STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY THROUGH IPL'S EXISTING STANDARD CONTRACT RIDER NO. 22 OF ASSOCIATED COSTS INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	)	**CAUSE NO.** 44945

PETITIONER'S SUBMISSION OF ADMINISTRATIVE NOTICE DOCUMENT

Indianapolis Power & Light Company ("IPL" or "Petitioner"), by counsel, hereby submits the following document, for which IPL is seeking Administrative Notice:

1. IPL's 2016 Integrated Resource Plan, filed November 1, 2016, including corrections filed November 21, 2016.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the forgoing was served by electronic transmission on the following:

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Dated this 17th day of May, 2017

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Indianapolis Power & Light Company

2016 Integrated Resource Plan

Public Version

November 1, 2016

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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		
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(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
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(b)(8) emissions allowance inventory and procurement	170 IAC 4-7-4(b)(8)	Section 7.3.1
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(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
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(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
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(b)(11)(B)(iv) transmission & generation reliability	170 IAC 4-7-4 (b)(11)(B)(iv)	Section 2.3.1
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(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		
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(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
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(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
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(a)(6) demand-side programs	170 IAC 4-7-6(a)(6)	Sections 5.1.2, 5.5, 8.1.2
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(b)(4) DSM impact projections	170 IAC 4-7-6(b)(4)*	Attachment 5.6, Confidential Attachment 8.2
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(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

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(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
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(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
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(b)(4) utilization of all resources	170 IAC 4-7-8(b)(4)	Section 8.4.2
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(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
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(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

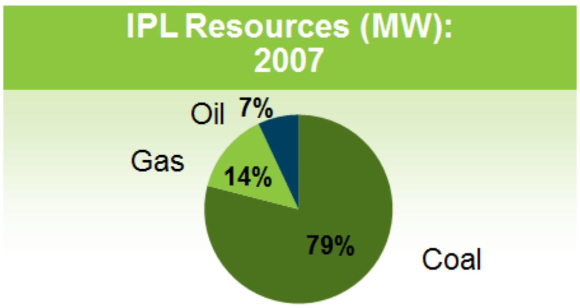
IPL provides retail electric service to more than 480,000 residential, commercial and industrial customers in Indianapolis and surrounding central Indiana communities and fully participates in the electricity markets managed by MISO.

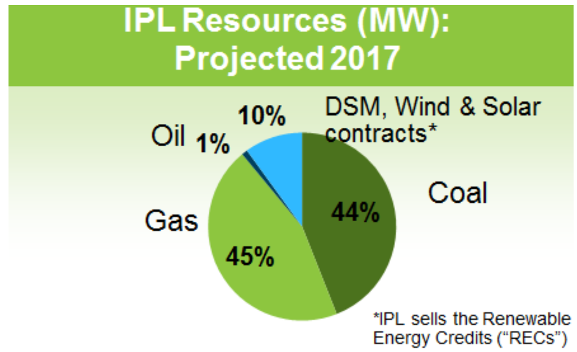
IPL owns and efficiently operates approximately 2700 MW of generation, including 1100 MW natural gas fired and 1700 MW of coal, is in the process of constructing 671 MW CCGT, supports 58 MW of DSM resources, and secured PPAs for approximately 96 MW of solar generation and approximately 300 MW of wind 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

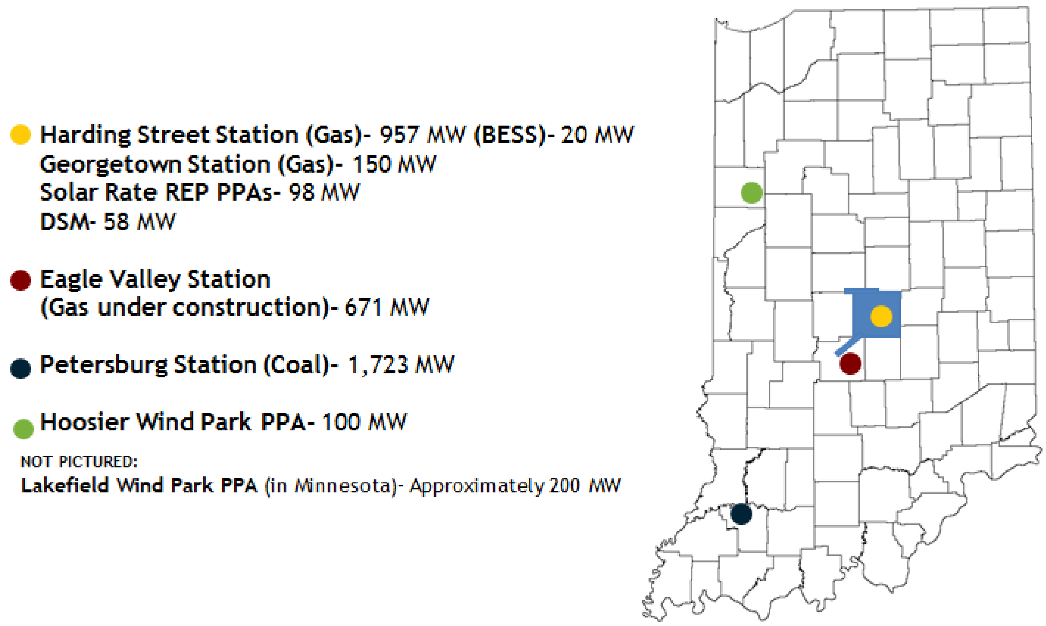




IPL prepared for Environmental Protection Agency ("EPA") regulations to improve air emissions and water quality by investing $1.4 billion in environmental controls and new generation. This investment program is expected to reduce SO2, NOx, mercury and particulate matter by over 50 percent in 2017 compared 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.

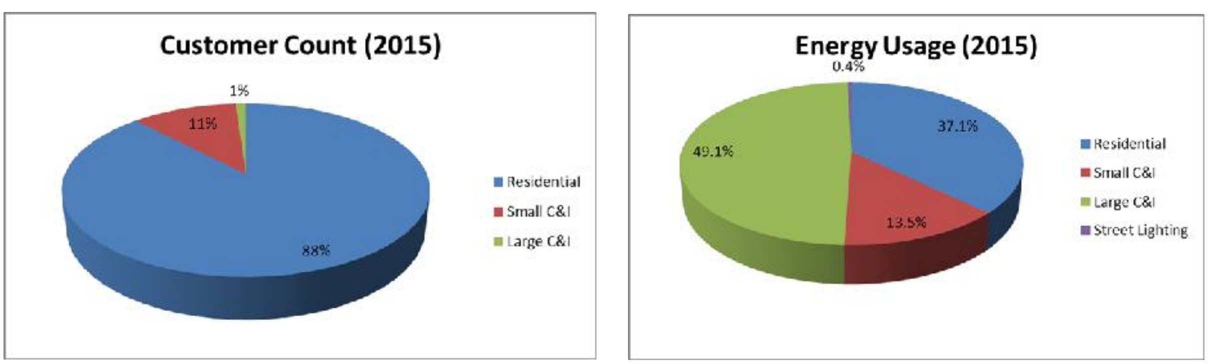
of its attributes and undifferentiated. No specific rights to claim fuel source or environmental impacts are allowed for null electricity. Also referred to as commodity or system electricity."

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.

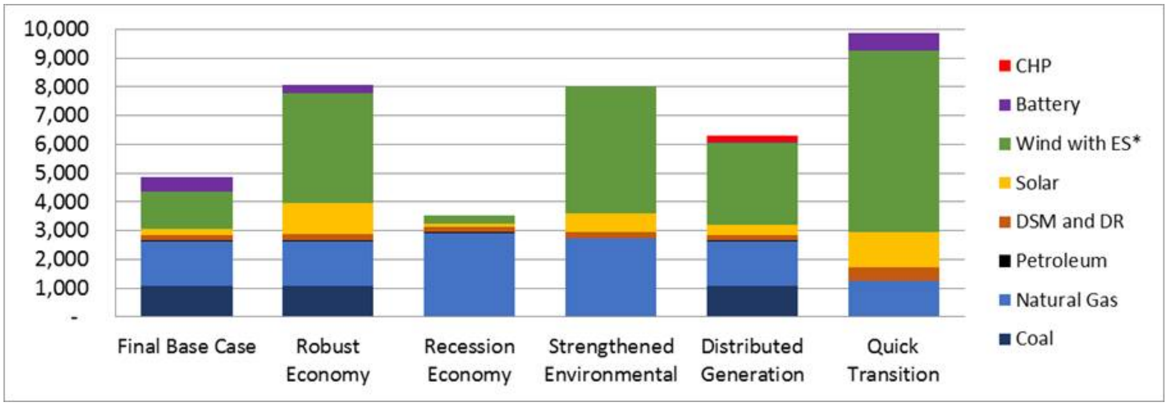
A base case was defined to only reflect a continuation of the status quo without significant changes in resources, regulations or customer use. Specific base case assumptions were modified to create the six scenarios in this IRP shown in Figure D below.

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.

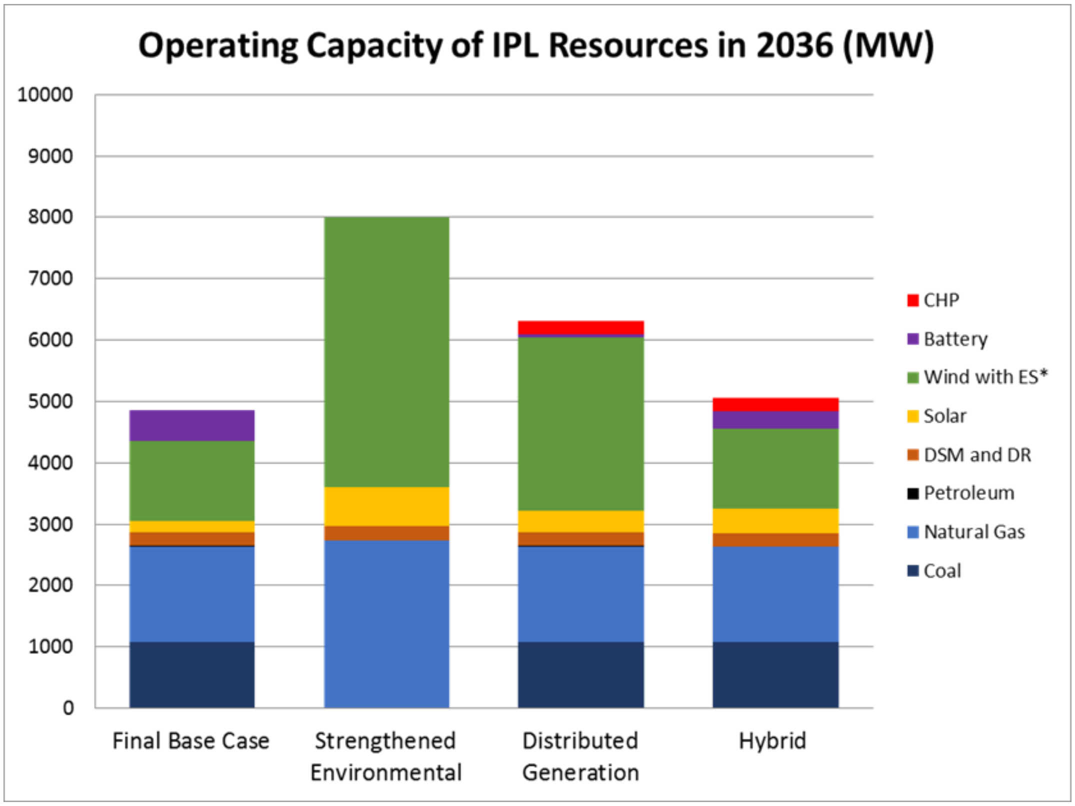
Under this scenario, a hybrid portfolio in 2036 could include two Pete coal units (although these units would not necessarily serve as baseload generation but could be utilized more as a capacity resource), natural gas generation focused on local system reliability, wind to serve load during non-peak 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

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[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.

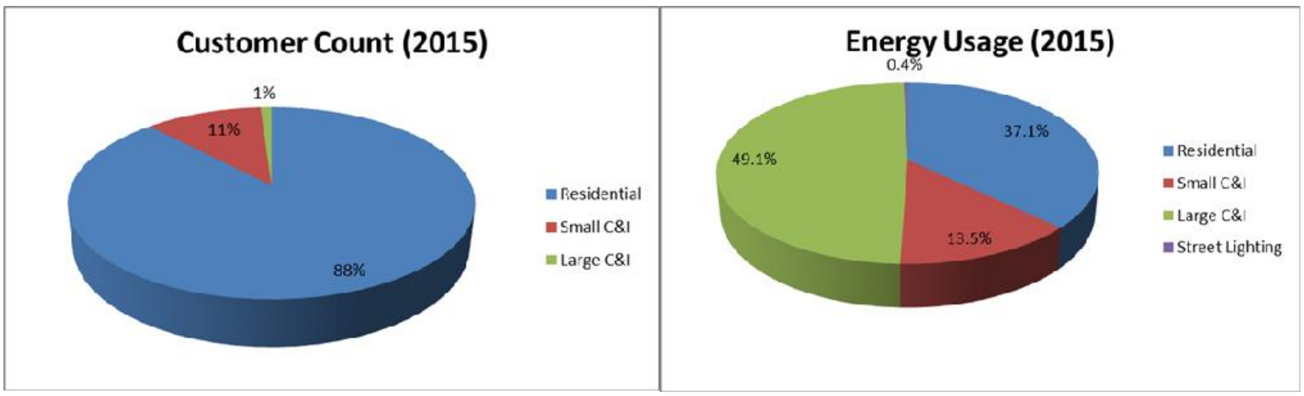
burdened communities, and use of an economic equity analysis to determine costs versus benefits.

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.

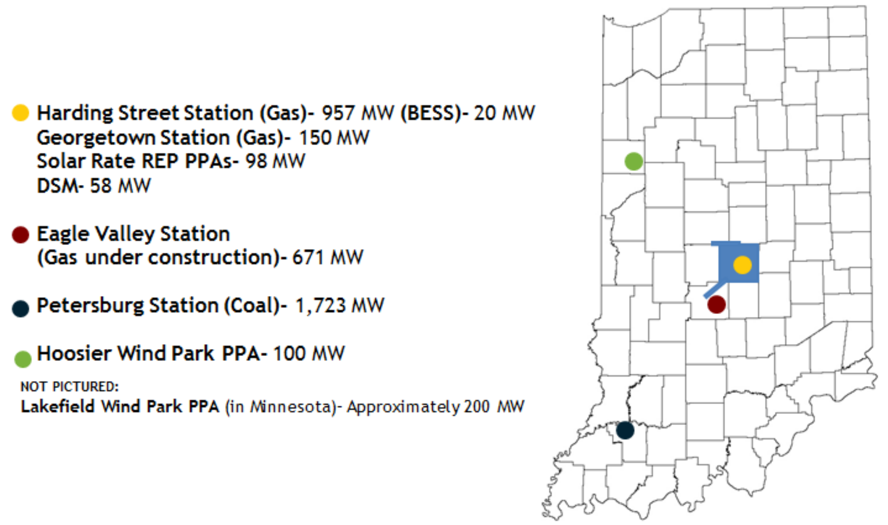
(3) The Georgetown Generating Station in Indianapolis, Indiana, includes two natural gas fired combustion turbines.

(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").

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[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

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[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.

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[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).

