal peaks.	IPL maintains inventory of 25 to 50 days for coal resources. In addition, long-term coal supply contracts with staggered expiration dates are used to ensure only a limited portion of IPL's coal position is open to the market at any one time. In addition, IPL seeks to have multiple coal suppliers and alternate transportation options available in the event that any one supplier or transportation facility is temporarily out of service. IPL executed natural gas transportation and delivery contracts which include seasonal firm and no-notice services to mitigate fuel availability risks for all three NG plants. IPL procures the natural gas ("NG") commodity on a day ahead basis in response to MISO dispatch orders.
MISO Market Changes	As a member of MISO, IPL is subject to changes in FERC approved MISO tariffs and business practices which may impact operations and long-term planning. These may be in the area of capacity credits, transmission expansion policy and costs, or demand response design.	IPL actively participates in MISO stakeholders processes including the Transmission Owners Committee to mitigate risks of changes. To protect the best interests of its customers, IPL intervenes at FERC when necessary.

Risk	Description	Mitigating Measure
Weather	Variances in weather directly affect IPL's retail load requirements, costs and revenues.	IPL evaluates 30 year weather patterns as part of the IRP process to forecast loads. In addition, IPL monitors load variances on a monthly basis to assess short-term impacts.
Reliability	Outages to distribution and occasionally transmission equipment due to public vehicular accidents, storms or mechanical failures can impact service reliability. In addition, transmission system design limitations affect the amount of power that can be imported to the IPL 138 kV system.	IPL's sites generation close to its load center and connected to its 138 kV system when needed to mitigate risks of limited import capabilities and fluctuations in voltage and reactive power.
Technology Advancements	Over the past several years, resource technologies continue to evolve to decrease costs and improve efficiencies. These may include gas turbines, distributed generation, solar PV, wind turbines, battery storage, electric vehicles, fuel cells, demand response, energy management systems and other applications.	IPL stays abreast of technology cost trends and uses up to date information in the IRP. For example, the CCGT capital costs in this IRP are lower than previous IRPs. IPL has included declining technology costs and DG options in this IRP. IPL continues to research best practices in this area and monitor developments in terms of innovation and adoption rates to plan for future impacts.
Construction Costs	Construction expenses vary based on commodity costs, scope creep, labor and material expenses.	IPL works diligently to schedule and manage its internal and contracted resources. It competitively bids contracts, negotiates fixed fees whenever commercially practical, coordinates changes in scope closely to minimize cost increases, requires transparent regular reporting of progress and costs and open audit rights to verify vendor expenses when negotiating vendor contracts. Cost savings are captured through project management efforts and reflected in fair rates and charges.
Production Cost Risk	Variances in production costs are dependent upon electricity demand, fuel supply, market pricing and other factors.	IPL's diverse portfolio helps to mitigate production cost risks through varying fuels, that is, coal, natural gas, oil, wind and solar, as well as technologies including simple and combined cycle turbines, distributed generation, demand response, etc.
Generation Availability	Generation equipment is subject to electro-mechanical failures which directly impact the availability of the units to produce electricity.	In accordance with asset management best practices, IPL performs planned maintenance on a regular basis and performs root causes analyses when failures occur as means to mitigate these risks.
Access to Capital	Adequate funding to finance large capital projects is essential to long-term business success. Varying interest rates and capital access may affect this.	IPL manages a balanced capital structure through a blend of equity, short term and long term debt to mitigate these risks.

Risk	Description	Mitigating Measure
Regulatory Risk	There is jurisdictional overlap in several areas where FERC has jurisdiction relative to markets, but the primary responsibility resides with the states. Jurisdiction over Resource Adequacy and Demand Response are two of those overlap areas.	IPL actively engages with MISO, IURC, FERC, and the Organization of MISO States ("OMS") to clarify the jurisdiction and maintain appropriate outcomes for its customers. Educating stakeholders and listening to other points of view helps to create collaborative results whenever possible.
Misc. - Catastrophic Events	Major events such as weather catastrophes can occur as part of normal business.	IPL has concrete plans for business continuity/disaster recovery for each area of the Company and as a whole. Annual drills in critical areas such as T&D operations are conducted. Debrief sessions are held to identify lessons learned and identify improvements.

These risks were discussed in the development of scenarios to model in this IRP and subsequent metrics as described in Section 7.

6.2. Financing

170-IAC 4-7-8(b)(6)(D)

As identified above, access to capital is a critical component of managing the electric utility business. IPL must secure funding to complete capital projects. Sources for principal payments on outstanding indebtedness and nonrecurring capital expenditures are expected to be obtained from: (i) existing cash balances; (ii) cash generated from operating activities; (iii) borrowing capacity on our committed credit facility; and (iv) additional debt financing. In 2015, CDPQ,[74] a Canadian based investment firm, acquired a minority interest in IPALCO.[75] In addition, due to current and expected future environmental regulations, equity capital from AES and CDPQ has been used as a significant funding source during the first half of 2016, and in recent years. In March 2016, and April 2015, IPALCO received equity capital contributions of $134.3 million and $214.4 million, respectively, from the issuance of 7,403,213 and 11,818,828 shares of common stock, respectively, to CDPQ for funding needs primarily related to existing environmental and replacement generation projects at IPL, which IPALCO then made the same investments in IPL. On June 1, 2016, IPALCO received equity capital contributions of (i) $64.8 million from AES U.S. Investments and (ii) $13.9 million from CDPQ. IPALCO then made the same investments in IPL. The proceeds were primarily used for funding needs related to IPL's environmental and replacement generation projects.

[74] CDPQ: Caisse de dépôt et placement du Québec

[75] IPALCO is a holding company incorporated under the laws of the state of Indiana. IPALCO's principal subsidiary is IPL, a regulated electric utility operating in the state of Indiana.

6.3. Environmental Considerations

Environmental regulations significantly affect IPL's resource planning efforts due to their dynamic and 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 abreast 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 that's currently under construction was designed in accordance with the most up-to-date regulations to ensure compliance. This section of the IRP focuses on the technical compliance requirements of environmental regulations.

EPA is in the process of developing and implementing a new suite of rules that will impact coal-fired fleet generation. The environmental regulations that utilities are facing continue to be challenging in terms of (1) the number of rules coming due simultaneously; (2) the compressed time frame for compliance; and (3) the wide array of rules covering all environmental media. As it relates to air, EPA is regulating for the first time greenhouse gas ("GHG") emissions. As it relates to water, EPA is regulating cooling water intake structures. Finally, as it relates to solid waste, EPA is placing further restrictions on ash management. The most recent activities related to EPA rules include, but are not limited to the following:

- In June 2014, EPA published its final Clean Power Plan, which regulates GHGs from existing sources beginning in 2022.
- 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").
- In September 2015, IDEM developed a State Implementation Plan to address the 2010 SO_2 NAAQS establishing new and more stringent emission limits for Petersburg.
- In November 2015, EPA published the final revisions to the Effluent Limitations Guidelines ("ELG") Rule requiring dry fly ash handling, dry or closed-loop bottom ash handling, and applying numerical limits on FGD Wastewater.
- In December 2015, EPA published the proposed Cross State Air Pollution Rule ("CSAPR") Update Rule to address interstate air quality impacts with respect to the 2008 Ozone National Ambient Air Quality Standards ("NAAQS").

These rules may require additional investment for compliance. Planning for compliance with these regulations is complicated by the significant level of uncertainty surrounding the final outcome of the regulations, including impacts, timing and potential legislative activity.

In light of these uncertainties, each of the EPA rules and any others relevant rules are incorporated into the IRP process and will be discussed in detail later in this section following a review of the existing environmental rules and regulations.

6.4. Existing Environmental Regulations

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

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

6.4.1. Air Emissions

IPL is subject to regulation on the following air emissions: Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_x"), Regional Haze, Mercury and Air Toxics Standard ("MATS"), National Ambient Air Quality Standard, and Greenhouse Gas ("GHG").

6.4.1.1 *Sulfur Dioxide*

Title IV of the Clean Air Act Amendments of 1990 ("CAAA") established a two-phase statutory program to reduce SO_2 emissions. The EPA allocated SO_2 emissions allowances based on a formula that uses historical operating data for specified years multiplied by the allowable limit and then converted to tons of emissions allowed. These tons of emissions are called "allowances" that can then be bought, sold or transferred between units for compliance purposes. Phase I of the program became effective on January 1, 1995, for larger, higher emitting units. In Phase I, the EPA allocated SO_2 emissions allowances based on an emission rate of 2.5 lbs. per MMBtu. Phase II of the program became effective on January 1, 2000, and the EPA lowered the emissions rate used to allocate SO_2 allowances from 2.5 to 1.2 lbs. per MMBtu.

In response to this regulatory program, 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").[76] 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 covered the 28 eastern states and the District of Columbia ("D.C."). The federal CAIR established a two-phase regional cap-and-trade program for SO_2 and NO_x. Phase I of CAIR for SO_2 had an effective date

[76] 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.

of January 1, 2010, and reduced SO_2 emissions by 4.3 million tons; 45% lower than 2003 levels. 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 No. 43403 approved April 2, 2008) in 2011 to help meet the additional SO_2 emission reduction requirements. IPL met the Phase I 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 IPL was developing and implementing its MPP, the United States ("U.S.") Court of Appeals for the D.C. Circuit vacated the federal CAIR in July 2008 and remanded it to the EPA. In December 2008, the U.S. Court of Appeals for the D.C. Circuit issued an order requiring the EPA to revise the federal CAIR and reinstate the effectiveness of the existing rule until the EPA revised CAIR. Thus, CAIR remained in effect until a replacement rule was in place.

In August 2010, the EPA issued a proposed replacement rule, known as CSAPR, which was subsequently finalized in July 2011. The CSAPR mandated additional cuts in SO_2 and NO_x emissions in two phases: 2012 and 2014. Further, it was a modified cap and trade rule with unlimited trading of allowances within individual states but limited interstate trading. However, prior to CSAPR becoming effective in 2012, several appeals were filed challenging its implementation. On December 31, 2011, the Court granted a request for stay and instructed EPA to implement CAIR during the stay. On August 21, 2012, the Court vacated and remanded back to EPA the CSAPR. As a result, CAIR remained in effect. Through 2014, IPL continued to meet the CAIR with its existing controls combined with purchases of allowances on the open market, when needed.

On April 29, 2014, the Supreme Court upheld CSAPR, remanding the Rule to the D.C. Circuit Court which lifted the stay on October 23, 2014. On November 21, 2014, EPA released a Notice of Data Availability ("NODA") that addressed allocations of emission allowances to certain units for compliance with CSAPR. These allowance allocations, which superseded the allocations announced in a 2011 NODA, reflected the changes to CSAPR made in subsequent rulemakings, as well as "re-vintaging" of previously recorded allowances so as to account for the impact of the tolling of the CSAPR deadlines pursuant to an order issued by the U.S. Court of Appeals for the District of Columbia Circuit. In effect, CSAPR became effective on January 1, 2015, and CAIR ceased to apply at that time. Phase II of CSAPR will become effective on January 1, 2017.

IPL met the 2015 CSAPR requirements through the operation of our existing pollution control equipment coupled with the purchase of allowances on the open market and plans to continue to comply with Phase II CSAPR using these measures.

6.4.1.2 *Nitrogen Oxide*

On September 24, 1998, the EPA issued a final rule, referred to as the NO_x State Implementation Plan ("SIP") Call. The rule imposed more stringent limits on NO_x emissions from fossil fuel-fired steam electric generators in 21 states in the eastern third of the U.S., including Indiana. In June 2001, the Indiana Air Pollution Control Board adopted the Federal NO_x SIP Call rule requiring IPL and other Indiana utilities to meet a system wide NO_x emissions rate of 0.15 lb. per MMBtu during the annual ozone season from May 1 – September 30 each year. Compliance was demonstrated via an emission allowance trading program. In order to meet these more stringent NO_x emission reduction requirements which became effective in 2004, 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. The federal CAIR not only required additional SO_2 emission reductions, but it also required further NO_x emission reductions. Phase I of CAIR became effective for NO_x on January 1, 2009, and required NO_x emission reductions by 1.7 million tons, 53% from 2003 levels. In addition, for the first time, NO_x compliance was required on a year-round basis in addition to the annual summer ozone requirements. Phase II of CAIR was scheduled to become effective on January 1, 2015.

IPL has already substantially met the Phase I CAIR emission reduction requirements for NO_x as a result of the installation of the SCR equipment on Pete Unit 2, Pete Unit 3 and HSS Unit 7. The only major impact from CAIR Phase I is IPL must now operate its NO_x emission reduction equipment on a year-round basis.

As mentioned earlier, EPA issued a replacement rule for CAIR, known as CSAPR, which became effective on January 1, 2015, and CAIR ceased to apply at that time. IPL met the 2015 CSAPR 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 plans to continue to comply using these measures.

6.4.1.3 *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. The EPA determined that states, such as Indiana, which adopt the federal CAIR cap-and-trade program for

SO_2 and NO_x will be allowed to apply federal CAIR controls to satisfy BART requirements. Indiana also has issued a final rule implementing BART which provides that sources in compliance with federal CAIR controls are also in compliance with BART requirements for SO_2 and NO_x.

EPA promulgated a final rule in 2012, finding CSAPR is "better than BART" in states participating in the CSAPR trading program, including Indiana. The rule is currently the subject of litigation. The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") had stayed the challenges to the CSAPR is better than BART rule pending the outcome of the challenges to CSAPR. In February 2016, the D.C. Circuit lifted its stay of the challenges to the CSAPR is better than BART rule. The court likely will not hold oral arguments on the challenges until 2017. In December 2015, Indiana issued a First Notice of a Comment Period for rulemaking to revise the CAIR reference to CSAPR in the Indiana rule implementing BART.

6.4.1.4 *Mercury and Air Toxics Standard ("MATS")*

In February 2012, EPA issued the final MATS Rule. MATS places strict emission standards equivalent to the top twelve percent in the industry for each of the four groups of Hazardous Air Pollutants ("HAPs"), as defined in Section 112 of the Clean Air Act ("CAA"): (1) mercury ("Hg"); (2) non-mercury metal HAPs (e.g., barium, beryllium, cadmium, and chromium, among others); (3) acid gas HAPs (e.g., hydrochloric acid ("HCl"); and (4) organic HAPs (e.g., dioxins and furans).

First, the MATS rule established a mercury limit of 1.2 lbs/TBtu on a 30-day rolling average on a single unit basis. The rule also allows for emissions averaging on multiple units. In the case of averaging multiple units, the rule establishes a mercury limit of 1.0 lb/TBtu on a 90-day rolling average. EPA allows emissions to be monitored using either Hg continuous emissions monitoring system ("CEMS") or sorbent trap monitoring. Second, the MATS rule limits acid gas emissions by establishing an emissions limit on HCl of 0.0020 1b/MMBtu with compliance demonstrated by frequent stack testing or HCl CEMS. Third, the MATS rule limits non-mercury metal HAPs allowing for compliance to be demonstrated with a filterable particulate matter ("PM") limit of 0.030 lb/MMBtu, based on PM continuous parametric monitoring system ("CPMS"), PM CEMS, or frequent stack testing.

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. Finally, the Compliance Plan includes CEMS for Hg, HCl, and PM. 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 is complete. 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.

6.4.1.5 *National Ambient Air Quality Standards*

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. Through this process, EPA has recently revised the SO_2, ozone, and particulate NAAQS.

On October 26, 2015, EPA published the final revised Ozone NAAQS, lowering the standard from 75 ppb to 70 ppb. Although ozone is not directly emitted by power plants, it forms in the atmosphere as a result of chemical reactions involving NO_x and volatile organic compounds in the presence of sunlight. As such, utilities could be required to reduce emissions of NO_x as a result of the revised Ozone NAAQS and associated SIP. However, based on the most recent ambient air monitoring data all Indiana counties in which IPL operates are expected to be in attainment with the revised standard.

As it relates to particulate, fine particulate matter ("$PM_{2.5}$"), on January 15, 2013, EPA issued a final rule, which lowered the NAAQS from 15 $\mu g/m^3$ (micrograms per cubic meter) to 12 $\mu g/m^3$. The counties in which IPL operates have been designated as unclassifiable/attainment. Therefore, no further PM reductions will be required at this time.

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 have been 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 as follows in Figure 6.2.

Figure 6.2 – NAAQs Emission Limits for IPL Petersburg Units

Emission Unit Description	Emission Limit (lbs/hour – 30 day rolling average)	Emission Limit (lbs/MMBtu – 30 day rolling average)
Unit 1	263.0	0.12
Unit 2	495.4	0.12
Unit 3	1,633.7	0.29
Unit 4	1,548.2	0.28

IPL must comply with these limits by January 1, 2017. Currently, Units 1 and 2 are each subject to a limit of 6.0 lbs/MMBtu when burning coal, and Units 3 and 4 are currently each subject to a limit of 1.2 lbs/MMBtu when burning coal. IPL Harding Street and Eagle Valley were also addressed in the SIP and will comply through the combustion of natural gas.

IPL estimates costs for compliance at Petersburg at approximately $48 million for measures that enhance the performance and integrity of the FGD systems. On May 31, 2016, IPL filed its SO_2 NAAQS compliance plans with the IURC in Cause No. 44794.

6.4.1.6 *Greenhouse Gas*

On June 18, 2014, EPA published its proposed Clean Power Plan ("CPP"), which establishes the proposed Best System of Emissions Reductions available for existing sources in accordance with Section 111(d) of the Clean Air Act. On October 23, 2015, EPA published the final Clean Power Plan concurrent with a proposed Federal Plan which also serves as a Model Plan for States. States were expected to submit their SIPs to EPA by September 6, 2016. Due to legal challenges described below, this has not yet occurred. Alternatively, States may request, by September 6, 2016, an extension for submittal of State Plans for two additional years, until September 6, 2018. EPA will implement a Federal Plan for States that do not submit an approvable State Plan.

The final Clean Power Plan establishes subcategory-specific rate-based (lbs. CO_2/MWh) standards for carbon intensity for which States must develop plans in order to achieve the applicable compliance dates. States may adopt the rate-based form of the subcategory-specific goal or an equivalent State-specific rate-based goal. Alternatively, States may apply a State-specific mass-based goal. States also have the option of including new sources within their goal and applying an alternative State mass-based goal. Interim compliance targets are required on average over 2022-2029, the interim period, with final compliance targets required beginning in 2030. EPA based reductions on "building blocks," or measures of reduction, which include heat rate improvements for existing coal-fired electric generating units ("EGUs"), and substituting generation from carbon-intensive affected EGUs with generation from existing (construction began prior to January 8, 2014) natural gas combined cycle units and new renewables. States may include some or all of these measures to varying degrees in their State regulations or they may use other measures, like demand side energy efficiency. EPA proposed an optional Clean

Energy Incentive Program ("CEIP") to incentive implementation of renewable energy projects or energy efficiency programs specifically targeted in low-income areas with early credits toward CPP goals. IPL plans to discuss this with IDEM and stakeholders and consider projects to benefit customers should Indiana opt to include this option in its CPP SIP. This is discussed more fully in Section 5.

EPA established a subcategory-specific limit for affected steam generating units of 1,534 lbs CO_2/MWh during the interim period and a final limit of 1,305 lbs CO_2/MWh. For Indiana, EPA established an alternate interim goal of 1,451 lbs CO_2/MWh and a final goal of 1,242 lbs CO_2/MWh. EPA based these standards on the "building blocks" previously mentioned. Specifically, EPA first used a basis of a 4.3 percent heat rate improvement of the coal-fired units. Second, EPA based the standards on an increase in dispatch of existing natural gas combined cycle units to a 75% capacity factor in 2030. Third, EPA based the standards on re-dispatch to new renewables. EPA did not base the standards on demand side energy efficiency measures, though these measures may be used for compliance in a State Plan.

At this time, IPL cannot predict the final outcome of the Clean Power Plan as the impact will be largely dependent on the Plan that is implemented in the State. The State of Indiana has not yet drafted a SIP and it is unknown at this time whether Indiana will implement a SIP or be subject to a Federal Plan. Further, EPA's Federal Plan, which also serves as a model plan, is currently in proposed form and it is unknown when it will be finalized.

Since publication of the CPP, several legal challenges and motions requesting a stay of the rule have been filed. On February 9, 2016, the U. S. Supreme Court issued orders staying the implementation of the CPP (including September 2016 deadline for extension request) pending resolution of challenges to the rule. An oral argument took place on September 27, 2016, in the U.S. Court of Appeals for the District of Columbia Circuit. *West Virginia v. EPA*, No. 15-1363 (D.C. Circuit). A ruling from DC Circuit Court is expected within the next few months. Additional legal challenges are expected.

6.4.1.7 *Existing Controls to Reduce Air Emissions*

As shown in Figure 6.3 below, IPL has already installed environmental pollution control equipment at its facilities.

Figure 6.3 – 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 6.3 – 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)

6.4.2. 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. IPL sought and received approval to extend this compliant date to September 29, 2017, through Agreed Orders from IDEM. The NPDES permits limit several pollutants, but the new mercury and selenium limits drive the need for additional wastewater treatment technologies at Petersburg and Harding Street. 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, a 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.

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

6.4.2.1 *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 are required to be submitted to IDEM by December 2017, for Petersburg and late 2019 for Harding Street. The potential impact of the results of these studies could be similar to the range of impacts described under 316(b) and will be included in subsequent IRP analyses.

6.4.2.2 *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. Two of the four IPL coal-fired units at Petersburg are currently equipped with closed cycle cooling systems. Another is equipped with a cooling tower which dissipates approximately one-half of the waste heat generated by that unit. The impact of this rule will be dependent upon IDEM's determination for entrainment BTA at Petersburg.

6.4.3. 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").

6.4.3.1 *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.

6.4.3.2 *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. The fly ash and bottom ash are generated from the combustion of coal. Historically, IPL has generated about 10% ash from the burning of coal or approximately 800,000 tons of ash per year, based on a typical coal burn of about 8,000,000 tons of Indiana coal per year. Going forward, based on only IPL's Petersburg Generating Station burning coal, approximately 4,500,000 tons of Indiana coal will be burned by IPL per year, generating about 450,000 tons of ash per year. All ash is managed in accordance with federal, state and local laws and permits.

Ash is normally placed in ponds for treatment via sedimentation, to which the effluent is regulated pursuant to NPDES, shipped back to mines, and/or reused in an environmentally sound manner. In addition, fly ash is 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 have 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.

IPL Harding Street and Eagle Valley have ceased coal combustion and must close their ponds in accordance with applicable local, state, and federal regulations. IPL Petersburg currently maintains three active ponds and will be required to comply with the requirements of the CCR Rule. IPL is unable to successfully demonstrate compliance with certain structural stability requirements set forth in the CCR rule at Petersburg, which are required to maintain operation of the ponds. As a result, IPL proposes to remove the ponds from service by April 2018, and make modifications to handle the material that is currently sent to the ash ponds. Specifically, in pending Cause No. 44794, submitted on May 31, 2016, IPL is proposing to use a closed-loop bottom ash handling system to dewater the bottom ash which would otherwise be sluiced to the active ponds.

6.5. 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 derived from the burning of coal. This includes, but is not limited to more stringent regulations requiring:

- Additional SO_2 emission reductions;
- Additional NO_x emissions reductions;
- More stringent ash management handling requirements.

6.5.1. National Ambient Air Quality Standards

As discussed above, NAAQS are routinely reviewed, and potentially lowered by EPA. As a result, future required reductions of SO_2 and NO_x are possible.

6.5.2. Cross State Air Pollution Rule - Ozone Update Rule

On September 7, 2016, EPA released an update to the Cross-State Air Pollution Rule ("CSAPR") to address the 2008 ozone National Ambient Air Quality Standards ("NAAQS") ("CSAPR

Update Rule"). EPA established NO_x reductions during ozone season (May 1 – September 30) for 22 states, including Indiana, to address downwind attainment with the 2008 Ozone NAAQS of 75 parts per billion ("ppb").

Affected facilities will receive fewer ozone season NO_x allowances in 2017 and beyond, which may result in the need to purchase additional allowances. IPL is currently evaluating the CSAPR Update Rule's impact on its facilities and projected emissions that will impact allowance allocations for inclusion in future IRPs. As NAAQS are reviewed and potentially lowered by EPA, future CSAPR Update Rules for SO_2, fine particulate matter, and the 2015 ozone NAAQS are possible.

6.5.3. Office of Surface Mining

The Department of Interior's Office of Surface Mining ("OSM") is expected to issue a Rule addressing placement of ash as backfill in mines in 2016, as this issue was not addressed by the CCR Rule discussed above. It is not expected that IPL would be directly subject to OSM Rule because IPL does not operate any coal mines. It is possible though that the Rule may ban the placement of ash, including ash generated by IPL, in mines. As such, the OSM Rule may require expansion of the existing landfill at Petersburg to provide for disposal of ash from Petersburg.

6.6. Summary of Potential Impacts

These regulations would potentially require IPL to incur additional expenses for compliance in the future. Figure 6.4 below provides a summary of these potential regulations including potential timing and preliminary cost estimates available at this time.

Figure 6.4 – Estimated Cost of Potential Environmental Regulations

Rule	Expected Implementation Year	Capital Cost Range Estimate ($MM)	Assumed Technology
OSM	2018	0-15	Onsite landfill
CWIS 316(b)*	2020	10-160	Closed cycle cooling
Ozone NAAQS	2020	0-150	Selective Catalytic Reduction ("SCR")
ELG	2018	0	None
CCR	2018	47	Bottom Ash Dewatering
SO_2 NAAQS	2017	48	FGD Improvements

*If IPL is unable to renew the existing Petersburg 316(a) variance, the 316(b) technology listed is the same technology which would be needed for compliance with the temperature water quality standards.

Source: IPL

IPL incorporated the most probable outcome of the regulations described above in the Base Case scenario in this IRP. This includes the CCR and NAAQS-SO_2 costs. The high costs for the remaining regulations are not believed to be most probable at this time but are included in the strengthened environmental scenario as described in the Resource Portfolio Modeling section of this IRP. IPL will continue to monitor changes in environmental regulations and incorporate compliance requirements into short-term and long-term plans.

Section 7: Resource Portfolio Modeling

170 IAC 4-7-4(b)(1) 170 IAC 4-7-8(A) 170 IAC 4-7-8(b)(7)(A)

Executive Summary

IPL conducted extensive research into IRP best practices before undertaking the 2016 IRP. Topics researched include scenario development, methods to model DSM as a selectable resource, key variables for load forecasting, and the use of metrics to compare portfolios. Not only did IPL research publicly available documents from other utility IRPs and MISO to assess the range of possible scenarios and metrics used to compare the scenario portfolios, but IPL staff coordinated a visit, along with the other Indiana IOUs, with the Tennessee Valley Authority to better understand its IRP process and how it modeled DSM as a selectable resource.

7.1. Scenarios

170 IAC 4-7-8(b)(7)(C)

Through the integrated resource planning process, IPL identified candidate resource portfolios to serve IPL customers. IPL derived these portfolios by modeling multiple scenarios to represent the risks of uncertain future landscapes. IPL initially developed five scenarios of future worlds in order to assess how changing certain aspects of those worlds would impact IPL's resource portfolio choice. A cross-functional IPL team identified several drivers that may impact future resource portfolios based upon extensively reviewing previous IPL IRPs, other utility IRPs, the MISO MTEP studies,[77] and previous strategic planning efforts. IPL's research identified uncertainty around these four categories of drivers:

- Economics affecting load requirements;
- natural gas and market prices;
- clean power plan and environmental costs;
- the level of customer distributed generation adoption.

IPL considered how these drivers may interact in the future to develop specific scenarios. IPL started from a "Base Case" scenario which includes business-as-usual projections for these drivers to trend as currently expected for the study period. According to the IURC Electricity Director's Report for the 2014-2015 IRPs, "[t]he base case should describe the utility's best judgment (with input from stakeholders) as to what the world might look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources

[77] MISO MTEP studies can be found at https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

or laws/policies affecting customer use and resources."[78] IPL also developed four other scenarios of future worlds by varying its projections for the four main categories of drivers list above. IPL titled these four scenarios as follows: Robust Economy, Recession Economy, Strengthened Environmental, and High Customer Adoption of Distributed Generation.

IPL presented these scenarios in the Public Advisory Meeting #2 and sought stakeholder feedback through an exercise and group discussions. Stakeholders agreed that the drivers IPL identified will have a major impact on the future. Some stakeholders recommended that IPL vary the commodity prices between scenarios, and others questioned whether a Robust Economy would lead to a higher load than the Base Case. IPL originally intended for the load forecast to be the only variable that changed for the Recession and Robust Economy scenarios, but IPL responded to the stakeholder suggestions by modeling low natural gas prices and market prices for the Recession Economy Scenario and high natural gas and commodity prices for the Robust Economy Scenario. Additionally, IPL gave an in-depth presentation on stochastic analysis during the Public Advisory Meeting #3 to explain that in addition to varying assumptions between scenarios, IPL also conducted probabilistic sensitivity analysis on each scenario's resulting portfolio to see how the portfolio responds to different levels of commodity and load forecasts. See Section 7.4 to learn more about the stochastic modeling.

During the Public Advisory Meeting #2, IPL asked stakeholders to predict what they thought IPL's future portfolio mix might look like. IPL aggregated stakeholder feedback to model a sixth scenario titled "Quick Transition," and IPL further revised this scenario based upon feedback from Public Advisory Meeting #3 to reflect retirement of Pete 1, and refueling of Pete 2-4 in 2022.

Descriptions of the scenarios are as follows, and Figure 7.1 shows the drivers for each scenario:

1. Base Case: Includes known events and expected trends (e.g., forecast of fuel prices, economic forecasts, estimated future capital costs, most probable load forecast). The base case uses IPL's current load forecast methodology and projects modest load growth between 2017 and 2036. The Base Case's commodity and market prices include Clean Power Plan ("CPP") beginning in 2022. Generally, low cost assumptions for expected environmental regulation will be realized. The Base Case projects moderate decreases in technology costs for wind, solar, and energy storage over the next 20 years and a minimum level of baseload generation connected to the 138 kV system to meet NERC standards for voltage stability.

2. Robust Economy: High local economic growth is realized in this scenario. Local economic growth is forecasted consistently higher than the base case. Downtown revitalization continues: growth in apartment and small business construction, customers

---

[78] *Electricity Director's Final Report 2014 - 2015 Integrated Resource Plans*, IURC. June 10, 2015. http://www.in.gov/iurc/files/Directors_Final_Report_IRP_20142015_June_10_at_1035_AM.pdf

buy electric vehicles and other electricity consuming gadgets, and Indy attracts a few more large Commercial and Industrial ("C&I") customers. For example, the old airport and Chevy plant sites will be revitalized, the Mass Avenue area continues to flourish, and redevelopment of brownfield areas in Indianapolis will take off!

3. Recession Economy: Due to local economic downturns, local employment declines between 2016 and 2036. IPL's industrial customer base shrinks, housing starts are stagnant, and customers do not buy new electricity-consuming gadgets. IPL's total customer count decreases as people begin leaving Indiana for areas of the US that are experiencing growth.

4. Strengthened Environmental Rules: Includes a 20% Renewable Portfolio Standard ("RPS") for Indiana, a higher carbon cost than the Base CPP, and high-cost estimates for other proposed and final environmental rules. Compliance costs for known regulations like Cooling Water Intake Rule (316b), Office of Surface Mining Rule related to ash backfill, Ozone NAAQS, and Coal Combustion Residuals ("CCR") are expected to reach estimated high levels.

5. High Adoption of Distributed Generation: Customers in all sectors adopt DG totaling approximately 15% of IPL's load. Micro-grids prevail, and customers seek energy independence.

6. Quick Transition: IPL developed this scenario based upon stakeholder feedback with all four Pete units retiring in 2030, minimum levels of baseload generation connected to the 138 kV system to meet NERC standards for voltage stability, maximum achievable DSM, and the balance of resources comprised of solar, wind, and batteries.. Stakeholders requested to see the impact of retiring Pete 1, and refueling Pete 2-4 to natural gas in 2022 which aligns with the planned implementation of the CPP. units . IPL revised the Quick Transition scenario to accommodate this request.

Figure 7.1 – Scenario Drivers

	Scenario Name	Load Forecast	Natural Gas and Market Prices	Clean Power Plan (CPP) and Environment	Distributed Generation (DG)
1	**Base Case**	Use current load growth methodology	Prices derived from an ABB Mass-based CPP Scenario	ABB Mass-based CPP starting in 2022. Low cost environmental regulations: ozone, 316b, and CCR	Expected moderate decreases in technology costs for wind, storage, and solar
2	**Robust Economy**	**High**	**High**	Base Case	Base Case
3	**Recession Economy**	**Low**	**Low**	Base Case	Base Case
4	**Strengthened Environmental Rules**	Base Case	Base Case	**20% RPS + high carbon costs. High costs: NAAQS ozone, 316b, OSM**	Base Case
5	**Distributed Generation**	Base Case	Base Case	Base Case	**Base case with fixed additions of 150 MW DG in 2022, 2025, and 2032**
6	**Quick Transition**	Base Case	Base Case	Base Case	**Fixed portfolio to retire coal, add max DSM, minimum baseload (NG), plus solar, wind and storage**

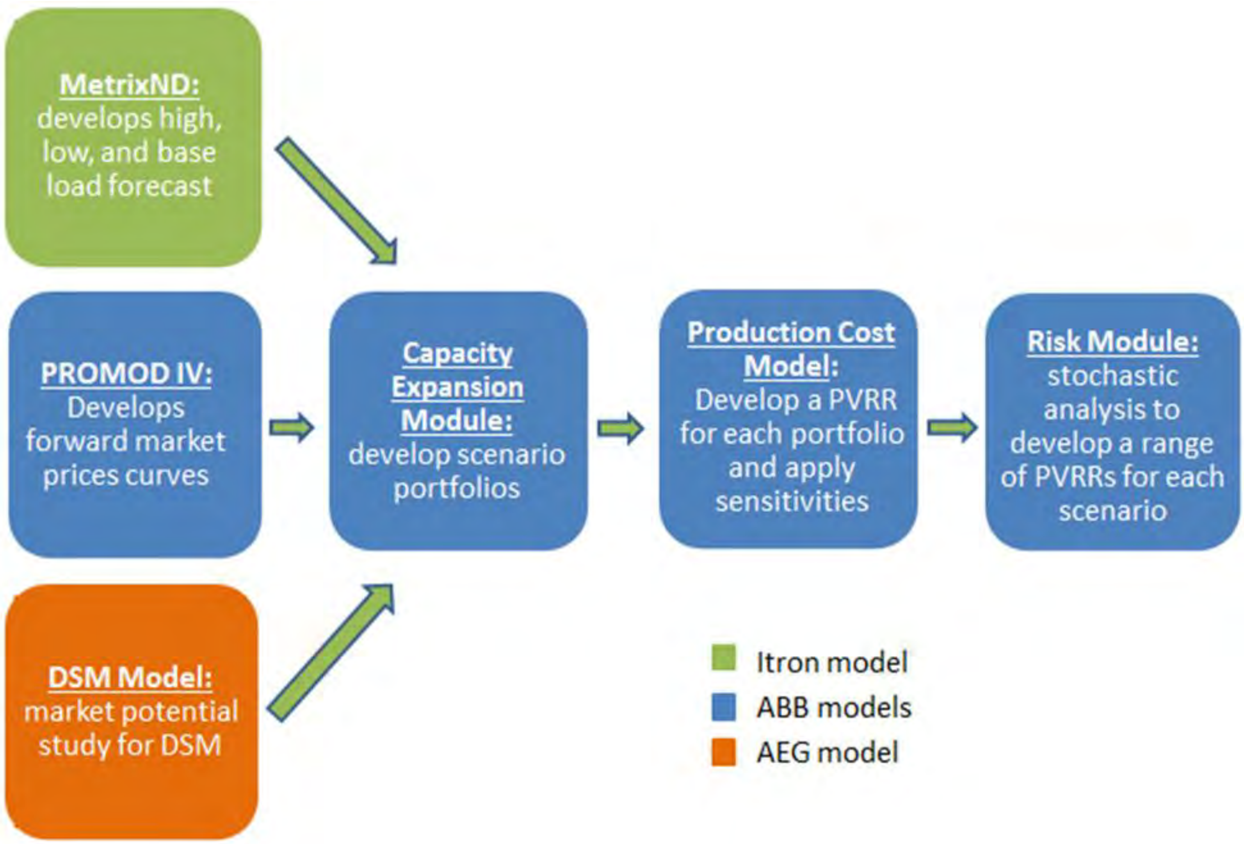
IPL varied these drivers in a way that would result in divergent resource portfolios once the scenario inputs are run through the Capacity Expansion Model. Analyzing a set of divergent resource portfolio scenarios via metrics allows IPL to understand the impact of portfolio options on IPL's customers, the environment, and the resiliency of the electric system.