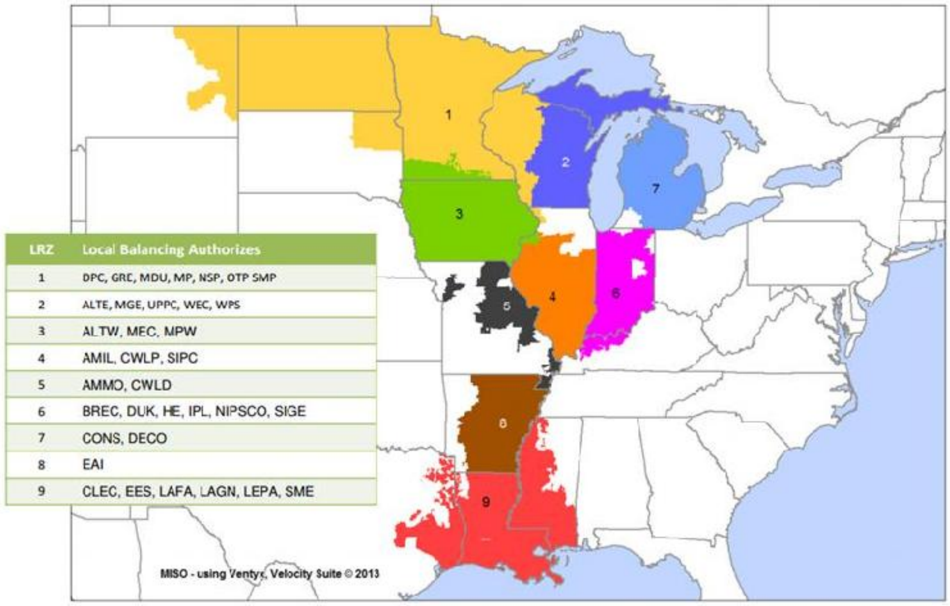
Because units with favorable availability are more likely to contribute more MWs during peak load periods than units with historically less favorable availability the ICAP MWs are adjusted based on their 3 year xEFORd ratings. ICAP MWs are multiplied by one minus the 3 year historic xEFORd rating to 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



MISO

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.

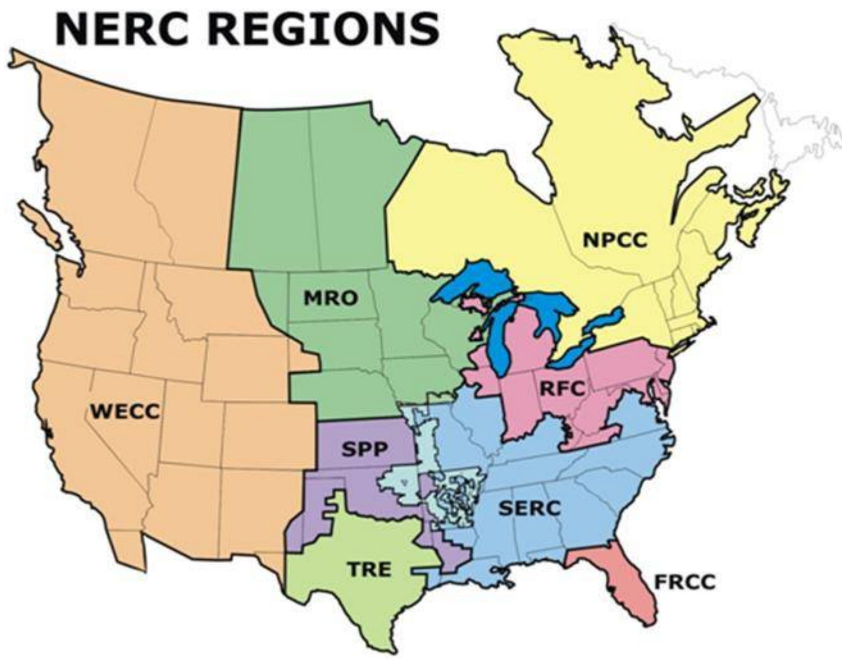
System congestion is analyzed through the MISO MTEP process. As part of the process, a Top Congested Flowgate Analysis is performed by MISO to identify near-term system congestion. A Congestion Relief Analysis is also performed to explore longer-term economic opportunities. The Market Efficiency Planning 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

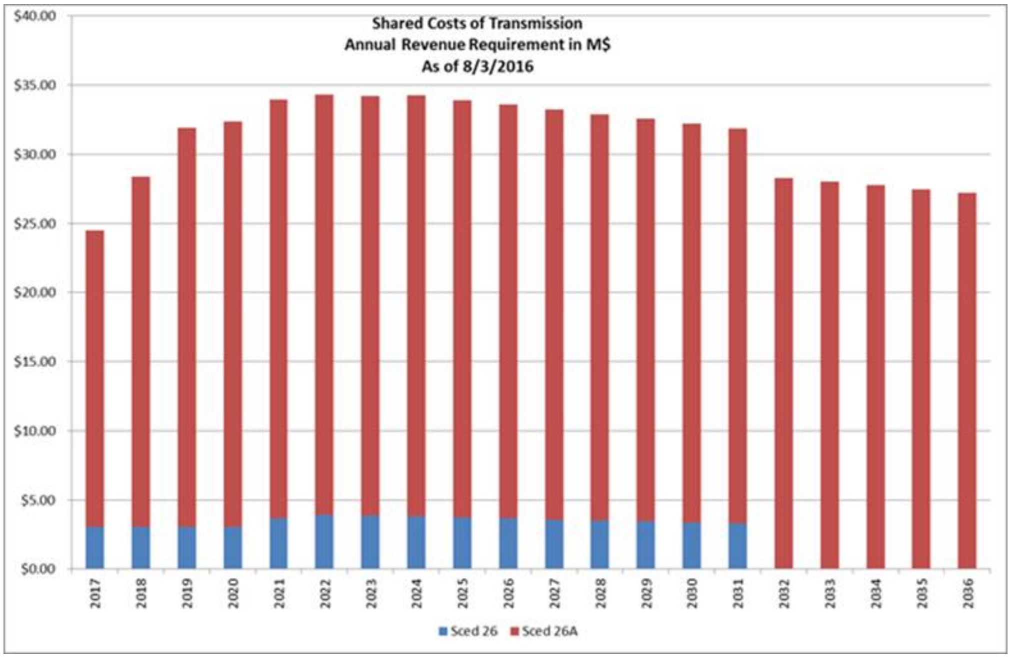
170 IAC 4-7-6(a)(5) 170 IAC 4-7-6(d)(3)

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	2,203	Guion South
2018	345-138 kV XFMR	2,402	345-138 kV XFMR
Breaker Failure			
2016	Guion North	2,004	Guion South 345-138 kV XFMR &
2018	345-138 kV XFMR	2,203	Guion to Rockville 345 kV line
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

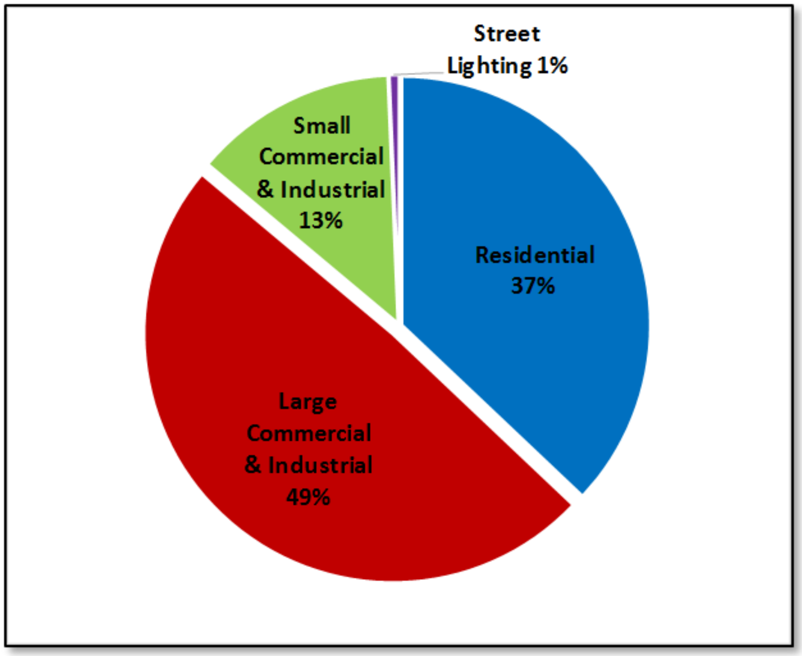
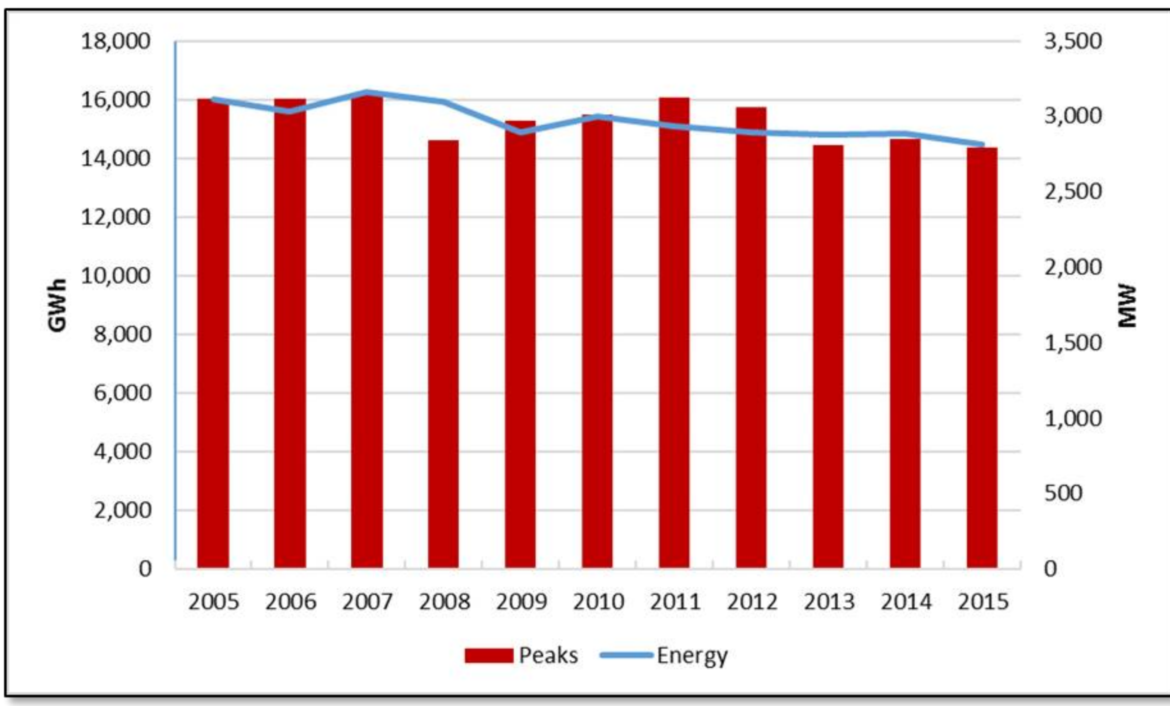


Figure 4.2 – IPL Historic System Energy Requirements 2005 – 2015



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 above 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*]

[21] Future DSM program savings refers to the amount of DSM that the Capacity Expansion Model selects.
[*] Figure 4.3 was an inadvertent duplication of Figure 4.2 and has been removed, with the remaining Section 4 numbering remaining as filed.

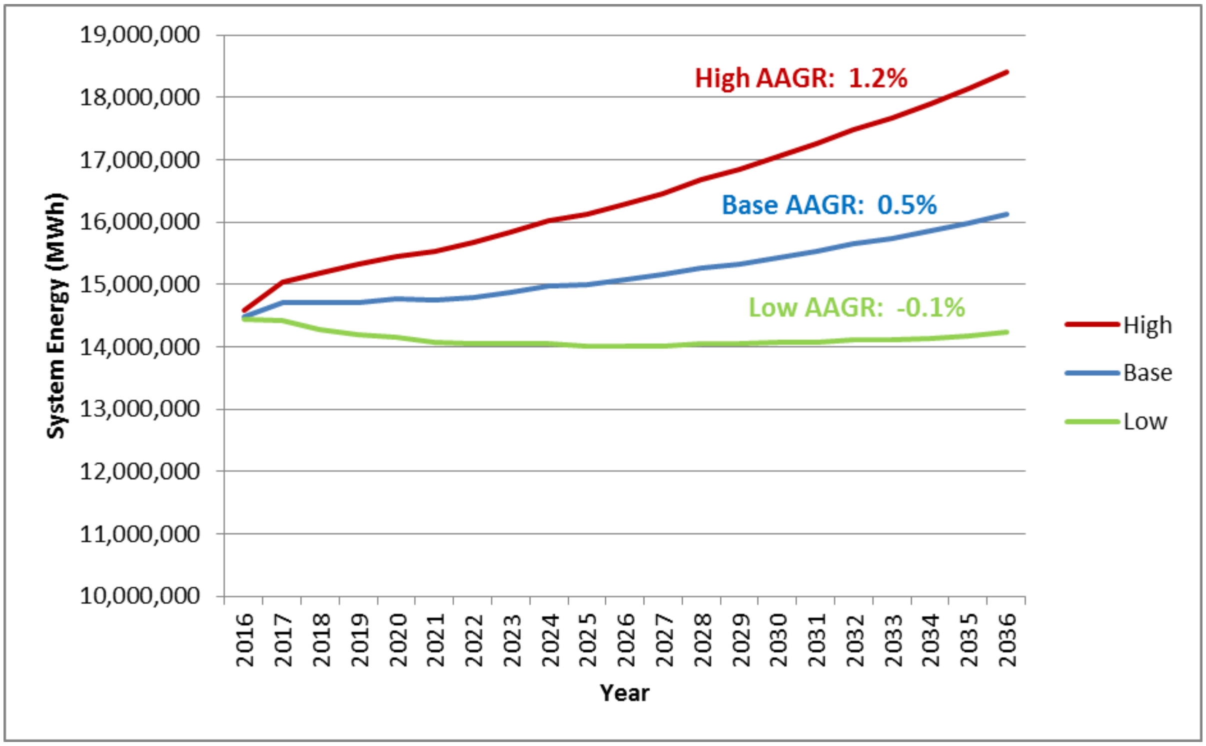
Figure 4.4 – Base Energy and Peak Forecast (2016-2037)

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

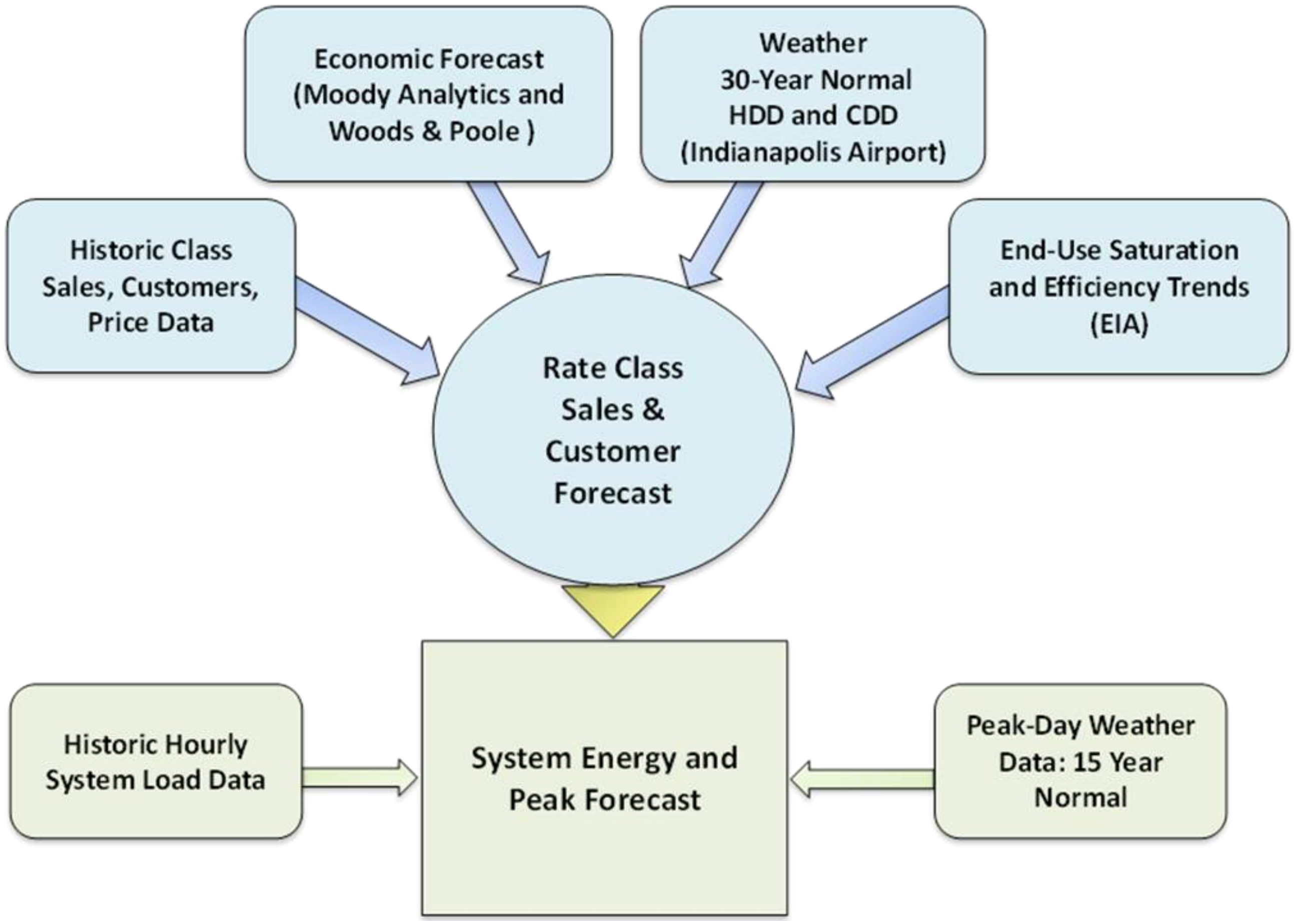
170 IAC 4-7-4(b)(4) 170 IAC 4-7-4(b)(11) 170 IAC 4-7-5(a)(5)

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 not 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.”