7.2. Modeling Summary

170 IAC 4-7-4(b)(11)(A)

IPL worked with several vendors and utilized models listed in Figure 7.2 based on core capabilities and proven experience with each for the IRP modeling process. IPL employees engage in training courses, update annual forecast data, and implement software enhancements to reflect contemporary methods. The flow chart below shows the specific modeling steps taken in the IRP:

Figure 7.2 – IPL 2016 IRP Modeling Summary



For the modeling steps shown in the above flow chart, IPL worked with the following vendors for the 2016 IRP process:

- AEG to develop the DSM Market Potential Study through the AEG model Load Map [See Section 7.3.2 for more detail.]
- Itron to develop high, low, and base load forecasts through the Itron model MetrixND [See Section 4 for more detail.]
- ABB to develop and evaluate the portfolios for each scenario through the ABB model PROMOD IV, ABB Capacity Expansion Model, ABB Strategic Planning Portfolio

Production Cost Model, ABB Strategic Planning Financial Module, and ABB Strategic Planning Risk Module [See Sections 7.3 – 7.5 for more detail]

7.3. Capacity Expansion Model

170 IAC 4-7-4(b)(11)(B)(ii) 170 IAC 4-7-7(a)

IPL used the ABB Capacity Expansion Model to develop potential resource portfolios by modeling the interaction of the following scenario drivers: load forecasts for peak and energy, forward market and commodity price curves, the level of CO_2 and other environmental regulation, DSM market potential, and resource technology price and performance trends. The interaction of these variables in the model results in resource expansion and retirement decisions. Some inputs to the Capacity Expansion Model - such as the load forecast, market and commodity price curves, and DSM bundles – are products of other modeling process done for the IRP, as shown in Figure 7.2.

7.3.1. Fundamental Modeling Inputs

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

The Capacity Expansion simulation uses minimum revenue requirements planning criteria to evaluate resource technologies based on a given set of future landscape assumptions. The model develops a reasonable, least-cost resource portfolio for each year of each scenario based on the scenario's key input forecasts:

- Carbon dioxide prices (Figure 7.3)
- Natural gas prices (Figure 7.4)
- Market prices (Figure 7.5)
- IPL Load Forecast (Figure 7.6)
- Capacity Prices (Figure 7.7)
- Coal prices (Figure 7.8)
- SO_2 and NO_X prices (Figure 7.9)
- Demand side Resources

Confidential versions of Figure 7.3 to Figure 7.9 are available in Confidential Attachment 7.1 based on data provided by ABB.

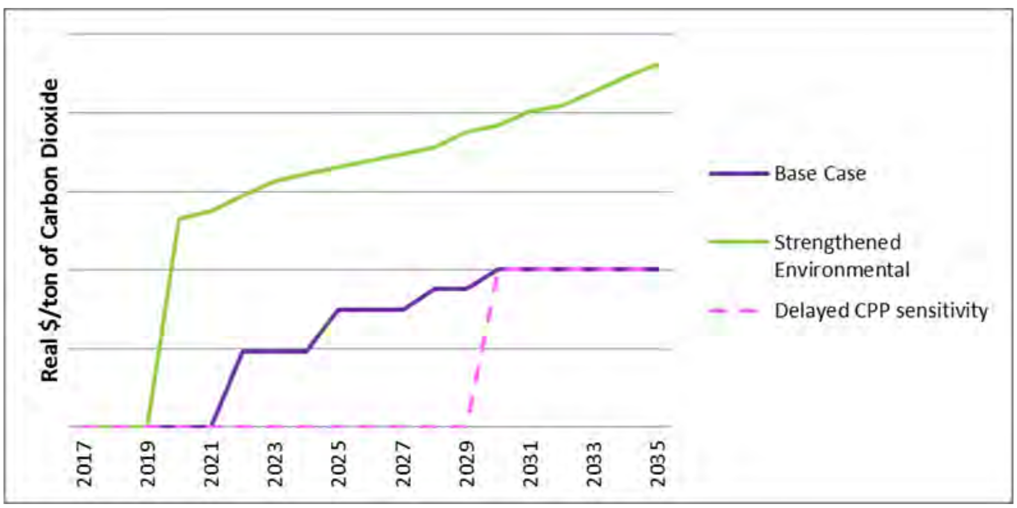
Using the defined inputs for each scenario, IPL's retail load and existing resources, the model performs an optimization of the sizing and timing of supply-side and demand-side resource alternatives for each scenario. An optimal plan is developed for each scenario. Decisions to add or retire resources are made based on the expected revenue from the market less costs, including both variable and fixed cost components. For the 2016 IRP, IPL used a 15% planning reserve margin requirement within the Capacity Expansion Model as defined by MISO and explained in Section 2.

The expansion simulation modeling is deterministic. For each scenario, the model looks at one set of future conditions to arrive at a specific set of results. Section 7.5 explains how IPL models variance to the key inputs through sensitivities and stochastic analysis.

Carbon dioxide prices:

For the 2016 IRP, ABB used its Clean Power Plan mass-based carbon tax assumptions from its ABB Fall 2015 Midwest Reference Case as the "Base Case" CO_2 prices. ABB used the consulting firm ICF's CO_2 tax assumptions for the "Strengthened Environmental" scenario of CO_2. The Delayed CPP sensitivity assumes no CO_2 costs until 2030, at which point the sensitivity's CO_2 prices will match the Base Case prices. IPL's carbon price estimates align with the Synapse 2016 CO_2 price forecast, falling within the Synapse range of High and Low price forecasts.[79]

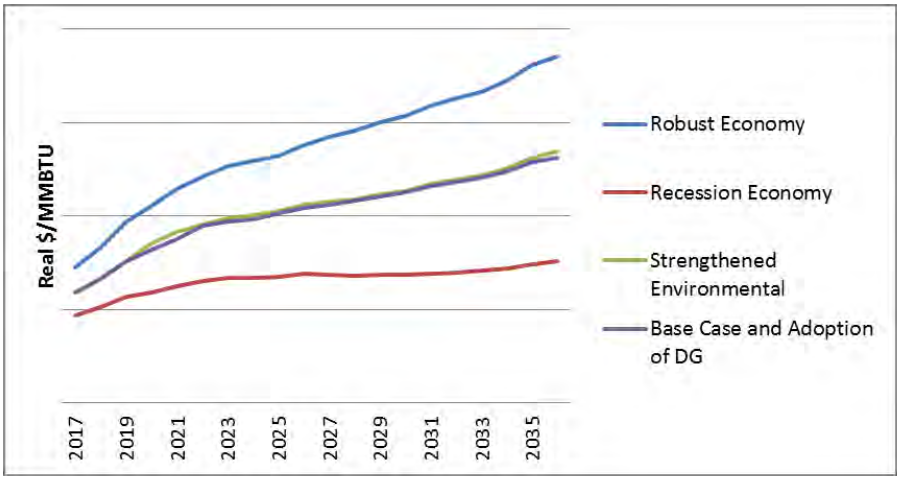
Figure 7.3 – Carbon Dioxide Prices



[79] *Spring 2016 National Carbon Dioxide Price Forecast*, Synapse Energy Economics. March 16, 2016. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

Natural gas prices: ABB forecasted natural gas prices for each scenario based on the carbon dioxide prices in that scenario. The level of carbon dioxide regulation will impact the demand for natural gas, which will impact natural gas prices.

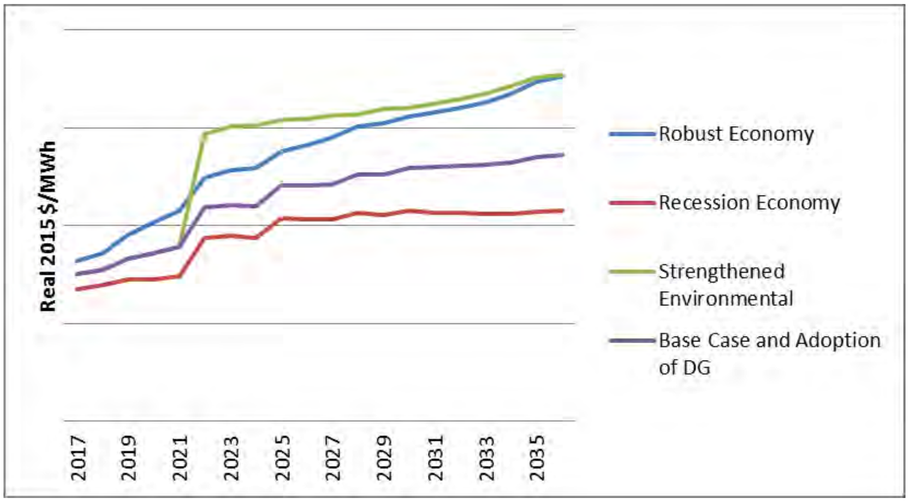
Figure 7.4 – Henry Hub Natural Gas Prices



Market prices: ABB uses the above natural gas price trends to forecast market prices through its PROMOD IV software and the Integrated Model.[80] ABB developed market prices for each scenario based on the carbon dioxide prices and natural gas prices in that scenario. PROMOD IV determines the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices.

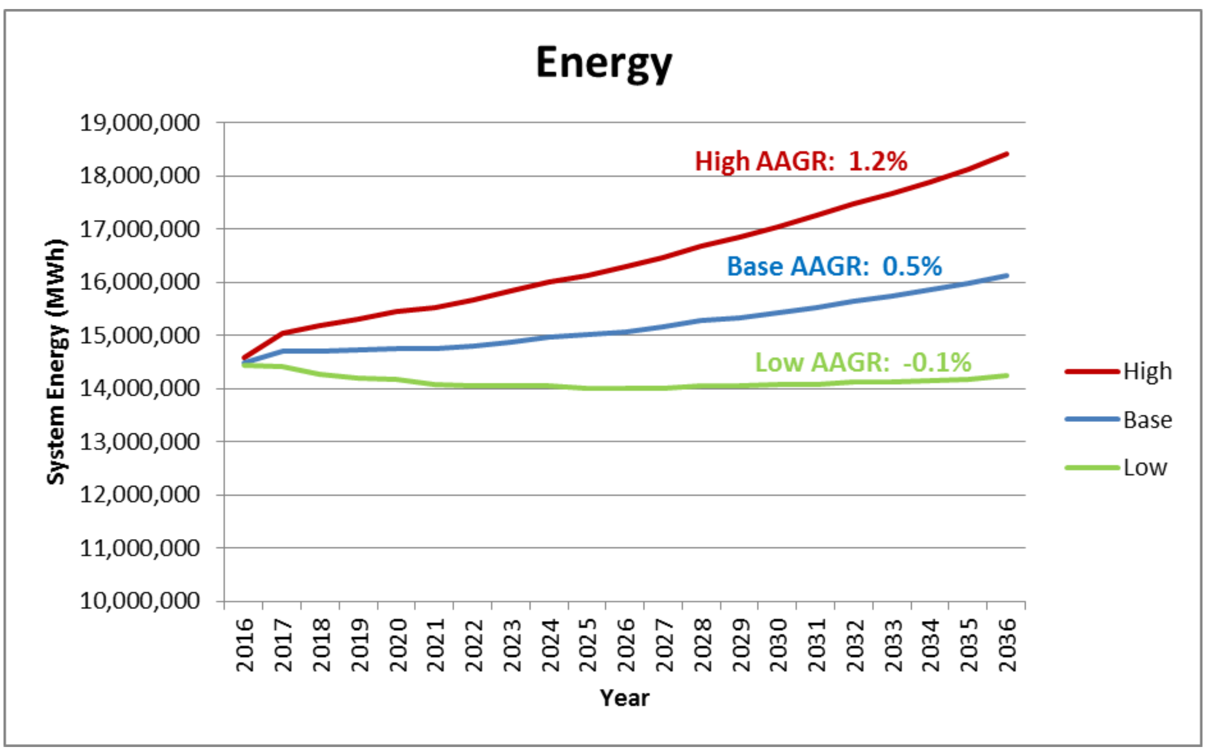
[80] The Integrated Model simulates the operation of each generating unit in the Eastern Interconnect to develop market prices. The Integrated Model simulates the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The model is based on a zonal approach where market areas (zones) are delineated by critical transmission constraints. The simulation is based on a mathematical function that performs economic power exchanges across zones until all eligible economic exchanges have been made.
See Attachment 2.1 for more details on ABB's Integrated Model.

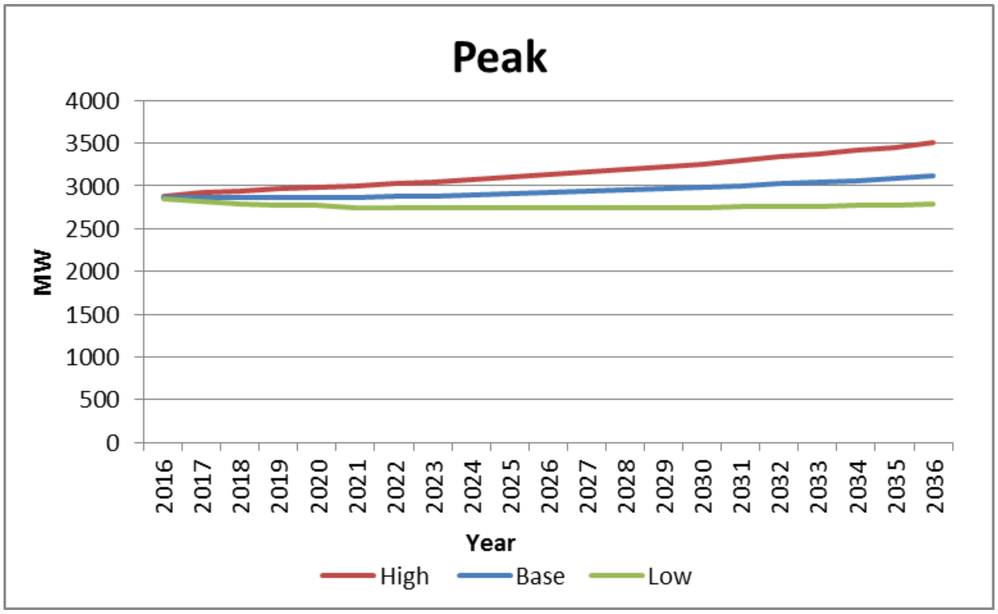
Figure 7.5 – Market Prices: MISO-IN (7x24)



Load Forecast: The High energy forecast has a growth rate of 1.2%, the Base energy forecast has a growth rate of 0.5%, and the Low load forecast has a growth rate of -0.1%. The High peak forecast has a growth rate of 1.0%, the Base peak forecast has a growth rate of 0.4%, and the Low peak forecast has a growth rate of 0.1%. For more details on the peak and energy forecast, see Section 4.

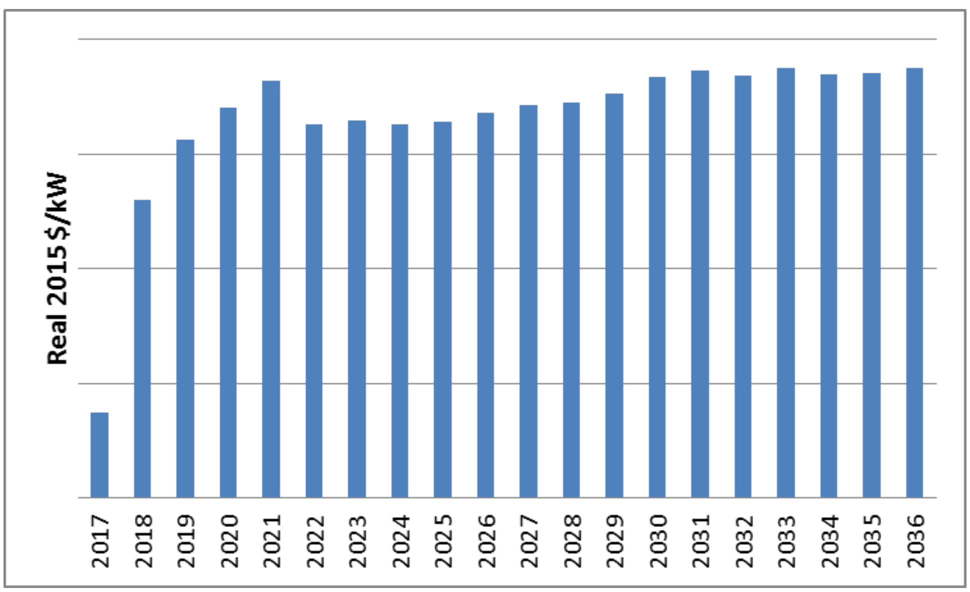
Figure 7.6 – IPL Peak and Energy Load Forecast





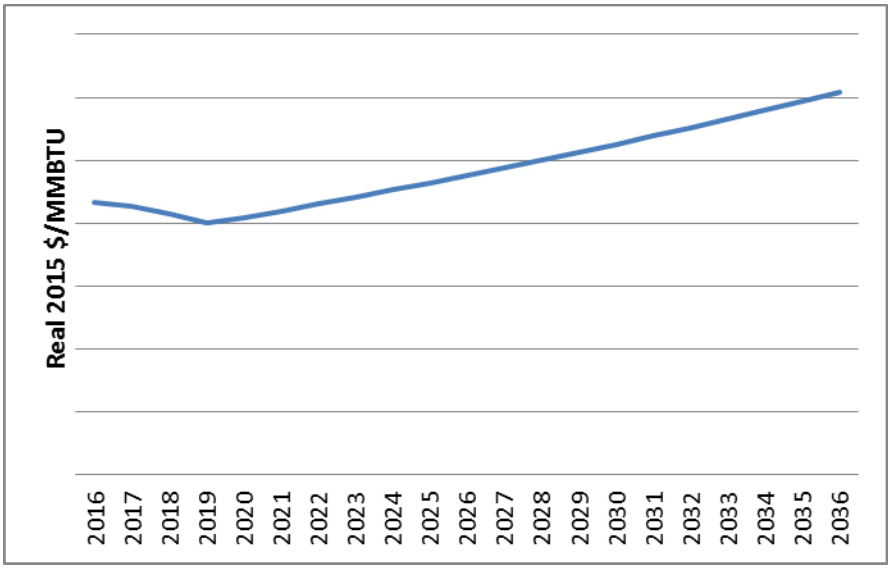
Capacity Prices: Capacity prices for Zone 6 of the MISO market, which IPL is located, have increased each year of MISO's Planning Resource Auction ("PRA"). As units in the MISO region retire, capacity prices are expected to rise toward CONE.

Figure 7.7 – Capacity Prices



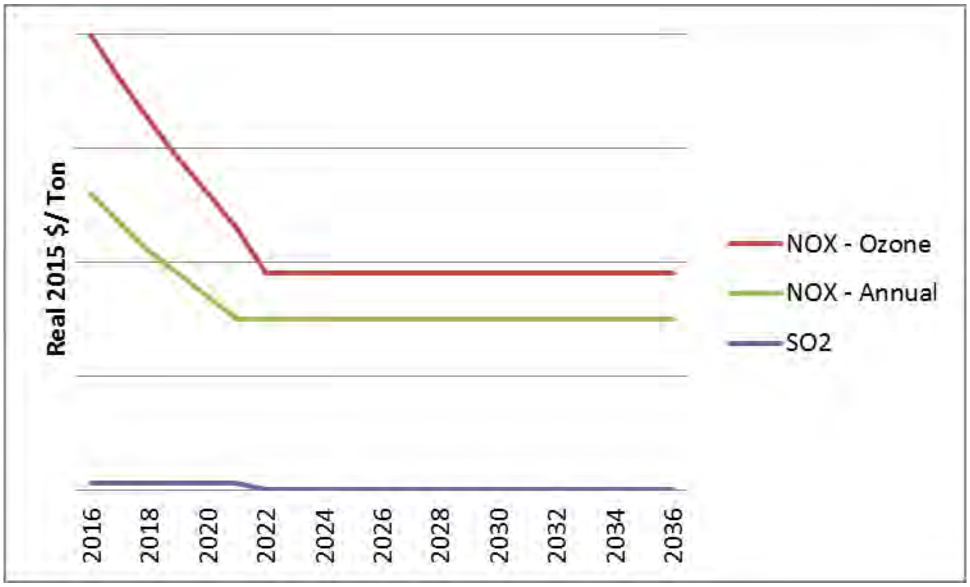
Coal Prices: IPL used internal estimates for coal prices for 2017-2025 based on upon expected coal supply and price options specific to IPL's Petersburg plants and their location in Southern Indiana. IPL applied a 2.5% annual escalation rate to the coal prices after 2025.

Figure 7.8 – Coal Prices for IPL



NO_x and SO_2 Prices: As environmental upgrades are completed at power plants across the U.S., the emission costs for electricity generators in the Midwest are expected to fall. While IPL may possess emission allowance inventory at the beginning of the study period, these levels fluctuate monthly and will change between the time the analysis began and the start of the study period. The model assumes zero emission inventory at the beginning of the study period and accounts for emission output and costs for all resources starting from this point to treat all resources on equal footing. The IRP modeling includes an annual allotment of proposed CSAPR SO2, seasonal NOx, and annual NOx allowances. Year-end balances are trued up through the sale of any excess allowances or the purchase of any shortage of allowances which aligns with IPL's procurement practices.

Figure 7.9 – NO_x and SO_2 Prices for Electricity Generators in the Midwest



7.3.2. Supply-Side Characteristics

In addition to the fundamental modeling inputs described above, IPL provided ABB with Supply-Side Resource characteristics to use in the Capacity Expansion and Production Cost Models as described in Section 5 and shown in Figure 5.14.

7.3.3. Demand Side Characteristics

170 IAC 4-7-8(b)(3)

IPL recognizes how the characteristics between supply-side and demand side resources differ as summarized in Figure 7.10 below. These differences in characteristics are fully considered and have been incorporated into the IRP process.

Figure 7.10 – Supply v. Demand Side Resources

Resource Characteristics

Parameter	DSM	Batteries	CT	CCGT	CHP	Solar	Wind
Capacity (MW)	X	X	X	X	X	X	X
Capacity factor		X	X	X	X	X	X
Capacity credit	X	X	X	X	X	X	X
Carbon impacts			X	X	X		
Customer adoption	X				X	X	X
Energy contribution (MWh)	X	X	X	X	X	X	X
EFOR			X	X	X	X	X
Heat rate			X	X	X		
Capital costs		X	X	X	X	X	X
Fuel costs			X	X	X		
O&M costs	X	X	X	X	X	X	X

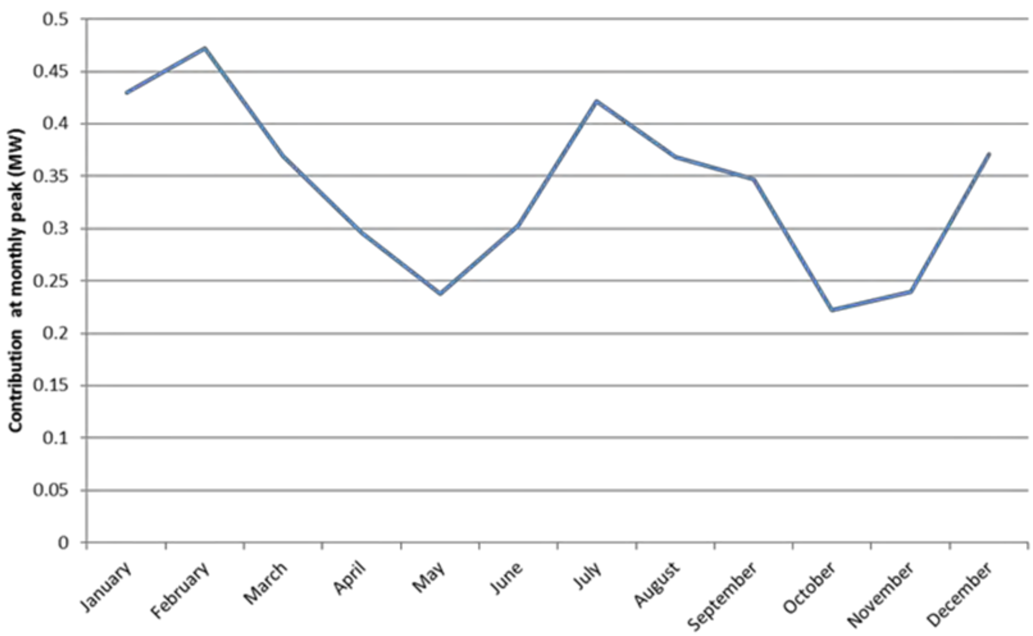
Section 5 described the process of creating DSM "bundles" that act as inputs into the Capacity Expansion Model. This section will continue that discussion by elaborating on how the Capacity Expansion Model evaluates these DSM bundles against supply-side resources.

IPL and ABB began preparing to model DSM as a resource in the IRP in the fall of 2015, with a pilot run of the Capacity Expansion Model using practice DSM bundles. The goal of the pilot was to understand the pros and cons of different configurations of DSM bundles and to understand how the model evaluates the bundles against supply-side resources. The hypothetical bundles were constructed using the 2015 DSM programs with each program represented by one bundle.

The team discovered some limitations to this approach. First, by inputting actual DSM programs as selectable resources there was a concern that the entire program would be eliminated in the Capacity Expansion Run. These DSM programs are still potentially viable if a revised measure mix is identified that is more cost-effective. These observations and findings from the pilot conducted last fall, led IPL to the decision to use bundles of measures, as defined by the average measure delivery costs. Second, because the measures within a program bundle have varying load shape characteristics, these measures don't neatly fit into the reference load shape for selection. This limitation was addressed by deciding to place measures with similar load shape characteristics into the final bundles, e.g., all residential HVAC measures represent a bundle. The Capacity Expansion Model was able to more accurately select the DSM bundles using this alternative approach.

For the final IRP Capacity Expansion Modeling, AEG provided information by bundle, including savings and costs over the IRP period and the average useful life of the bundle measures as inputs into DSMore. IPL worked with Morgan Marketing Partners, to use DSMore to create each bundle load shape. Additionally, levelized bundle costs were split proportionally to avoided energy and capacity benefits in DSMore to calculate the bundle cost per kWh (to then be compared to market prices in the Capacity Expansion Model) and cost per kW-year (to then be compared to the levelized cost of capacity in the Capacity Expansion Model). Figure 7.11 provides the annual load shape output from DSMore for a Residential HVAC bundle. Note the load shape exhibits summer and winter peaks sharing similarities with the Capacity Expansion reference load shape or IPL system load shape. Had the bundle consisted of an unrelated mix of measures, the load shape likely would not have exhibited such a similar pattern.

Figure 7.11 – Residential HVAC Load Shape



When evaluated in the Capacity Expansion Model, DSM is being screened against supply-side resources. Just like evaluating a supply-side resource, the model looks at the need to meet the system load plus a reserve margin as described in Section 2 over the planning horizon. If the reserve margin is not being met for a particular period, the model will evaluate the price to build new generation or purchase capacity to meet this reserve requirement. Additionally, the model considers the price to reduce load in order to satisfy the reserve margin requirements to a level where it is being met by existing resources – in other words – implement DSM. Since in the Base Case IPL has no need for capacity in the short term, DSM "bundles" are being selected against as an economic choice instead of market purchases, rather than based on a need to meet the reserve margin. The least expensive strategy to meet the load requirements is to implement DSM as opposed to running IPLs' existing units or going to the market to purchase power.

An important point to note – since IPL decided to split the DSM bundles into two periods – 2018 to 2020 and 2021 to 2036 (as described in Section 5), the amount of annual DSM within each "bundle" and corresponding period is solely influenced by the Market Potential for those period years. For example, let's say the model picks the Residential Lighting block for the 2021–2036 period. The level of DSM within this bundle is pre-set for this period based on the Market Potential Study. DSM within this bundle is static and will not increase in year 2030, if there is a need for additional capacity to meet the reserve margin. An additional DSM bundle of different measures may need to be selected.

7.4. Production Cost Model

The Strategic Planning software is an integrated mathematical model which captures both the production and financial aspects of electrical generating units. ABB uses the **Production Cost Model** to examine more detailed operational characteristics of IPL's fleet and to compare how each potential portfolio will fare in a Base Case future world. The Production Cost Model is an hourly model that uses unit commitment logic for the next 20 years to take into account load forecasts, as well as plant specific parameters such as the following:

- Ramp rates
- Minimum/maximum run times
- Startup costs
- Forced outage rates

The ABB model dispatches the resource portfolio for each scenario competitively against the assumptions for the Base Case scenario. The model simulates the load in every hour and then in the most economic manner serves that load with purchases from the market and captures the associated operating costs. This allows IPL to analyze how each portfolio will perform against the most likely future world, that is, if the Base Case assumptions come to fruition. For example, the Production Cost model dispatches the Strengthened Environmental scenario portfolio off of Base Case market, natural gas, and carbon prices. In response to recent IURC Director's IRP reports, IPL sought to model scenarios that reflect a diverse range of portfolios. Comparing all candidate resource portfolios against the Base Case assumptions is a way to level set the results. Stochastic analysis provides further insights about cost volatility from variable inputs as further described below.

The Financial Module models other financial aspects regarding costs that are external to the operation of units such as plant in service, depreciation expense, deferred taxes, investment tax credits, income taxes, property and other taxes. The discount rate does not vary between scenarios.

The Strategic Planning Software then consolidates the production and financial cost information in order to derive an annual revenue requirement for each year of a simulation. Annual revenue requirements were used to calculate the PVRRs, which were then used by IPL to evaluate each scenario. The resulting PVRR for each scenario is a deterministic PVRR. IPL subsequently compared the deterministic PVRR for each scenario with a probabilistic PVRR developed through stochastic analysis.

7.5. Sensitivity Analysis

A sensitivity measures how a 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.

7.5.1. Deterministic Environmental Sensitivity Analysis

To better understand the impact of carbon regulations on the Base Case, IPL conducted two deterministic sensitivities on the Base Case and compared the PVRR from those sensitivities to the original Base Case PVRR. ABB modeled the sensitivities using the Production Cost Model by taking the Base Case portfolio and dispatching the units for different carbon prices. Altering the carbon price assumptions changes the amount at which the units can run economically over the next 20 years, which then changes the fuel and variable operating and maintenance ("VOM") costs that IPL incurs over that time period. These variable and operating costs include the costs for IPL's units to meet environmental regulations on a $/MWh basis. The change in VOM then causes changes to the portfolio's PVRR.

- **Sensitivity 1:** IPL modeled a delay in timing of the Clean Power Plan from 2022 until 2030. The Base Case portfolio was not constrained by any carbon prices until 2030, at which point carbon prices were put into the model.
- **Sensitivity 2:** IPL modeled higher than expected carbon prices for the Base Case by using a high carbon cost curve from 2022-2036.

7.5.2. Probabilistic Stochastic Analysis

ABB's Risk Module conducts a probabilistic stochastic analysis of the IRP fundamental modeling inputs

- resource technology cost
- coal prices
- oil prices
- coal unit availability
- gas unit availability
- natural gas prices
- energy load forecast

- peak load forecast
- carbon prices
- long-term combined cycle capital cost
- long-term wind and solar capital cost
- long-term utility scale and community solar capital cost
- long-term battery storage capital cost

Market prices change as those inputs change. This analysis captures future uncertainties by allowing those inputs to vary over a range of possible values. For each scenario, ABB does 50 random draws for a range of input values by using a stratified Monte Carlo sampling program, called Latin Hypercube. The program uses these random draws to generate forward price curves and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e., Short-Term hourly, Mid-Term monthly, and Long-Term annual).

Through the stochastic modeling process, ABB develops 50 PVRR values, and the mean of those PVRR is the "Expected" PVRR for each scenario. The difference between the "Deterministic PVRR" and the "Expected PVRR" is called "The Value at Risk." The greater the Expected PVRR is than the Deterministic PVRR, the greater the risk that the scenario's portfolio will cost more than the Deterministic PVRR developed through the Production Cost Model.

7.6. Metrics Development Process

170 IAC 4-7-4(b)(9)

In previous IRPs, IPL primarily used the present value revenue requirement ("PVRR") of scenarios to compare the candidate portfolios. While PVRR is still a very important metric to compare scenarios, it does not tell the entire story of a portfolio's outcomes. IPL and its stakeholders also want to understand how the portfolios compare in terms of other outcomes, such as rate impact, air emissions, and the reliability of our electric system. For the 2016 IRP, IPL expanded its comparison of portfolios to several other quantitative metrics in addition to PVRR. IPL first researched metrics that other utilities, including the Tennessee Valley Authority ("TVA") and the Indiana Municipal Power Authority ("IMPA"), use in their IRPs. After identifying several metrics that apply to IPL, IPL determined that the metrics fit into four categories:

1. Cost
2. Financial Risk
3. Environmental Stewardship
4. Resiliency

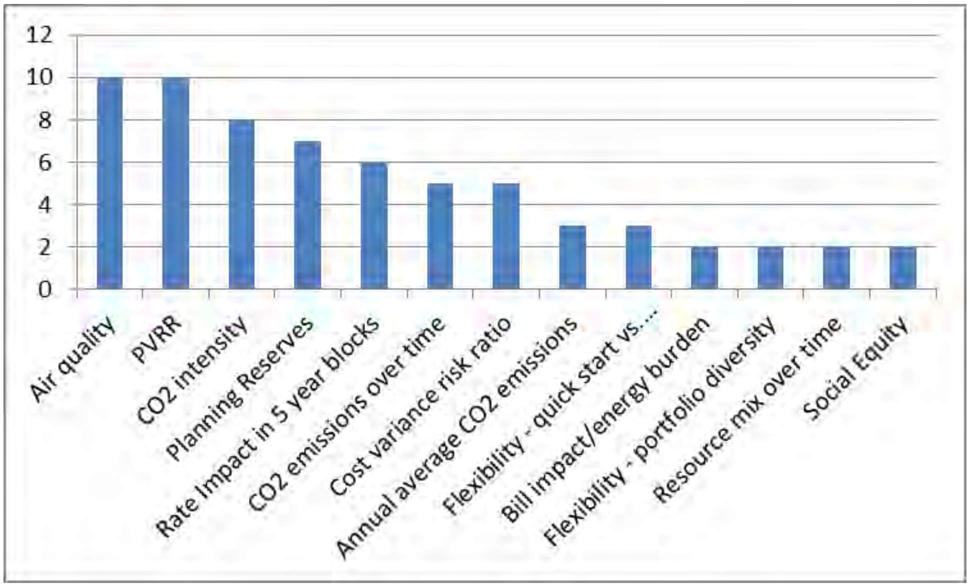
IPL proposed the use of several metrics under these four categories to stakeholders at the Public Advisory Meeting #2 and solicited stakeholder feedback and ideas for additional metrics. Stakeholders were divided into small groups and then given a chance to discuss the proposed metrics and to suggest metrics of their own. Stakeholders then selected their "top 3" metrics, including both the metrics proposed by IPL and metrics proposed by the stakeholders. Figure 7.12 summarizes the results of the stakeholders' top three metrics. Metrics in green were proposed by the stakeholder, and metrics in blue were proposed by IPL. Figure 7.13 below shows the stakeholder rankings graphically.

Figure 7.12 – Metrics Scoring Summary

Metrics	Scores
Air quality*	10
PVRR	10
CO_2 intensity	8
Planning reserves	7
Rate impact in 5 year increment	6
CO_2 emissions over time	5
Cost variance risk ratio	5
Annual average CO_2 emissions	3
Flexibility - Quick start vs. peak load	3
Bill impact / energy burden	2
Flexibility - Portfolio diversity (fuel)	2
Resource mix over time	2
Social Equity	2

green = stakeholder proposed
blue= IPL proposed
*other pollutants including PM, NOx, SO2, methane emissions

Figure 7.13 - Stakeholder Metric Rankings



As a result of stakeholder feedback, IPL added metrics to measure SO_2 and NO_X emission, the percentage of IPL's resources that is distributed generation, and IPL's planning reserves. IPL conducted one-on-one sessions with large industrial customers unable to attend the public advisory meetings to discuss these metrics. Many expressed keen interest in customer costs while others shared sustainability approaches holistically related to their total portfolio exposure to environmental impacts versus Indiana impacts alone. For example, one company described efforts to secure renewable energy in favorable sites such as facilities in Arizona rather than relying on renewable options at each of its locations. The discussions were insightful to IPL.

Figure 7.14 shows the four metrics categories, the individual metrics, and the metric definitions. Figure 7.15 shows the metrics formulas.

Figure 7.14 – Metrics Categories and Definitions

Category	Metric	Unit	Definition
Cost	Present Value Revenue Requirements (PVRR)	$MM	The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period
	Incremental Rate Impact (over 5 years)	cents/kWh	The incremental impact to customer rates of adding new resources, shown in five year time blocks
	Average Rate Impact (over 20 years)	cents/kWh	The average 20 year cost impact of adding new resources divided by total kWh sold
Financial Risk	Risk Exposure	$	The difference between the PVRR at the 95th percentile of probability and the PVRR at 50% percentile probability (expected value)
Environmental Stewardship	Annual average CO_2 emissions	tons/year	The annual average tons of CO_2 emitted over the study period
	Annual average SO_2 emissions	tons/year	The annual average tons of SO_2 emitted over the study period
	Annual average NO_X emissions	tons/year	The annual average tons of NO_X emitted over the study period
	CO_2 intensity	tons/MWh	Total tons of CO_2 during the study period per MWh of generation during the study period
Resiliency	Planning Reserves as a percent of load forecast	%	Planning reserves are the MW of supply above peak forecast. This metric measures planning reserves as a percent of peak load forecast
	Distributed Energy Generation	%	Percent of IPL's resources that is distributed generation, shown in five year time blocks
	Market reliance energy	%	Percent of customer load met with market purchases
	Market reliance capacity	MW	Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin

Figure 7.15 – Metrics Categories and Formulas

Category	Metric	Unit	Formula
Cost	Present Value Revenue Requirements	$MM	Present Value Revenue Requirements 2017-2036
	Incremental Rate Impact (over 5 years)	cents/kWh	Five year averages (2017-2021, 2022-2026, 2027-2031, 2032-2016) of the following calculation for each year of the study period: (Year X revenue requirement/Year X kWh sales) - (Prior Year revenue requirement/Prior Year kWh sales)
	Average Rate Impact (over 20 years)	cents/kWh	$\frac{\text{PVRR (20 year period)}}{\text{kWh Sales (20 year period)}}$
Financial Risk	Risk Exposure	$	PVRR at the 95% probability – PVRR at the 50% probability
Environmental Stewardship	Annual average CO_2 emissions	tons/year	$\frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$
	Annual average SO_2 emissions	tons/year	$\frac{\text{Sum of } SO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$
	Annual average NO_X emissions	tons/year	$\frac{\text{Sum of } NO_x \text{ tons emitted}}{\text{\# of years in the study period}}$
	CO_2 intensity	tons/MWh	$\frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{MWh energy generated}}$
Resiliency	Planning Reserves as a percent of load forecast	%	$\frac{\text{IPL's resources (MW) – peak utility load forecast (MW)}}{\text{peak utility load forecast}}$
	Distributed Energy Generation	%	$\frac{\text{Distributed generation supply (MW)}}{\text{IPL resources (MW)}}$
	Market reliance energy	%	$\frac{\text{MWh of market purchases}}{\text{Retail MWh}}$
	Market reliance capacity	MW	Total capacity purchases

IPL does not intend for the metrics to create a "scorecard" for each scenario. Instead, the metrics provide a comparison of how the candidate portfolios differ in terms of cost, financial risk, environmental stewardship, and resiliency. Quantitative metrics of the portfolio results outcomes allow IPL and stakeholders to ask questions and dig deeper into the meaning of the portfolio results. Questions that may arise include, "What are the main drivers of the portfolio's PVRR? If one variable changes, how does that impact the PVRR? What causes one scenario to have a higher range of financial risk than another? For portfolios with low environmental emissions, what is the rate impact?"

Additionally, metrics show the trade-offs that IPL must consider when selecting its preferred resource portfolio. For example, a portfolio with low air emissions due to high deployment of renewable energy may have also have a high PVRR due to the cost of installing that technology.

The metrics results are presented in Section 8 in terms of the metrics described above.

Section 8: Model Results

Executive Summary

The IRP modeling process produced six very different portfolios. IPL took the portfolios for each scenario and modeled it against Base Case assumptions to examine how each portfolio would fare if Base Case assumptions for the future come to fruition. Additionally, stochastic analysis, also known as "probabilistic analysis," enabled IPL to assess the financial risk to each portfolio if key variables changed. IPL used several metrics to compare the portfolios across four categories: Cost, Financial Risk, Environmental Stewardship, and Resiliency.

IPL recognizes that the IRP represents the analysis at this point in time using forecasts of technology costs, customer load, and environmental rules available to-date. Should technology costs decline more quickly than modeled and a blend of variables from the Base, Strengthened Environmental and DG scenarios come to fruition, perhaps a hybrid preferred resource portfolio would result as described in this section.

8.1. Candidate Resource Portfolios

170 IAC 4-7-6(a)(2) 170 IAC 4-7-7(a) 170 IAC 4-7-8(a)

The Capacity Expansion Model produces a portfolio for each of the six scenarios described in Section 7 using the resources described in Section 5. The resultant portfolios vary significantly as shown in Figure 8.1 for 2036, which is the final year of the study period. Figure 8.1 shows the candidate resource portfolios in 2036 by operating capacity which is close to the nameplate capacity.

The total operating capacity varies significantly between the scenarios due to the types of resources selected by the Capacity Expansion Model. As explained in Section 2, MISO requires IPL to secure capacity equal to its peak load plus its planning reserve margin requirement. The capacity credit from MISO is also known as "planning capacity." The dispatchable nature of the thermal unit resources allows them to receive a planning capacity credit that is very similar to their operating capacity. However, solar and wind resources can only count a much smaller percentage of their operating capacity towards planning capacity. The low planning capacity credit for wind and solar reflects the variability of wind and solar resources. Portfolio operating capacities are significantly larger than portfolio planning capacities if they contain significant amount of wind and solar resources. "Capacity credit," or the amount of capacity considered available at peak times, is different than "capacity factor," which is based on the unit's actual performance 24/7 compared to its maximum achievable performance. New wind is modeled with a capacity factor of 35%, which says that on average, the wind will output 35% of its maximum achievable output.

The Figures below represent ABB modeling results.

Figure 8.1 – Scenario Candidate Resource Portfolios by Operating Capacity (MWs in 2036)

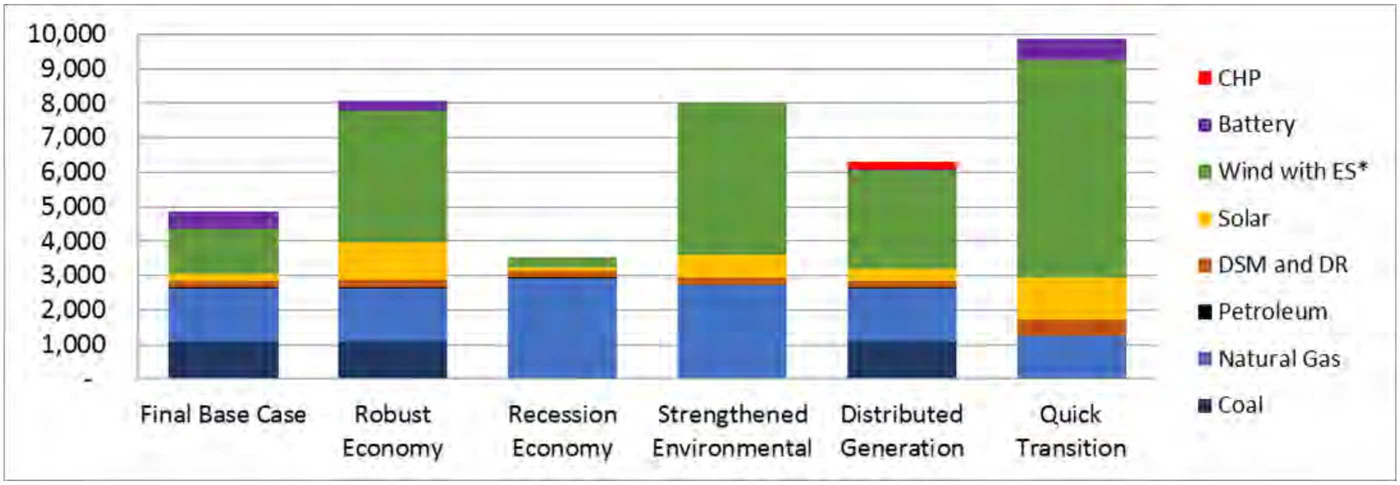


Figure 8.2 shows the operating capacity of supply side resource additions and retirements for each year of the study period for each scenario. The net demand side resource additions are shown in separate table for ease of reading.

Figure 8.2 – Annual Supply-Side Capacity Additions and Retirements

YEAR	Base Case	Robust Economy	Recession Economy	Strengthened Environmental Rules	High Customer Adoption of Distributed Generation	Quick Transition
2017						
2018	**Upgrade Pete 1-4**	**Upgrade Pete 1-4**	**Refuel Pete 1 - 4**	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG**	**Upgrade Pete 1-4**	**Upgrade Pete 1-4**
2019						
2020				Wind 500 MW PV 280 MW		
2021						
2022				Wind 100 MW PV 50 MW	PV 65 MW Wind 10 MW CHP 75 MW	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG**
2023	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil** PV 10 MW	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**
2024				PV 10 MW		
2025					PV 65 MW Wind 10 MW CHP 75 MW	
2026				PV 10 MW		
2027				PV 10 MW		
2028				PV 10 MW Comm Solar 1 MW		
2029				PV 10 MW Comm Solar 5 MW		
2030	**Retire HS 5&6 (-200MW) NG**	**Retire HS 5&6 (-200MW) NG** Wind 500 MW	**Retire HS 5&6 (-200MW) NG**	**Retire HS 5&6 (-200MW) NG** Wind 500 MW	**Retire HS 5&6 (-200MW) NG**	**Retire Pete 2-4 (-1495 MW) NG, HS GT4-6 (294 MW) NG, HS 5&6 (-200 MW) NG, HS IC1 (3 MW) Oil, Pete IC1-3 (8 MW) Oil** Wind - 6000 MW Solar - 1146 MW Battery - 600 MW
2031		Wind 500 MW Market 200 MW		Wind 500 MW		
2032	**Retire Pete 1 (-234 MW) Coal**	**Retire Pete 1 (-234 MW) Coal** Wind 500 MW PV 370 MW	**Retire Pete 1 (-234 MW) Coal**	Wind 500 MW Comm Solar 3 MW	**Retire Pete 1 (-234 MW) Coal** PV 65 MW Wind 510 MW CHP 75 MW	
2033	**Retire HS7 (-428 MW) NG** Wind 250 MW Market 50 MW PV 90 MW Battery 100 MW	**Retire HS7 (-428 MW) NG** Wind 500 MW PV 440 MW	**Retire HS7 (-428 MW) NG**	**Retire HS7 (-428 MW) NG** Wind 500 MW Comm Solar 5	**Retire HS7 (-428 MW) NG** Wind 500 MW	**Retire HS7 (-428 MW) NG**
2034	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 250 MW	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) NG** H-Class CC 450 MW	**Retire Pete 2 (-417 MW) NG** H-Class CC 450 MW Wind 500 MW Comm Solar 5 MW	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 500 MW	H-Class CC 450 MW
2035	Wind 250 MW Battery 250 MW Market 150 MW	Wind 500 MW PV 190 MW Battery 250 MW Market 50 MW Comm Solar 1 MW	H Class CC 200 MW	Wind 500 MW PV 70 MW Market 50 MW Comm Solar 5 MW	Wind 500 MW Battery 50 MW Market 50 MW	
2036	Wind 250 MW Battery 150 MW PV 10 MW	Wind 500 MW Battery 50 MW Comm Solar 5 MW		Wind 500 MW PV 60 MW Comm Solar 5 MW	Wind 500 MW PV 60 MW Comm Solar 1 MW	

* Upgrades for Pete 1-4 for NAAQS SO2 and CCR

The model results indicate the environmental upgrades for the Petersburg Units to comply with the NAAQs, SO_2, and CCR rules are economic in the Base Case, Robust Economy and High Customer Adoption of DG Scenarios.[81]

Figure 8.3 shows the incremental amount of DSM additions for each scenario. This table takes into account the impact of new DSM measures net of the impact of past DSM measures reaching the end of their useful life. Therefore, the total at the bottom of the table indicates the amount of load reductions provided by DSM in 2036. For example, the Base Case in 2036 will have a total of 208.4 MW of DSM provided load reductions.

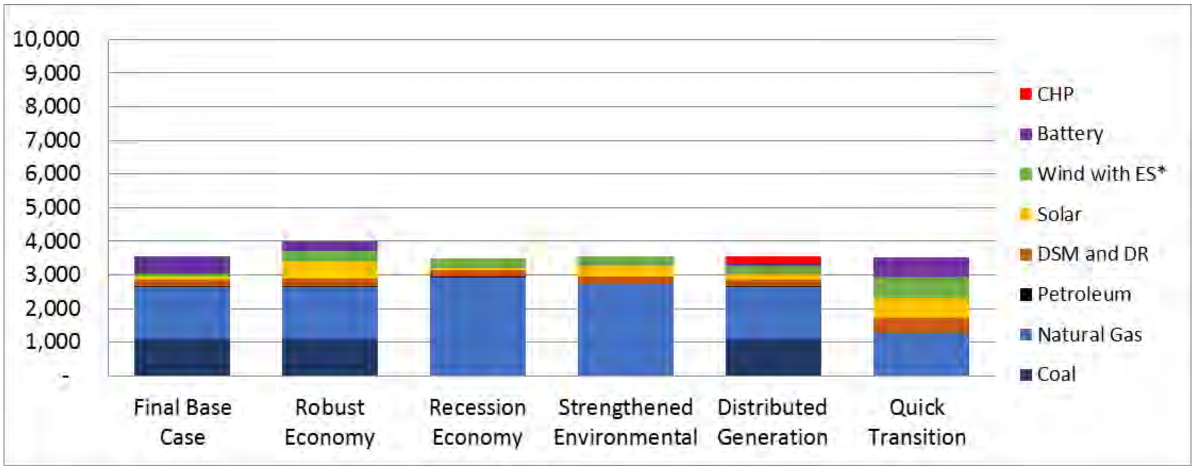
Figure 8.3 – Net Annual Incremental DSM (MW)

YEAR	Base Case	Robust Economy	Recession Economy	Strengthened Environmental Rules	High Customer Adoption of Distributed Generation	Quick Transition
2017	58.1	58.1	58.1	58.1	58.1	58.1
2018	17.3	22.5	22.3	22.5	17.3	27.8
2019	16.5	16.7	16.5	16.7	16.5	59.1
2020	12.1	12.3	12.1	12.3	12.1	46.8
2021	15.2	10.5	10.1	10.5	15.2	52.2
2022	10.2	10.6	10.2	10.6	10.2	18.5
2023	10.2	10.6	10.2	10.6	10.2	18.2
2024	11.1	11.6	11.1	11.6	11.1	15.7
2025	10.5	11.0	10.5	11.0	10.5	18.1
2026	9.2	9.8	9.2	9.8	9.2	18.0
2027	4.2	4.7	4.2	4.7	4.2	12.5
2028	4.5	4.9	4.5	4.9	4.5	13.0
2029	0.8	1.2	0.8	1.2	0.8	9.5
2030	2.0	2.7	2.0	2.7	2.0	11.5
2031	2.7	3.4	2.7	3.4	2.7	12.6
2032	9.0	9.7	9.0	9.7	9.0	18.1
2033	8.7	9.4	8.7	9.4	8.7	16.4
2034	2.0	2.7	2.0	2.7	2.0	9.5
2035	1.9	2.7	1.9	2.7	1.9	10.9
2036	2.1	3.0	2.1	3.0	2.1	11.5
TOTAL	208.4	218.1	208.3	218.1	208.3	457.9
*The 2017 value includes existing Demand Response						

The planning capacity by resource for each scenario in 2036 is shown in Figure 8.4. The planning capacity is relatively similar across all of the scenarios. The planning capacity for the Robust Economy Scenario is higher than the others due to higher peak and energy forecasts in this scenario than the Base Case forecast. The planning capacity for the Recession Economy scenario is lower than the other scenarios due to lower peak and energy forecasts than the Base Case Forecast.

[81] The NAAQs SO_2 and CCR environmental compliance projects are estimated to cost approximately $97 million. Approval to complete these projects is being sought in IURC Cause No. 44794, which is currently pending before the Commission.

Figure 8.4 – Scenario Candidate Resource Portfolios by Planning Capacity (MWs in 2036)



Except for the Recession Economy and Strengthened Environmental scenarios, the scenarios result in a diverse portfolio of resources. Portfolio diversity is important to mitigate risk of fuel price variation and/or potential fuel shortages. From a cost-mitigation or reliability standpoint, it may not be wise to pursue a portfolio that heavily relies on one fuel, such as the Recession Economy and Strengthened Environmental portfolios' high reliance on natural gas fueled resources capacity additions. This is especially demonstrated in Figure 8.13 and Figure 8.16, which show that the Recession Economy and Strengthened Environmental portfolios would result in high reliance on market purchases if Base Case assumptions come to fruition. When the low natural gas prices of the Recession Economy scenario and high carbon prices of the Strengthened Environmental scenario do not occur in a Base Case world, it is more economical to purchase energy from the market instead of running the natural gas fueled Pete units.

Three of the six scenarios show the Pete 1 - 4 coal units either retiring early or refueling to natural gas before the units' target dates for age-based retirement. The Recession Economy scenario refuels Pete 1-4 in 2018 due to the low natural gas prices in that scenario. The Strengthened Environmental scenario retires Pete 1 and refuels Pete 2-4 due to higher carbon costs and costs of environmental compliance than the Base Case scenario. The Quick Transition scenario retires Pete 1 and refuels Pete 2-4 in 2022 due to stakeholder input. Each scenario for which Pete units retire early or refuel to natural gas has a high reliance on the market for energy. The Load Resource Balance Sheet for each Scenario is available as Attachment 8.1.

8.1.1. Portfolio Capacity and Energy Results

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

The IRP modeling process produced six portfolios, each of which are shown below. Each scenario's portfolio was then modeled against Base Case assumptions to examine how each portfolio would fare if Base Case assumptions for the future come to fruition.

8.1.1.1 *Base Case Portfolio Capacity Expansion*

The Base Case Portfolio planning capacity results are shown in Figure 8.5. The solid black line in the Figure 8.5 shows the Base Case load before DSM, while the dotted black line shows IPL's resources plus the required 15% reserve margin. For this future landscape, IPL adds DSM in each year of the 20 year study period, even though IPL surpasses its 15% planning reserve margin in the early years of the study period. The Capacity Expansion Model selected DSM in the early years because it is economic from an energy stand-point, despite the fact that there is not a capacity need in the early years.

Other than DSM, no additional resources are added for capacity until 2033. Figure 8.6 shows the operating capacity of resource additions. Harding Street natural gas units and Pete 1 and 2 coal units do not retire early; instead, they retire at their currently scheduled retirement date. Between 2030 and 2034, 1279 MW of resources retire due to end of useful life. Between 2033 and 2036, IPL adds a mix of wind, solar, battery, market purchases, and natural gas combined cycle. While IPL prefers not to rely on the market long-term for capacity, the Capacity Expansion Model found it more economic to rely on the market for one year in 2033 and again in 2035, once its reserve margin fell below 15% than to immediately add a new resource.

Figure 8.5 – Base Case Planning Capacity

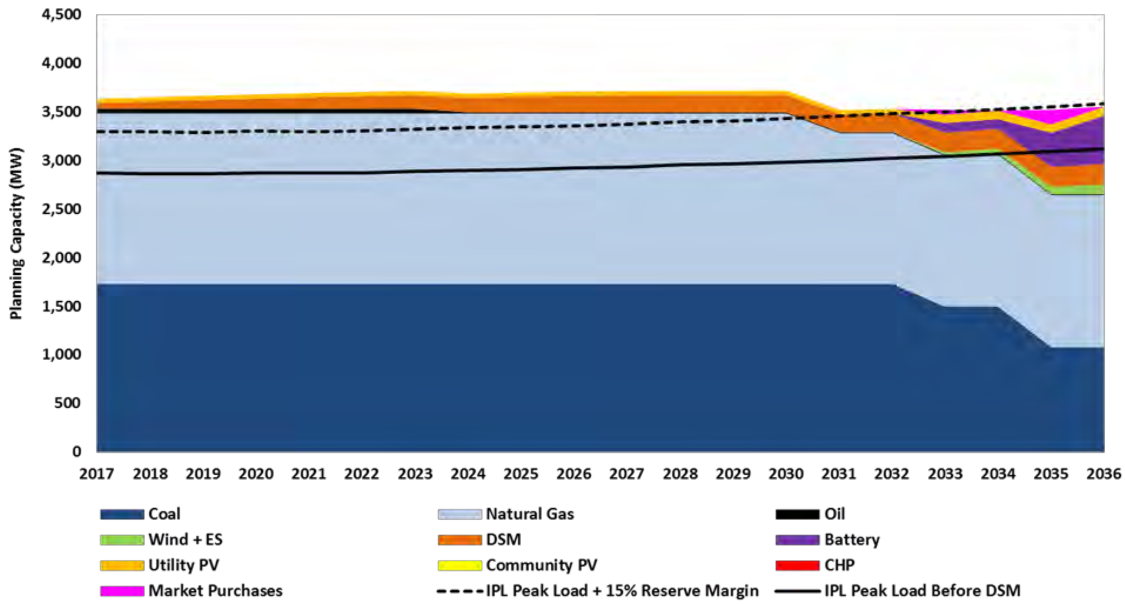


Figure 8.6 – Base Case Operating Capacity Additions

	2017-2018	2019-2020	2021-2022	2023-2024	2025-2026	2027-2028	2029-2030	2031-2032	2033-2034	2035-2036	TOTAL
Natural Gas	671								450		1121
Battery									100	350	450
Wind with ES*									500	500	1000
DSM and DR	75	29	25	20	22	9	3	12	11	4	209
Solar									90	10	100
Community Solar											0
CHP									50	150	200
Market											0

Figure 8.7 – Base Case Energy

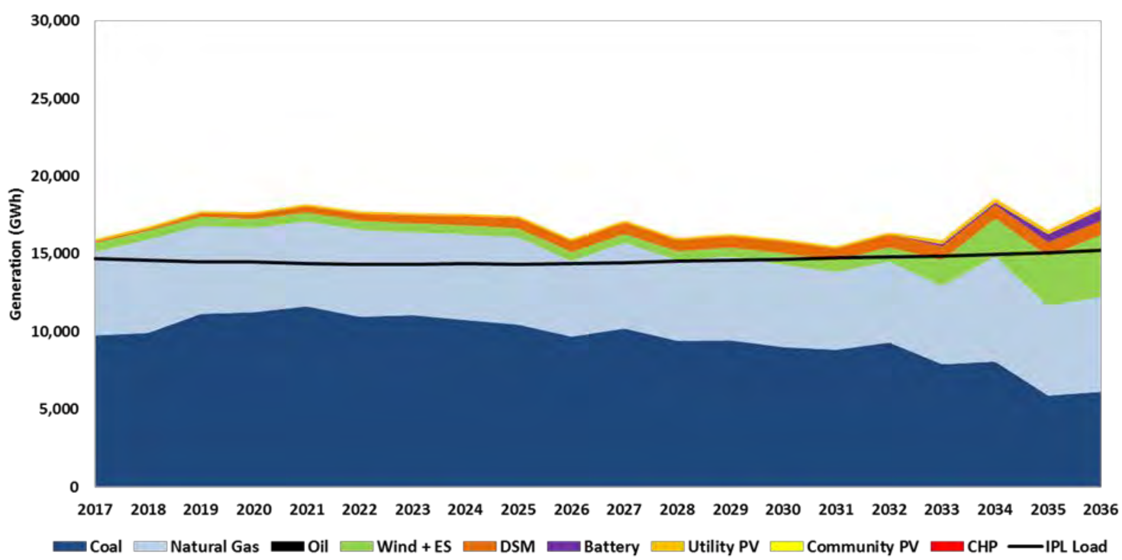
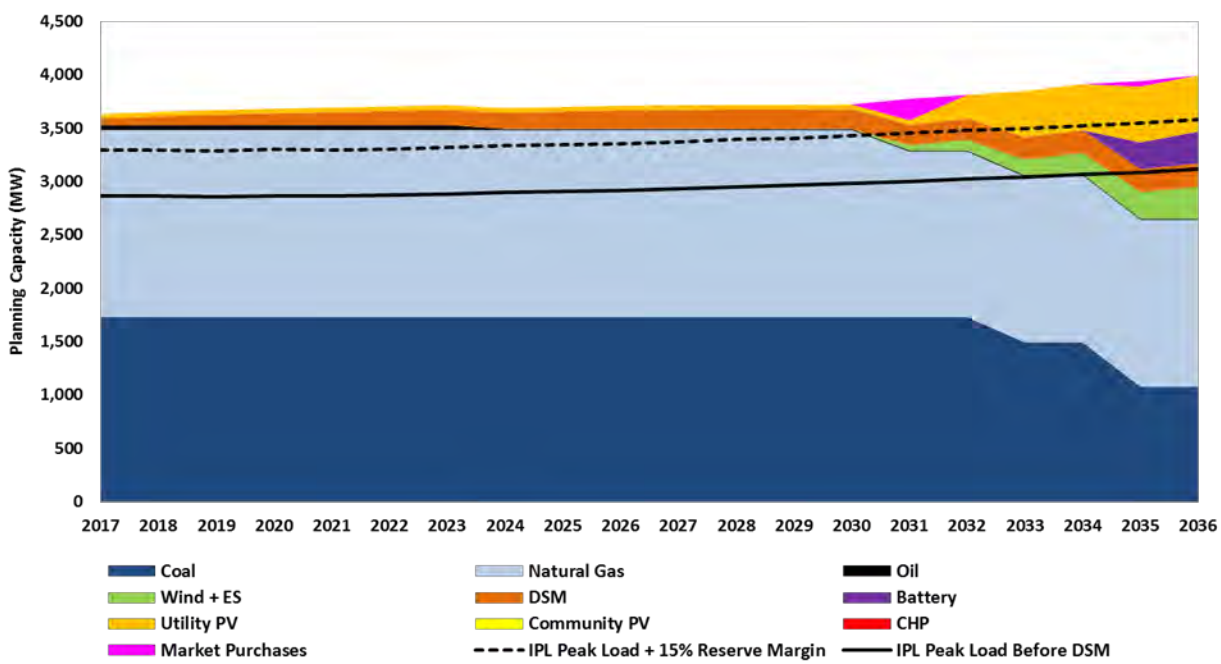


Figure 8.7 shows the forecasted energy results for the Base Case portfolio for 2017–2036. For this case, annual generation shows that the base case has enough resources each year to meet the load requirements designated by the black line. However, this figure does not show that on an hourly basis, there are times when market purchases are required to meet load. For example, IPL relies on the market during planned and unplanned outages and when purchases are more economic than running the units. Market purchases are further described below. The orange band shows how many GWh can be contributed to DSM.

8.1.1.2 *Robust Economy Portfolio Capacity Expansion*

The Robust Economy planning capacity results are shown in Figure 8.8. For this future landscape, the Capacity Expansion Model selects more resources than the Base Case landscape due to a high peak demand and high load forecast; however, the peak demand shown in Figure 8.8 is the Base Case peak demand forecast before DSM. IPL compares the Robust Economy capacity expansion results to the Base Case peak demand before DSM to show how a Robust Economy portfolio would fare in the most likely future landscape.

Figure 8.8 – Robust Economy Planning Capacity



Other than DSM, no additional resources are added for capacity until 2030. Figure 8.9 shows the operating capacity of resource additions. Like the Base Case portfolio, Harding Street natural gas units and Pete 1 and 2 coal units do not retire early; instead, they retire at their currently scheduled retirement dates due to age. Between 2030 and 2034, 1279 MW of resources retire due to end of useful life. Between 2030 and 2036, a mix of wind, solar, battery, natural gas, and market purchases is added. The Capacity Expansion Model begins adding significant amounts of wind in 2030 in order to meet IPL's high peak and energy demand forecast. The model selects wind, battery, and solar over natural gas, due to the scenario's high natural gas prices. Natural gas is added in 2034 to maintain system reliability, not for economic reasons.

Figure 8.9 – Robust Economy Operating Capacity Additions

	2017-2018	2019-2020	2021-2022	2023-2024	2025-2026	2027-2028	2029-2030	2031-2032	2033-2034	2035-2036	TOTAL
Natural Gas	671								450		1121
Battery										300	300
Wind with ES*							500	1000	1000	1000	3500
DSM and DR	80	29	21	22	21	10	4	13	12	6	218
Solar								370	440	190	1000
Community Solar										6	6
CHP											0
Market								200		50	250

Figure 8.10 – Robust Economy Energy

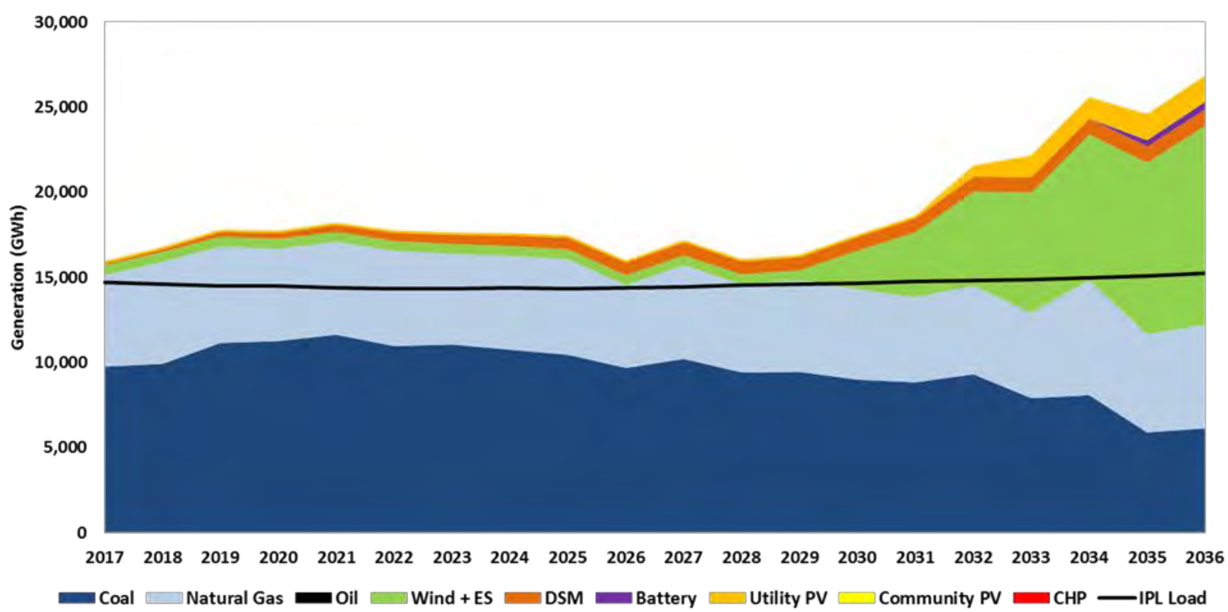


Figure 8.10 shows the Robust Economy portfolio energy mix as modeled against Base Case assumptions in the ABB Production Cost model. As explained in Section 7, IPL models each portfolio against the Base Case assumptions to assess how each portfolio would perform in the most likely future landscape. Hence, the load in this figure is the Base Case load. Figure 8.8 shows that a Robust Economy portfolio would overbuild capacity as compared to the capacity needed for a Base Case future. This portfolio shows that IPL will sell excess energy into the market. Much of this excess energy comes from wind, since IPL estimates that it will only receive 10% capacity credit for wind starting in 2030.

8.1.1.3 *Recession Economy Portfolio Capacity Expansion*

The Recession Economy planning capacity results are shown in Figure 8.11. For this future landscape, the Capacity Expansion Model selects fewer resources than the Base Case landscape due to a low peak demand and low load forecast; however, Figure 8.11 compares the Recession Economy capacity expansion results to the Base Case peak demand before DSM to show how a Recession Economy portfolio would fare in the most likely future landscape. The Recession Economy portfolio will result in a capacity deficit beginning in 2033 if the Base Case load assumptions come to fruition.