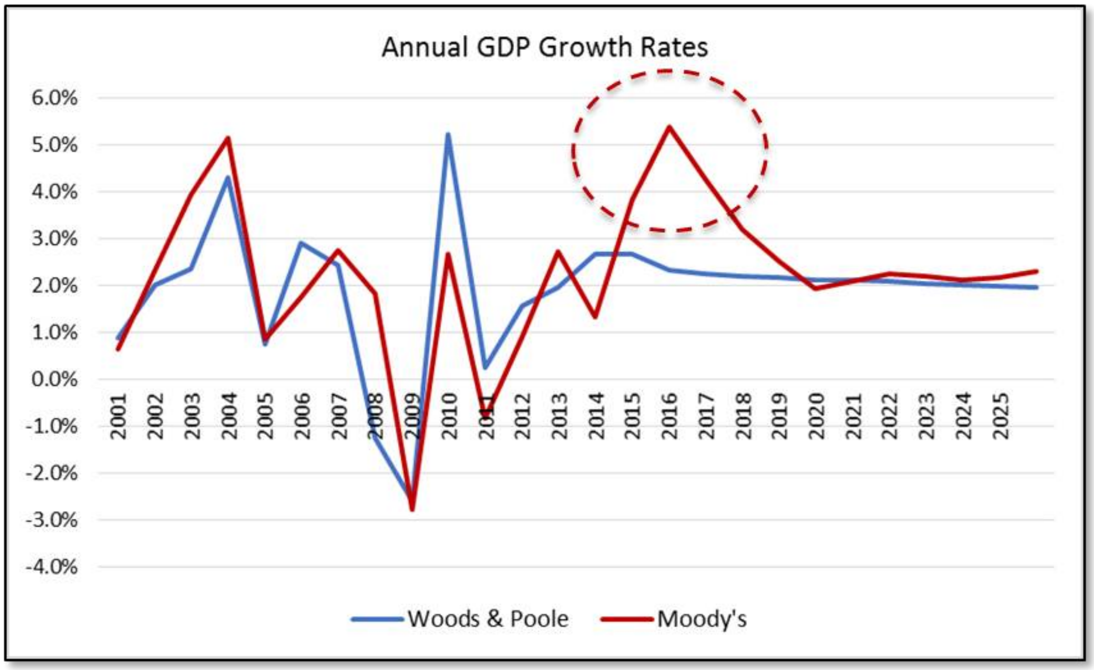
“The high case forecast is based on Moody Analytics “stronger near-term rebound” scenario for the Indianapolis MSA. In this scenario output is projected to average 3.5% annual growth through the forecast period. The low case is based on Moody Analytics “protracted slump” scenario.” In “slump” scenario 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.

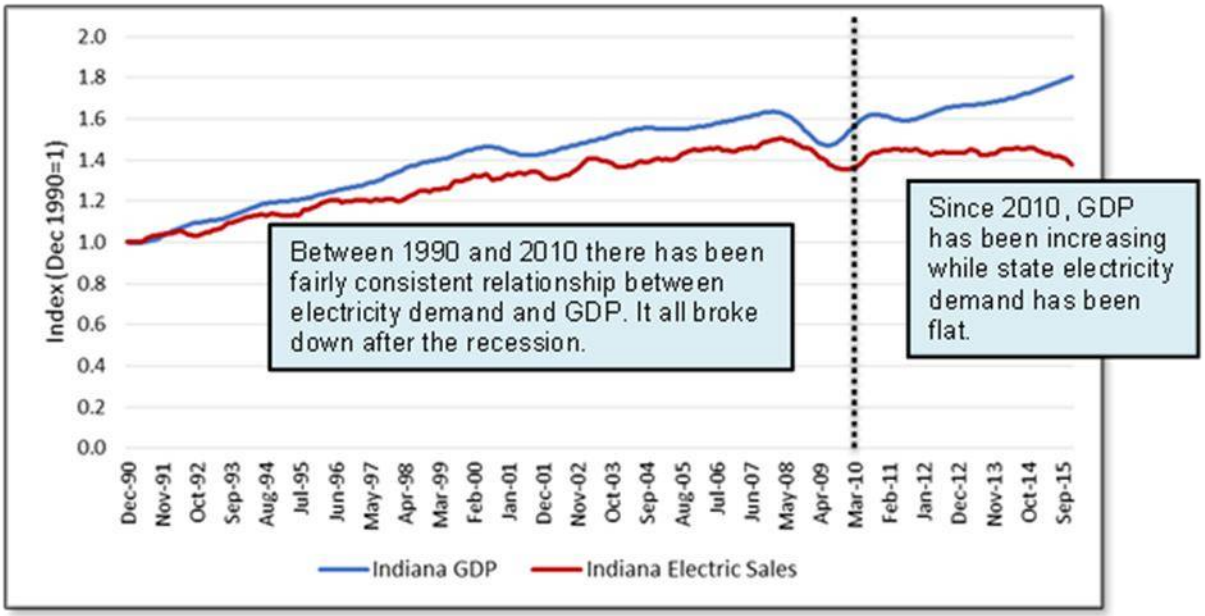
Figure 4.7 – Moody's and Woods & Poole Annual GDP Growth Rates



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

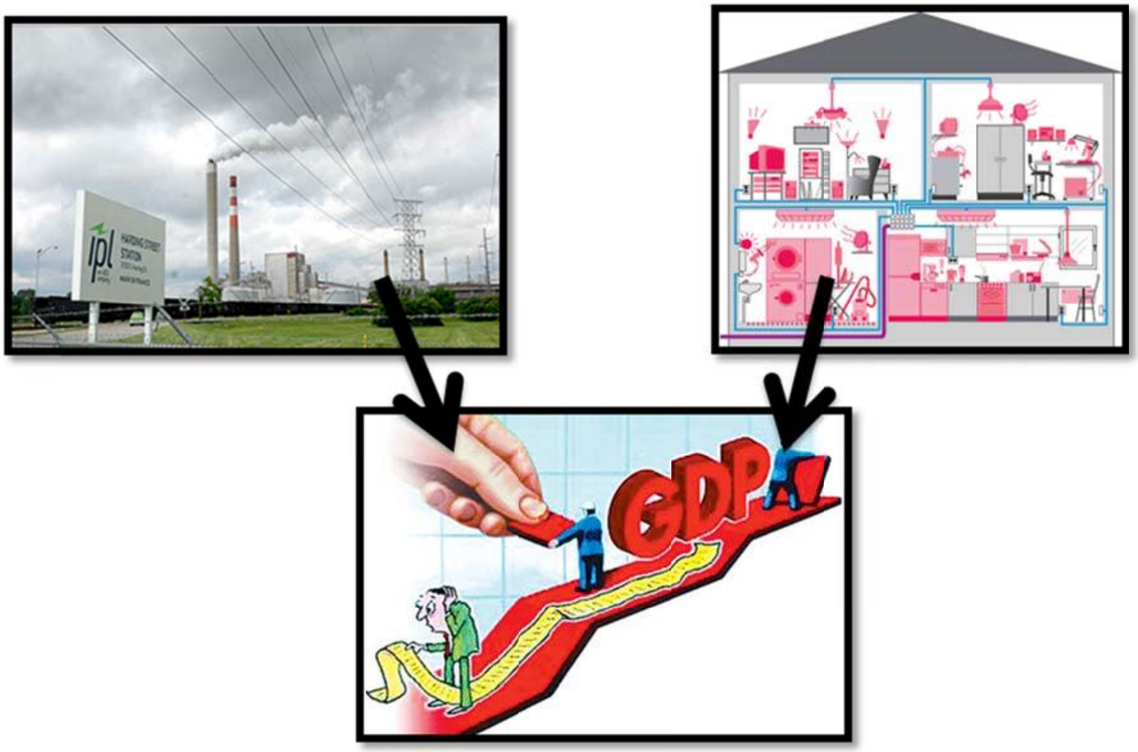


As illustrated in Figure 4.8 above, the relationship between GDP and electric sales is correlative and not causal. Electric sales act as an input into calculating GDP in addition to the products that we buy and use in our homes. While customers are buying more of these products than ever before, the 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 4.8 – Utility sales and consumer products as inputs into GDP



4.5. Key Forecast Drivers by Sector

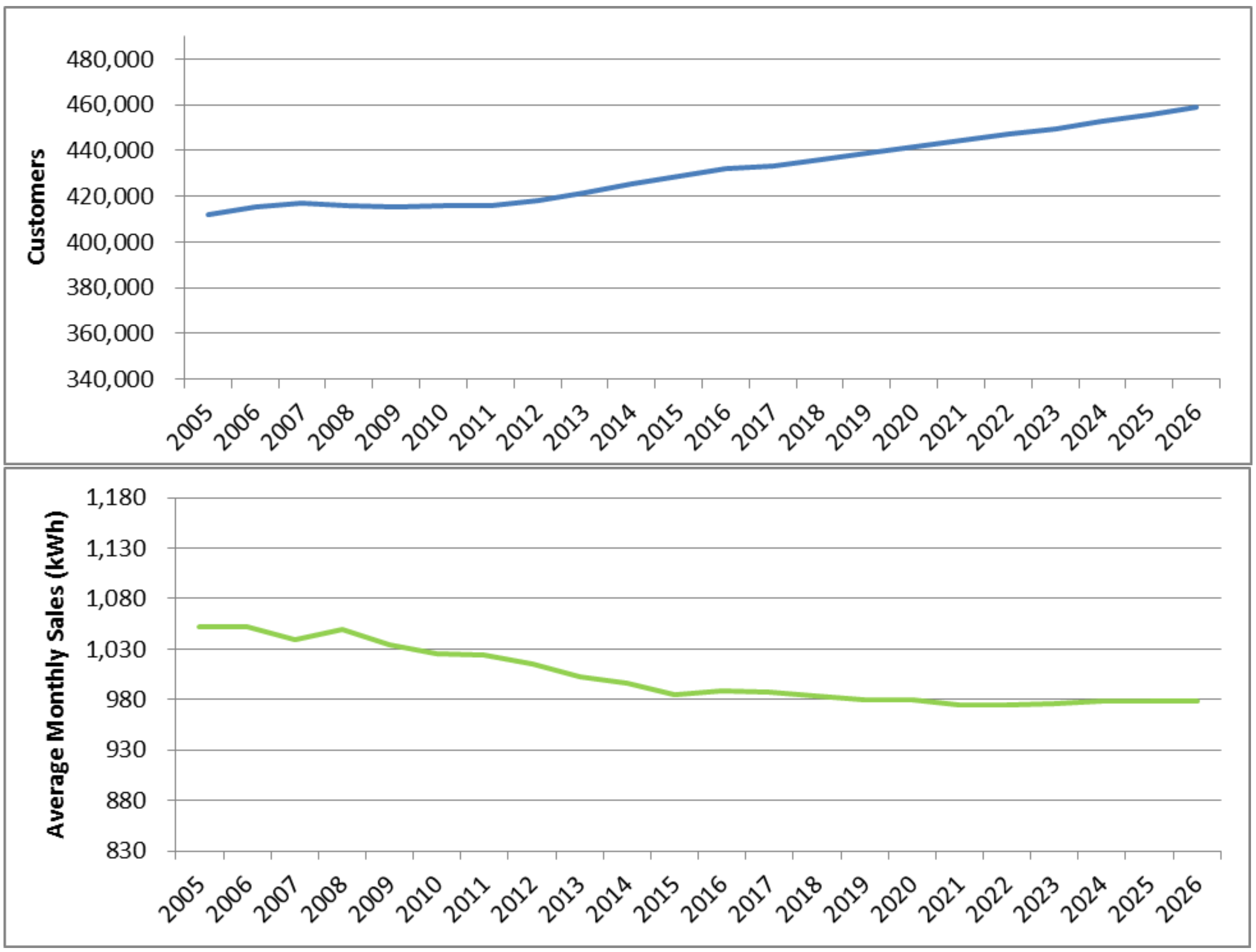
This section provides an overview of the drivers and trends in each of the three IPL customer sectors – Residential, Small C&I and Large C&I. The forecast summaries and charts have not been adjusted downward to demonstrate the impacts of the DSM selected by the Capacity Expansion Model in the IRP Base 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)