For this future landscape, Petersburg units 1-4 refuel to natural gas in 2018 due to low natural gas prices. Pete 1 and 2 units, as well as the Harding Street gas units, then retire at their currently scheduled retirement dates. Between 2030 and 2034, 1279 MW of resources retire due to end of useful life. Between 2034 and 2035, IPL adds 650 MW of natural gas combined cycle resources.

Figure 8.11 – Recession Economy Planning Capacity

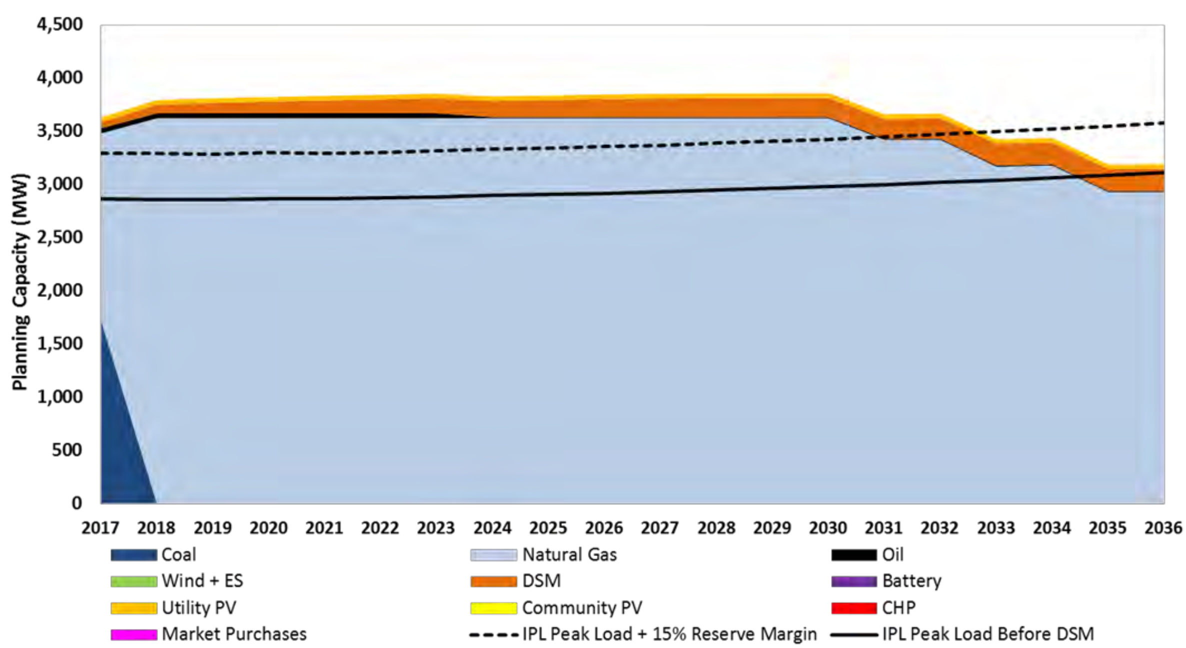
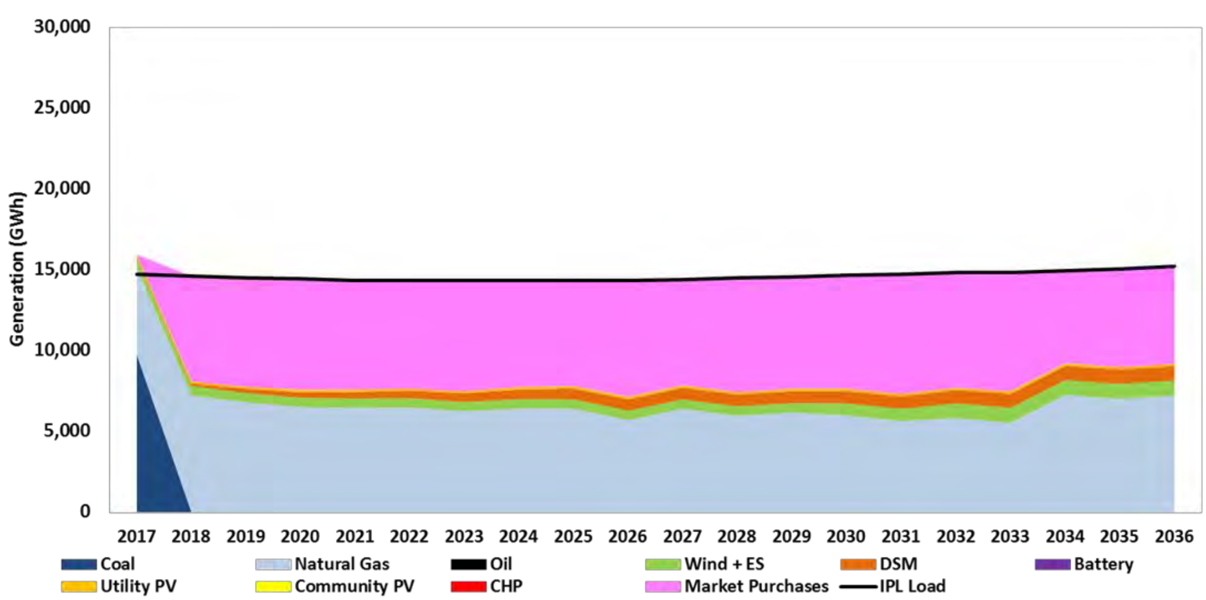


Figure 8.13 shows the Recession Economy portfolio energy mix as modeled against Base Case assumptions in the ABB Production Cost model. Hence, the load in this figure is the Base Case load. Figure 8.11 shows that a Recession Economy portfolio would under-build capacity as compared to the capacity needed for a Base Case future. Figure 8.12 shows the operating capacity of resource additions. This portfolio shows that IPL will rely heavily on the market for its energy needs if Base Case assumptions come to fruition, even though its portfolio meets the 15% reserve excess energy into the market. The coal units were refueled because of low gas prices in the Recession Economy scenario. However, under Base Case assumptions, the refueled units are not as economic and have lower capacity factors. As a result, there is heavy reliance on the market for energy to meet IPL's load requirements.

Figure 8.12 – Recession Economy Operating Capacity Additions

	2017-2018	2019-2020	2021-2022	2023-2024	2025-2026	2027-2028	2029-2030	2031-2032	2033-2034	2035-2036	TOTAL
Natural Gas	2542								450	200	3192
Battery											0
Wind with ES*											0
DSM and DR	80	29	20	21	20	9	3	12	11	4	208
Solar											0
CHP											0
Community Solar											0
Market											0

Figure 8.13 – Recession Economy Energy



8.1.1.4 *Strengthened Environmental Portfolio Capacity Expansion*

For the Strengthened Environmental Case, the Capacity Expansion Model took into account an Renewable Portfolio Standard ("RPS") of 20%, a carbon cost higher than the Base Case, and Petersburg environmental upgrade costs based on the highest estimated cost shown in Section 6. Without the RPS requirements, the model did not select wind prior to 2033. The model only selected wind once the RPS constraint was added, which results in higher portfolio costs. Since the model was constrained to choose a certain amount of wind for the RPS, the model added wind prior to 2022 to take advantage of the production tax credit ("PTCs") and to provide energy for load. However, since the wind does not receive capacity credit until 2030, it does not show up in Figure 8.14. The high carbon cost tax and higher environmental upgrade costs resulted in the retirement of Pete 1 in 2018, and refueling of Pete 2-4 to natural in 2018. Figure 8.15 shows the operating capacity of resource additions.

Figure 8.14 – Strengthened Environmental Planning

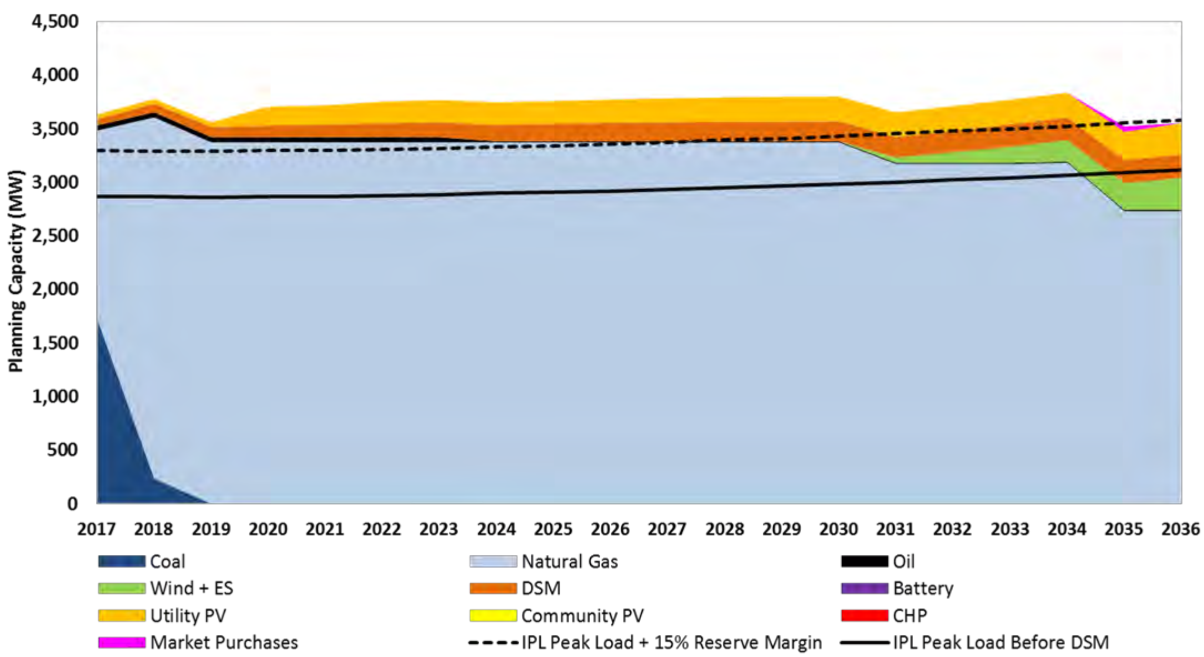
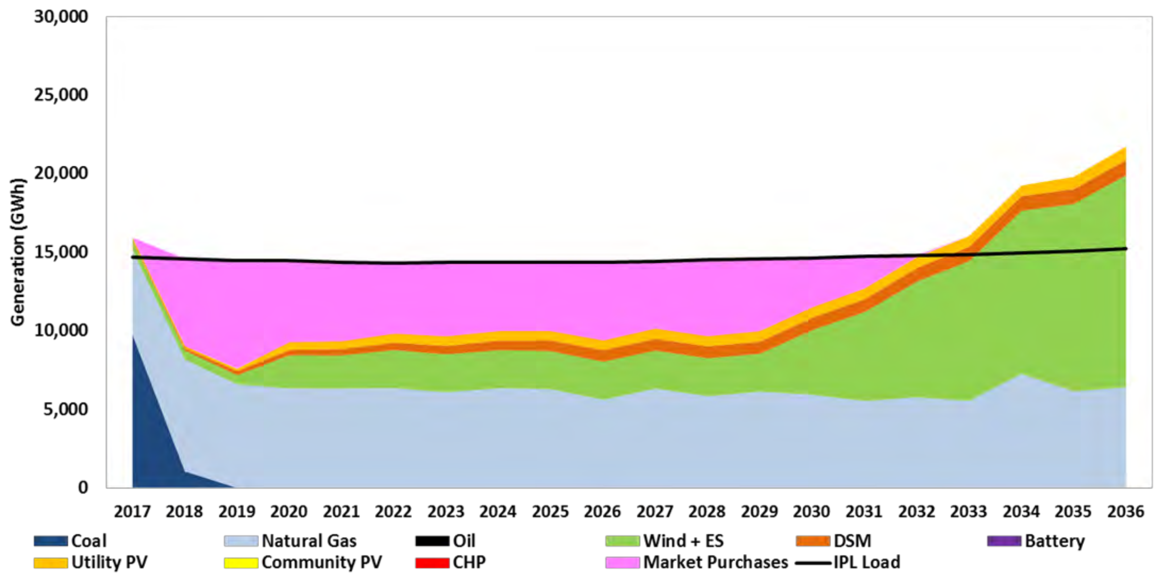


Figure 8.15 – Strengthened Environmental Operating Capacity Additions

	2017-2018	2019-2020	2021-2022	2023-2024	2025-2026	2027-2028	2029-2030	2031-2032	2033-2034	2035-2036	TOTAL
Natural Gas	2289								450		2739
Battery											0
Wind with ES*		500	1000	1000	1000	1000	1000	1000	1000	1000	8500
DSM and DR	80	29	0	0	0	0	10	10	10	10	148
Solar		280	50	20	10	20	10			130	520
Community Solar						1	5	3	10	10	29
CHP											0
Market										50	50

Figure 8.16 shows the Strengthened Environmental portfolio energy mix as modeled against Base Case assumptions in the ABB Production Cost model. This figure shows that a Strengthened Environmental portfolio will rely heavily on the market for its energy needs if Base Case assumptions come to fruition, even though its portfolio meets the 15% reserve excess energy into the market. The coal units are refueled to natural because of high carbon prices in the Strengthened Environmental scenario. However, under Base Case assumptions, the refueled units are not as economic and have lower capacity factors. As a result, there is heavy reliance on the market for energy to meet IPL's load requirements.

Figure 8.16 – Strengthened Environmental Energy



8.1.1.5 *High Customer Adoption of DG Portfolio Capacity Expansion*

Figure 8.17 shows the planning capacity results for the High Customer Adoption of Distributed Generation scenario.

Figure 8.18 shows the operating capacity of the resource additions. 65 MW of solar, 75 MW of CHP, and 10 MW of wind are added as customer-owned distributed generation in each year for 2022, 2025, and 2032. Other than DSM and the 450 MW of customer-owned DG, no additional resources are added for capacity until 2033. Harding Street natural gas units and Pete 1 and 2 coal units do not retire early; instead, they retire at their currently scheduled retirement date. Between 2030 and 2034, 1279 MW of resources retire due to end of useful life. Between 2033 and 2036, IPL adds a mix of wind, solar, battery, market purchases, and natural gas combined cycle. While IPL prefers not to rely on the market long-term for capacity, the Capacity Expansion Model found it more economic to rely on the market for one year in 2033 and again in 2035, once its reserve margin fell below 15% than to immediately add a new resource.

Figure 8.17 – High Adoption of DG Planning Capacity

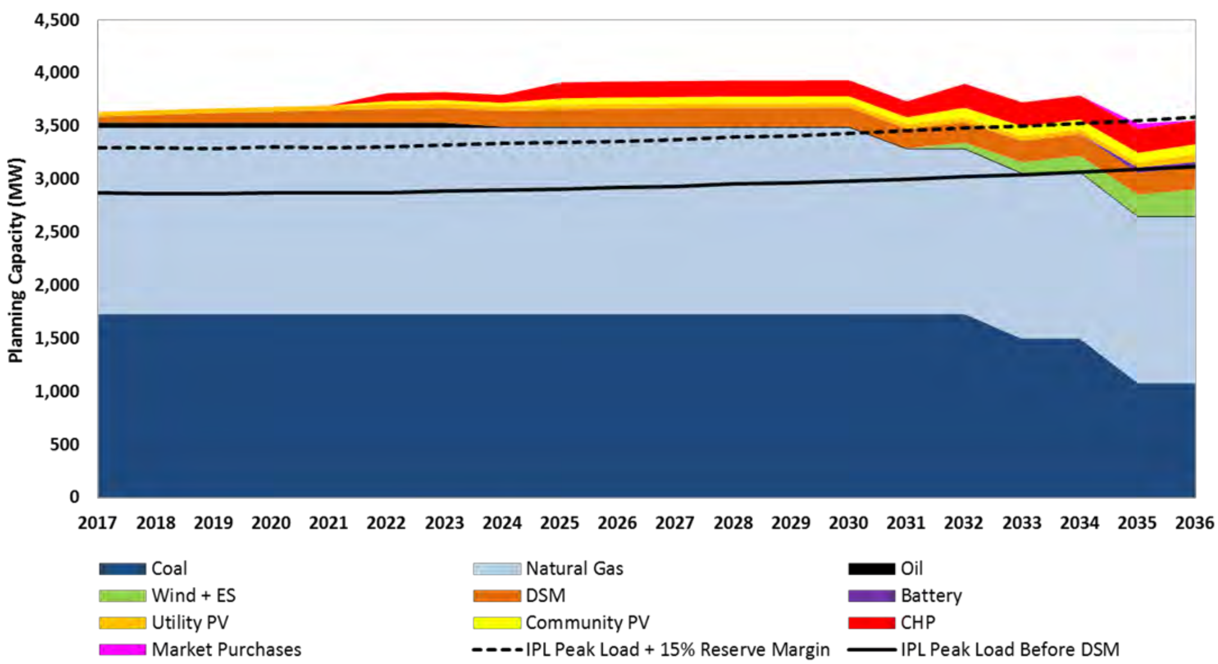
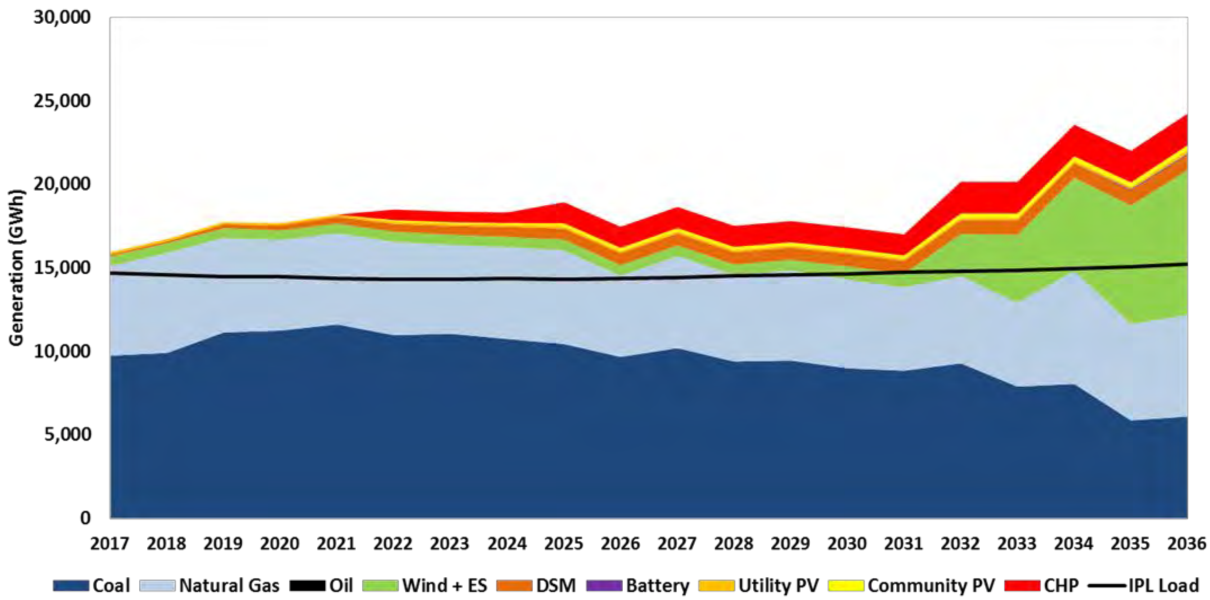


Figure 8.18 – High Customer Adoption of DG Operating Capacity Additions

	2017-2018	2019-2020	2021-2022	2023-2024	2025-2026	2027-2028	2029-2030	2031-2032	2033-2034	2035-2036	TOTAL
Natural Gas	671								450		1121
Battery										50	50
Wind with ES*			10		10			510	1000	1000	2530
DSM and DR	75	29	25	20	22	9	3	12	11	4	209
Solar			65		65			65		60	255
Community Solar										1	1
CHP			75		75			75			225

Figure 8.19 shows the forecasted energy results for the High Customer Adoption of DG case portfolio for 2017–2036. For this case, annual generation shows that this scenario has enough resources each year to meet the load requirements designated by the black line.

Figure 8.19 – High Customer Adoption of DG Energy



8.1.1.6 *Quick Transition Capacity Expansion*

Figure 8.20 shows the planning capacity results for the Quick Transition scenario. Figure 8.21 shows the operating capacity of resource additions. This portfolio is the only candidate portfolio not developed by the Capacity Expansion Model; instead, stakeholder input helped create this portfolio so that IPL could model the impact of a scenario that minimizes use of fossil fuels. For this future landscape, IPL adds all DSM that the AEG market potential study identified to be economic. Pete 1 retires, and Pete 2-4 coal units refuel to natural gas in 2022, which the first year that the Clean Power Plan sets a carbon emissions target. Other than DSM, no resources are added or retired between 2023 and 2029. In 2030, all Pete units, Harding Street 5 and 6, Harding Street GTs, and all petroleum units retire in 2030. IPL does not retire Harding Street 7 or the Georgetown natural gas units in 2030, because IPL needs a minimum of 600 MW of natural gas on its 138 kV system to retain system reliability. Harding Street 7 retires in 2033, due to end of useful life, and 450 MW of natural gas resources are added in 2034 to maintain system reliability. 6000 MW wind, 1146 MW solar, and 600 MW of battery are added in 2030.

Figure 8.20 – Quick Transition Planning Capacity

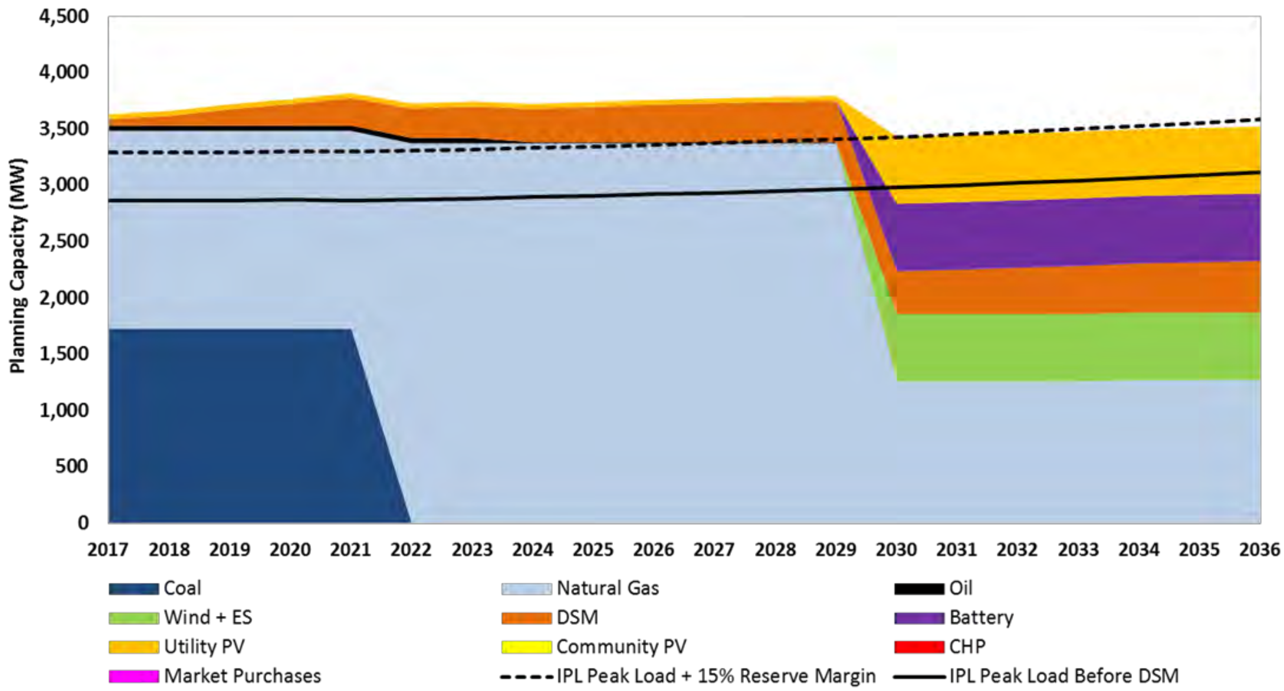
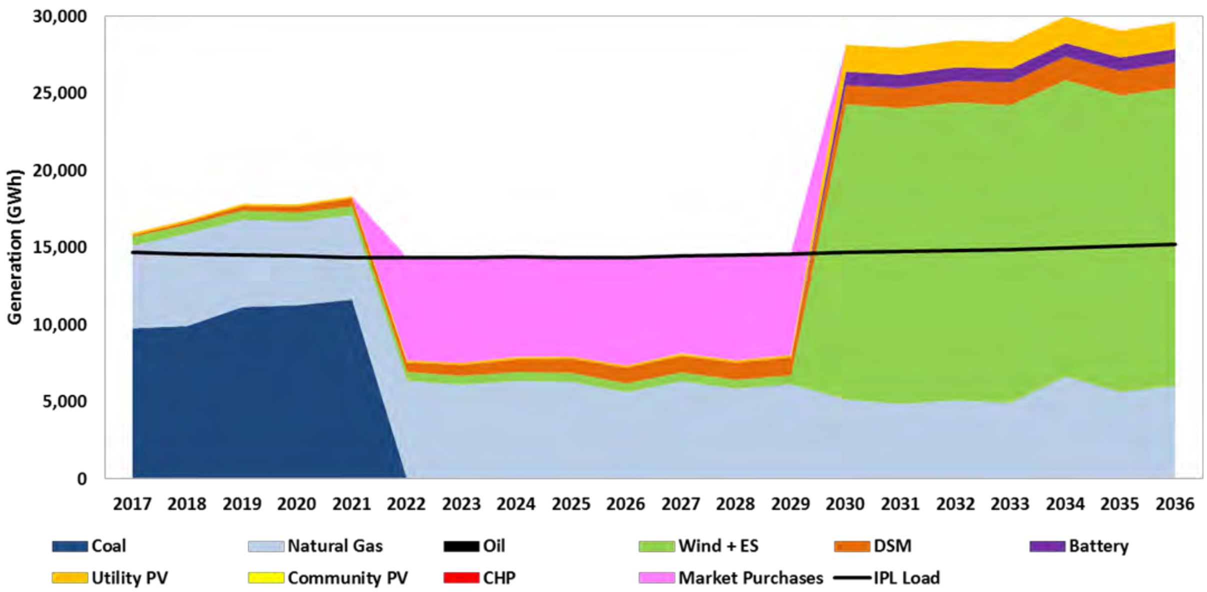


Figure 8.21 – Transition Operating Capacity Additions

	2017-2018	2019-2020	2021-2022	2023-2024	2025-2026	2027-2028	2029-2030	2031-2032	2033-2034	2035-2036	TOTAL
Natural Gas	671		1618.0002						450		2739
Battery							600				600
Wind with ES*							6000				6000
DSM and DR	86	106	71	34	36	25	21	31	26	22	458
Solar			100		65		1146	65		60	1436
Community Solar											0
CHP											0
Market											0

Figure 8.22 shows the Quick Transition portfolio energy mix as modeled against Base Case assumptions in the ABB Production Cost model. This figure shows that a Quick Transition portfolio will rely heavily on the market for its energy needs if Base Case assumptions come to fruition, even though its portfolio meets the 15% reserve excess energy into the market. The coal units are refueled to natural gas to assess the impact of quickly switching away from coal. However, under Base Case assumptions, the refueled units are not economic and have low capacity factors. As a result, there is heavy reliance on the market for energy to meet IPL's load requirements until a large amount of solar, wind, and battery resources are added in 2030.

Figure 8.22 – Quick Transition Energy



8.1.2. DSM in each portfolio

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

As previously discussed in Section 5, the Capacity Expansion Model was allowed to select bundles of DSM as a resource. This section describes the amount of DSM that was selected in each portfolio. The Capacity Expansion Model selected DSM bundles beginning in 2018 – the first year DSM was available to be selected. Due to the timing of the IRP development, the DSM resources for 2017 are already identified and were therefore not selectable. A request for approval of the DSM plan for 2017 is currently pending before the IURC in Cause No. 44792.[82]

IPL created bundles of similar energy efficiency measures as identified by the Maximum Achievable Potential. These measures were bundled by segment (Residential and C&I) and by technology in order to take advantage of load-shape similarities among like measures. Except for the Residential Behavioral Program, "bundles" were further disaggregated by the 'direct cost to implement' in $ per MWh - *up to $30/MWh; $30-60 /MWh; and $60+/ MWh).*

Figure 8.23 and Figure 8.24 below provide an overview of the DSM "bundles" along with selection results from the Base Case scenario.

[82] The 2017 DSM Plan is a proposal to extend the current DSM offerings for a year one period. This was necessary to maintain continuity of the IPL DSM programs, pending the completion of the 2016 IRP and identification of the DSM that was selected to be offered in the years 2018 and beyond.

Figure 8.23 – *Near-term* DSM "Bundles" developed for 2018-2020 (Base Case Selections)

	Levelized Utility Cost per MWh		
Sector and Technology	**(up to $30/MWh)**	**($30-60/MWh)**	**($60+ /MWh)**
EE Residential HVAC	Selected	Not Selected	Not Selected
EE Residential Lighting	Selected	N/A	N/A
EE Residential Other	Selected	Not Selected	Not Selected
EE C&I HVAC	Selected	Not Selected	Not Selected
EE C&I Lighting	Selected	Not Selected	Not Selected
EE C&I Other	Selected	Not Selected	Not Selected
EE C&I Process	Not Selected	Not Selected	N/A
EE Residential Behavioral	Not Selected		
DR Water Heating DLC	Not Selected		
DR Smart Thermostats	Not Selected		
DR Emerging Tech	Not Selected		
DR Curtail Agreements	Not Selected		
DR Battery Storage	Not Selected		
DR Air Conditioning Load Mgmt	Not Selected		

*N/A indicates that a bundle was not needed; all measures fell within lower cost bundles.

Figure 8.24 – *Long-term* DSM "Bundles" developed for 2021-2036 (Base Case Selections)

	Levelized Utility Cost per MWh		
Sector and Technology	**(up to $30/MWh)**	**($30-60/MWh)**	**($60+ /MWh)**
EE Residential HVAC	Not Selected	Not Selected	Not Selected
EE Residential Lighting	Selected	N/A	N/A
EE Residential Other	Selected	Not Selected	Not Selected
EE C&I HVAC	Selected	Not Selected	Not Selected
EE C&I Lighting	Selected	Not Selected	Not Selected
EE C&I Other	Selected	Not Selected	Not Selected
EE C&I Process	Not Selected	Not Selected	N/A
EE Residential Behavioral	Selected		
DR Water Heating DLC	Not Selected		
DR Smart Thermostats	Not Selected		
DR Emerging Tech	Not Selected		
DR Curtail Agreements	Not Selected		
DR Battery Storage	Not Selected		
DR Air Conditioning Load Mgmt	Not Selected		

*N/A indicates that a bundle was not needed; all measures fell within lower cost bundles.

8.1.3. DSM Plan Proposed Programs (2017-2020)

The 13 DSM programs proposed for delivery in 2017 for Residential and Business customers are the same as the programs currently being delivered pursuant to the approvals received in Cause No. 44497 (for DSM program delivery in 2015 and 2016). See Attachment 5.5 for the 2017 DSM Action Plan that was filed in Cause No. 44792.

As the next step, for programs delivery in the 2018-2020 time frame, IPL intends to take the DSM bundles that were selected by the Capacity Expansion Model in the Base Case as the foundation for a Request for Proposals ("RFP") for DSM program delivery. The RFP will be issued to the implementation vendor community with the intention to identify implementation contractors to deliver IPL's DSM programs for this three year period. IPL's DSM initiatives will only be successful with broad customer participation. Therefore, customer adoption remains the most important element of successful DSM implementation. IPL endeavors to ensure that the customer has positive interactions with IPL's many program partners and IPL will continue to carefully choose these partners and monitor their efforts.

While the specific programs to be delivered in the period 2018-2020 have not yet been determined, it is expected that the portfolio will be consistent with and reflect the savings selected in the IRP Capacity Expansion model.

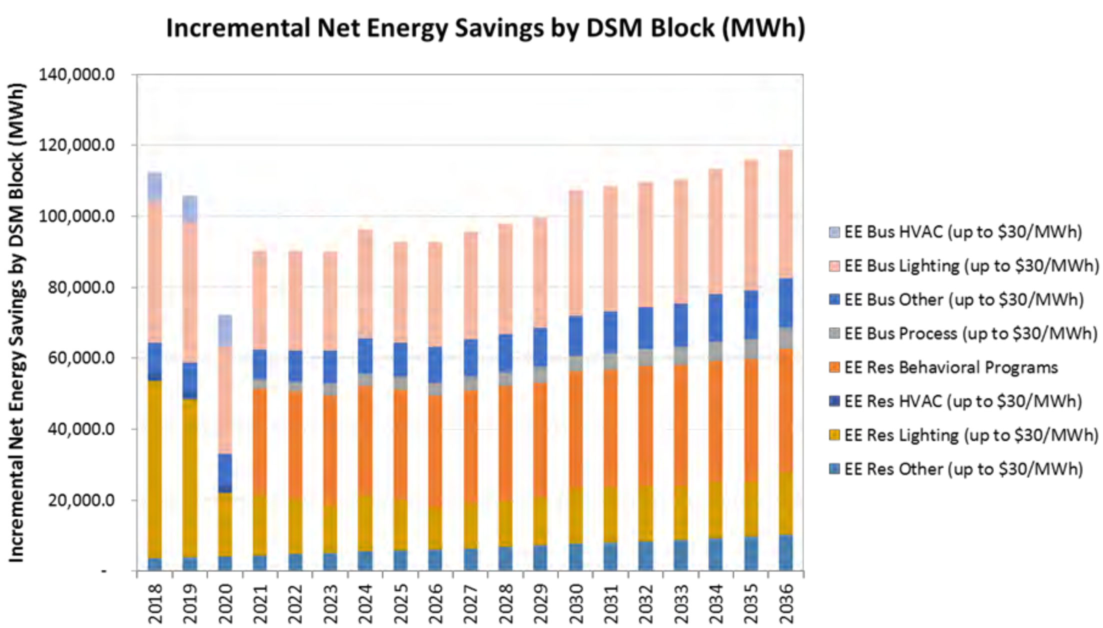
Target demand and energy savings by year for each scenario are presented below. The DSM selected by the Capacity Expansion model is at the measure (rather than at the Program level); therefore, DSM does not have certain of the metrics at this time (estimated bill reduction, participation incentive, and program cost and program penetration rate for example). However, Attachment 8.2 in addition to containing the Base Case targets does provide considerable information on related metrics such as the estimated energy (kWh) and demand (kW) savings by measure as well as estimated savings and costs by measure.

The narrative and graphs below represent the amount of DSM selected by the Capacity Expansion Model by measure bundle by year for the IRP period for each portfolio. The DSM bundles in the graphs are grouped by colors that as explained by the keys that accompany the graphs.

8.1.3.1 *Base Case Portfolio DSM Selected*

As indicated in Figure 8.25 below, in the Base Case, the model selected six bundles of DSM measures for 2018-2020. These six bundles of DSM measures selected by the model, total 290 GWh of net energy savings in 2018-2020. In the Base Case the reduction of DSM in 2020 is due primarily to toughening federal lighting standards. Again, the energy savings amounts in the first 3 years serve as the short term action plan for DSM achievement. Six measure bundles were also selected for the 2021 to 2036 period. The 20 year period for the DSM MPS started one year after the IRP study period.

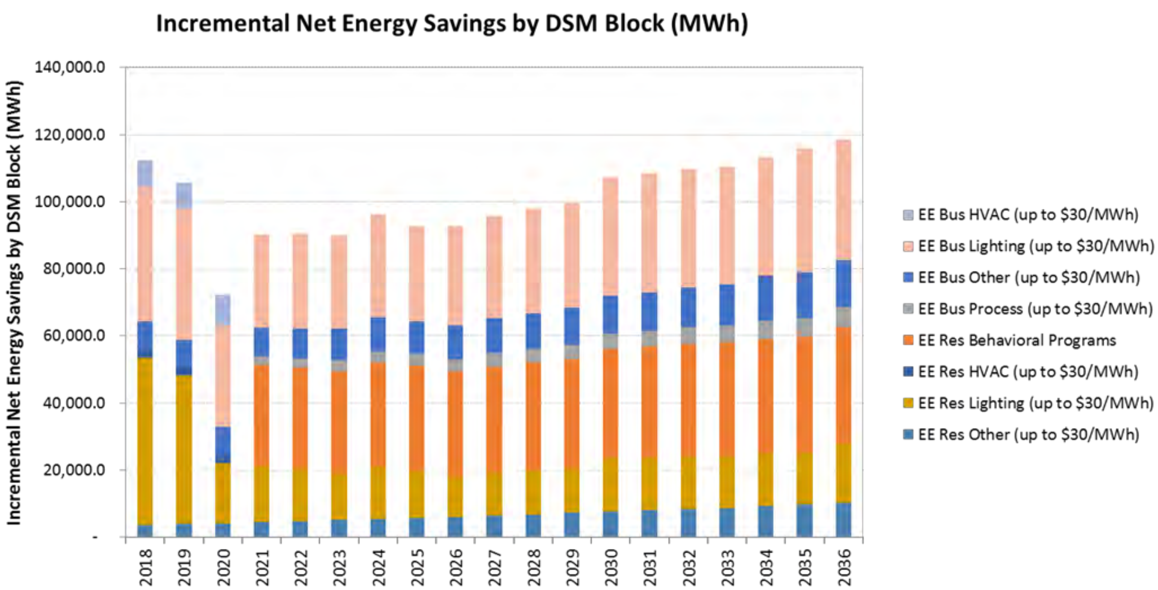
Figure 8.25 – Base Case DSM Results



8.1.3.2 *Robust Economy DSM Selected*

Figure 8.26 illustrates that the model selected six bundles of DSM measures for 2018-2020 for the Robust Economy scenario. These six bundles of DSM measures selected by the model, total 290 GWh of net energy savings in 2018-2020. Consistent with the base case, six measure bundles were also selected for the 2021 to 2036 period.

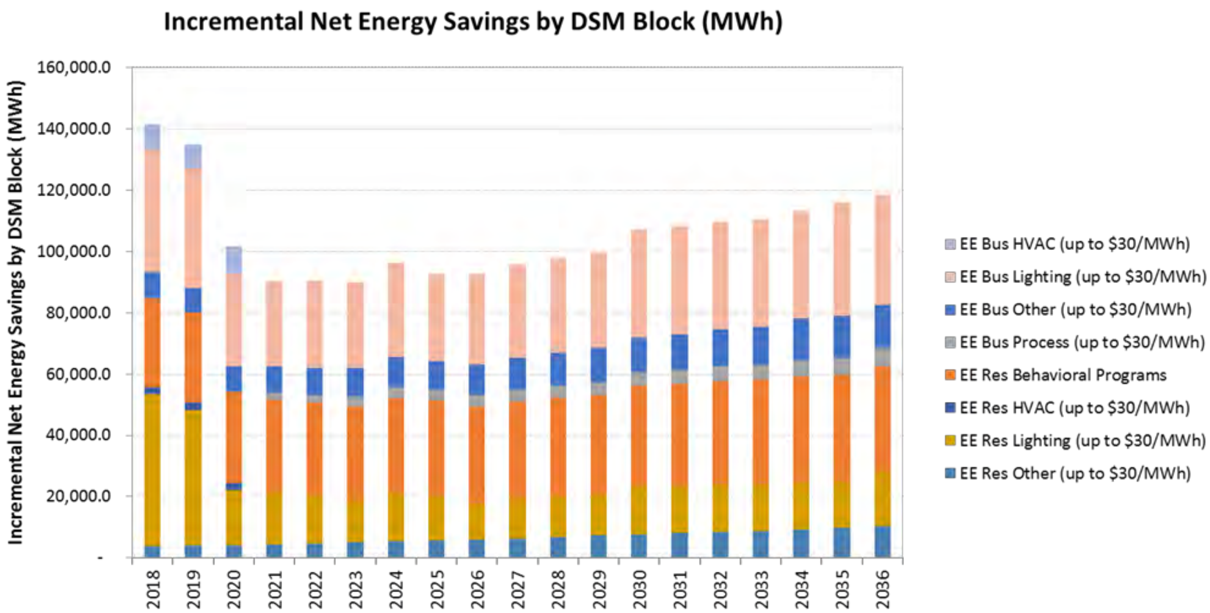
Figure 8.26 – Robust Economy DSM Results



8.1.3.3 *Recession Economy DSM Selected*

Figure 8.27 illustrates that the model selected seven bundles of DSM measures for 2018-2020 for the Recession Economy scenario. These seven bundles of DSM measures selected by the model, total 378 GWh of net energy savings in 2018-2020. Consistent with the base case, six measure bundles were selected for the 2021 to 2036 period.

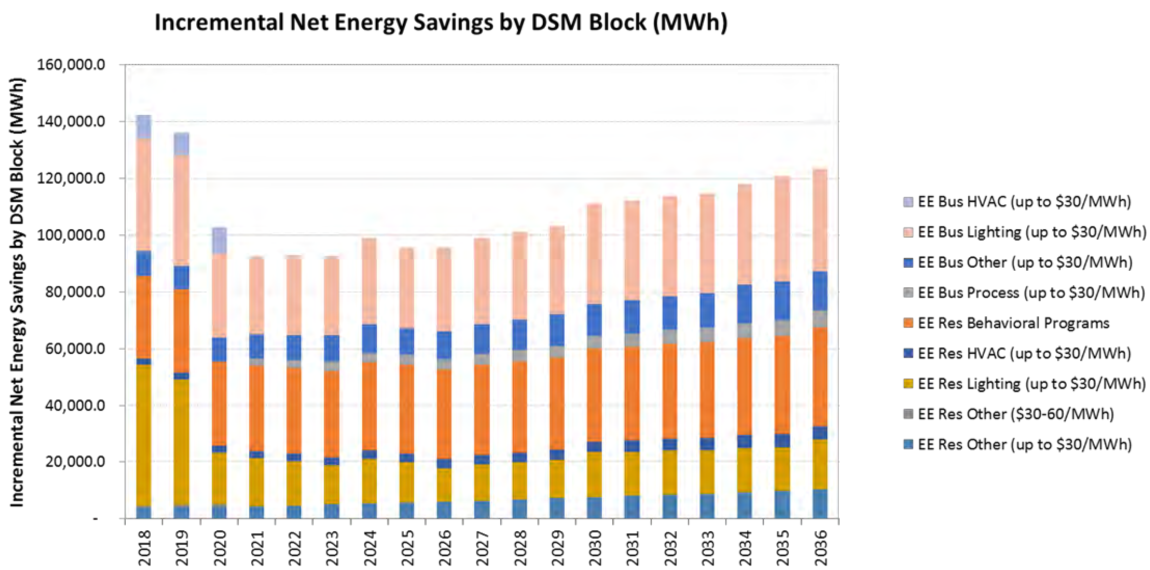
Figure 8.27 – Recession Economy DSM Results



8.1.3.4 *Strengthened Environmental DSM Selected*

Figure 8.28 illustrates that the model selected eight bundles of DSM measures for 2018-2020 for the Strengthened Environmental scenario. These eight bundles of DSM measures selected by the model, total 381 GWh of net energy savings in 2018-2020. The model selected seven measure bundles for the 2021 to 2036 period.

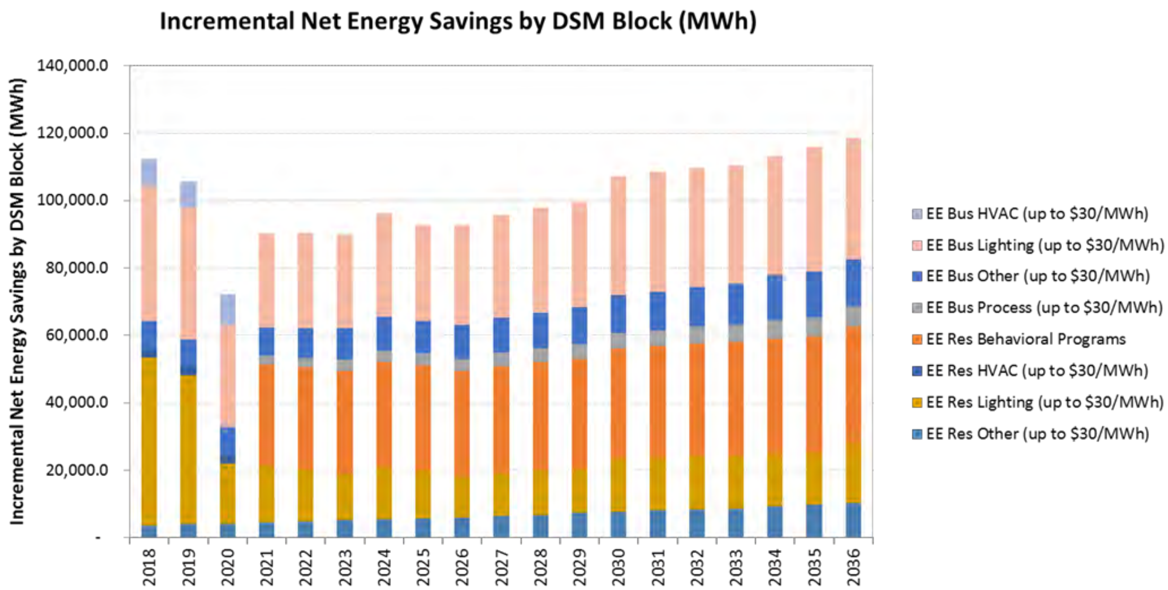
Figure 8.28 – Strengthened Environmental DSM Results



8.1.3.5 *High Customer Adoption of DG DSM Selected*

In the High Customer Adoption of Distributed Generation scenario, the Capacity Expansion Model again selected six DSM bundles as Figure 8.29 illustrates. The amount of net energy savings totaled 291 GWH for the three year period 2018-2020.

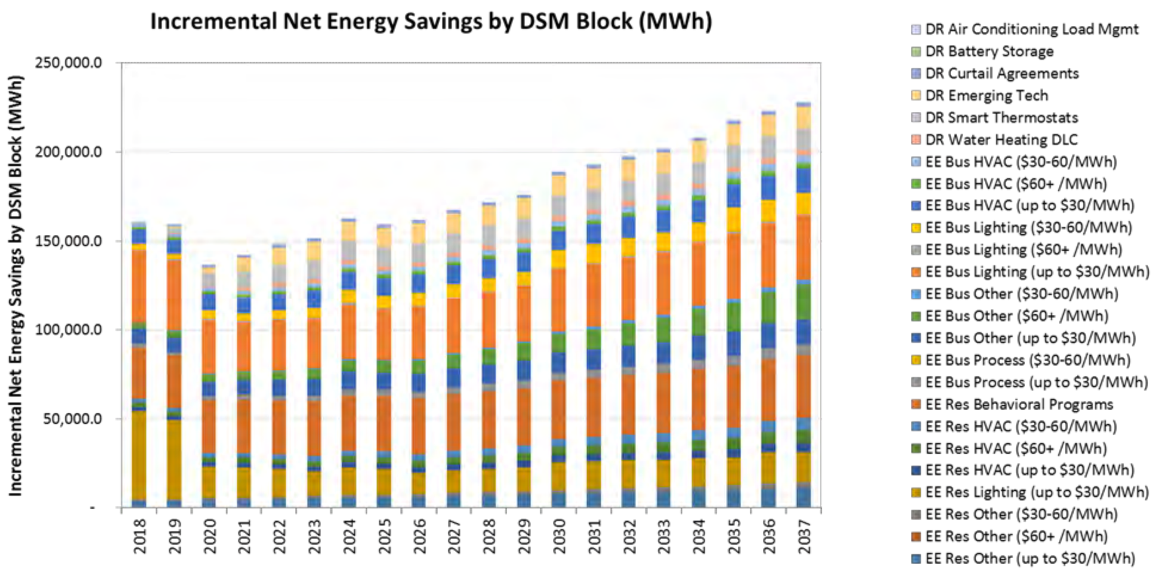
Figure 8.29 – High Customer Adoption of DG DSM Results



8.1.3.6 *Quick Transition DSM Selected*

In the Quick Transition scenario, the Capacity Expansion Model was directed to select all of the DSM bundles that were available (19 EE bundles and 6 DR bundles in both periods of interest). As Figure 8.30 illustrates, there was significantly more DSM selected in this scenario than in the other cases with the amount of energy savings totaling 457 GWH of net energy savings in 2018-2020.

Figure 8.30 – Quick Transition DSM Results



8.1.4. PVRR Results

170 IAC 4-7-8(b)(6)(A) 170 IAC 4-7-8(b)(7)(D)

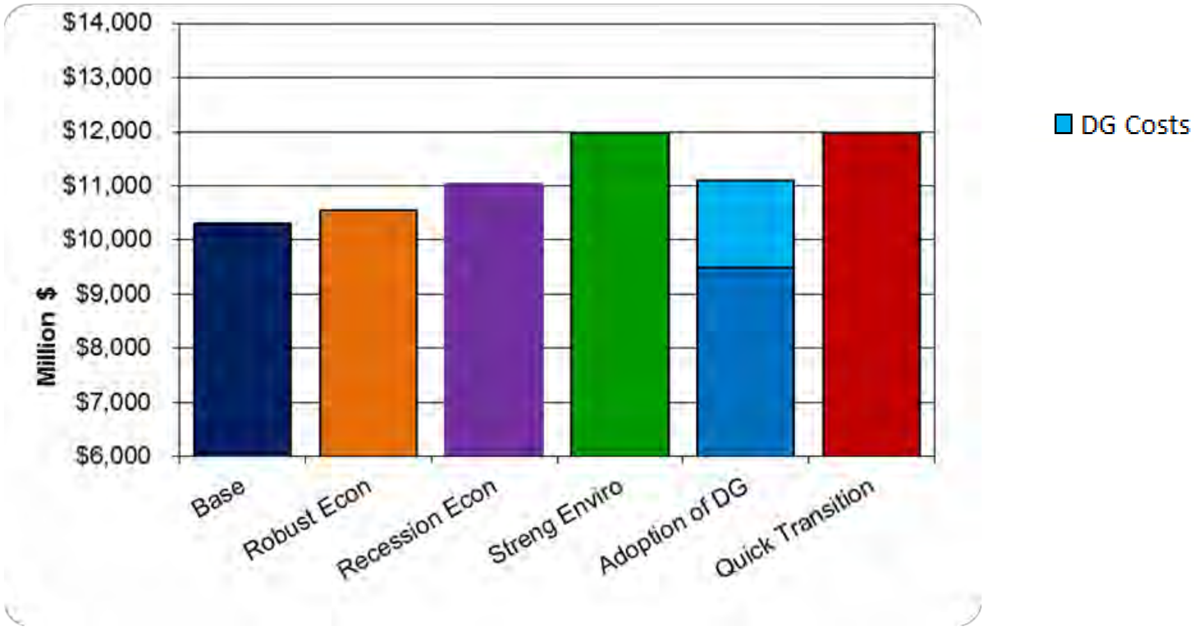
Figure 8.31 – PVRR Results (2017-2036) shows the deterministic PVRR for each scenario under Base Case assumptions. The Production Cost model took each portfolio produced by the Capacity Expansion Model and applied it to Base Case assumptions including natural gas, power prices, carbon prices, and load forecast. The Production Cost Model results, including operating and capital costs of each candidate resource portfolio, are presented in Confidential Attachment 8.3. These values are in millions in Figure 8.31 below:

Figure 8.31 – PVRR Results (2017-2036)

Scenario	PVRR ($ Million)
Base Case	$10,309
Robust Economy	$10,549
Recession Economy	$11,042
Strengthened Environmental	$11,989
Adoption of DG	$11,092
Quick Transition	$11,988

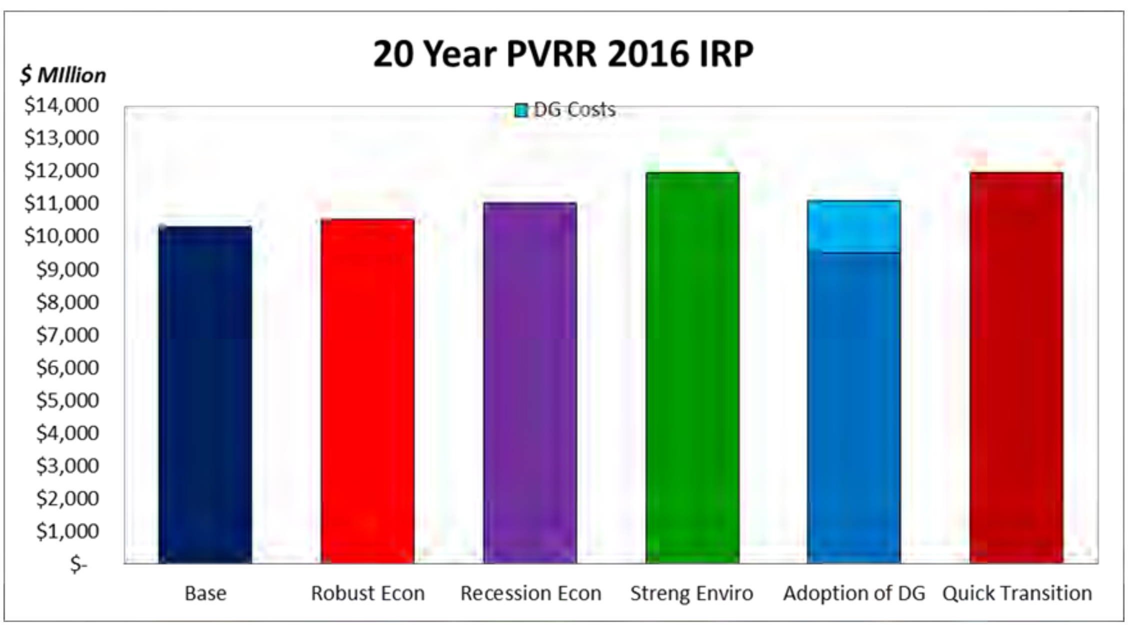
The Adoption of DG scenario includes estimated DG costs for 450 MW. These costs are represented in the light blue block below. The Production Cost model used the same technology costs and IPL's capital structure for DG, but actual customer costs may vary according to the customer's own financial situation and the size of the DG project being developed. The incremental representative costs for DG are shown in lighter blue to provide transparency. Not including these DG costs in the Adoption of DG scenario's PVRR would be comparing apples to oranges because the DG additions are used to meet the planning reserve requirement of 15% of peak demand. Figure 8.32 represents PVRR graphically.

Figure 8.32 – PVRR Results (2017-2036)



In response to stakeholder feedback in Public Advisory Meeting #4, IPL rescaled the axis with $0 as the starting point, as shown below in Figure 8.33.

Figure 8.33 – PVRR Results (2017-2036) on an Axis Scaled to Zero Dollars



8.2. Sensitivity Analysis Results

As explained in Section 7, IPL conducted sensitivity analysis to determine how changing the scenario assumptions may impact the robustness of a portfolio. A sensitivity measures how a resource portfolio performs across a range of possibilities for a specific risk or variable. IPL used both deterministic and probabilistic analysis to examine risks of the portfolios. Deterministic sensitivities change just one variable in the scenario to isolate the impact on the portfolio's PVRR, whiles probabilistic analysis (also known as stochastic analysis) changes many variables in the scenario to find a range of PVRRs for that portfolio.

IPL has used deterministic sensitivity analysis in previous IRPs, but IPL did not include stochastic analysis in recent IRPs. In response to the 2014-2015 IURC Director's Report, which discusses the benefits of risk analysis, IPL initiated a process in the 2016 IRP to apply probabilistic analysis to the candidate portfolios. The report states that "The range of risk analysis should include both those events the utility regards as high probability events as well as relatively low probability events that have significant potential implications for affecting the delivered cost of electricity to customers and/or for reliability."[83]

8.2.1. Deterministic Carbon Analysis for Base Case

To better understand the impact of carbon regulations on the Base Case, IPL conducted two deterministic sensitivities on the Base Case, and compared the PVRR from those sensitivities to the original Base Case PVRR. Two carbon sensitivities were modeled around the Base Case. IPL also modeled the price of carbon stochastically, but IPL also wanted to be able to isolate the impacts of CPP regulation on the Base Case PVRR.

Base Case Deterministic Sensitivity 1 – "Delayed CPP" - Timing of Clean Power Plan

- Same modeling assumption as base plan with CPP starting in 2030 instead of 2022

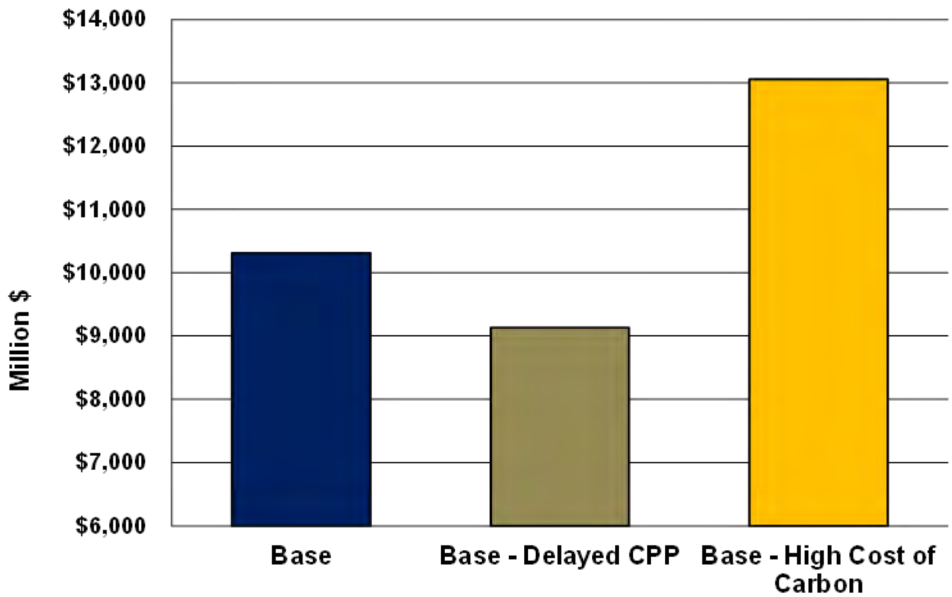
Base Case Deterministic Sensitivity 2 –"High Cost of Carbon" - More Stringent Clean Power Plan

- Same modeling assumption as base plan except used a high carbon price.

The results of the deterministic carbon analysis align with expectations and provide insight into the potential carbon cost impacts. Figure 8.34 below compares the results for the two sensitivities cases against the Base Case. These values are in millions of dollars: Base Plan $10,309; Case 1 $9,129; Case 2 $13,054.

[83] IURC 2014-2015 Director's Report, Page 6.

Figure 8.34 – PVRR Deterministic Sensitivities Results (2017-2036)



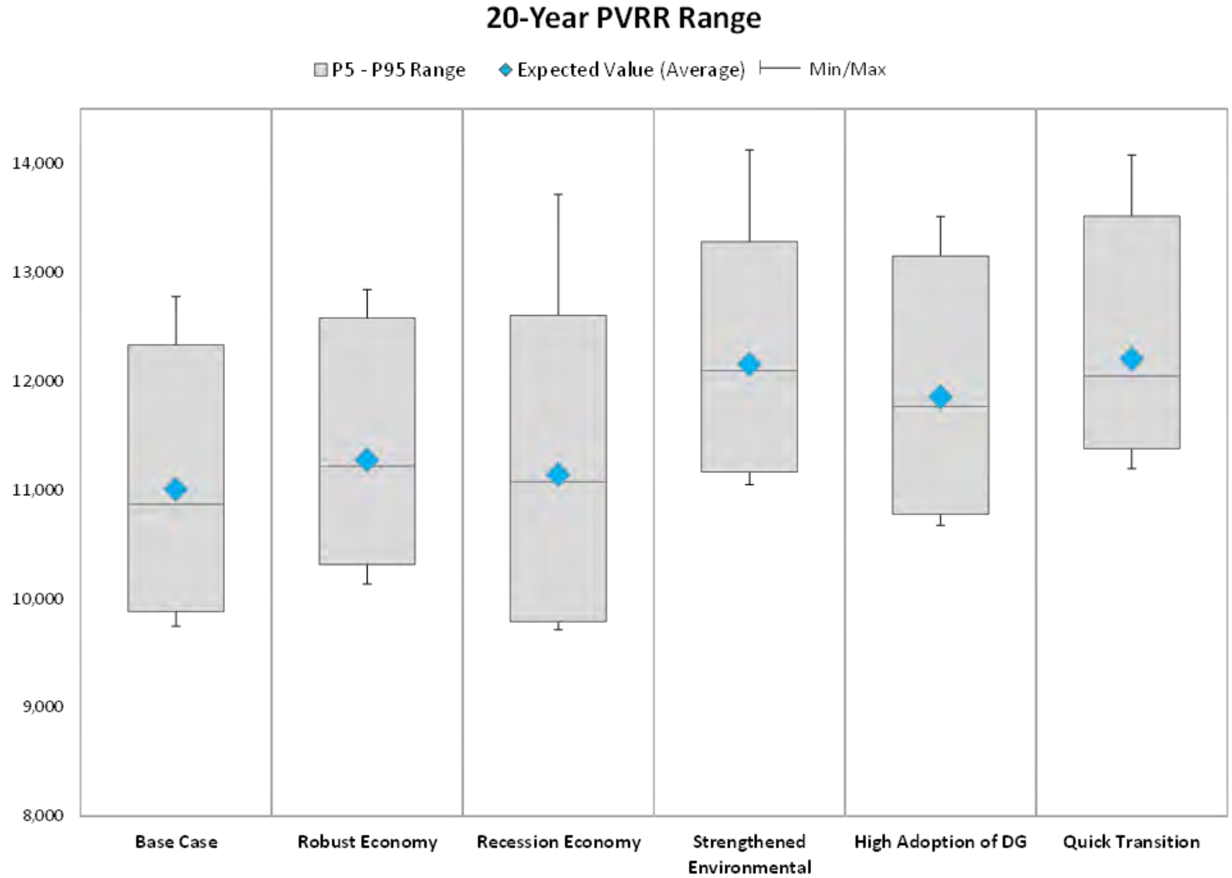
8.2.2. Stochastic Analyses Results for All Scenario Portfolios

170 IAC 4-7-4(b)(11)

The stochastic sensitivity analysis provides insight into how each portfolio performs against a range of future outcomes. Each portfolio introduces risk by the nature of having a varying mixes of resource types, so quantifying that risk and identifying the drivers of that risk helps guide the development of a preferred resource portfolio. The ABB report in Attachment 2.1 contains more detail on the modeling assumptions and results from the stochastic model runs.

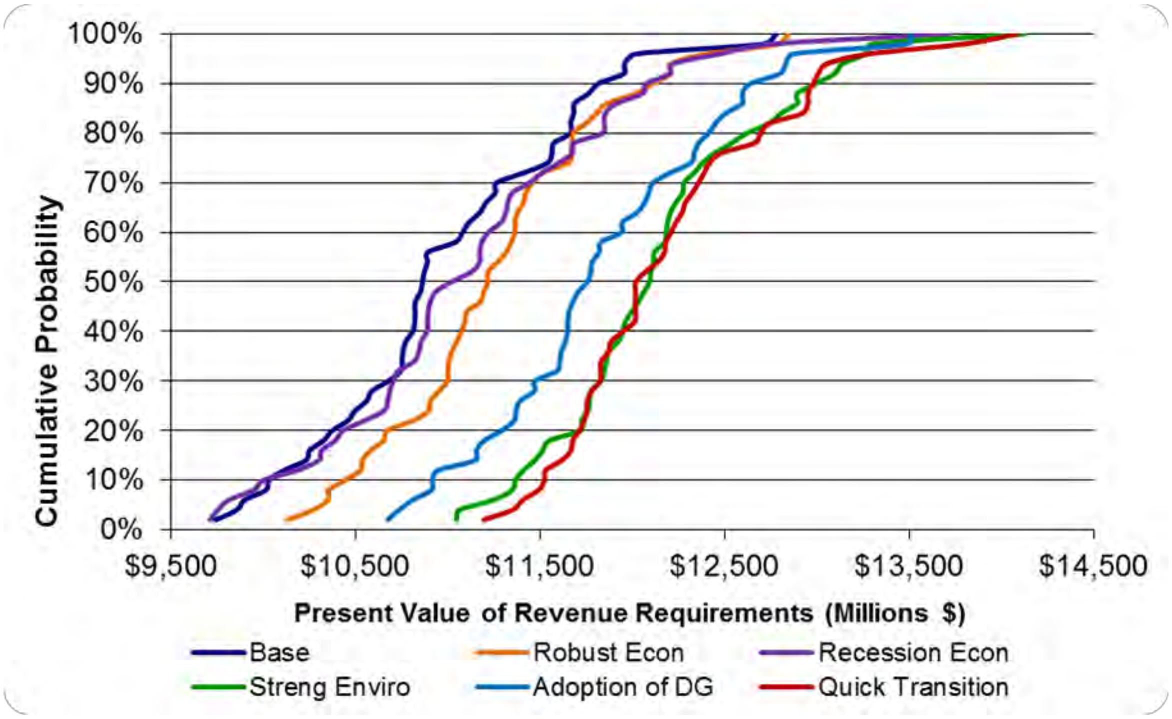
Figure 8.35 that follows contains a summary of the range of PVRRs for each portfolio based on results from the stochastic model. The gray box represents the range of PVRRs between the 5th and 95th percentiles, which means that 90% of the PVRR outcomes fell in this range. The horizontal bar within that box is the 50th percentile or median value, and the blue diamond is the expected value or average of the outcomes. Two useful comparisons across the portfolios are the expected value and the height of the top of the 5th-95th box. The expected values of the Base Case, Robust Economy, and Recession Economy are similar.

Figure 8.35 – PVRR Ranges



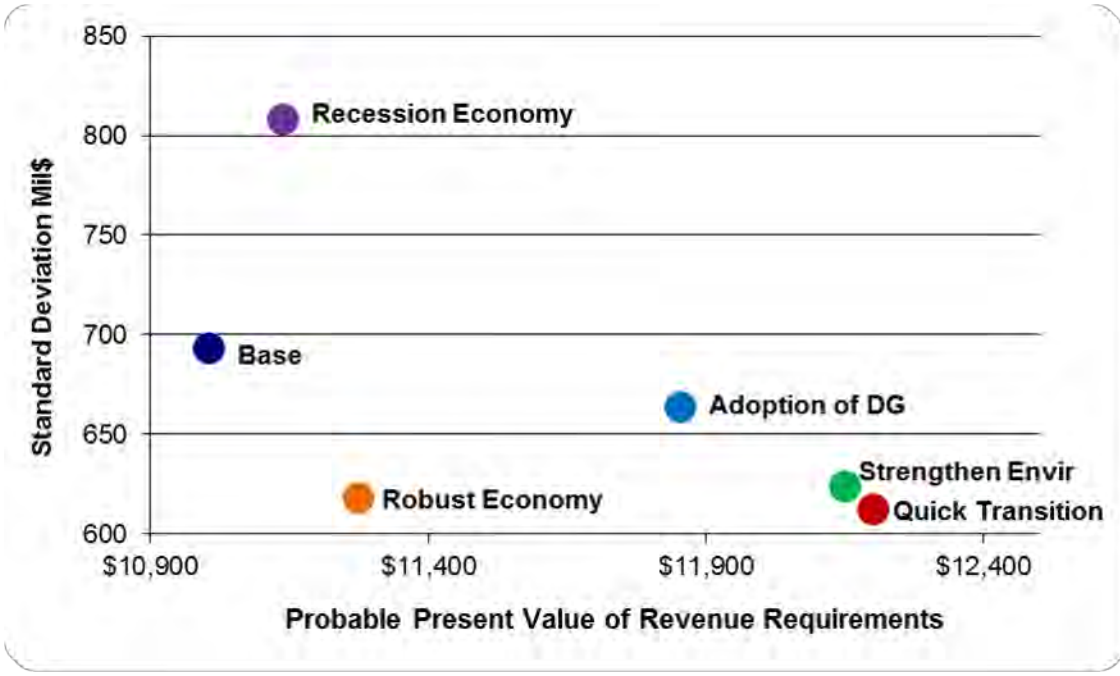
Another useful took to compare the portfolios is a risk profile chart, or a cumulative probability chart. The risk profile shows the distribution of PVRR outcomes from the fifty stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%. Figure 8.36 contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall. The Base Case (shown in the dark blue) is the lowest cost portfolio across all but the lowest 10% of outcomes, where the Recession Economy portfolio moves lower.

Figure 8.36 – Cumulative Probabilities by Scenario



Another way to compare the portfolios is looking at a tradeoff diagram with the expected value of each portfolio against the standard deviation of the PVRR outcomes. This comparison provides insight into how the portfolios differ in terms of cost in terms of PVRR and standard deviation. As shown in Figure 8.37 that follows, the Base Case has an expected value of $11,005 Million, and the standard deviation of the fifty stochastic runs was close to $700 Million. The next lowest expected value is the Recession Economy at $11,139 Million, but that portfolio has over $100 Million higher standard deviation, which means there is more risk associated with that portfolio. The Adoption of DG, Strengthened Environmental, and Quick Transition scenarios have lower standard deviations of PVRR outcomes than the Base Case, but the expected value PVRRs are about $850 Million to $1.2 Billion higher than the Base Case.

Figure 8.37 – Risk Trade Off



The PVRR range, risk profiles, and tradeoff diagrams are useful for quantifying the risk associated with each portfolio across the stochastic iterations. An additional step IPL took was to identify the drivers of the risk by creating "tornado charts" in 10-year periods for each portfolio. A tornado chart uses a regression analysis to measure changes in Total Base Revenues – the dependent variable – in response to changes in independent variables such as load, gas prices, coal prices, and carbon prices. The vertical line is the "Expected Value," and the "Total Base Revenues" bar to the left and right of the Expected Value is the range of PVRRs for that scenario. The independent variables on the tornado chart are listed in order of their impact on the PVRR. For example, Figure 8.38 shows that the load forecast, labeled "energy," has the highest impact on PVRR for the Base Case 2017-2026, and that CO_2 has the lowest impact. However, the changes to the PVRR are not cumulative through the independent variables: the sum of the independent variable horizontal bars will not equal the horizontal bars of the PVRR. Instead, the horizontal bars of the independent variables indicate the magnitude of change to the PVRR due to changes in one single variable. Figure 8.38 to Figure 8.49 show the tornado charts for each portfolio. These tornado charts were provided by IPL's consultant ABB.