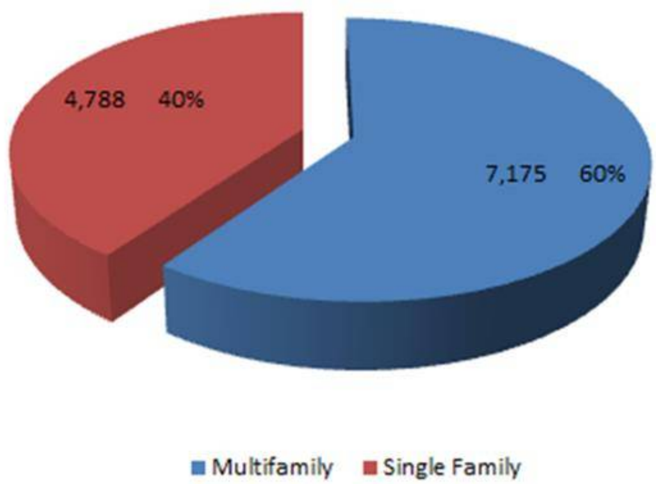
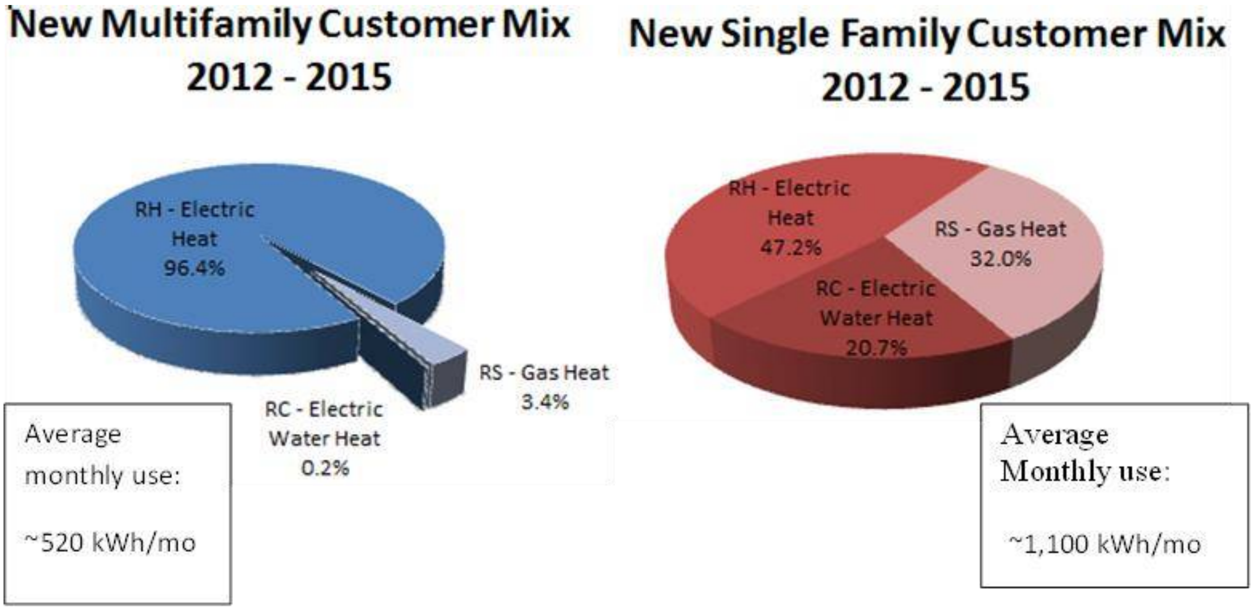


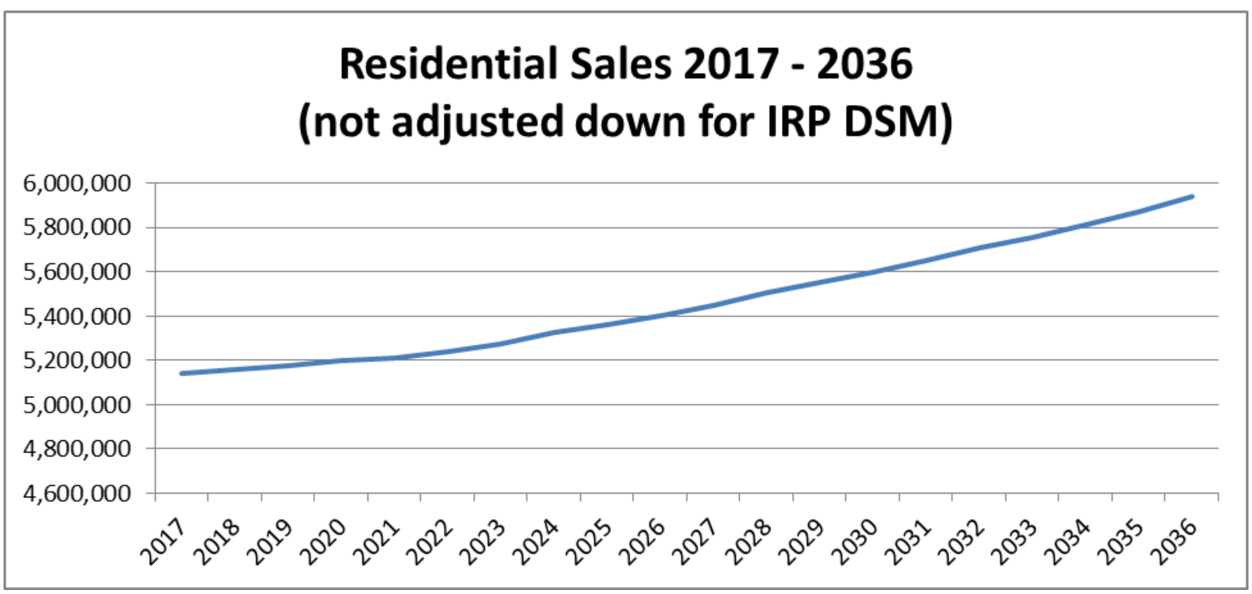
Figure 4.12 presents the mix of heating types from these new multifamily and single family customers. Because the majority of the new multifamily construction is occurring in downtown Indianapolis where gas service connections are more costly due to working around existing infrastructure, 96% of the 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

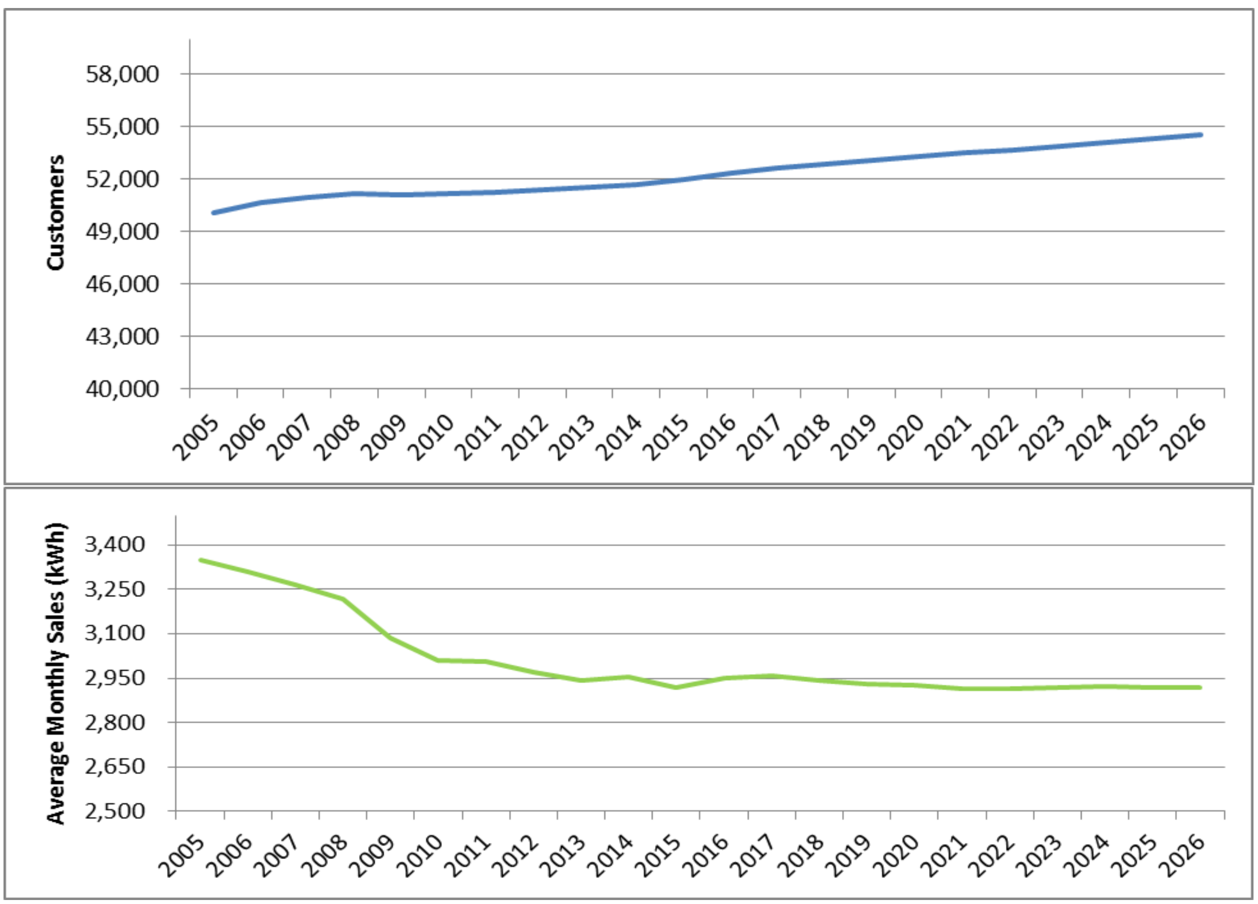


4.5.2. Small C&I

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.

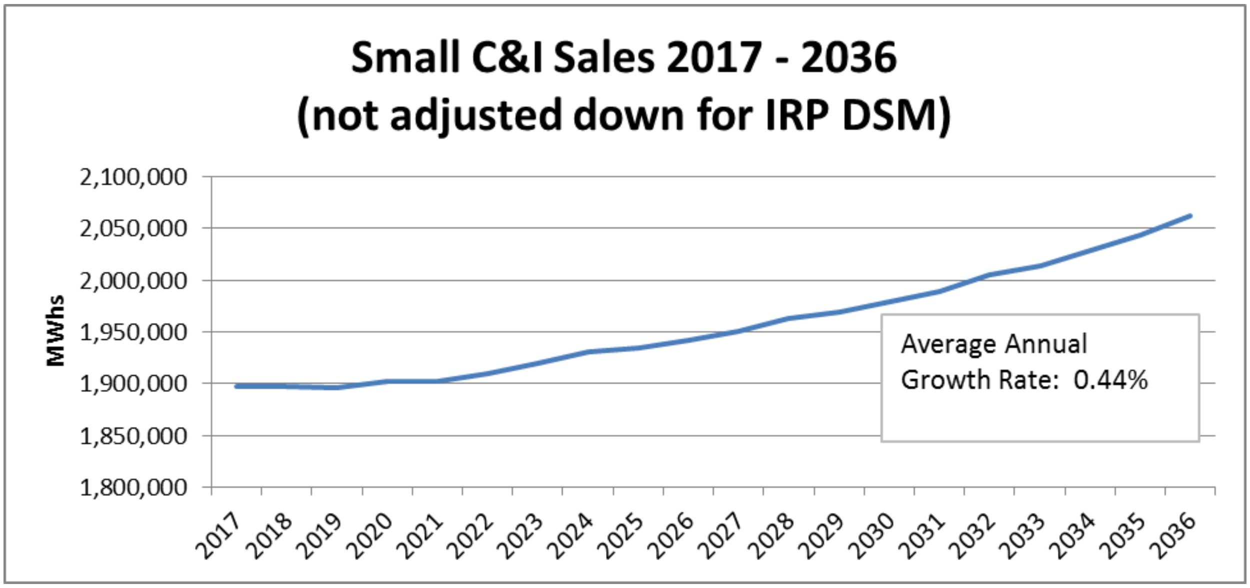
Figure 4.14 displays the projected customer count growth and average electricity use for the Small C&I sector. The numbers of new customers are projected to grow at an average annual rate of 0.4%; however, the average use per customer is anticipated to decline at an average annual rate of -0.1%. With 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

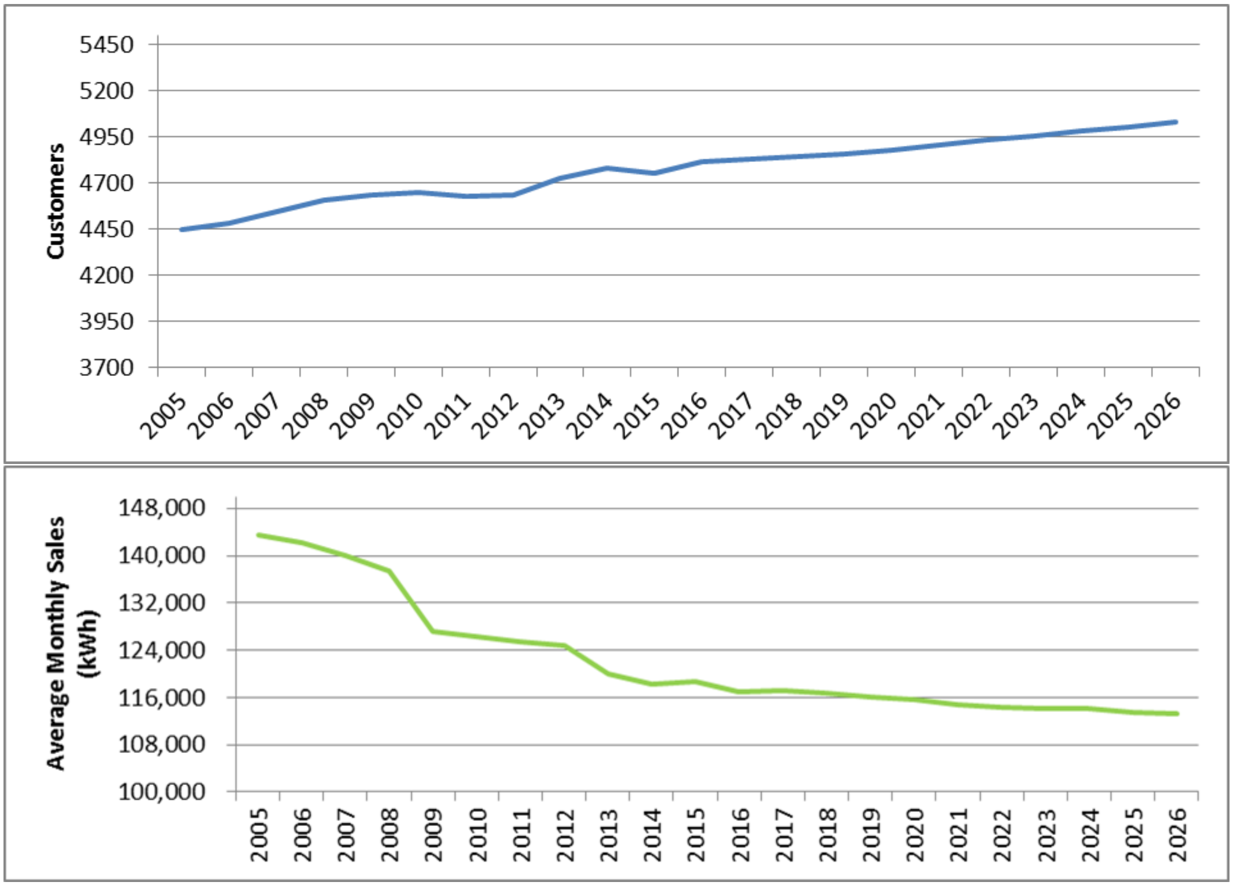


4.5.3. Large C&I

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%.