Through the first ten years of the study, the primary risk drivers for each portfolio look similar. Natural gas prices and energy (IPL retail MWh) are the top two drivers of variability in PVRR. In the second ten years, new variables move up the list in response to divergent portfolio mixes. For portfolios with significant capital expenditures in the back half of the study (i.e., Strengthened Environmental, Quick Transition), interest expense is a top five risk driver for PVRR variance.

Figure 8.38 – Final Base Plan - Tornado Chart (2017-2026)

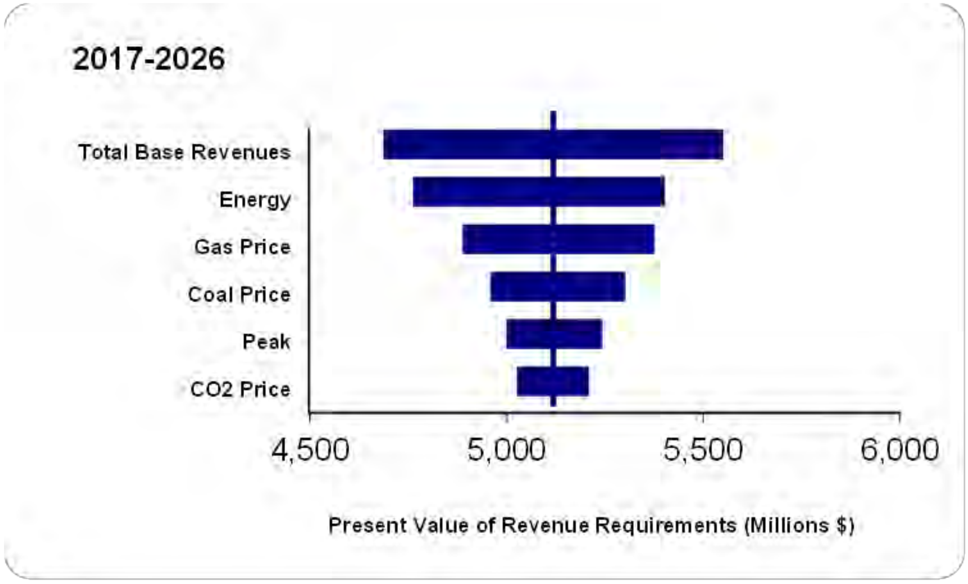


Figure 8.39 – Final Base Plan - Tornado Chart (2027-2036)

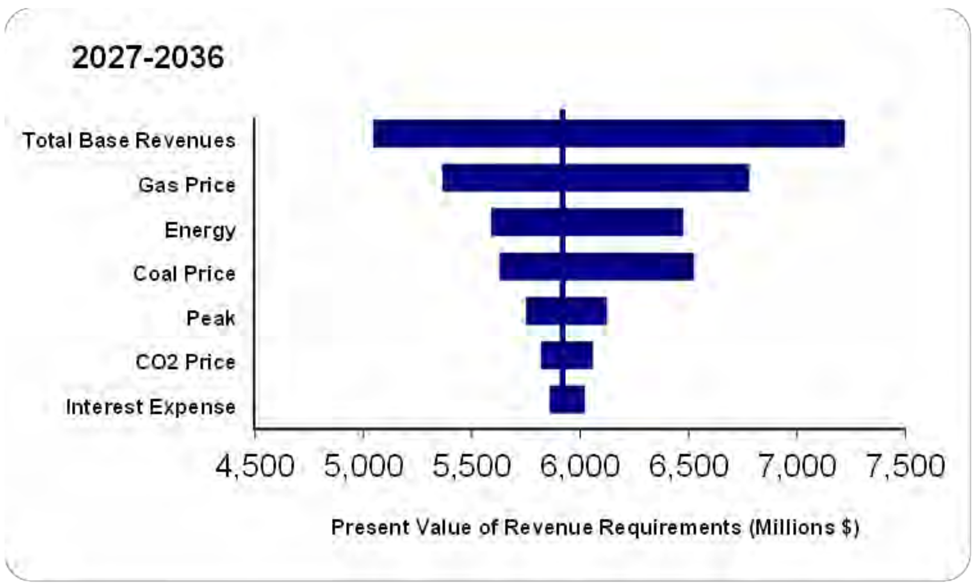


Figure 8.40 – Robust Economy - Tornado Chart (2017-2026)

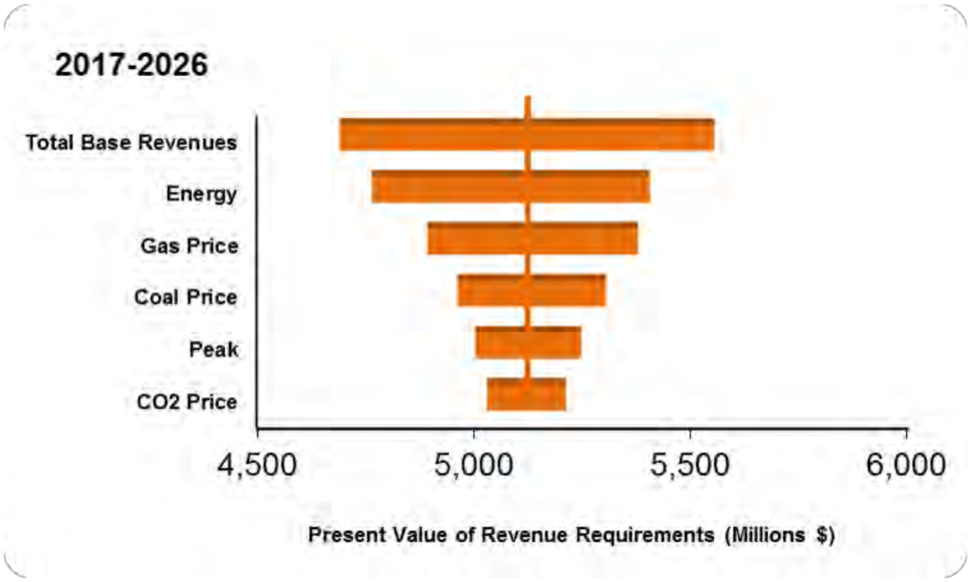


Figure 8.41 – Robust Economy - Tornado Chart (2027-2036)

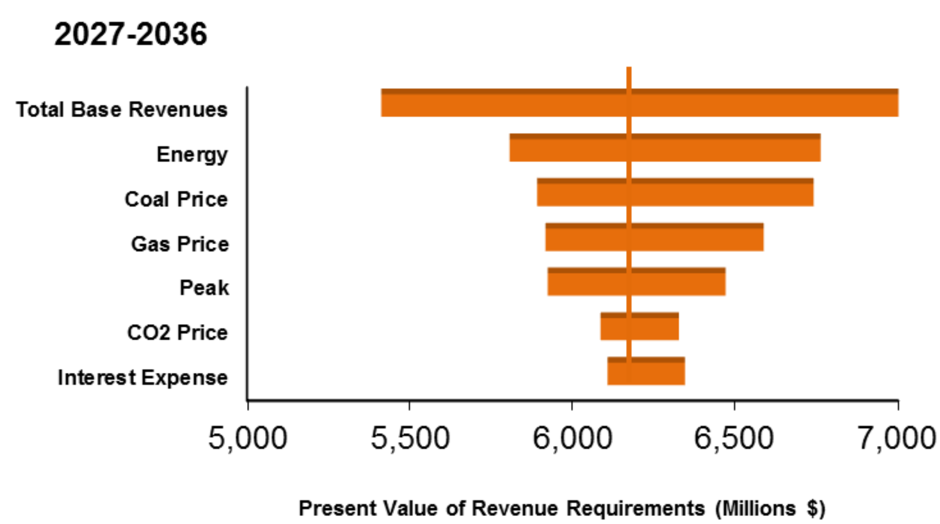


Figure 8.42 – Recession Economy - Tornado Chart (2017-2026)

Figure 8.43 – Recession Economy - Tornado Chart (2027-2036)

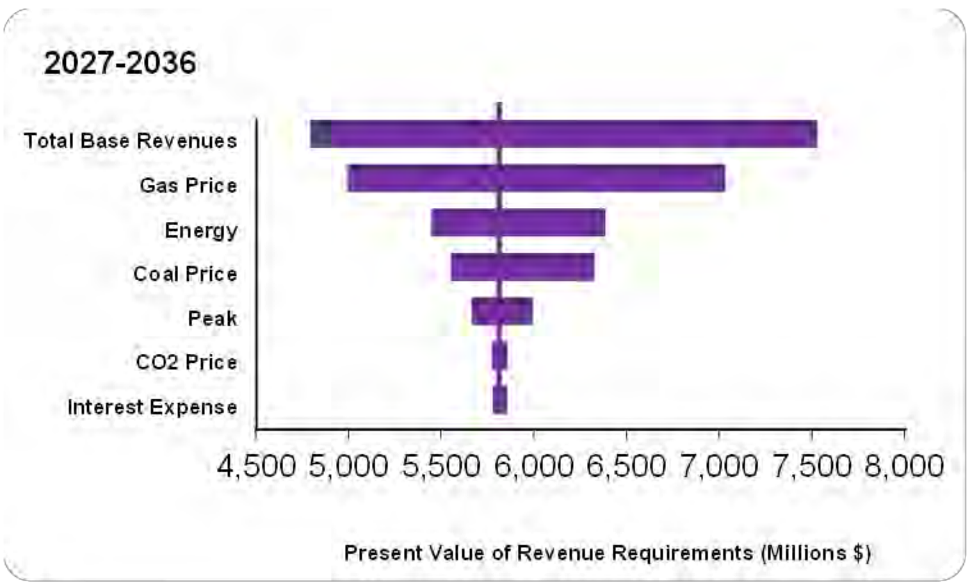


Figure 8.44 – Strengthened Environmental - Tornado Chart (2017-2026)

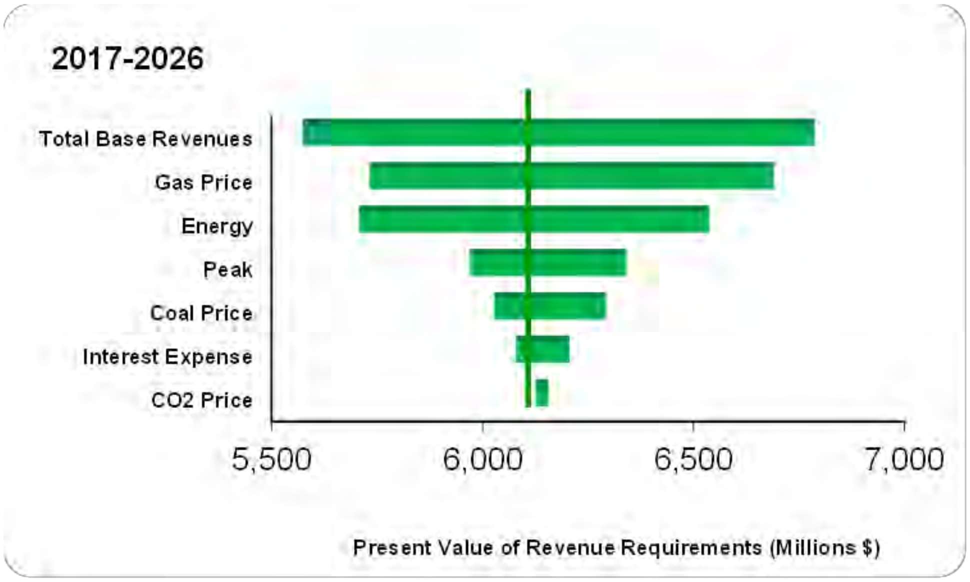


Figure 8.45 – Strengthened Environmental - Tornado Chart (2027-2036)

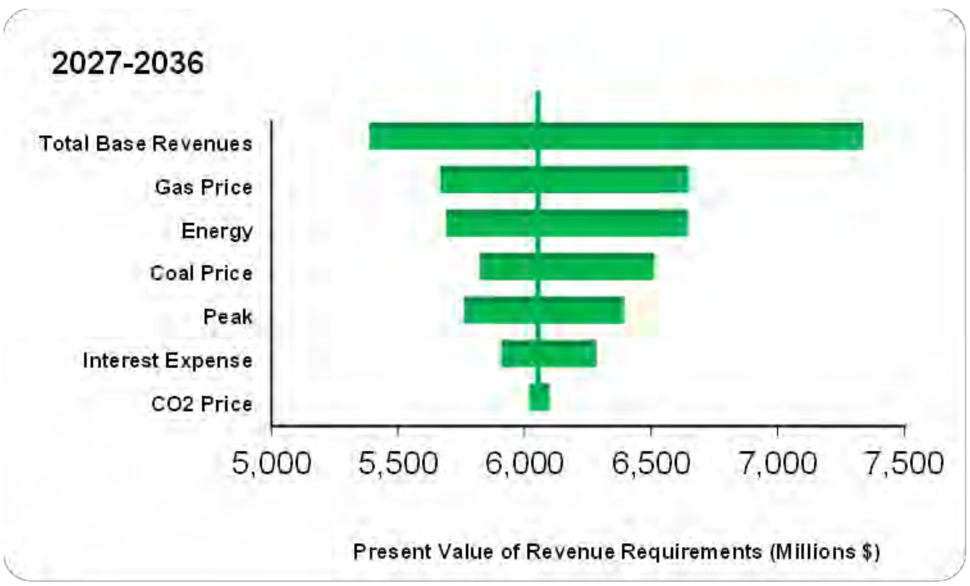


Figure 8.46 – Adoption of DG, Tornado Chart (2017-2026)

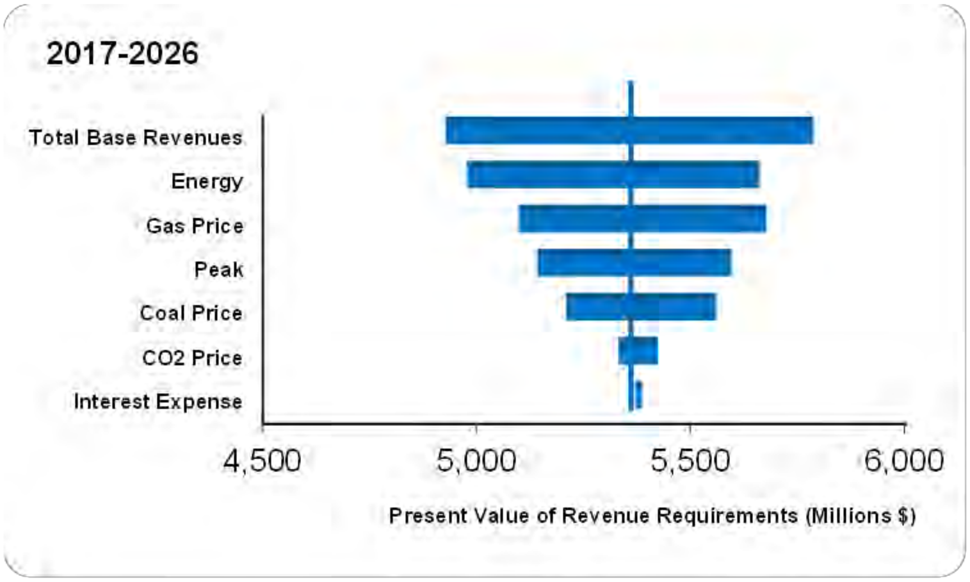


Figure 8.47 – Adoption of DG - Tornado Chart (2027-2036)

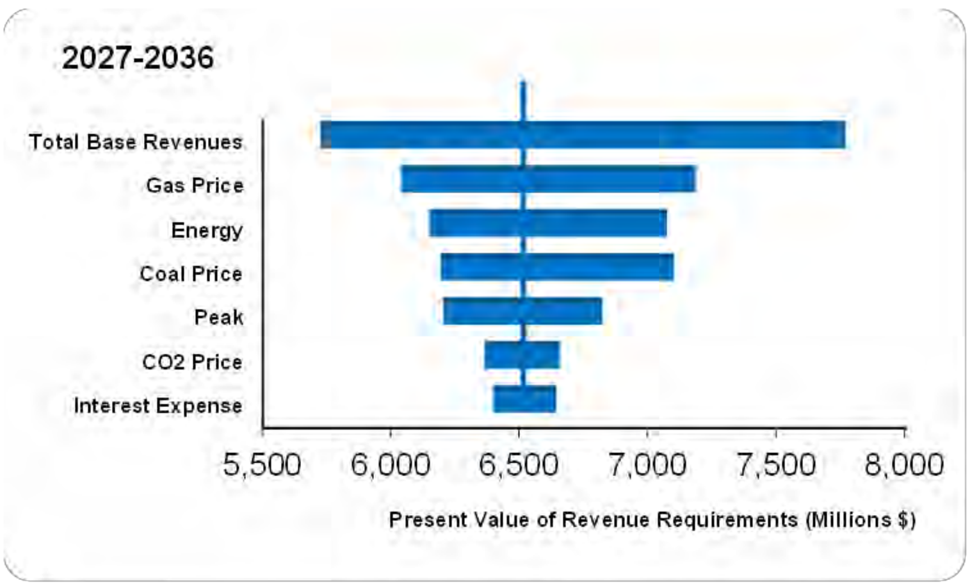


Figure 8.48 – Quick Transition - Tornado Chart (2017-2026)

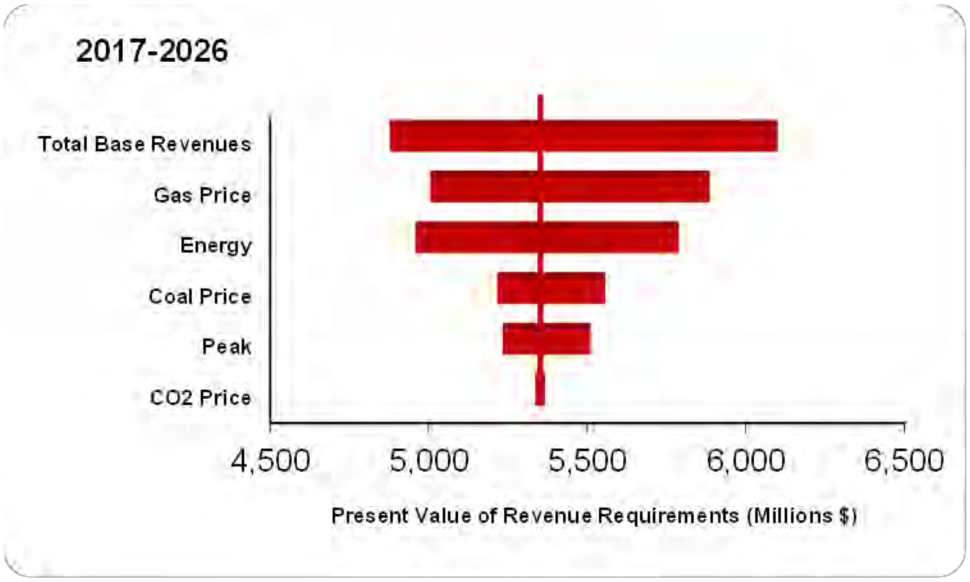
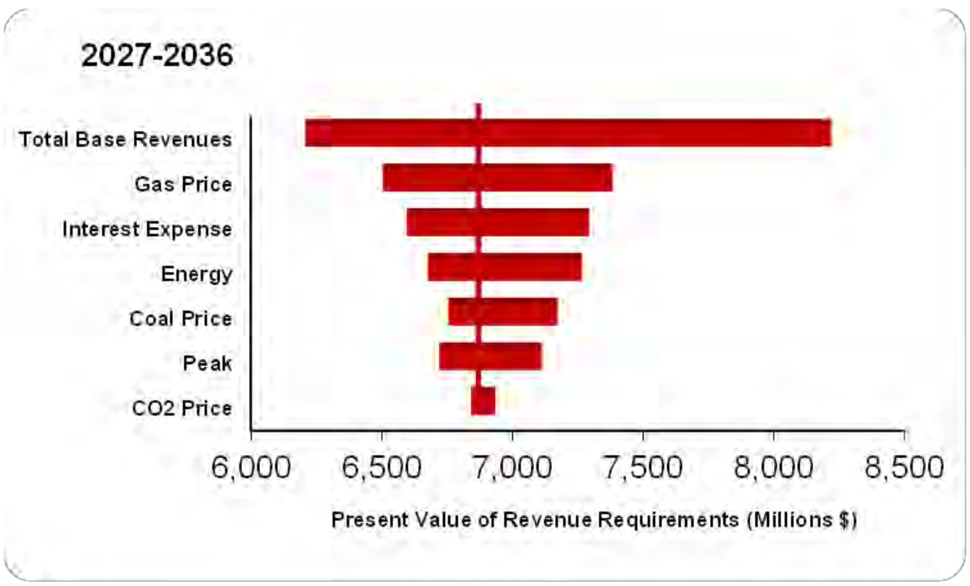


Figure 8.49 – Quick Transition - Tornado Chart (2027-2036)



8.3. Scenario Metrics Results

170 IAC 4-7-8(b)(2)

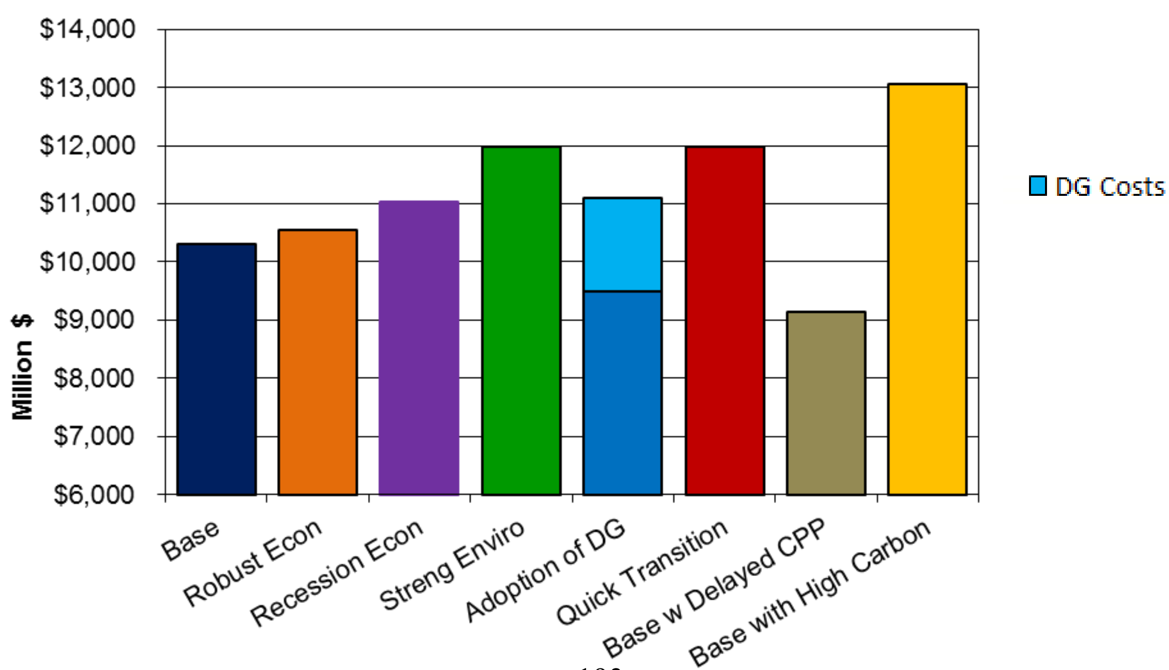
As explained in Section 7, IPL used four categories of metrics to compare the portfolios: Cost, Financial Risk, Environmental Stewardship, and Resiliency. The results of the eleven IPL metrics in the four metrics categories are summarized below. As explained in Section 7, metrics are not meant to provide answers. Instead, they are meant to show the results in a way that will improve IPL's and stakeholders' understanding of each scenario, provide a comparison of each scenario, and allow IPL and stakeholders to ask questions and dig deeper into the results.

8.3.1. Cost Category

8.3.1.1 *Metric 1: Present Value Revenue Requirement*

As explained above, the Base Case has lowest PVRR. Figure 8.50 shows the PVRR for each scenario. The Robust Economy portfolio has a higher PVRR than the Base Case because it had to build more resources for a higher load. The Recession Economy scenario also has a higher PVRR because it underbuilt for a low load forecast and has to go to the market for more energy and capacity under base case assumptions. The Strengthened Environmental scenario also overbuilt to meet RPS during years when IPL does not need to add capacity. The Adoption of DG scenario, when taking into account the cost of customer adoption of DG, has a higher PVRR than the Base Case due to the DG additions occurring based on customer decisions other than economics. The Quick Transition scenario also includes retirements and additions to the portfolio based on stakeholder input, not economics.

Figure 8.50 – PVRR Metric Result

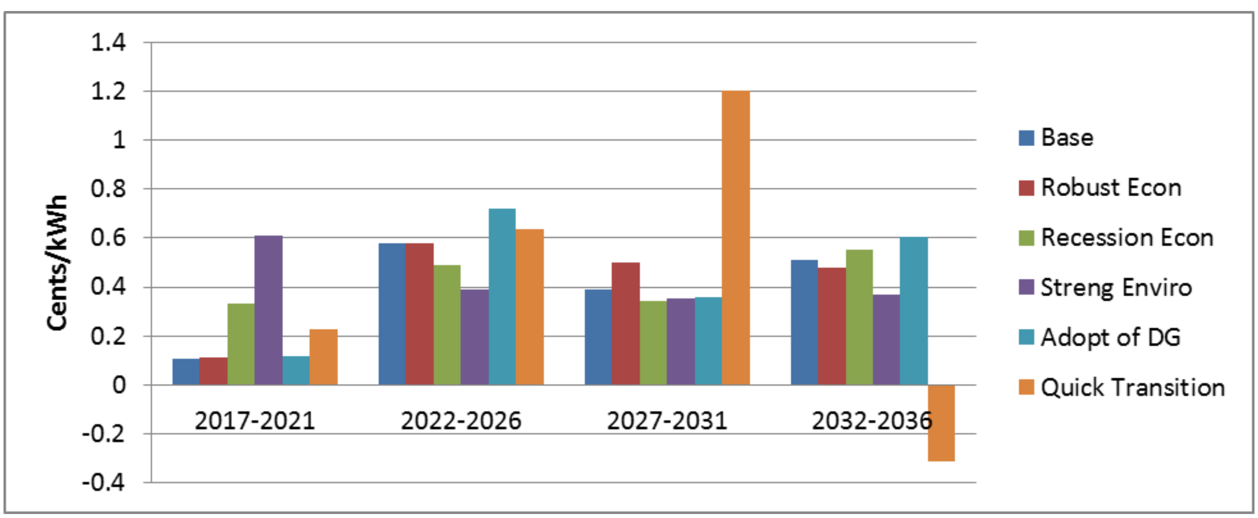


8.3.1.2 *Metric 2: Rate Impact*

IPL calculated each scenario's annual cost impact by dividing each year's revenue requirement by the load forecast. IPL then found the incremental annual rate impact by subtracting each year's cost impact from the prior year's cost impact. In order to show how each scenario's rate impact changes over time, IPL examined the average rate impact in five-year increments. The variable cost of operating existing resources and adding new resources are included in the revenue requirement for each year. The revenue requirement calculation does not include transmission and distribution upgrades for new resources, fixed generation costs, or general administration costs. Figure 8.51 shows the rate impact of each scenario in five year time blocks.

For the first five years, the Strengthened Environmental scenario has the highest rate impact, because not only do the Pete units retire early or convert to natural gas, but a large amount of wind and solar is added to meet the a renewable portfolio standard ("RPS"). For the second five years, the High Customer Adoption of DG scenario and Quick Transition scenario have the highest rate impact. This occurs because the customer DG is added for reasons other than economics, and the early retirement of Pete 1 and refueling of Pete 2-4 in the Quick Transition scenario happened for reasons other than economics. For the third five years, the Quick Transition scenario had the highest rate impact, because a large amount of capacity was added in 2030, whereas the other scenarios spread out their capacity additions over several years. Finally, for the last five years, the revenue requirement for the Quick Transition dropped from the very high amount shown in the third five years.

Figure 8.51 – Average Cents/kWh in Five Year Time Blocks



The 20 year average rate impact is shown in Figure 8.65, titled the Metrics Summary. For this metric, instead of subtracting each year's cost impact from the prior year's cost impact, IPL instead took the PVRR of the 20 year study period and divided it by all the kWh generated over the 20 year study period. This provides a 20 year average rate impact. IPL shows this metric in terms of cents/kWh.

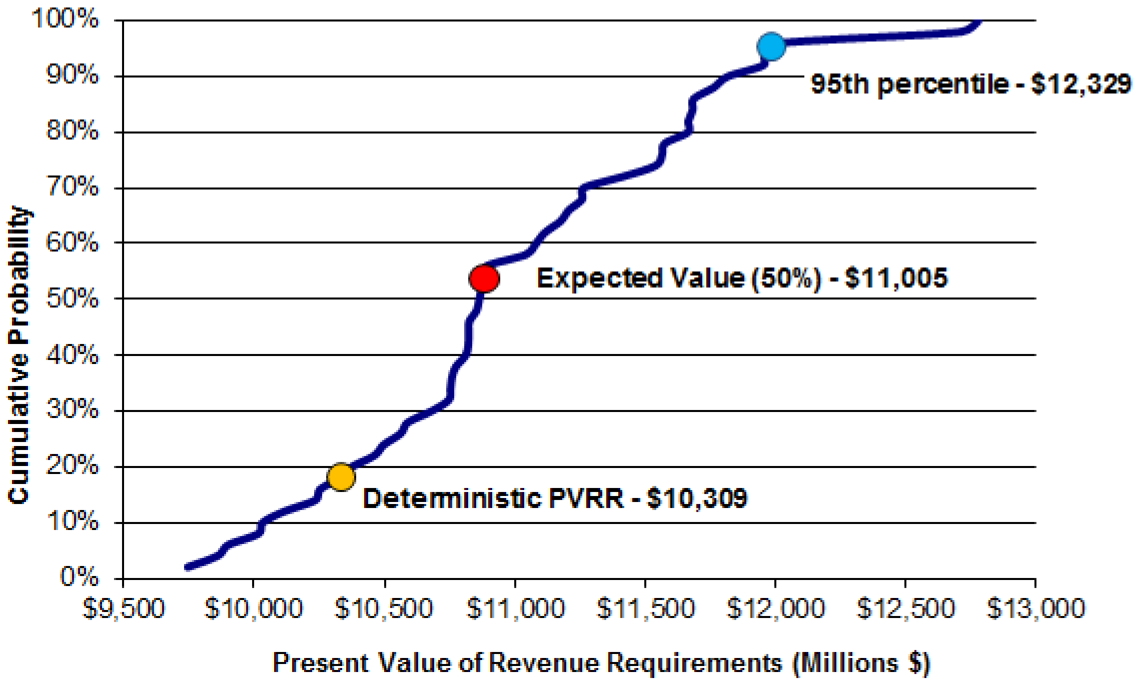
8.3.2. Financial Risk Category

Because the PVRR results from the Production Cost model (explained in Section 7) are produced from a deterministic set of assumptions for each scenario, IPL did additional stochastic analysis to show the range of PVRR results that could occur if key assumptions changed. This process is explained in Section 7.5.2 and Section 8.2.2.

8.3.2.1 *Metric 3: Risk Exposure*

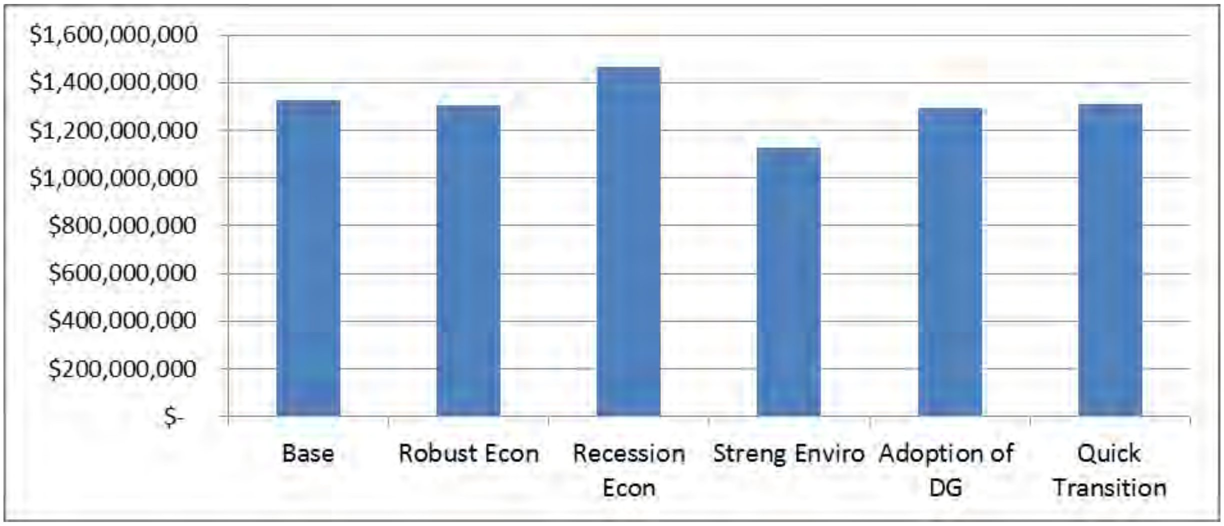
The Risk Exposure metric calculates risk exposure by subtracting the PVRR at the Expected Value from the PVRR at the 95th percentile. Figure 8.52 shows the risk profile for the Base Case and illustrates how this metric is calculated, and Figure 8.52 shows the results of the Risk Exposure metric for each scenario. The deterministic PVRR for the Base Case, which IPL showed above in Figure 8.50, is $10.3 billion for the Base Case portfolio if all Base Case assumptions come to fruition. As shown in the Risk Profile graph below, there is an approximately 20% probability that the Deterministic PVRR will occur for the Base Case. However, as explained above, IPL conducted 50 runs of stochastic analysis for each scenario to show the PVRR if the scenarios' assumptions change for variables such as load, commodity prices, or technology prices. The Expected Value for a scenario is the average PVRR of the 50 stochastic runs for that scenario. As shown in the Risk Profile below, an Expected Value of $11 billion shows that there an approximately 52% probability that the PVRR for the Base Case will be at or below $11 billion. There is a 95% probability that the PVRR for the Base Case will be at or below $12.3 billion. This gives the Base Case a Risk Exposure of $1.3 billion.

Figure 8.52 – Risk Profile for the Base Case



An alternate representation of the risk exposure of each scenario is shown in Figure 8.53. The Recession Economy scenario has the highest risk profile, due to the fact that the portfolio was developed for low natural gas prices and low load. As higher levels of load and natural gas prices are applied to the Recession Economy portfolio, the portfolio becomes riskier. The Strengthened Economy portfolio has a lower risk profile, because the portfolio was already developed for high carbon prices, and hence faces less risk of higher carbon prices than do the other portfolios.

Figure 8.53 – Difference between Expected Value and 95th probability



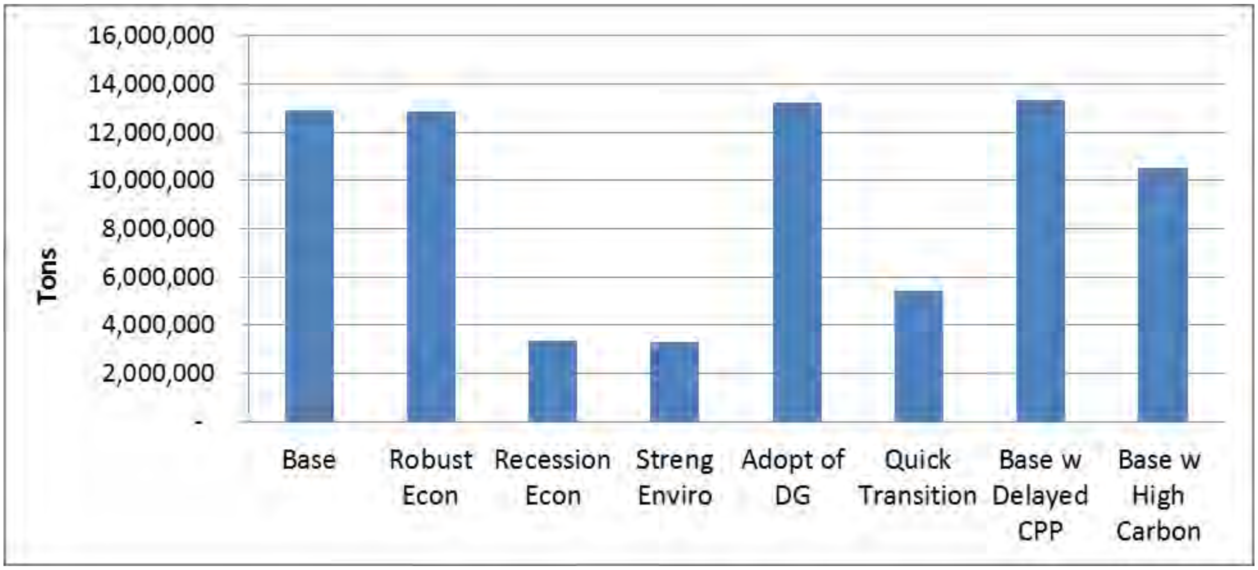
8.3.3. Environmental Stewardship Category

For CO_2, NO_x, and SO_2, IPL calculated each scenario's average annual emissions over twenty years and each scenario's emission intensity. The two metrics show something different. The first metric, the average annual emissions over twenty years, reflects total emissions for each portfolio. However, this metric does not show how changing load or the addition of renewable energy impacts the intensity of the emissions per MWh. The second metric provides this additional insight. For example, the metric shows how higher load can reduce CO_2, NO_x, and SO_2 intensity if no coal units early but renewable energy and DSM is added to meet the higher load. This means that there are more MWh to spread out the same amount of emissions.

8.3.3.1 *Metric 4: Average annual CO_2 emissions*

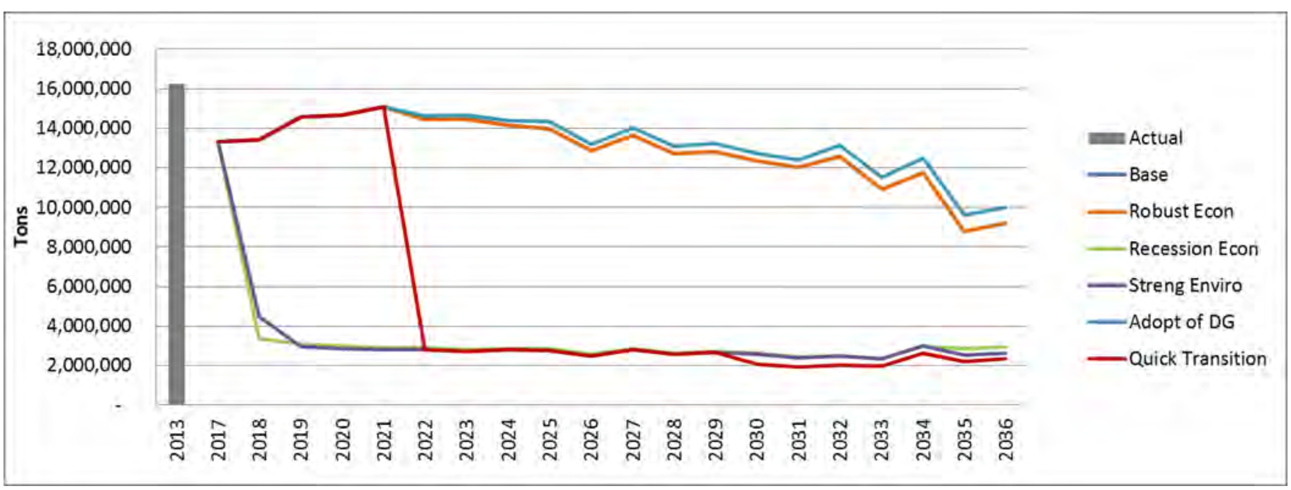
Figure 8.54 shows the annual average CO_2 emissions by scenario. These results were calculated by taking the total CO_2 emissions over the study period and dividing them by 20, the number of years in the study period.

Figure 8.54 – Results CO_2 emissions by Scenario



Scenarios in which Pete coal units either retire early or refuel to natural gas have lower CO_2 emissions. Figure 8.55 shows the projected annual emissions for each scenario compared to the 2013 annual CO_2 emissions. IPL chose 2013 for its comparison year, because 2013 is the last year before IPL's 2014 IRP.

Figure 8.55 – Historical and Forecasted IPL Annual CO_2 Emissions



The Production Cost model shows the Base Case and the Adoption of DG portfolios result in the highest CO_2 emissions, with the Adoption of DG portfolio resulting in very similar CO_2 emissions to the Base Case. The similarity in CO_2 emissions between the two cases stem from the fact that the two portfolios are very similar throughout the study period, as well as the fact that the 225 MW of CHP DG additions emit 677 tons CO_2/MWh. A key takeaway is that while the Production Cost model did not adjust IPL's thermal fleet generation in response to customer Adoption of DG, IPL responded to stakeholder feedback and calculated the emission reductions that would result from the Adoption of DG. The Production Cost model, as set up in the 2016 IRP, does not adjust IPL's sale of electricity into the wholesale market for the amount of distributed generation that is added to the system. Stakeholders provided feedback that the adoption trends of DG in the MISO footprint would probably be similar to the adoption of the 450 MW of DG additions in IPL's service territory, which means that IPL would sell less electricity into the wholesale market. IPL used this stakeholder feedback to change its calculation of total CO_2 tons to reflect the CO_2 emissions that are avoided by the adoption of DG wind, solar, and CHP. To do this, IPL assumed that for each MWh of DG wind and solar generation, IPL's portfolio of resources will generate that much fewer MWh and hence emit that much fewer CO_2 tons/MWh. For each MWh of CHP generation, IPL's portfolio of thermal resources will generate that much fewer MWh, but the CO_2 tons/MWh of CHP are still included in the calculation of total CO_2 emissions.

As a result of IPL's adjustment to the CO_2 emissions calculation, the Adoption of DG portfolio's 20 year emissions of CO_2 changed from 271,126,254 tons to 264,398,387 tons. 3.2 million tons of CO_2 are avoided by the customer owned DG wind and solar units, and 3.5 million tons of CO_2 are avoided by CHP units. However, even though the CO_2 rate per GWh is lower for the CHP units than IPL's thermal fleet, the CHP units still emit a total of 13.5 million tons of CO_2 during the study period. The Production Cost model also applies a random outage rate to thermal units, including CHP. This random outage rate for each scenario resulted in the Adoption of DG scenario producing more GWh than the Base Case scenario, which results in higher CO_2 for the Adoption of DG scenario than the Base Case emissions even after taking into account the reduction of IPL's thermal fleet generation in response to the addition of DG.

IPL did not recalculate the PVRR to reflect change in IPL's thermal generation due to customer adoption of DG, since the PVRR is an output of the Production Cost model. Although the 2016 version of Production Cost model was not set up to adjust the thermal generation as a result of customer adoption of DG, IPL will work to improve this for the next IRP.

8.3.3.2 *Metric 5 and 6: Average annual SO_2 and NO_x emissions*

Figure 8.56 shows the average annual NO_x and SO_2 emissions over the twenty year study period.

Figure 8.56 – 20 Year Average Annual NO_x and SO_2 emissions by Scenario

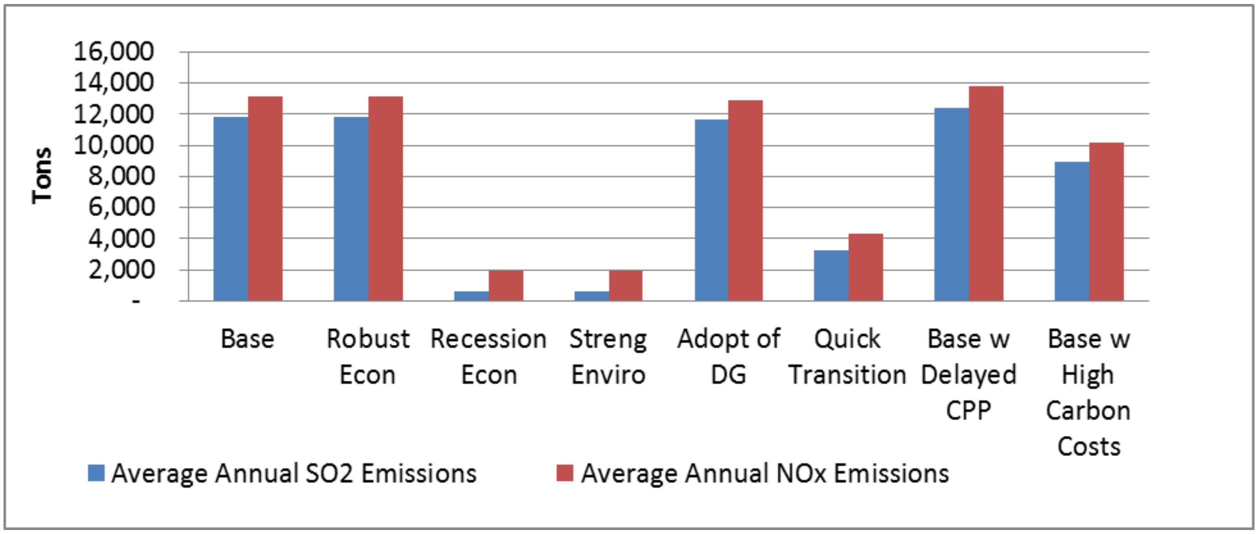


Figure 8.57 and Figure 8.58 show the projected annual emissions for each scenario compared to the 2013 annual NO_x and SO_2 emissions. Scenarios in which Pete units retire early or refuel to natural gas also have lower SO_2 and NO_x emissions. The Quick Transition scenario, in which Pete 1-4 use coal until 2022, has slightly higher emissions than the Recession Economy or Strengthened Environmental emission scenarios, in which Pete units retire or refuel to natural gas in 2018.

Figure 8.57 – Historical and Forecasted IPL Annual NO_x Emissions

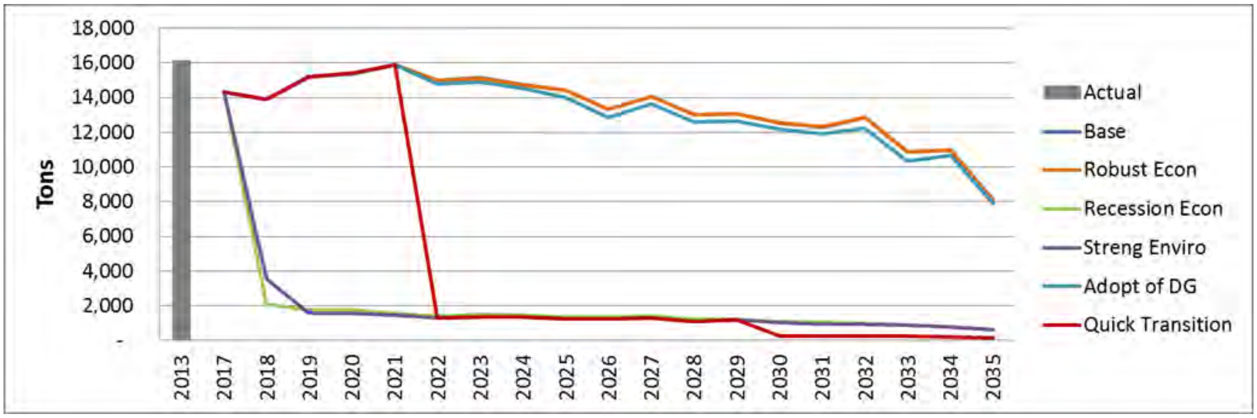
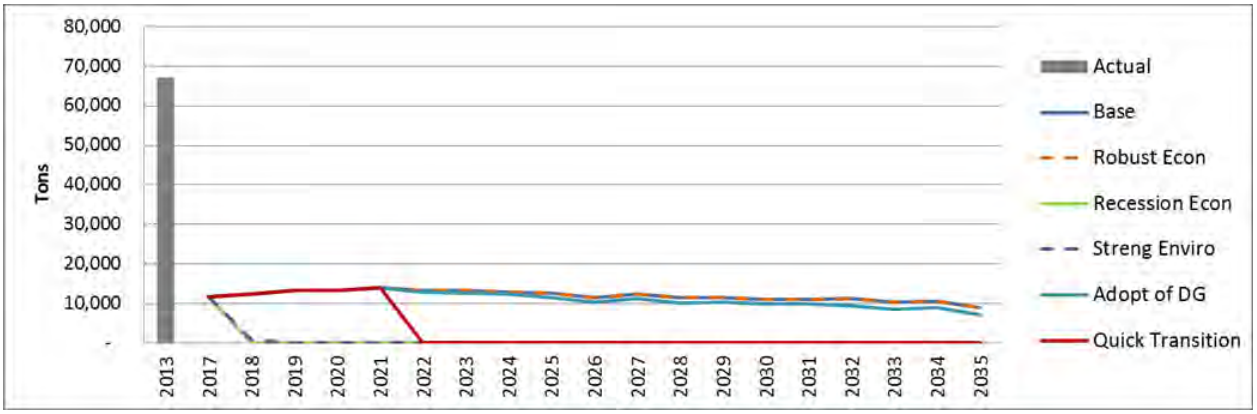


Figure 8.58 – Historical and Forecasted IPL Annual SO_2 Emissions

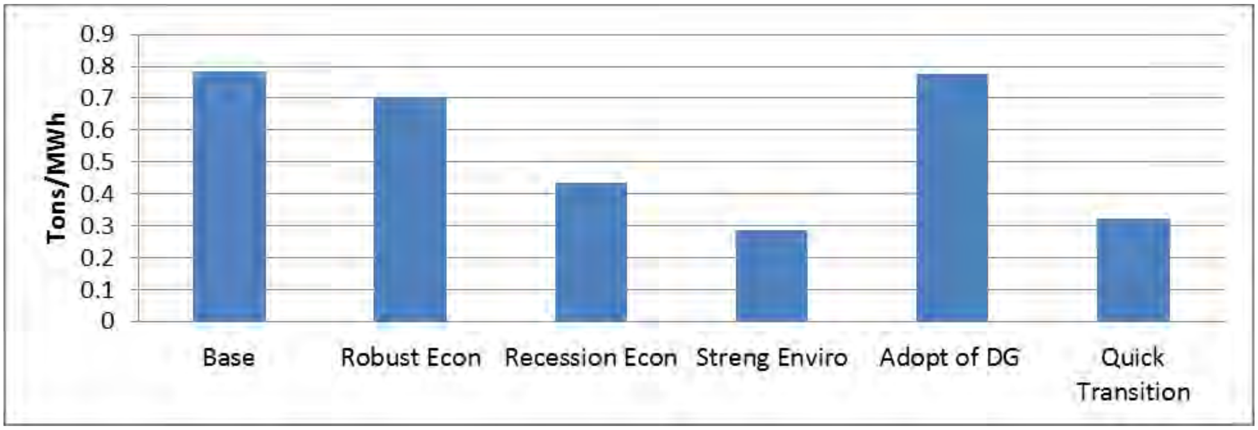


The Production Cost model shows the Base Case and Adoption of DG portfolios resulting in similar NO_x and SO_2 emissions. Not only do the two scenarios result in similar portfolios throughout most of the study period, but 225 MW of CHP is added to the Adoption of DG scenario. As modeled in the 2016 IRP, CHP emits 0.36 tons NO_x/MWh. CHP does not emit SO_2. As explained above, the Production Cost model, as set up in the 2016 IRP, does not adjust IPL's sale of electricity into the wholesale market for the amount of distributed generation that is added to the system. Stakeholders provided input that the adoption trends of DG in the MISO footprint would probably be similar to the adoption of the 450 MW of DG additions in IPL's service territory, which means that IPL would sell less electricity into the wholesale market. IPL used this stakeholder feedback to change its calculation of total SO_2 and NO_x tons to reflect the SO_2 and NO_x emissions that are avoided by the adoption of DG wind, solar, and CHP. To do this, IPL assumed that for each MWh of DG wind and solar generation, IPL's portfolio of resources will generate that much fewer MWh and hence emit that much less SO_2 tons/MWh and NO_x tons/MWh. For each MWh of CHP generation, IPL's portfolio of thermal resources will generate that much fewer SO_2 tons/MWh and NO_x tons/MWh, but the NO_x tons/MWh of CHP are still included in the calculation of total NO_x emissions. Customer adoption of DG solar and wind resulted in 3,256 fewers tons of NOx and 3,019 fewer tons of SO_2 over the twenty year study period. Customer adoption of CHP resulted in 9,534 fewer tons of NO_x and 15,665 fewer tons of SO_2 over the twenty year period.

8.3.3.3 *Metric 7: CO_2 intensity*

Figure 8.59 shows the CO_2 intensity by scenario. This metric was calculated by taking the total CO2 emissions over the twenty year study period and dividing them by the total MWh generated during the twenty year study period. Scenarios in which Pete coal units either retire early or refuel to natural gas have lower CO_2 emissions. The Robust Economy scenario has a lower CO_2 intensity than the Base Case despite having the same portfolio of thermal resources. This occurs because not only does the Robust Economy have more MWh to spread out the CO_2 tons, but it also adds more DSM and non-CO_2 emitting resources than does the Base Case, which lowers the CO_2 intensity of the portfolio.

Figure 8.59 – CO_2 intensity by Scenario



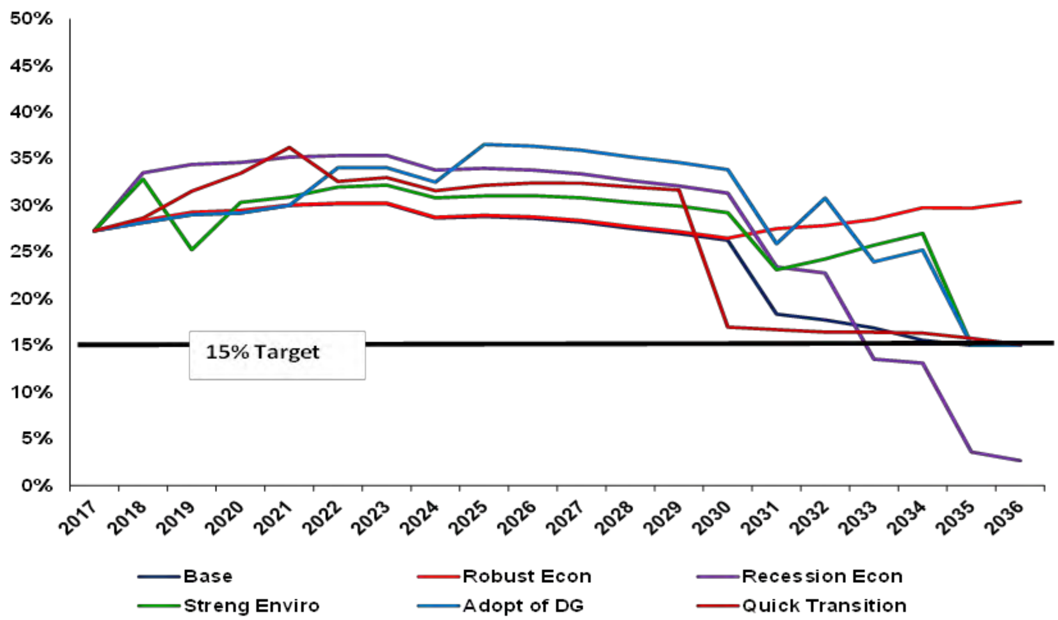
8.3.4. Resiliency

For each scenario, the metrics within the category of resiliency capture customer exposure to price volatility and market reliance. By securing the required planning reserve margin requirement and limiting market reliance for capacity or energy, IPL and its customers can have a high level of resiliency. IPL received stakeholder feedback that recommended that the IRP also measure distributed generation as a percent of total resources, which shows the amount of load that IPL may not need to meet in the future if customers choose to adopt DG.

8.3.4.1 *Metric 8: Planning Reserves*

Figure 8.60 shows the capacity reserve margins for each portfolio under Base Case model assumptions, including base load, base commodity prices, etc. Each portfolio has reserve margins at or above 15% for each year of the study period, except for the Recession Economy. The Recession Economy portfolio assumed low load in the Capacity Expansion Model, so it has a capacity deficit in a Base Case world.

Figure 8.60 – Planning Reserves as a Percent of Total Resources



8.3.4.2 *Metric 9: Distributed Generation Penetration*

Figure 8.61 shows percent of total resources that is DG for each scenario. The operating capacity of IPL's existing and future solar resources are included in the calculation of the percent of total resources that is distributed generation ("DG"). The percent of total resources that is DG increases for all scenarios, since solar, wind, and CHP DG are added to the Adoption of DG scenario and solar is added to all scenarios but the Recession Economy. The percent of DG in the Recession Economy scenario increases not because of DG additions, but because of declining load. The percent of total resources that is DG is highest in the Robust Economy and Quick Transition scenarios, because these scenarios add the most solar. For all scenarios, the percent of total resources that is DG is higher in the last ten years of the study period, since many thermal units do not retire until after 2030.

Figure 8.61 – Distributed Generation as a Percent of Total Resources in Terms of Operating Capacity

Scenario	2017-2021	2022-2026	2027-2031	2032-2036
Base	2%	2%	2%	4%
Robust Econ	2%	2%	2%	13%
Recession Econ	2%	2%	2%	3%
Strengthened Environmental	5%	9%	9%	8%
Adoption of DG	3%	8%	10%	10%
Quick Transition	2%	2%	6%	17%

8.3.4.3 *Metric 10: Market Reliance - Energy*

Figure 8.62 the annual market purchases as a percent of annual load. The Base Case, Robust Economy, and Adoption of DG portfolios have the lowest reliance on the market for energy when they are applied to a world of Base Case assumptions. Those three scenarios do not refuel or retire the Pete units early. The Base Case market reliance on energy ranges from 2.4% to 9.2%, which is similar to IPL's recent average market reliance of 6% for 2013-2015. The Recession Economy, Strengthened Environmental, and Quick Transition portfolios have high reliance on the market for energy, and each of those scenarios refuel or retire the Pete units early. The market reliance for the Recession Economy, Strengthened Environmental, and Quick Transition portfolios go as high as 50% in certain years. IPL prefers to limit its reliance on the market, because a heavy reliance on the market could expose customers to price volatility.

Figure 8.62 – Market Purchases as a Percent of Load ("MWh")

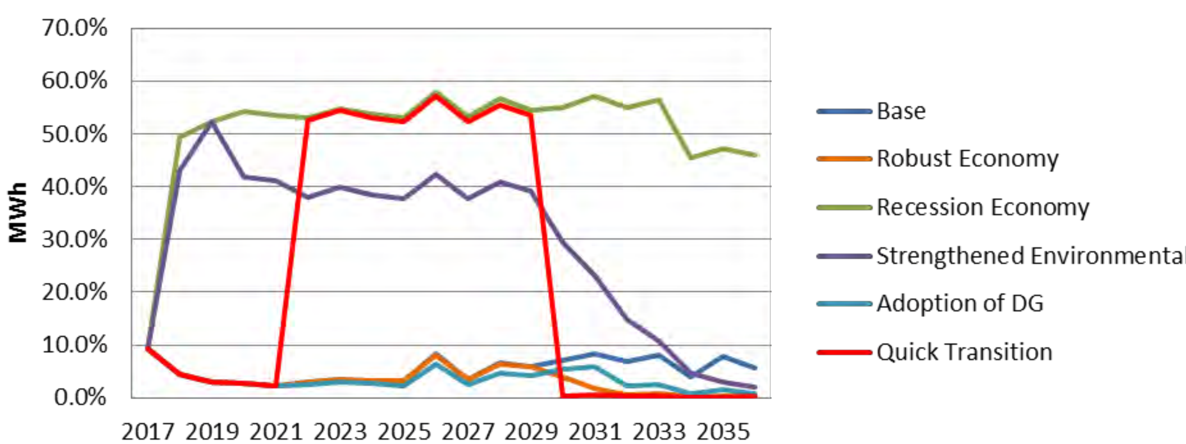
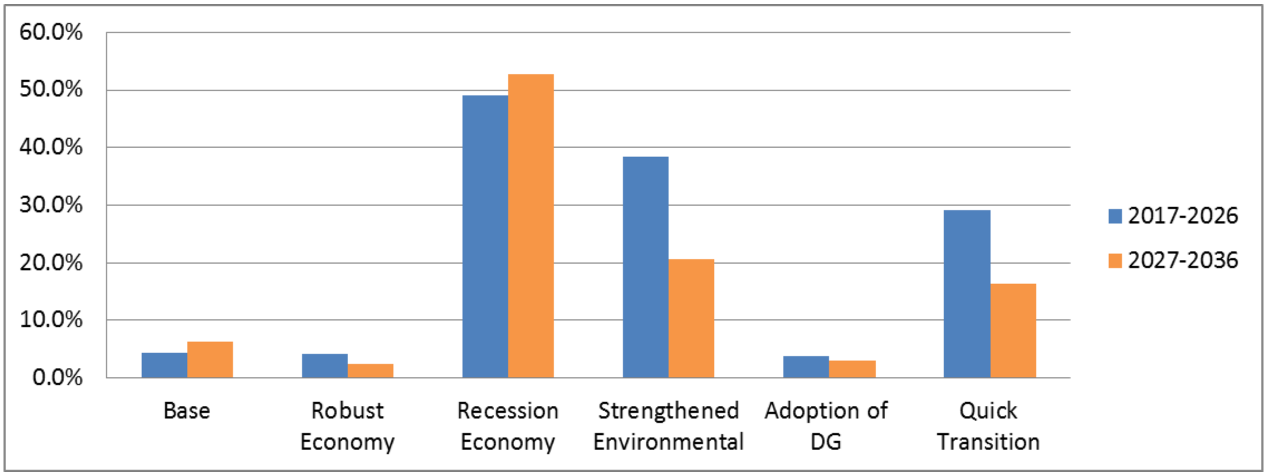


Figure 8.63 shows ten year averages of market reliance for each scenario. Based on ten year averages, the Recession Economy scenario has the high market reliance for energy, which shows that converting Pete to natural gas and then adding very few resources will expose IPL to a high level of market volatility if the Base Case assumptions for the future come to fruition.

Figure 8.63 – Market Purchases as a Percent of Load, 10 Year Averages



8.3.4.4 ***Metric 11: Market Reliance - Capacity***

As shown in Figure 8.64, each scenario's portfolio has very little market reliance for capacity, with most of the capacity purchases occurring after 2030. Although it is IPL's policy to limit market purchases for capacity to reduce price or supply volatility, the Capacity Expansion Model identified that in a certain years it is more cost-effective to delay adding resources for capacity and instead temporarily rely on the market.

Figure 8.64 – Market Reliance for Capacity

Year	Base	Robust Economy	Recession Economy	Strengthened Environmental	Adoption of DG	Quick Transition
2030						
2031		200				
2032						
2033	50					
2034						
2035	150	50		50	50	
2036						

Metrics Summary

Figure 8.65 shows a summary of each metric by scenario. Some stakeholders liked the "traffic signal" approach that other Indiana utilities have used in the IRP process to compare portfolios. IPL used a similar approach in the metrics summary table to show when one scenarios metric is "better" or "worse" than another. As explained in Section 7, the metrics summary is not meant to be a "scorecard," but rather a tool for comparison. In summary, the Base case has lowest PVRR, lowest cost impact, and low market reliance for energy. The Base Case does have higher environmental emissions than certain other cases due to the fact that it does not retire coal units early, but the scenarios with lower emissions have higher PVRRs and rate impacts. Every portfolio when applied to a Base Case world, except for Recession Economy, gives us the MISO required reserve margin of 15%. The Recession Economy reserve margin falls as low as 3%. If the portfolio met the reserve margin of 15%, it was color coded green. Most scenarios had little market reliance for capacity, so no scenario is color coded red for that metric. Because some metrics were calculated in 5 year time blocks, this metric summary shows a similar calculation, but for a 20 year time period.

Figure 8.65 – Metrics Summary

Scenarios	Cost		Financial Risk	Environmental Stewardship				Resiliency			
	20 yr PVRR ($ MN)	Rate Impact, 20 yr average (real cents/kWh)	Risk Exposure ($)	Average annual CO2 emissions (tons)	Average annual NOx emissions (tons)	Average annual SO2 emissions (tons)	Total CO2 intensity (tons/MWh)	Planning Reserves (lowest amount over 20 yrs)*	Distributed Generation (Max DG as percent of capacity over 20 yr)	Market Reliance for Energy (Max over 20 yrs)	Market Reliance for Capacity (Max MW over 20 yrs)
Base	$ 10,309	3.53	$1,324,989,546	12,883,603	13,181	11,808	0.79	15%	3%	9%	150
Robust Econ	$ 10,550	3.62	$1,303,754,944	12,883,183	13,181	11,808	0.70	27%	15%	9%	200
Recession Econ	$ 11,042	3.78	$1,463,842,563	3,334,067	1,925	593	0.44	3%	3%	58%	0
Streng Enviro	$ 11,990	4.11	$1,126,983,327	3,309,326	1,910	629	0.28	15%	10%	52%	50
Adopt of DG	$ 11,092	3.80	$1,294,337,690	13,219,942	12,910	10,874	0.78	15%	11%	9%	50
Quick Transition	$ 11,988	4.20	$1,311,247,113	5,403,645	4,320	3,243	0.32	15%	35%	57%	0

Key:

Green	Best
Yellow	Better
Red	Worse

8.4. Preferred Resource Portfolio

170 IAC 4-7-8(b)(1)

8.4.1. Decision Criteria

170 IAC 4-7-4(b)(9) 170 IAC 4-7-8(b)(2)

IPL has traditionally relied primarily upon costs to customers in terms of PVRR to select its preferred resource portfolio.

The "Preferred Resource Portfolio" based upon the lowest cost to customers in terms of the PVRR would be the base case scenario. IPL performed stochastic or probabilistic analyses to determine how changing variable may impact scenario outcomes for PVRR. Variables that IPL changed include fuel and market prices, load requirements, technology costs, and carbon costs. IPL used this stochastic analysis to make a risk tradeoff diagram with the expected value of each portfolio's PVRR plotted against the standard deviation of the PVRR outcomes for each scenario. This risk tradeoff diagram, shown in Section 8 of this IRP, indicated that the Base Case has the lowest risk-tradeoff.

In this IRP, IPL presented additional metrics for each candidate resource portfolio as a means to compare results. The metrics scorecard is a tool to consider other impacts such as carbon impacts, short term versus long-term rate impacts, risk exposure, other air emissions, and reliance on the MISO market for capacity and energy. These metrics were not weighted, rather they provide insights for discussion.

In addition to PVRR analyses, IPL developed metrics related to environmental stewardship, financial risk, resiliency, and rate impact metrics to compare the portfolios derived from multiple scenarios which are summarized in Figure 8.58.

These metric results spurred discussions about how best to meet the future needs of customers. In the fourth public advisory meeting, IPL shared the Base Case as the preferred resource portfolio. Subsequent review and stakeholder discussions prompted further developments which lead IPL to believe the ultimate preferred resource portfolio will likely be a hybrid of multiple model scenario results.

IPL recognizes the challenge of balancing affordability with environmental risk uncertainty and costs. As stated in the 2014-2015 IRP Director's Report at pg. 4, "This preferred Plan might be the Base Case. The Base Case should describe the utility's best judgment (with input from stakeholders) as to what the world might look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws/policies affecting customer uses and resources." [84]

8.4.2. Hybrid Preferred Resource Portfolio

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

Following a review of metric results and scenario assumptions, IPL believes future resource mixes may vary. While the Base Case has the lowest PVRR, it also has the highest collective environmental emission results and least amount of DG penetration. The economic variables used to model environmental and DG costs reflect what is measurable today, for example, costs for potential future regulations and an estimate of CHP costs. The model does not include estimated costs for regulations not yet proposed, potential technical advances to ramp thermal units to lower minimum levels, public policy changes which may occur in the study period or specific customer benefits of DG adoption.

IPL recognizes dynamic conditions in the electric utility industry and believes additional changes may occur more rapidly than the scenarios modeled. By comparison, the 2014 IRP analysis indicated less than 50% of the wind resources selected in this IRP, no solar additions and did not even include energy storage as a selectable option. In this IRP, energy storage capacity and energy attributes are modeled. In subsequent IRPs, IPL expects to model grid support benefits following the development of market tools to quantify them appropriately.

Should a blend of variables from the base, strengthened environmental and DG scenarios come to fruition, such as public pressure to reduce emissions, customer adoption of DG, and some additional environmental costs, perhaps a hybrid preferred resource portfolio would result. In addition, technology costs may decrease more quickly than the modeled inputs which would likely drive changes in renewable and distributed generation penetration.