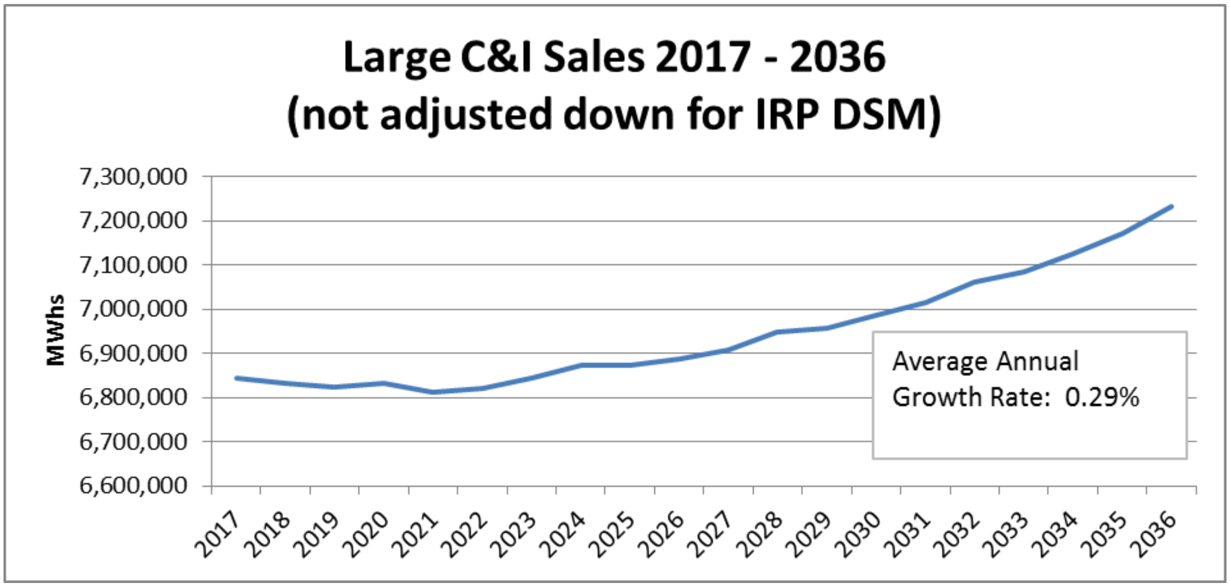
Figure 4.16 displays the projected customer count growth and average use per customer for the Large C&I sector. As with the Small C&I Sector, the number of new customers is expected to grow at an average annual rate of 0.4%, while average use is anticipated to decline at a rate of -0.3% annually. Customer 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

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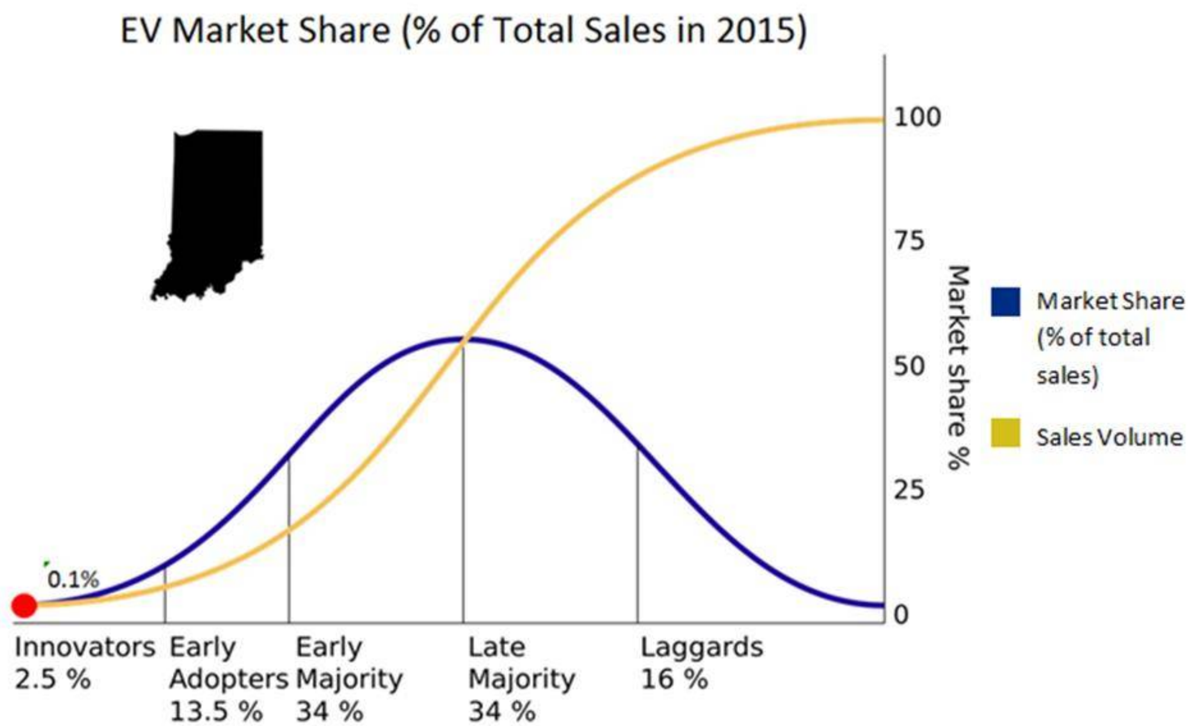
Electric Vehicle ("EV") adoption has the potential to result in measurable future grid impacts. Excluding fleet vehicles, there are approximately 1,700 EVs registered in the State of Indiana as of late 2015, with approximately 300 registered in the greater Indianapolis area. Given the low EV penetration 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

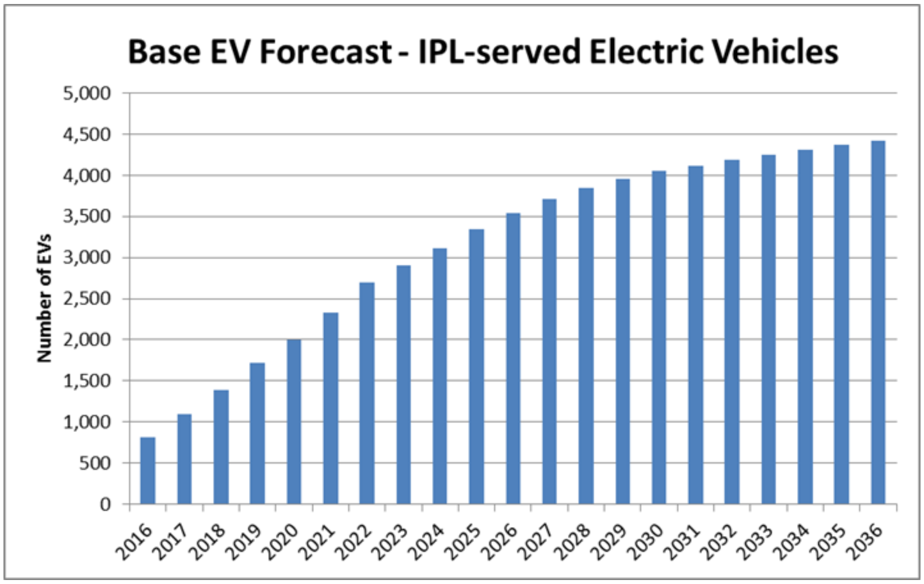
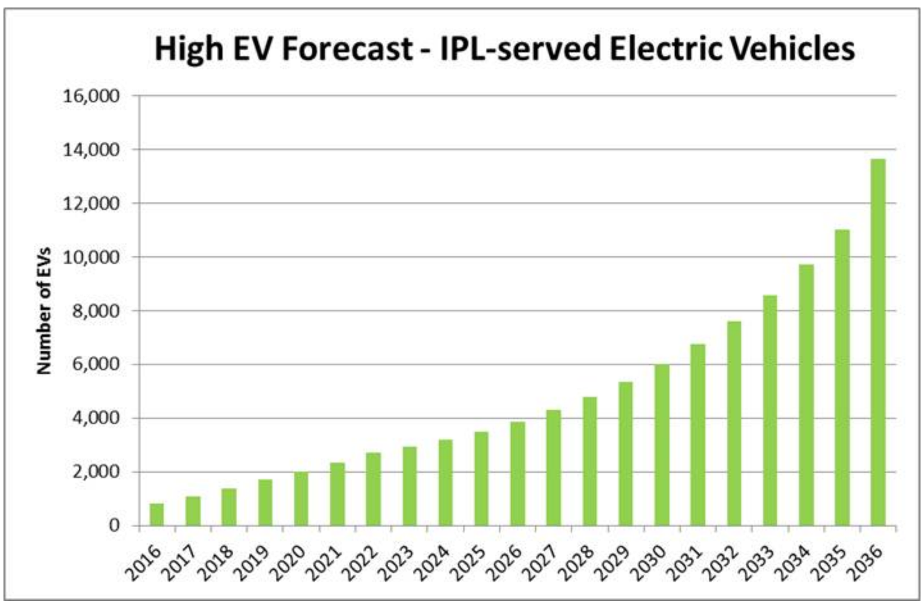


Figure 4.21 – Forecasted volume of Electric Vehicles served by IPL – High Scenario



4.6. Load Model Performance and Analysis

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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

		Forecast Made:				
For	Actual Sales *	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

		Forecast Made:									
For	Actual Peak Demand	One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago	Six Years Ago	Seven Years Ago	Eight Years Ago	Nine Years Ago	Ten Years Ago
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

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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

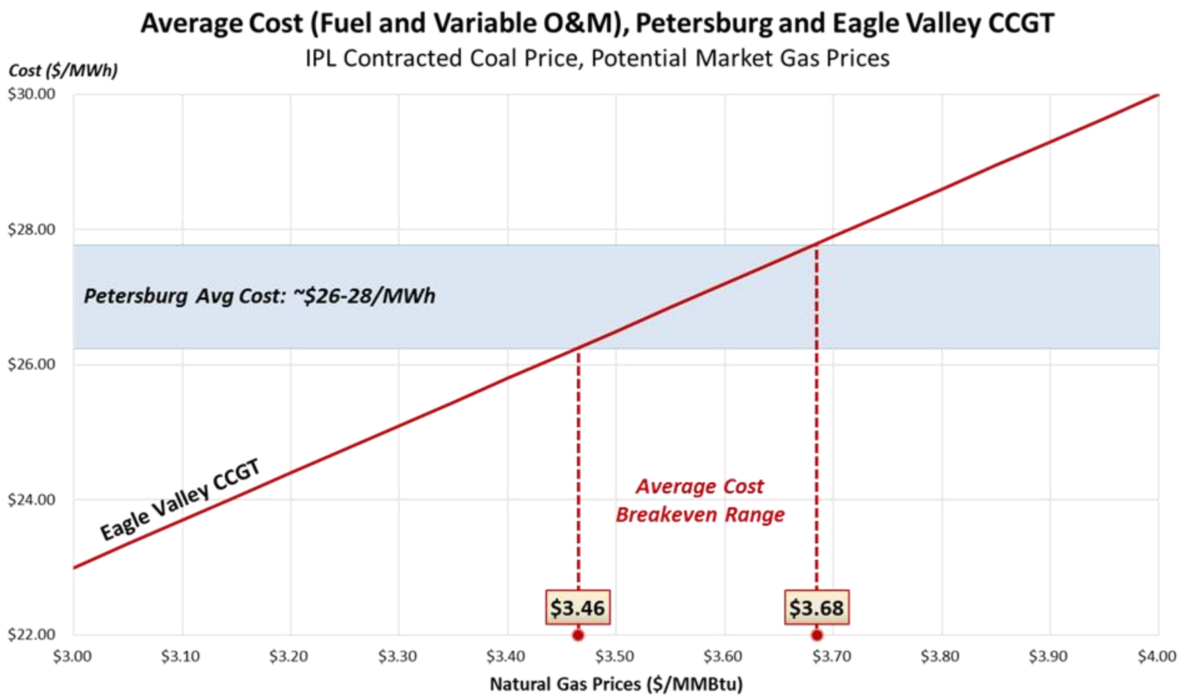

Figure 5.3 utilizes the same data for Petersburg and wider range of natural gas prices from $2/MMBtu to $6/MMBTU for Eagle Valley to show a different graphical representation of the relative costs of the Petersburg units and the CCGT.

Figure 5.3 – Unit Graphical Comparison

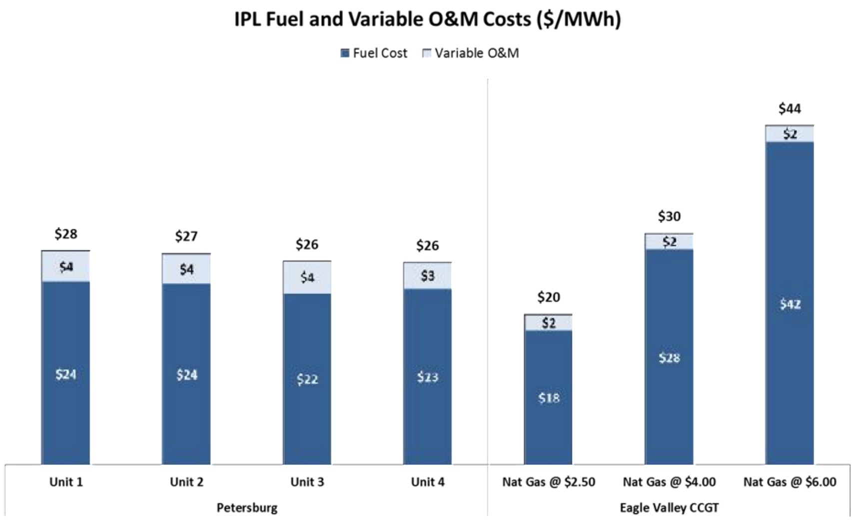

Figure 5.4 shows both the nameplate capacity and ICAP value for IPL's wind and solar PPAs. MISO gives IPL zero capacity credit for wind and solar, yet IPL subtracts 43 MW of solar from its load forecast for MISO planning purposes.

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

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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

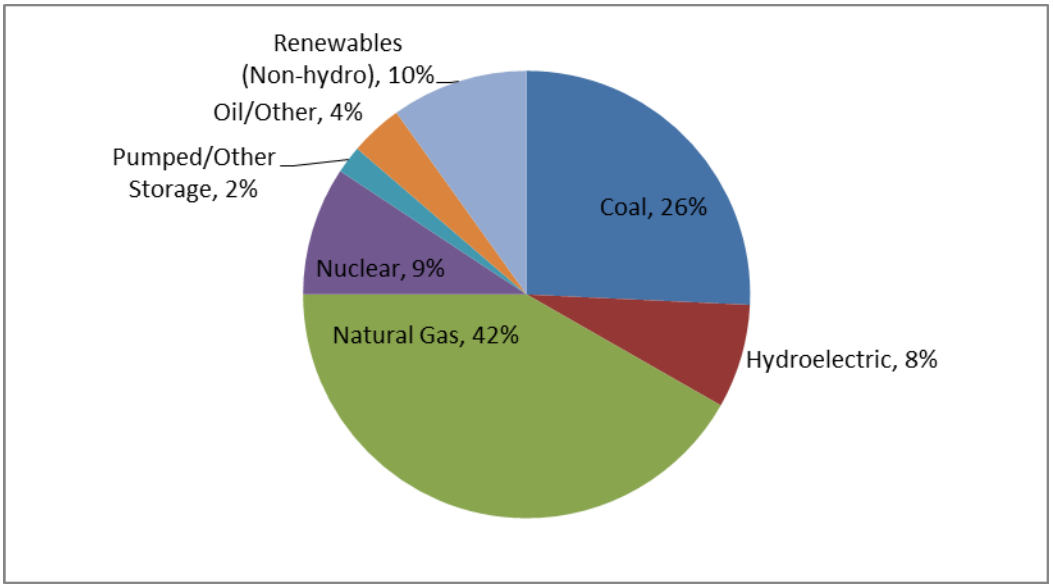
The resource mix throughout the United States ("U.S.") and within the MISO footprint continues to change each year with a heavier prevalence of renewables and natural gas fired generation than historic reliance on coal-fired generation as described below.

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.

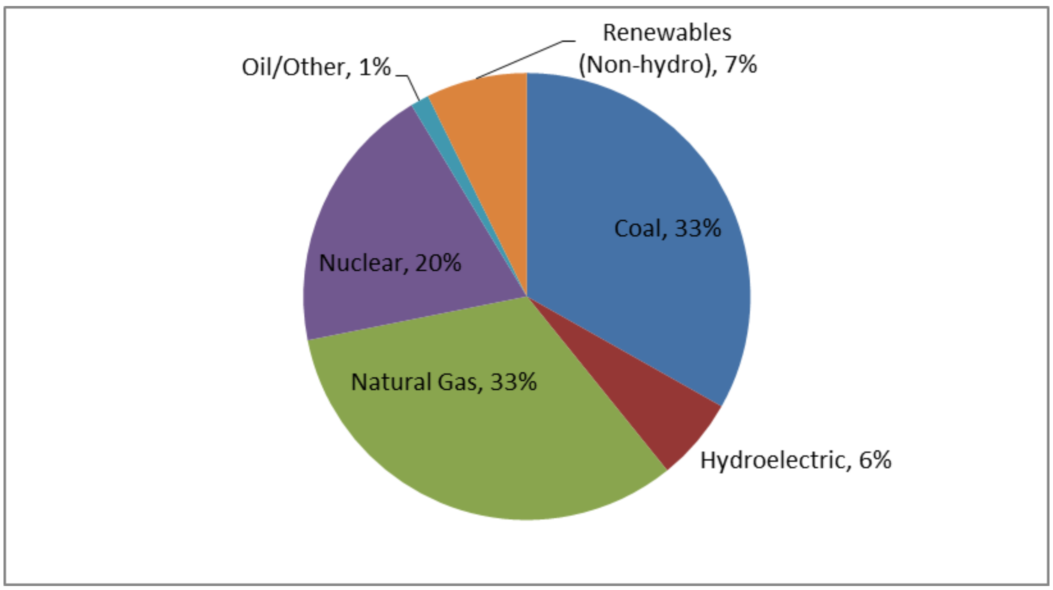
[30] The source for all resource mix comments in this section is *Electricity & Fuel Price Outlook, Midwest Spring 2015*, ABB, unless otherwise noted.

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



Source: EIA

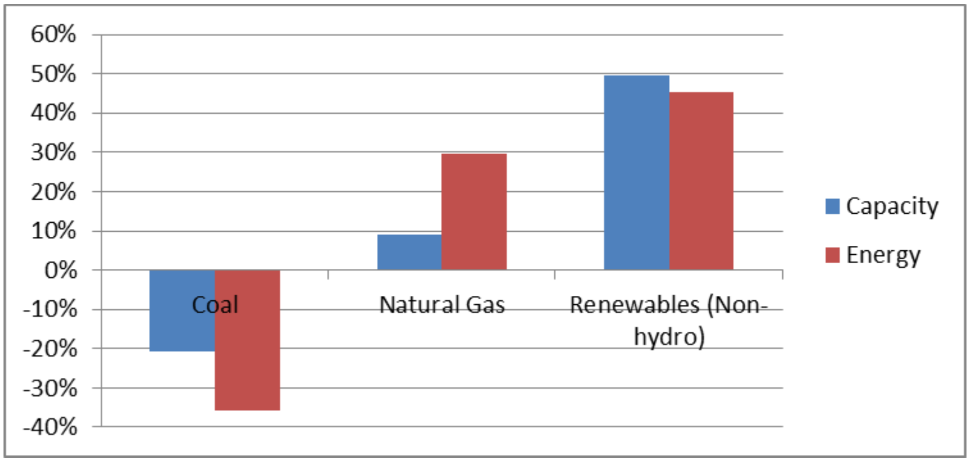
Figure 5.9 – U.S. Electric Power – Electricity Energy Production (2015)



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.

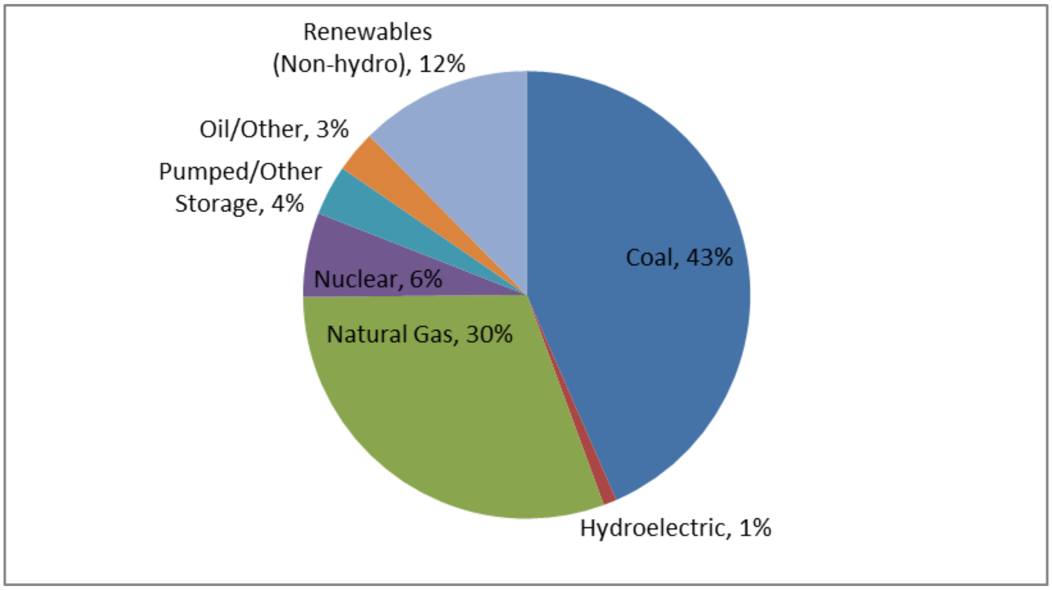
Recent trends suggest that natural gas and renewables will continue to increase their role in the U.S. generation mix, but the sheer size of the installed coal generating resources will continue to make it an important contributor. Nuclear and hydroelectric resources will likely continue to remain flat 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.

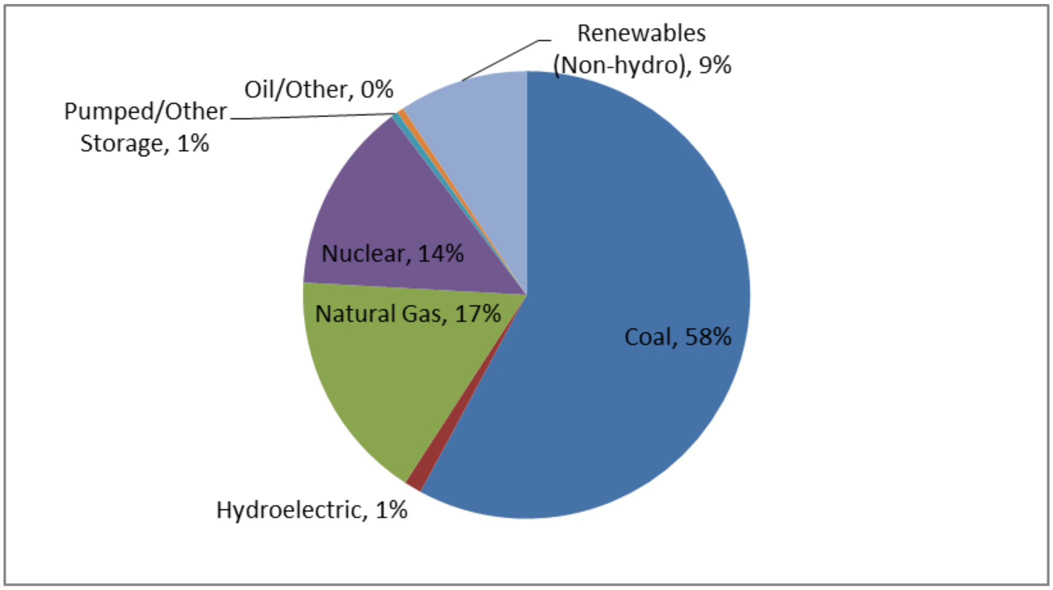
Figure 5.11 – MISO-North Generating Capacity by Fuel Type (2016)



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.

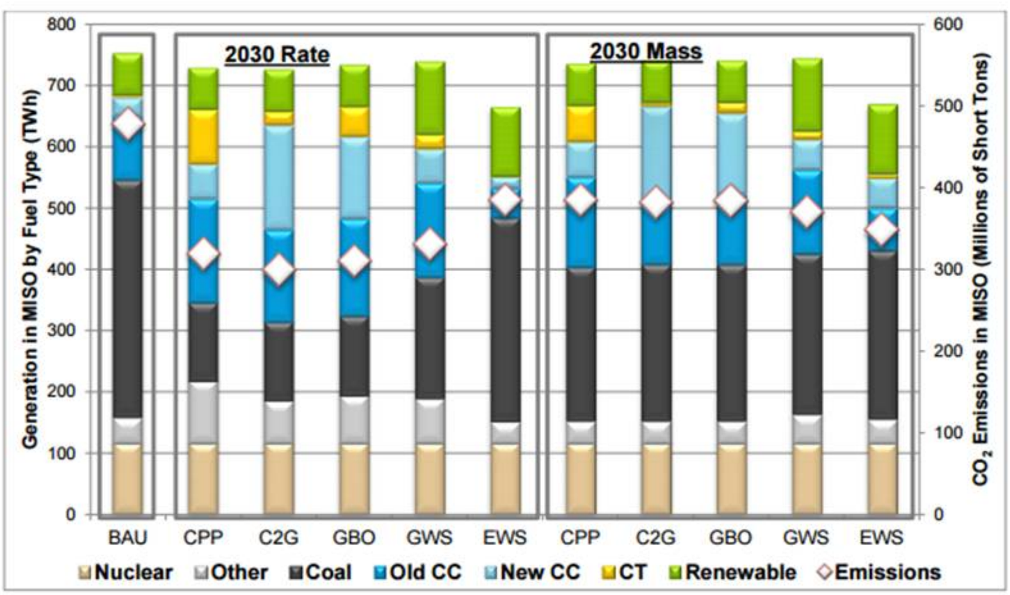
[31] Analysis by author of data listed on coal retirements at https://www.snl.com (subscription required).

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.

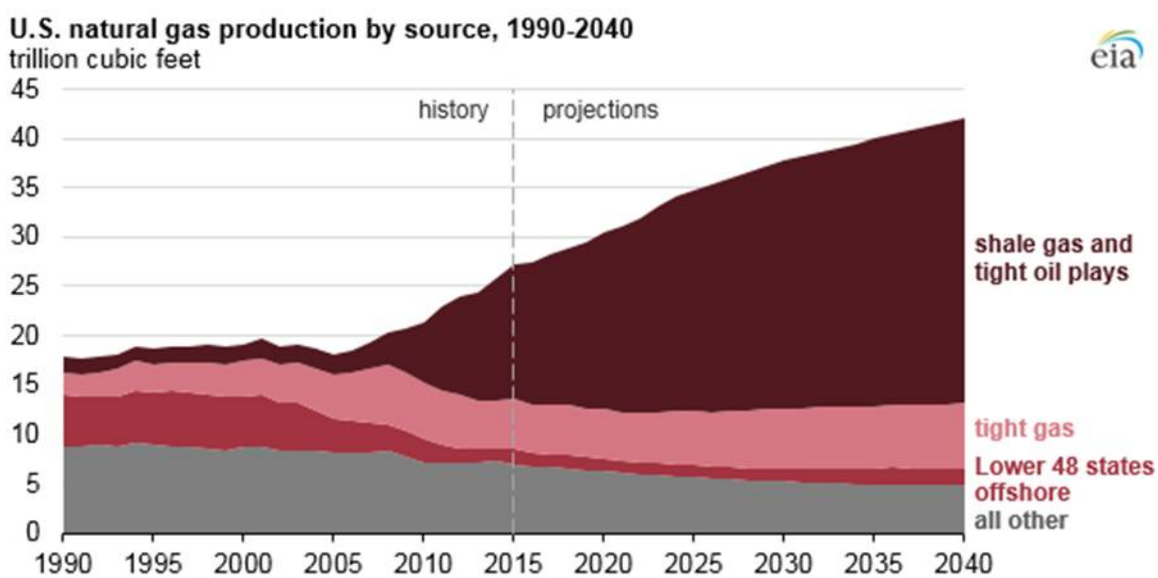
5.3.1.4 *Shale and the New Gas Supply Paradigm*

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.

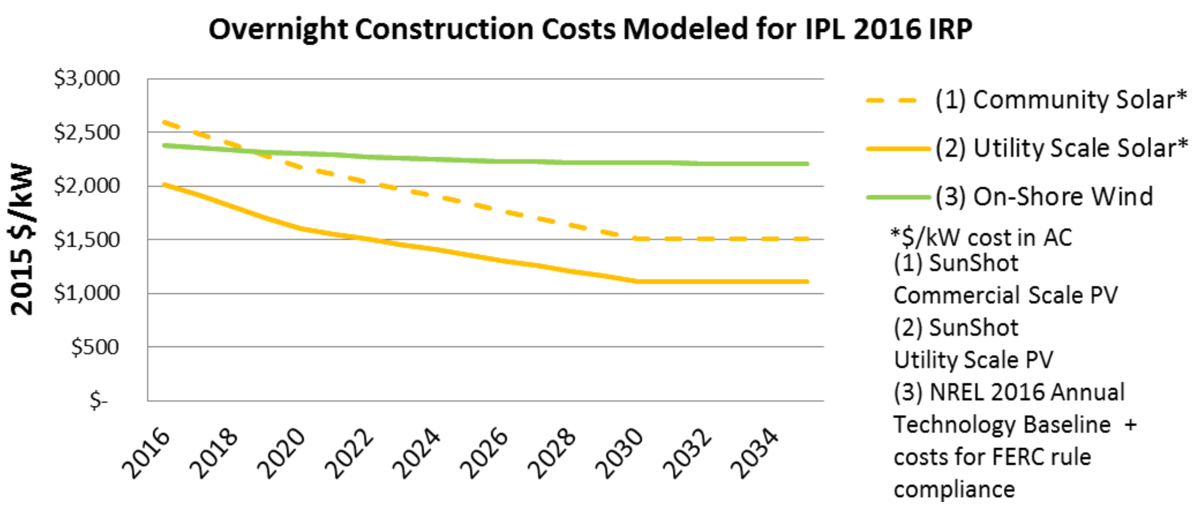
IPL continues to monitor developments in nuclear and renewable energy technology and will consider nuclear alternatives in any decision for future capacity additions.

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.

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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.

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[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."

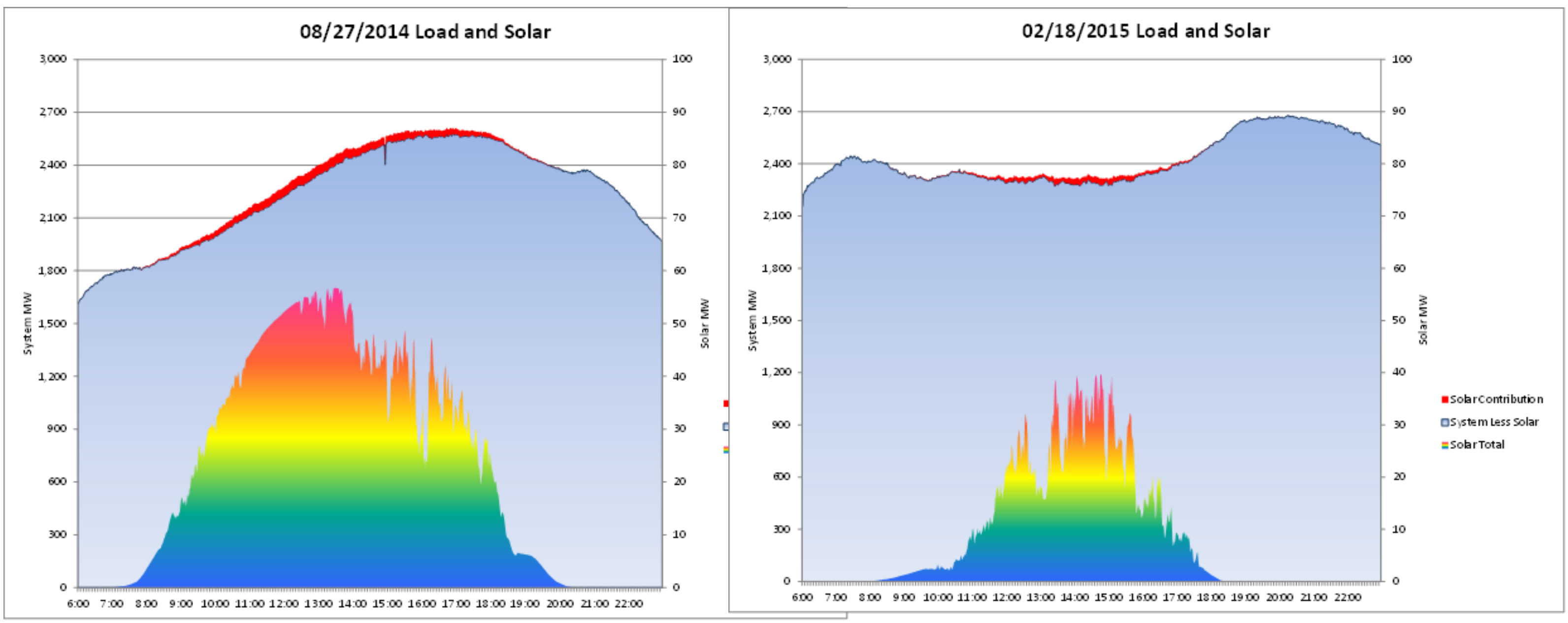
[44] http://www.seia.org/research-resources/us-solar-market-insight.