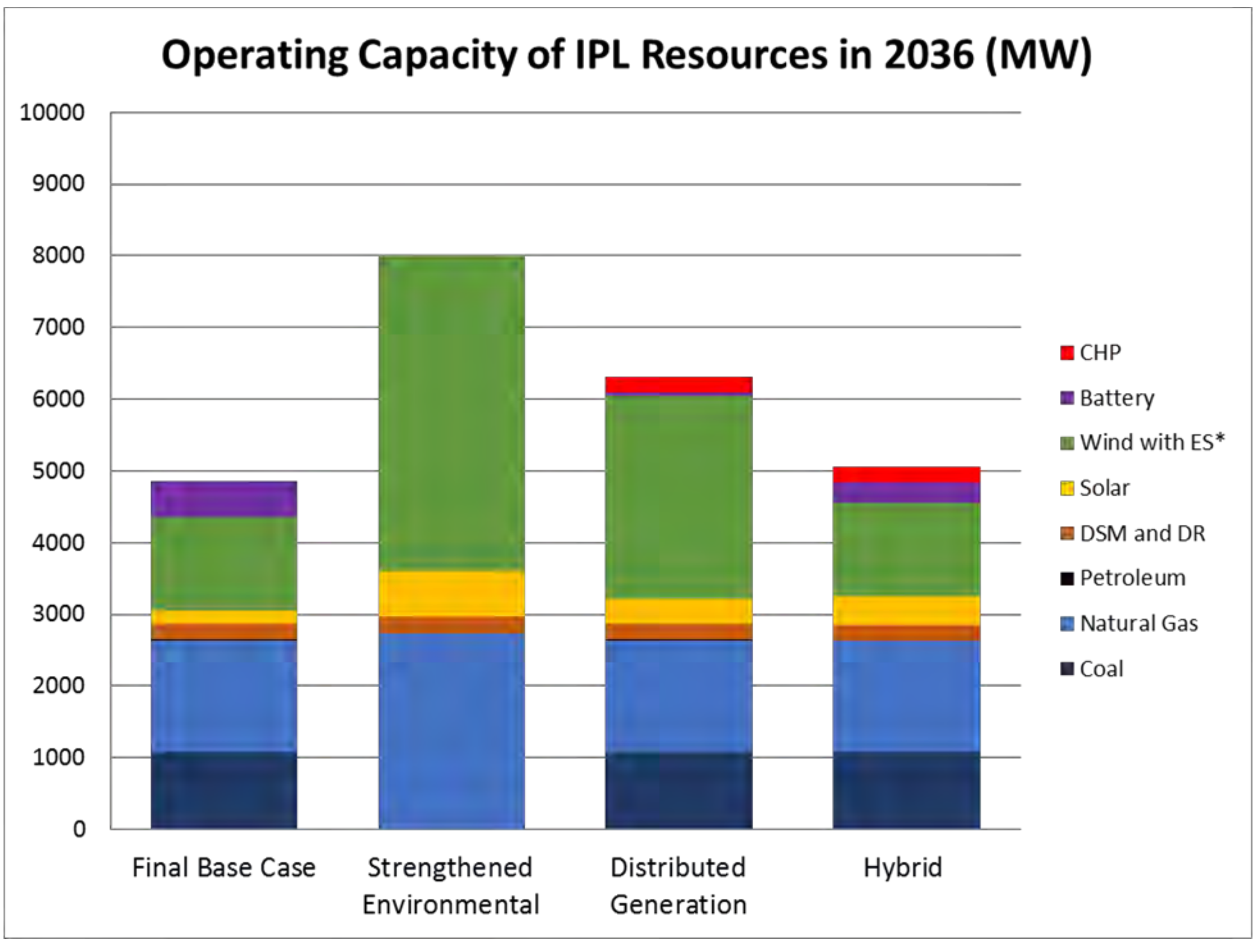
A hybrid portfolio in 2036 may include two Pete coal units, minimum natural gas generation for local system reliability, wind to serve load during non-peak periods, and an average of DSM, solar, energy storage levels from the three scenarios as summarized in Figure 8.66 and Figure 8.67 below.

[84] http://www.in.gov/iurc/files/Directors_Final_Report_IRP_20142015_June_10_at_1035_AM.pdf.

Figure 8.66 – Summary of Resources (cumulative changes 2017-2036)

	Final Base Case	Strengthened Environmental	Distributed Generation	Hybrid
Coal	1078	0	1078	1078
Natural Gas	1565	2732	1565	1565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1300	4400	2830	1300
Battery	500	0	50	283
CHP	0	0	225	225
totals	4858	8006	6319	5060

Figure 8.67 – Operating Capacity in 2036 with Hybrid Portfolio



IPL anticipates potential changes not easily modeled may affect future resource portfolios, such as the impacts of pending local gubernatorial and national Presidential elections, public policy changes, or stakeholder input.

Although the model selects specific resources in each scenario based upon current market conditions and what IPL knows today, other cost-effective resources may exist in the future. IPL will evaluate these resource options in subsequent IRPs to develop the Preferred Resource Portfolio based on updates to market and fuel price outlooks, future environmental regulations, relative costs of technologies, load forecasts and public policy changes.

IPL continually monitors risks associated with resource planning and completes project specific analyses as needed in response to acute changes. In addition, monthly budget variance analysis is completed to identify short-term trends which may impact long-term changes. Subsequent IRP analyses will consider changes to assumptions and risks.

Section 9: Conclusions and Recommendations

Executive Summary

As a culmination of the IRP process, observations about the analysis and results as well as a summary of how IPL incorporated stakeholder feedback are described in this section. A comparison of the previous IRP short term action plan and new action plan is also presented. Lastly, future expected enhancements are identified.

9.1. IPL Short Term Action Plan

170 IAC 4-7-9(1)(A)

As suggested in the revised 170 IAC 4-7-9, IPL has included a comparison of the last IRP short-term action plan to what actions actually transpired, a summary of actions planned for the next three (3) years including a schedule and budgetary costs as well as a description of its Preferred Resource Portfolio.

9.1.1. Comparison to Last IRP

170 IAC 4-7-9(1)(B) 170 IAC 4-7-9(4)

IPL measures its progress and success in relation to the IRP objective by comparison of the previous IRP goals and what actually transgressed for the time period 2015-2017. The 2014 IRP short-term action plan centered on developing cost-effective DSM programs to meet energy efficiency goals, complying with strict new EPA rules for MATS and NPDES that prompted conversion of Harding Street Station coal units to natural gas, and compliance measures for MATS and NPDES regulations for Petersburg units.

A summary of specific items show below:

Completed Items

1. Implemented DSM for 2015- IPL sponsored DSM programs for 2015 achieved annual targets for energy savings.
2. Retired Eagle Valley coal units – The coal units totaling approximately 260 MW of capacity were retired in April 2016.
3. Refueled Harding Street Station ("HSS") units 5, 6 and 7 – These unit conversions from coal to natural gas were completed in December 2015 and May 2016.
4. Retrofitted Petersburg units for Mercury and Air Toxics Standards ("MATS") regulation – this work was completed in April 2016.

5. Secured market capacity purchases for 2015-2017 – IPL utilized a mix of bilateral contracts and the MISO auction for capacity needed for two planning year periods.
6. Built HSS 20 MW Battery Energy Storage System – This transmission asset became operational in 2016 and provides frequency support services to the 138 kV grid.
7. Completed transmission projects to accommodate new EV CCGT – The transmission line and substation enhancements including the construction of a Static Var Compensator ("SVC") in the Indianapolis area were completed in 2016.

In progress

1. Implementing DSM for 2016-2017 – The 2016 DSM programs are on track to meet annual targeted energy savings. The 2017 DSM plans have been proposed and are pending approval by the IURC. A DSM Market Potential Study ("MPS") was completed to support DSM planning for 2018 to 2036 in this IRP process.
2. Construct EV Combined Cycle Gas Turbine ("CCGT") – Eagle Valley CCGT is well underway and on track for scheduled commercial operations in the spring of 2017.
3. Complete EV CCGT substation construction – Substation construction at the plant site continues and is expected to be completed to enable CCGT commercial operations.
4. Retrofit Pete and HSS for National Pollutant Discharge Elimination System ("NPDES") permit compliance – This work is underway at Petersburg and Harding Street Stations for 2017 completion.
5. Continue to support Blue Indy electric car sharing program – As of summer 2016, 74 of the 200 proposed locations are complete. IPL continues to support line extensions.

9.1.2. 2016 Short Term Action Plan (2017-2019)

170 IAC 4-7-9(2) 170 IAC 4-7-9(3)

The short-term action plan covering 2017 through 2019 includes completing generation and environmental construction projects and offering DSM as shown below in Figure 9.1 and Figure 9.2, which include a timeline of the projects mentioned above and their projected costs.

Figure 9.1 – IPL 2016 Short Term Action Plan (2017-2019)

2016 Short Term Action Plan Items (2017-2019)		
Resource Changes	2017	Implement DSM proposed for 2017, seek approval for 2018-2020 DSM action plan
	2017	Complete EV CCGT Construction
	2018	Complete CCR/NAAQs-SO_2 Petersburg Upgrades
Transmission	2017	Upgrade (1) 138 kV line, replace (1) 345kV to 138 kV auto-transformer and continue long-term planning
	2018	Upgrade 3 substations, (3) 138 kV lines, and replace breakers at 2 substations and continue long-term planning
	2019	Implement projects identified in 2017 and 2018

Figure 9.2 – Short Term Action Plan Current Capital and DSM Cost Estimates

Project	Timing	Total Cost
Eagle Valley 671 MW CCGT	2014-2017	$585M
Pete NAAQS – SO_2 Pete	2016-2018	$47M
Pete CCR project	2016-2017	$49 M
Transmission Expansion	2014-2017	$36M
DSM Programs	2017	$21.4M
Blue Indy-Electric Vehicle Project	2016-2017	$3.68M
Total Costs		**$738M**

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

9.1.3. Existing Generation Environmental Upgrades

Environmental requirements for NAAQS, SO_2 and CCR require upgrades to Petersburg coal-fired units as proposed in Cause No. 44794. Subject to IURC approval, two compliance projects estimated to cost $97 million are expected to be completed by 2018.

9.1.4. Transmission

IPL's has completed construction to integrate needed transmission and substation projects for changes in resources connected to the IPL 138 kV system to ensure deliverability of power to the IPL load zone. These projects include the installation of new 345 kV breakers, autotransformers, and 138 kV capacitor banks to improve power import capability from the 345 kV system to load centers on the 138 kV system. IPL added a BESS and Static VAR Compensator ("SVC") to provide dynamic voltage and VAR support and is in the process of completing the Eagle Valley CCGT substation enhancements which will be complete by spring of 2017. Attachment 2.3 provides specific transmission project information.

9.1.5. Research & Development

IPL continually evaluates emerging technologies, new applications of technologies and contemporary methods to improve operational excellence, identify future business opportunities and enhance long-term planning. IPL is analyzing the ability to reduce the minimum generating capacity of the Petersburg units to improve efficiency and air emissions. Analysis is underway, therefore, no specific incremental capacity in terms of MWs are included in the preferred resource portfolio.

9.1.6. Demand Side Management

The IRP Short-Term Action Plan includes a forward three-year period as required by the IRP rule. IPL included a description of a fourth year of DSM plans to align with anticipated future DSM proceedings in this section.

9.1.6.1 *DSM Programs for 2017*

In Cause No. 44792 filing, IPL proposed the details of the first year (2017) of the three year short-term action plan. This filing describes the request for approval to extend the delivery of our current DSM programs for one year (indicated as "Phase I" of the Short Term Action Plan). The one year extension of DSM programs for 2017 was based on the planning completed in the 2014 IRP process. The 2017 DSM programs are expected to result in 106,056 MWh of energy savings which are included in this IRP as an offset to load. The DSM programs proposed to be offered are indicated in Figure 9.3 below.

Figure 9.3 – DSM Programs Proposed in Cause No. 44792

Programs
Residential Lighting
Residential Income Qualified Weatherization
Residential Air Conditioning Load Management
Residential Multi Family Direct Install
Residential Home Energy Assessment
Residential School Kit
Residential Online Energy Assessment
Residential Appliance Recycling
Residential Peer Comparison Reports
Business Energy Incentives - Prescriptive
Business Energy Incentives – Custom
Small Business Direct Install
Business Air Conditioning Load Management

9.1.6.2 *DSM Programs for 2018-2020*

As is described in Section 8, the Capacity Expansion Model selected six bundles of DSM measures in the Base Case which total 296,300 MWh of net energy and 45 MW of demand savings in 2018-2020. As the next step, IPL intends to include the DSM that was selected by the Capacity Expansion Model in a Request for Proposals ("RFP") for DSM program delivery for the period 2018-2020 in collaboration with the IPL Oversight Board ("DSM OSB").

In the Cause No. 44792 filing, IPL described the proposed approach to seek approval for the delivery of DSM programs in 2018-2020 (indicated as "Phase II" in testimony). The Phase II 2018-2020 DSM Plan will be consistent in terms of the energy savings and cost targets with the amount of DSM that was selected by the Capacity Expansion Model and, therefore, consistent with the 2016 IRP.

It is likely that the RFP will allow the bidders some latitude to innovate in the program designs, reflecting the fact that some of the current IPL programs (such as Home Energy Assessment) are likely nearing saturation. The bids will be evaluated and an implementation vendor will then be selected in collaboration with the IPL OSB. IPL intends to utilize the program information (program designs and estimated costs) to support a filing with the IURC seeking approval of the 2018-2020 DSM programs in early 2017.

IPL expects the resulting three year DSM plan, covering the years 2018-2020, to be filed for IURC approval near the end of the first quarter of 2017. This filing will reflect the programs and related pricing that will be identified by the bidding and contracting process. If approved, the DSM programs will allow IPL to continue to offer a broad range of cost-effective programs to our customers.

It should be noted that the 2018-2020 Market Potential Study results were adjusted to reflect decreased savings projections that result from the opt-out related reduction in customer participation in IPL's DSM programs. [85]

Following is a summary of the expected timeline for the plan development and filing seeking IURC approval for implementation of the 2018-2020 DSM Plan:

- December 2016 – Receive and review RFPs from Implementation Vendor(s) for 2018-2020 DSM Program Delivery
- December 2016 and January 2017 – Complete bid evaluations and select vendors to negotiate final pricing for DSM Program Delivery
- On or before May 31, 2017 – File 2018-2020 DSM Action Plan with the IURC for DSM program delivery approval

[85] Large customers with electrical demand greater than 1 MW are eligible to opt-out of participation in IPL's DSM programs per recent Indiana legislation as described in Section 5).

Please see Figure 9.4 for a summary of historic and future estimated DSM.

Figure 9.4 – Historic and Future Estimated DSM Summary

	Net Energy Efficiency (MWh)					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Segment	Actual	Forecast	As Requested	IRP Selected Bundles		
Residential	59,350	67,129	58,175	57,766	52,644	26,522
Business	46,327	59,878	48,151	56,638	55,073	47,664
Total	105,677	127,007	106,326	114,404	107,717	74,186
Sales	13,762,113	13,731,562	13,838,176	13,769,834	13,717,938	13,721,071
DSM as % of Sales	0.8%	0.9%	0.8%	0.8%	0.8%	0.5%

Notes: 2015 data is from the IPL Final EM&V Report, 2016 data reflects programs approved in Cause No. 44497, 2017 data reflects the programs filed in Cause No. 44792, and 2018-2020 estimates were selected in the Capacity Expansion Model in this IRP.

Although neither the ACLM programs nor the Residential Peer Comparison program was selected for the 2018-2020 time frame, IPL expects to continue to offer these programs in 2018-2020 subject to IURC approval. The Residential Peer Comparison Reports program has been very successful in driving significant energy savings and net benefits while also motivating participants to make energy-saving improvements during the past and current program cycles. The Residential Peer Comparison program, and the related PowerView® web portal, is a critical element of IPL's customer education and outreach, playing an integral role in meeting other objectives for IPL's DSM plan and providing additional benefits to customers. These benefits include heightened awareness of energy usage and efficiency opportunities, resulting in a significant increase in the number of participants and program uplift in the other IPL DSM programs. The Residential Peer Comparison report was selected for delivery in the 2021 and beyond time period. Discontinuing the program for a three year period would cause customer confusion and dissatisfaction. Given the ongoing need for and the critical nature of a web portal to provide customers with usage information and energy saving tips, it would not be practical to eliminate the Peer Comparison report for the 2018-2020 period. Therefore, for the reasons indicated above and in alignment with IPL's guiding principles to provide program delivery on a consistent basis, IPL expects to seek approval to continue to offer the Peer Comparison report in 2018 and beyond. IPL will continue to work with our program delivery partner to try to identify a program design that is cost-effective at current avoided costs.

IPL intends to retain the level of customer participation through its ACLM programs. Since the cost of customer acquisitions and switch installations are sunk costs, it is logical to maintain the existing switch population which provide significant capacity benefits. Costs for the ongoing maintenance of the ACLM program at the current level were included in the resource costs as an input to the Capacity Expansion Model. IPL will also continue to evaluate with the OSB, the replacement of a portion of the existing ACLM switch population with smart thermostats pending the completion of the current ongoing pilot is completed and evaluated in the first quarter of 2017. While the Capacity Expansion Model did not select incremental ACLM additions due to IPL's long capacity position maintaining the existing resources is cost-effective.

IPL's amount of DSM related demand and energy savings were determined by the selection of bundles by the Capacity Expansion Model. Future programs will be developed for the balance of the IRP period and presented in subsequent IURC proceedings.

9.1.6.3 *Evaluation, Measurement & Verification Process*

[170-IAC 4-7-7(b)] [170 IAC 4-7-7(c)] [170-IAC 4-7-7(d)(1)] [170-IAC 4-7-7(d)(2)]

IPL will continue to contract with an independent third-party as a utility industry best practice. To assess and evaluate demand and energy savings of IPL's DSM programs, evaluation of the IPL's programs has been performed by Cadmus and OpinionDynamics. IPL's EM&V reports have been provided to the IURC pursuant to previous decisions in Causes and are expected to continue to be provided in the next three years. Measures that were selected by the IRP modeling will be grouped into programs and then evaluated for cost-effectiveness using the four traditional California Standard Practice Methodology cost-effective tests. These include the Participant Cost Test ("PCT"), Utility Cost Test ("UCT" – sometimes referred to as the Program Administrator Cost Test or "PACT"), Rate Impact Measure ("RIM") Test and the Total Resource Cost Test ("TRC") as previously described in Section 5. A general description of the major tests, including the tests' components, is in Attachment 5.8.

9.2. Analyses Observations

170 IAC 4-7-8(b)(7)(E) 170 IAC 4-7-8(b)(8)

IPL's resource mix has undergone significant changes since the 2014 IRP with a significant decrease in coal-fired generation and increase in natural gas-fired generation which positions IPL well to continue to adapt to industry changes.

IPL notes the following observations in this IRP process:

- The results of this IRP are quite different from the 2014 IRP with more renewables in the candidate resource portfolios due to declining technology costs and the inclusion of various levels of carbon costs in the model.
- Stakeholder input has shaped the modeling process and results.
- Metrics have prompted stakeholder discussions.
- Scenario development and related economic modeling results produced varying portfolios.
- The future will vary from this snapshot analyses. The need for resource flexibility and optionality is stronger than ever in the dynamic energy market environment.
- The ultimate resource portfolio may differ from model results should assumptions vary. (For example, when Recession Economy and Strengthened Environmental portfolios were modeled with Base Case assumptions, market purchases were secured to serve retail customers over ~ 50% of the time. This high market reliance metric would likely prompt changes to reduce price risk for customers by securing additional resources.)
- Resources perform to meet the scenario parameters with varying capacity factors and may perform as baseload, intermediate or peaking resources based upon the scenario assumptions.
- Stakeholders suggested that economic impacts in terms of existing businesses' viability and unemployment rates should be considered when assessing customer cost variances between portfolio options. IPL has not included this level of analysis in this IRP but is open to considering ways to do so in the future.
- Stakeholders have inquired about job creation opportunities with changing resources. During construction phases, short term jobs increase, but renewable resources require fewer people to operate throughout the life of the asset. IPL has not included this level of analysis in this IRP but is open to considering ways to do so in the future.

- IPL expects to continue collaborative discussions about environmental impacts of candidate resource portfolios in future IRP public advisory forums.

IPL recognizes the level of uncertainty involved in making long-term resource decisions. Therefore, the IRP scenarios were developed to result in a diverse set of portfolios that captured as much variability in future outcomes as possible. Additionally, the probabilistic sensitivity analysis provided insight into how each of these portfolios performed across a set of futures with varying market prices, commodity prices, and other variables. The end result of both the scenario-based Capacity Expansion Model and the stochastic sensitivity model was a thorough look at how candidate resource portfolios will perform over time and how each portfolio will respond to changes.

The Base Case portfolio was the lowest cost plan on a risk-adjusted basis. However, IPL recognizes that while the IRP process identified and quantified uncertainty in the marketplace, it is difficult to capture and model all of the factors that may affect the resource portfolio performance in the future. For example, new legislation or regulations, acceleration in the decrease in technology costs beyond the current forecast, and new demand-side technologies and their economics are difficult to model. Therefore, the identification of a Hybrid Preferred Resource Portfolio is a recognition that future changes in the industry are certain, and IPL will be ready to react to those changes and make the best decision possible for the customer.

Continuing to operate the Petersburg coal-fired units provides flexibility in the short-to mid-term and allows customers to benefit from low-cost baseload energy and capacity. Results from the Strengthened Environmental and High Adoption of DG scenarios indicate that stricter environmental policy and changing customer preferences for the source of their power may result in a change in the lowest cost resource alternative to additional renewable technology, gas-fired generation, and/or demand-side resources.

The Hybrid Preferred Resource Portfolio provides opportunities to react quickly and prudently to changing market conditions. By remaining online with coal as the primary fuel source, the Petersburg units retain their option value early in the study, and opportunities to refuel or retire remain available. The Base Case included all four units running through their expected life; however, low load, low natural gas prices, high environmental costs, or a combination of these items could change the economics on these plants, which was observed in the results of three of the six modeled scenarios. Should some or all of these factors come to fruition, IPL may respond quickly by increasing DSM, retiring individual units, converting fuel sources on a unit by unit basis, adding solar and wind resources incrementally, or a combination of these actions. The IPL recently demonstrated nimble resource portfolio changes by converting the Harding Street units. The analysis and flexibility lessons of these actions would be applied should this be necessary.

The resource mix identified in the hybrid portfolio provides additional benefits in terms of flexibility. Traditional resource planning that involved large, centralized thermal generation changes is lumpy, which means that temporary shortfalls or long positions occurred due to the size of the units and the lead time required to build those units. Outside of the amount of gas-fired generation required to meet reliability standards, the resources selected in the future for all scenarios involved a mix of wind, solar, batteries, and demand-side resources. All of these resources are smaller and more modular, require less lead time for construction and allow for greater flexibility in reacting to changing market conditions.

In summary, the Hybrid Preferred Resource Portfolio provides the right mix of resource types that minimizes cost and risk for the customer, allows for flexibility in the response to future market changes, and provides balance to the portfolio in terms of cost, environmental impact, and risk.

9.2.1. Response to Stakeholder Feedback

As described in Section 1, IPL made significant changes in the 2016 IRP based upon feedback following its 2014 IRP submission. These changes include more robust risk analysis through probabilistic methods, reviewing and updating load forecasting correlations and assumptions, modeling DSM as a selectable resource, incorporating DG more fully, and enhancing stakeholder engagement.

IPL appreciates the commitment of time and energy stakeholders made to participate in its public advisory process. The discussions were helpful to improve understanding of various points of view and shape a more thorough analysis.

Throughout this process, IPL sought stakeholder input and feedback and incorporated this as much as possible. In response to stakeholder requests in the fourth public meeting, this summary was created to reflect how IPL incorporated feedback in the 2016 IRP.

1. IPL invited stakeholders to present their points of view in the second stakeholder meeting. Representatives from four interested parties presented materials which are included in the meeting materials posted on https://www.iplpower.com/irp/.
    a. A representative from the local National Association for the Advancement of Colored People ("NAACP") suggested IPL integrate energy burden and social equity elements into its IRP. IPL participated in follow-up discussions with NAACP leaders and explained limits to doing so in the IRP process and welcomed opportunities to further this discussion in other forums. Candidate resource portfolio emission metrics were included for each scenario in this IRP.

b. A scientist from IU Fairbanks School of Public Health presented information about climate change threats. IPL included a range of costs for CO_2 impacts as modeling inputs in this IRP.

c. A representative from Hoosier Interfaith Power & Light ("HIPL") discussed values which guide resource decision making and asked specific questions about DSM program coordination with HIPL and a specific proposed multi-family rooftop solar project. IPL makes decisions guided by core values including strong ethics and acting with integrity. In the IRP process, assumptions and guiding principles, as well as results were shared transparently. IPL conducted follow-up discussions with HIPL to review DSM program coordination options and project details.

d. A representative from Sierra Club cited IPL's recent conversion of coal-fired units to natural gas and shared a letter from a physician in southern Indiana related to patient health issues from poor air quality. She encouraged IPL to integrate clean sources of energy in its resource portfolio as quickly as possible. IPL included DSM from its local Market Potential Study ("MPS") and renewable resources with declining technology costs, as described in Section 5, as selectable resources in this IRP. DSM resources were selected in all scenarios, and wind, solar and batteries were selected in five of the six scenarios.

e. IPL shared a summary of the topics presented at this meeting with its Advisory Board to raise awareness and seek additional feedback. One Advisory Board member coordinated follow-up discussions with the NAACP.

2. Scenarios were developed and adapted based on stakeholder input. For example, the Recession and Robust Economy assumptions about gas and market prices were modified to include low and high variations upon stakeholder request. The Quick Transition scenario was created and then revised based on stakeholder feedback from exercises and discussions as described in Section 7.

3. Metrics to compare portfolios were developed with stakeholder input, including an exercise in which stakeholders weighted the metrics to show which one they felt were the most important. This resulted in additions and changes. For example, meeting participants suggested adding environmental emissions in addition to CO_2, and requested rate impacts to be reported in 5 year increments in addition to the 20 year time period, which IPL did as described in Sections 7 and 8.

4. IPL corrected some slide materials following questions from stakeholders.

5. Based on the stakeholder feedback about the need to engage with large customers, IPL reached out and met with several C&I customers to gain their insights about the

framework for strategic process and metric prioritization. In addition, IPL met with Citizens Energy three times to discuss planning and the potential for future coordination and demand response programs.

6. Upon request of stakeholders, IPL modified the presentation of Capacity Expansion results, DSM in terms of MWhs in addition to program spend, and PVRR values on a zero scale.

7. Following stakeholder requests, IPL prepared unit by unit comparisons for Petersburg and EV CCGT as shown in Section 5.

8. During the fourth public IRP public advisory meeting, a stakeholder asked if IPL considered vanadium flow batteries as a potential resource. IPL's subsequent research indicates this technology has significantly higher costs at this time. This resource was not modeled in this IRP. See http://www.sandia.gov/ess/tools/es-select-tool/ for detailed technology cost information.

9. In early October 2016, a stakeholder requested IPL model EE at a level of 2% of sales per year as a scenario. IPL was not able to fulfill this request. This input alone would not define a scenario which needs to include assumptions for load forecast, fuel and market price forecast, environmental assumptions, etc. Also, the proposed level of EE exceeds the maximum achievable DSM from the IPL Market Potential Study prior to 2034. This approach is directly opposed to IPL's commitment to model DSM as a selectable resource as suggested by many stakeholder in comments related to IPL's 2014 IRP. IPL provided the graphical representation of the maximum achievable DSM from the Quick Transition scenario which had been presented in Meeting 4.

An energy industry colleague described the IRP stakeholder process as a horse race where each stakeholder wants their horse to win. Of course, only one horse does win, so the majority of stakeholders are not happy. IPL recognizes that not all stakeholders are pleased with the results of the candidate portfolios but hopes that stakeholders found the process to be transparent, well-supported, and understandable.

9.3. Expectations for future improvements

IPL plans to continue its effort to improve its IRP process and has identified the following items to do so.

1. Refine demand side resource modeling – IPL recognizes the newness of DSM modeling in the IRP and expects this to evolve in subsequent IRPs. The following steps are anticipated as part of a continuous improvement process.

    a. Review other IRPs to assess similarities and differences in methodologies and potential improvements.
    b. Complete a North American Industry Classification System ("NAICS") code audit of IPL customer accounts to improve the accuracy of business classifications for purposes of DSM planning and tracking.
    c. Develop process to use Advanced Metering Infrastructure ("AMI") data for more robust forecasting and variance analysis. IPL recognizes the ability to enhance the load forecast and DSM planning processes through more granular analysis of interval data. There may also be ways to incorporate load research data into the forecasting process as well.
    d. Review DSM RFP results to assess potential future programs and bundling. IPL looks forward to reviewing RFP results for DSM programs in 2018-2020 to understand creative approaches to program design and bundling DSM resources.

2. Refine supply-side resource modeling through the following steps:

    a. Research wind congestion modeling and analyses options. Reviewing congestion studies and identifying trends and criteria are expected.
    b. Enhance transmission analysis to consider ways to support more renewables. IPL anticipates analyzing ways to decrease transmission system import limitations while accounting for holistic benefits.
    c. Refine requirements of a new wind asset with complimentary BESS and capacitor assets. IPL intends to work with colleagues from the AES Distributed Energy and Battery Storage groups to determine ways for new wind to meet requirements in the FERC proposed rulemaking to include grid service capability.
    d. Analyze the operation and benefits of collocated batteries and renewables. IPL intends to work with colleagues from the AES Distributed Energy and Battery Storage groups to better understand optimal combinations of renewables and storage leveraging their growing experience.
    e. Assess the ability to ramp units down to lower minimums to reduce carbon/environmental impacts. As mentioned above in the R&D action item, IPL

intends to understand options to reduce minimum generation levels to manage carbon emissions while optimizing capacity value of existing assets.

3. Continue stakeholder engagement between IRP periods.
   a. Conduct 2016 IRP review session. IPL intends to schedule a stakeholder review meeting to address questions following the November 1, 2016 filing for early 2017, prior to the IURC stakeholder comment filing deadline.
   b. Post annual status updates of Short Term Action Plan items to IPL's website and highlight significant changes in the business environment compared to assumptions as suggested by stakeholders.
   c. Plan to begin stakeholder scenario development discussions early in the next IRP process.
   d. Continue policy discussions with open questions such as:
      - How can IPL best meet the future needs of customers cost-effectively while minimizing environmental impacts?
      - How can IPL optimize existing assets while minimizing long-term environmental effects?
      - How can customers afford increasing costs? Residential? Non-residential?

Stakeholders also suggested the following topics for future IRP stakeholder education sessions:

- Consider societal impacts such as community and local economy, pollution burden, impact on local jobs and low-income customers.
- Basic modeling information
- Risk profile information
- Recent trends and fuel price forecasts
- Advanced Metering Infrastructure ("AMI")
- Co-located batteries and wind (e.g. AES Laurel Mountain)

Section 10: Attachments

Public Attachments are available in Volumes 2 & 3 of the IRP Report

Attachment 1.1 (IPL 2016 IRP Non-Technical Summary) **170 IAC 4-7-4(a)**

Attachment 1.2 (Public Advisory Meeting Presentations) **170 IAC 4-7-4(b)(14)**

Attachment 2.1 (ABB 2016 Integrated Resource Plan Modeling Summary) **170 IAC 4-7-4(b)(11)(B)(ii)**

Confidential Attachment 2.2 (ABB Modeling Summary – Confidential Version) **170 IAC 4-7-4(b)(11)(B)(ii)**

Attachment 2.3 (Transmission and Distribution Estimated Cost)

Attachment 3.1 (Smart Grid 2015 Annual Report)

Attachment 3.2 (V2G 2016 Report)

Attachment 3.3 (Rate REP Projects and Map)

Attachment 4.1 (Load Research Narrative) **170 IAC 4-7-4(b)(3)**

Attachment 4.2 (2015 Hourly Load Shapes by Rate and Class) **170 IAC 4-7-4(b)(3) 170 IAC 4-7-5(a)(1) 170 IAC 4-7-5(a)(2)**

Attachment 4.3 (Itron Report 2016 Long-Term Electric Energy and Demand Forecast Report)

Confidential Attachment 4.4 (EIA End Use Data) **170 IAC 4-7-4(b)(4) 170 IAC 4-7-5(a)(8)**

Attachment 4.5 (End Use Modeling Technique) **170 IAC 4-7-4(b)(4) 170 IAC 4-7-5(a)(8)**

Attachment 4.6 (10 Yr. Energy and Peak Forecast) **170 IAC 4-7-5(a)(9)**

Attachment 4.7 (20 Yr. High, Base and Low Forecast) **170 IAC 4-7-5(a)(9)**

Confidential Attachment 4.8 (Energy–Forecast Drivers) **170 IAC 4-7-4(b)(2) 170 IAC 4-7-5(a)(2) 170 IAC 4-7-5(a)(3) 170 IAC 4-7-5(a)(6) 170 IAC 4-7-5(a)(9)**

Attachment 4.9 (Energy Input Data–Residential) **170 IAC 4-7-4(b)(2) 170 IAC 4-7-5(a)(9)**

Attachment 4.10 (Energy Input Data–Small C&I) **170 IAC 4-7-4(b)(2) 170 IAC 4-7-5(a)(9)**

Attachment 4.11 (Energy Input Data–Large C&I) **170 IAC 4-7-4(b)(2) 170 IAC 4-7-5(a)(9)**

Attachment 4.12 (Peak–Forecast Drivers and Input Data) **170 IAC 4-7-4(b)(2) 170 IAC 4-7-4(b)(3) 170 IAC 4-7-4(b)(13) 170 IAC 4-7-5(a)(6)**

Attachment 4.13 (Forecast Error Analysis) **170 IAC 4-7-5(a)(7)**

Attachment 5.1 (Supply Side Resource Option Cost Chart)

Confidential Attachment 5.1 (Supply Side Resource Option Cost Chart)

Attachment 5.2 (Modeling Parameters – Generic CHP, May 20 2016)

Confidential Attachment 5.2 (Modeling Parameters – Generic CHP, May 20 2016)

Confidential Attachment 5.3 (AES Proprietary Battery Cost Information)

Attachment 5.4 (IPL LGP Committee)

Attachment 5.5 (2017 DSM Action Plan) **170 IAC 4-7-6(b)(1)**

Attachment 5.6 (IPL 2016 DSM MPS) **170 IAC 4-7-4(b)(4) 170 IAC 4-7-6(b)(3)* 170 IAC 4-7-6(b)(4)* 170 IAC 4-7-6(b)(5)* 170 IAC 4-7-6(b)(6)* 170 IAC 4-7-6(b)(7)* 170 IAC 4-7-6(b)(8)***

Attachment 5.7 (DSM Cost Test Components and Equations) **170 IAC 4-7-7(d)(1)**

170 IAC 4-7-7(d)(2)

Attachment 5.8 (Standard DSM Benefit Cost Tests) **70 IAC 4-7-7(d)(1)**

170 IAC 4-7-7(d)(2)

Confidential Attachment 5.9 (Loadmap DSM Measure Detail) **170 IAC 4-7-7(c)***

Confidential Attachment 5.10 (Avoided Cost Calculation) **170 IAC 4-7-4(b)(12) 170 IAC 4-7-6(b)(2) 170 IAC 4-7-8(b)(6)(C)**

Confidential Attachment 7.1 (Confidential Figures in Section 7)

Attachment 8.1 (Load Resource Balance by Scenario)

Attachment 8.2 (DSM Savings and Costs) **170 IAC 4-7-6(b)(1) 170 IAC 4-7-6(b)(3) 170 IAC 4-7-6(b)(4)* 170 IAC 4-7-6(b)(5)* 170 IAC 4-7-6(b)(6)* 170 IAC 4-7-6(b)(7)* 170 IAC 4-7-6(b)(8)***

Confidential Attachment 8.3 (ABB Results) **170 IAC 4-7-8(b)(6)(A)**