[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



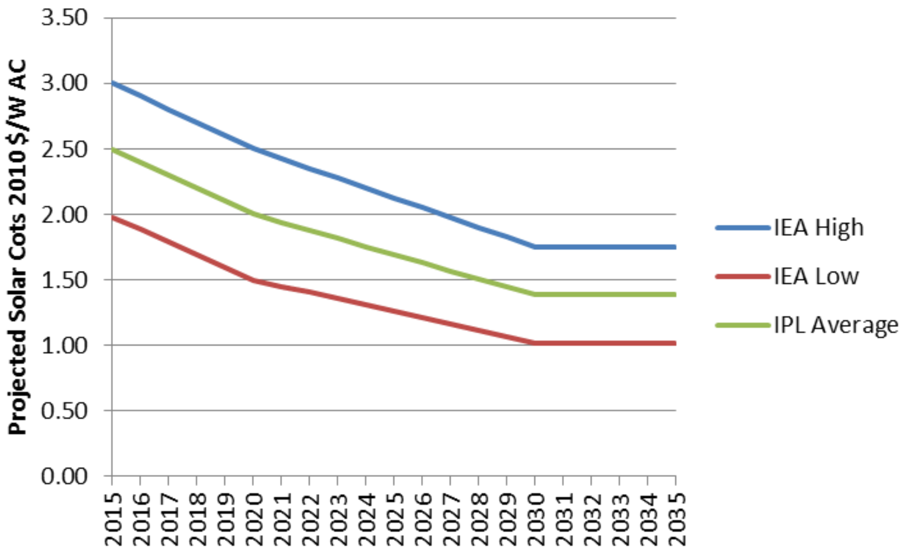
IPL's model allowed additional PV to be selected in 10 MW blocks and CS to be selected in 1 MW increments.

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.

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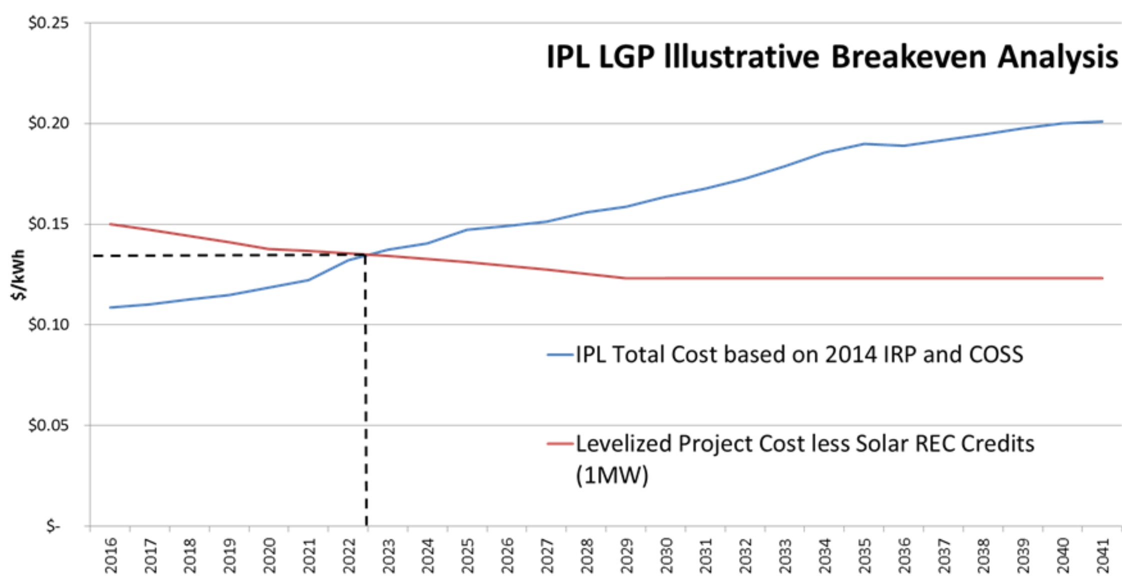
[48] http://understandsolar.com/calculating-kilowatt-hours-solar-panels-produce/.
[49] https://www.solarelectricpower.org/media/422095/community-solar-design-plan_web.pdf.

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.

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[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.

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[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.

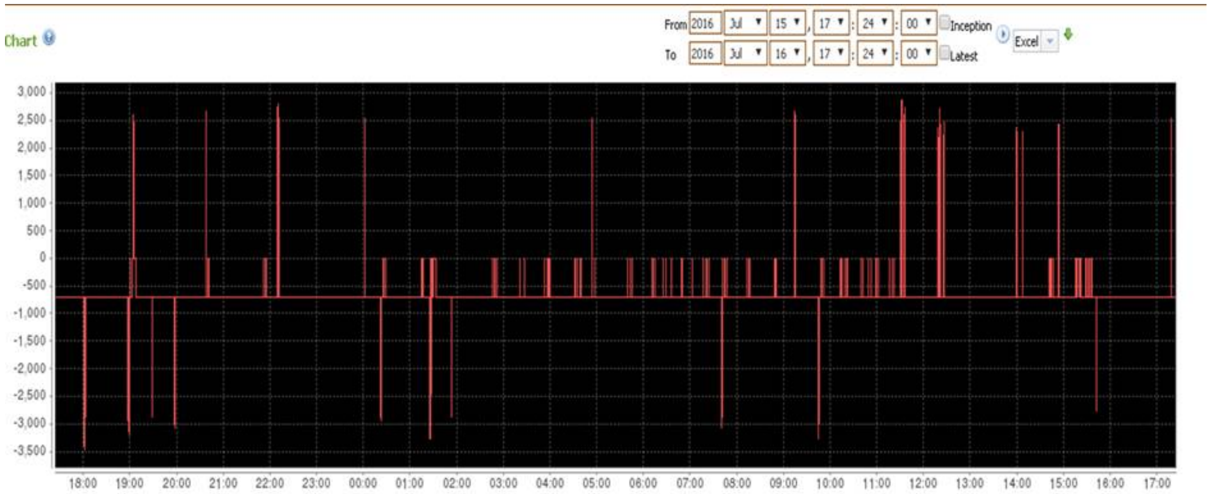
The Array provides the reliability service of frequency control automatically without the need for dispatch or other human intervention. This includes Regulation and Primary Frequency Response ("PFR"), both of which mitigate deviations from the standard of ±60 Hertz. Regulation mitigates the normal and 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]

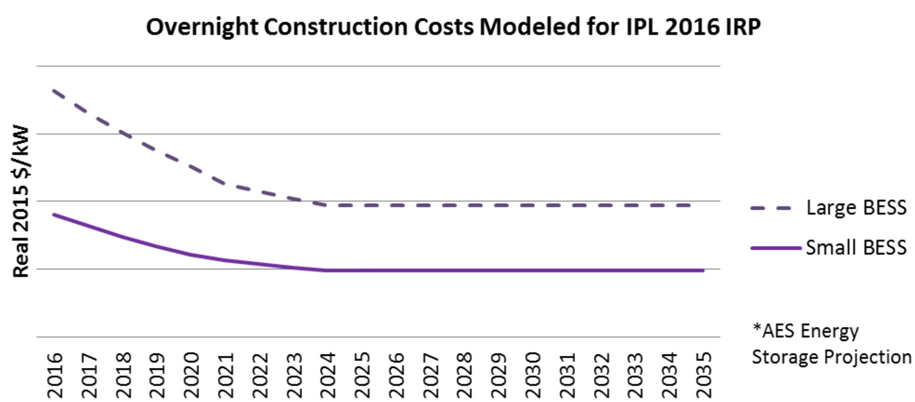
The IPL Array is also a given credit in MISO as a source of capacity to meet IPL's resource adequacy requirements as an LMR. It was successfully tested to provide 5 MW of energy continuously over the four hours of the peak as designed. The Array can switch from providing frequency control to providing 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.

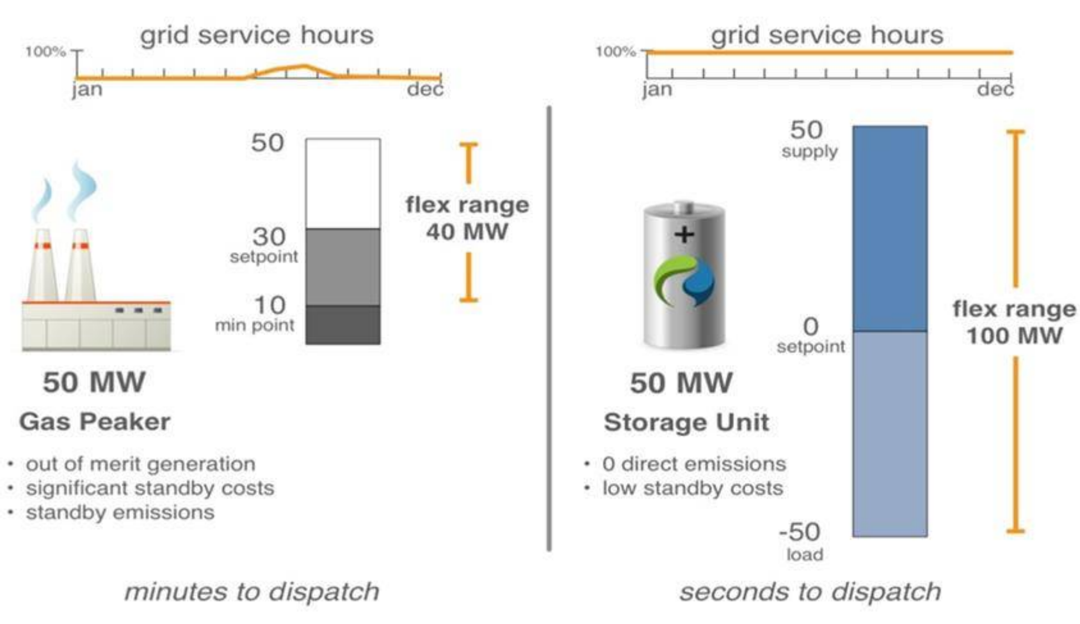
5.3.4.3 *Comparison to a Simple Cycle CT*

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.

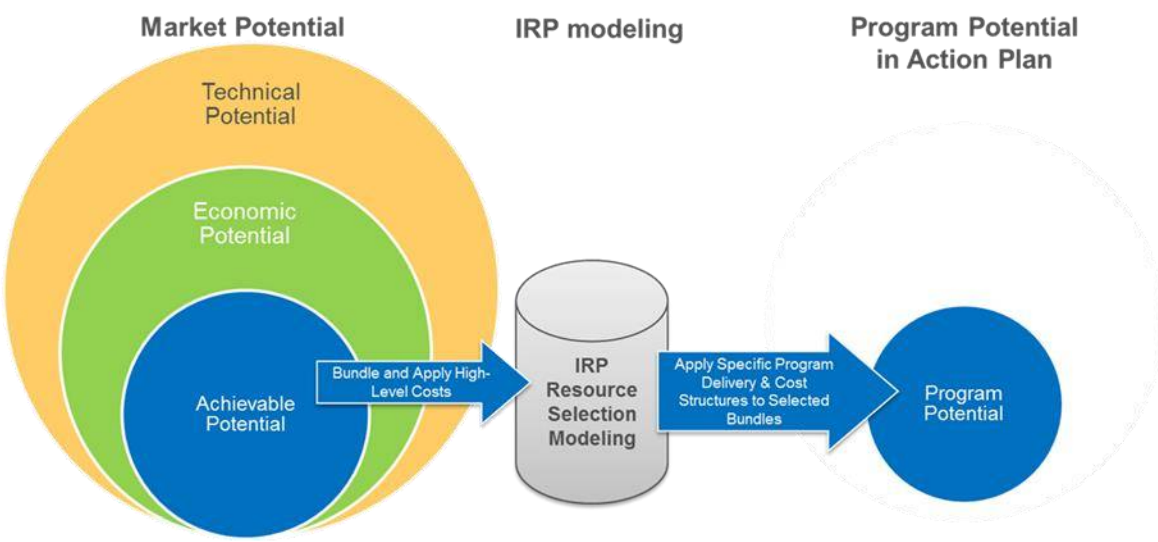
[71] "The 2015 State Energy Efficiency Scorecard", American Council for an Energy-Efficient Economy by Annie Gilleo, Seth Nowak, Megan Kelly, Shruti Vaidyanathan, Mary Shoemaker, Anna Chittum and Tyler Bailey, October 2015, Figure 2, page 23.

[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.

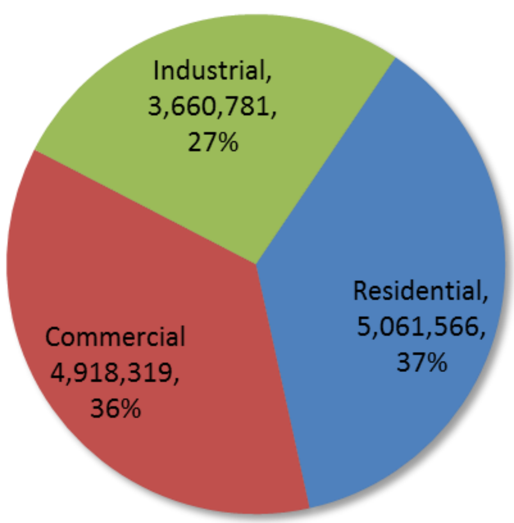
5.6.2. Market Characterization

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



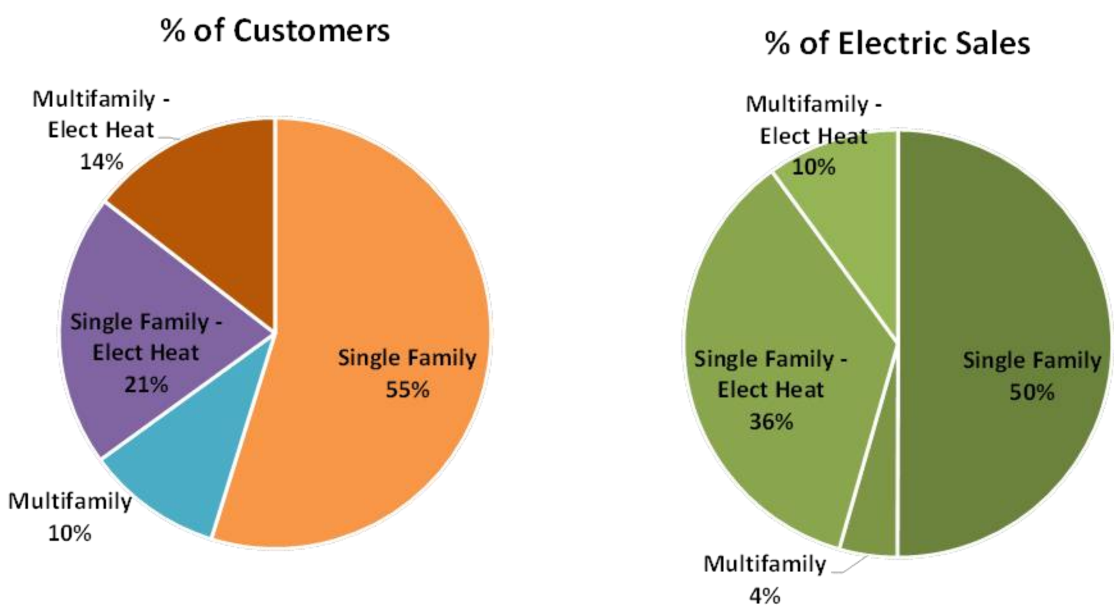
Each customer sector is then further disaggregated using load data into segments as follows –

- 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 <u>combined</u> 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

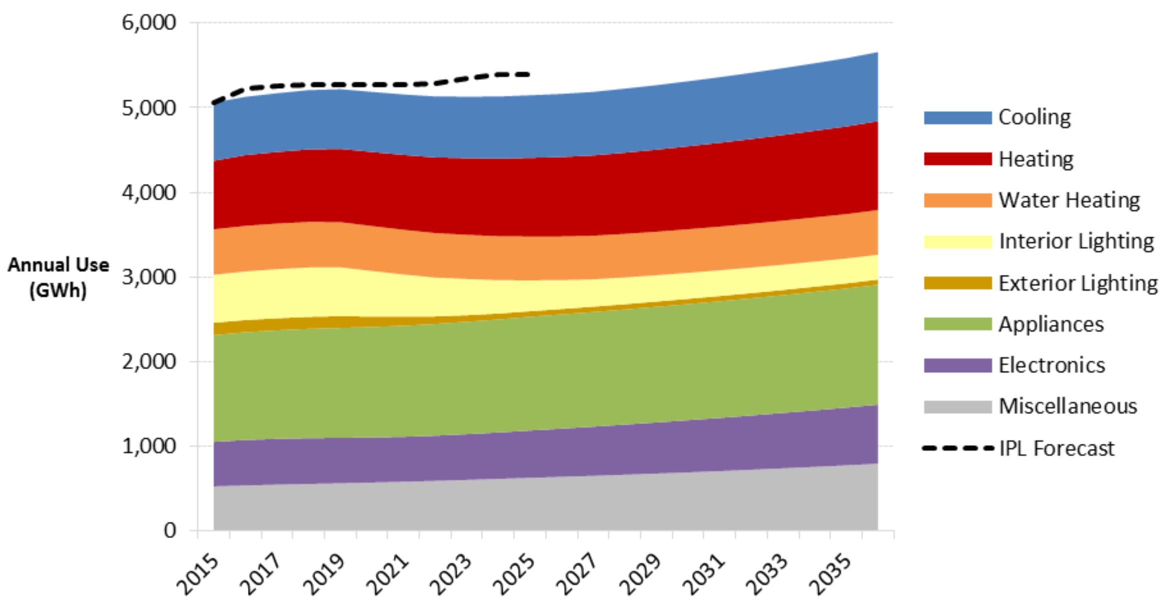
The base-year Market Characterization profiles are used to develop a forecast of annual energy use by customer segment and end use from 2017 to 2036 which serve as the baseline projections. These projections include relatively certain impacts of codes and standards that will unfold over the study timeframe.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

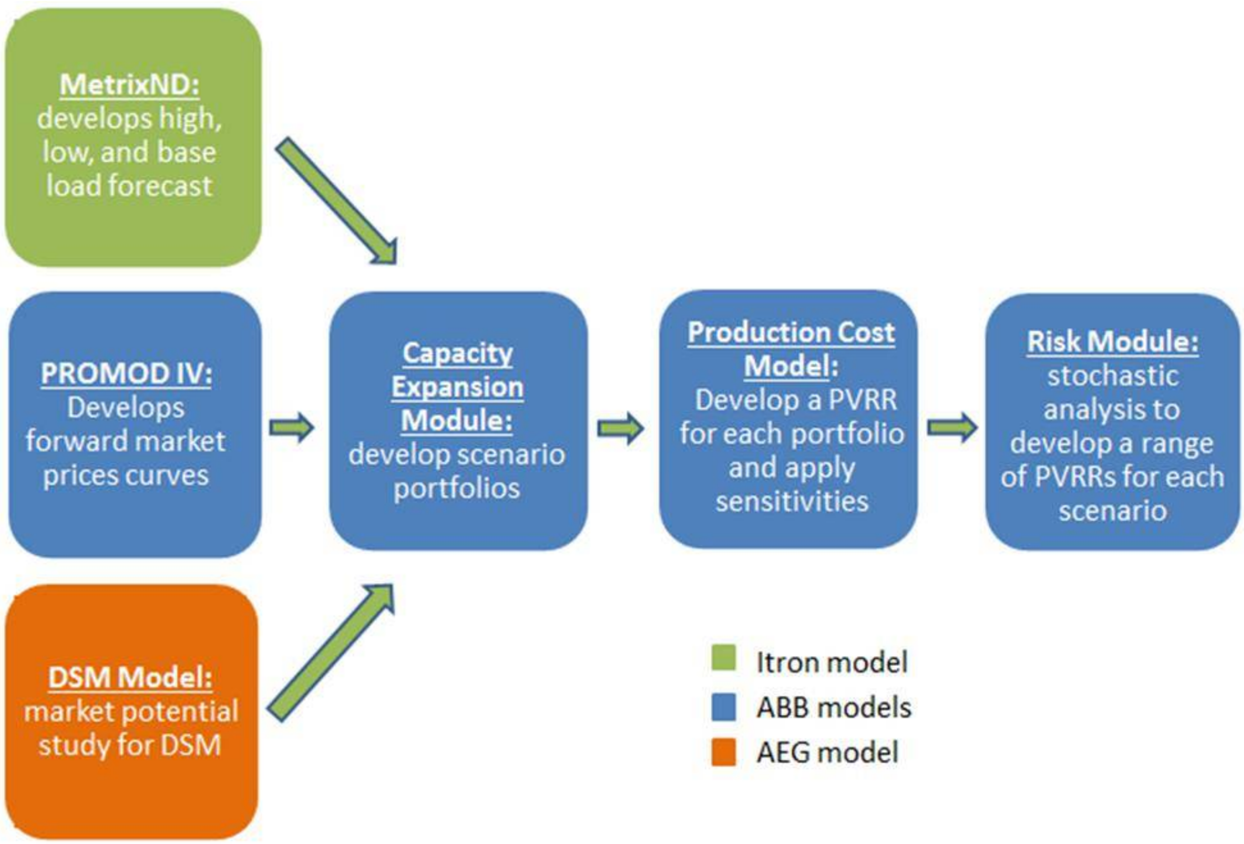
IPL varied these drivers in a way that would result in divergent resource portfolios once the scenario inputs are run through the Capacity Expansion Model. Analyzing a set of divergent resource portfolio scenarios via metrics allows IPL to understand the impact of portfolio options on IPL's customers,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

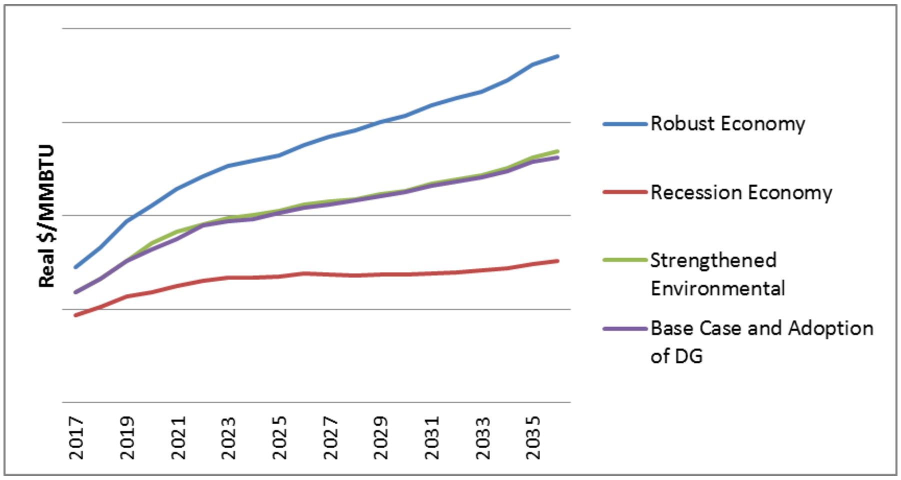
For the 2016 IRP, ABB used its Clean Power Plan mass-based carbon tax assumptions from its ABB Fall 2015 Midwest Reference Case as the "Base Case" CO_2 prices. ABB used the consulting firm ICF's CO_2 tax assumptions for the "Strengthened Environmental" scenario of CO_2. The Delayed CPP sensitivity assumes 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.

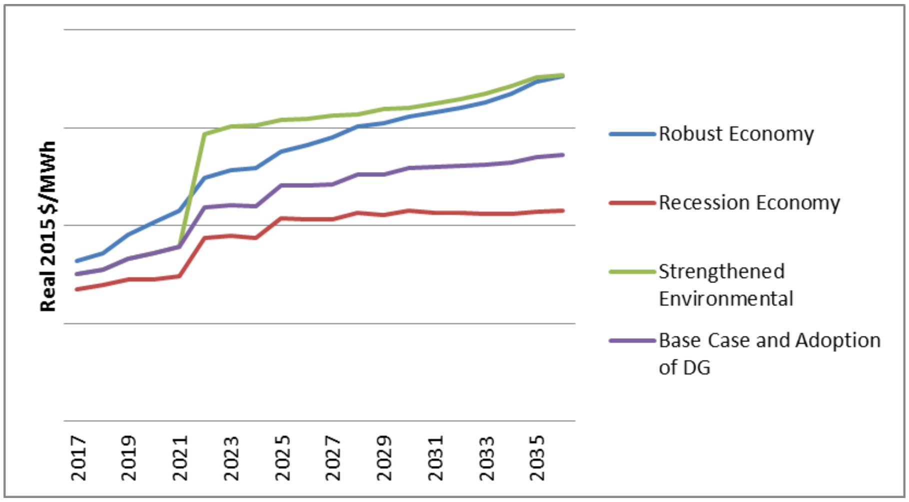
Figure 7.4 – Henry Hub Natural Gas Prices



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.

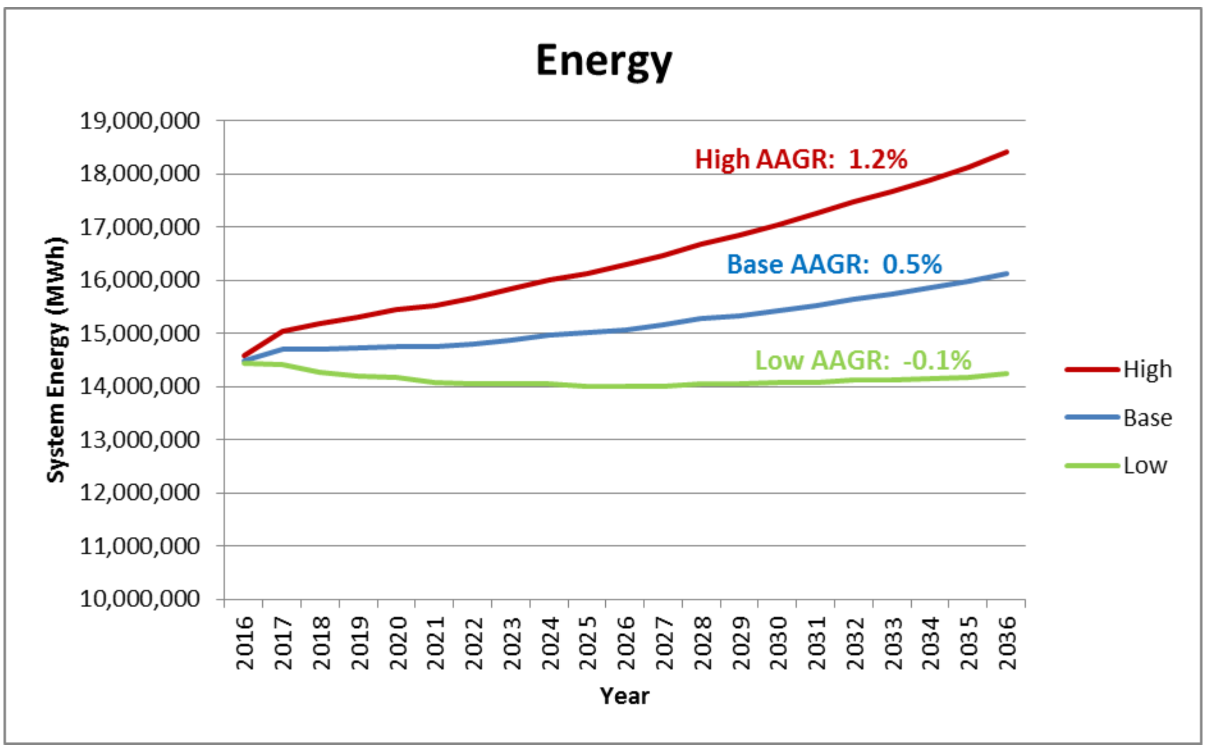
[80] The Integrated Model simulates the operation of each generating unit in the Eastern Interconnect to develop market prices. The Integrated Model simulates the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The model 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.

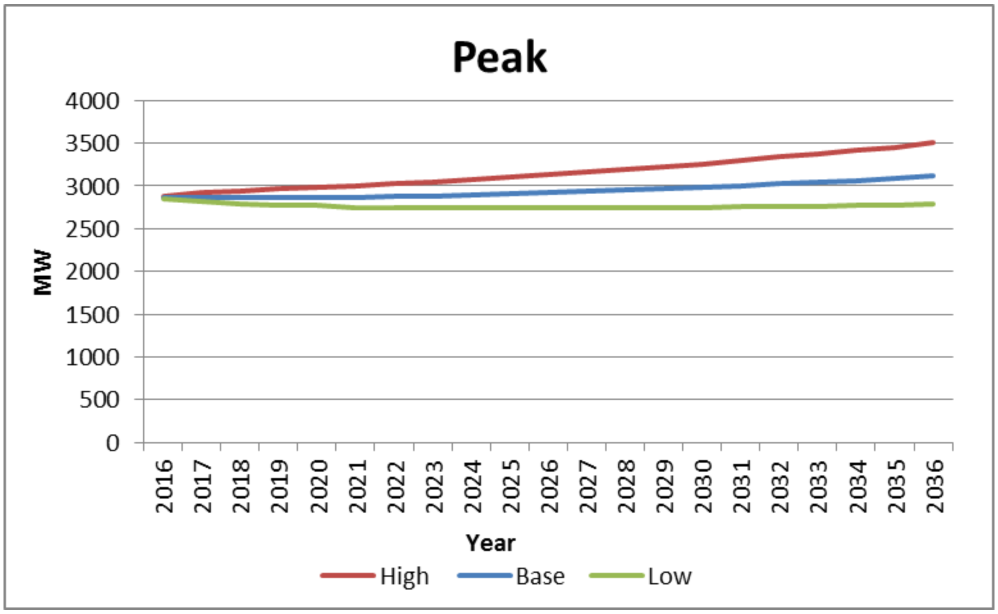
Figure 7.5 – Market Prices: MISO-IN (7x24)



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.

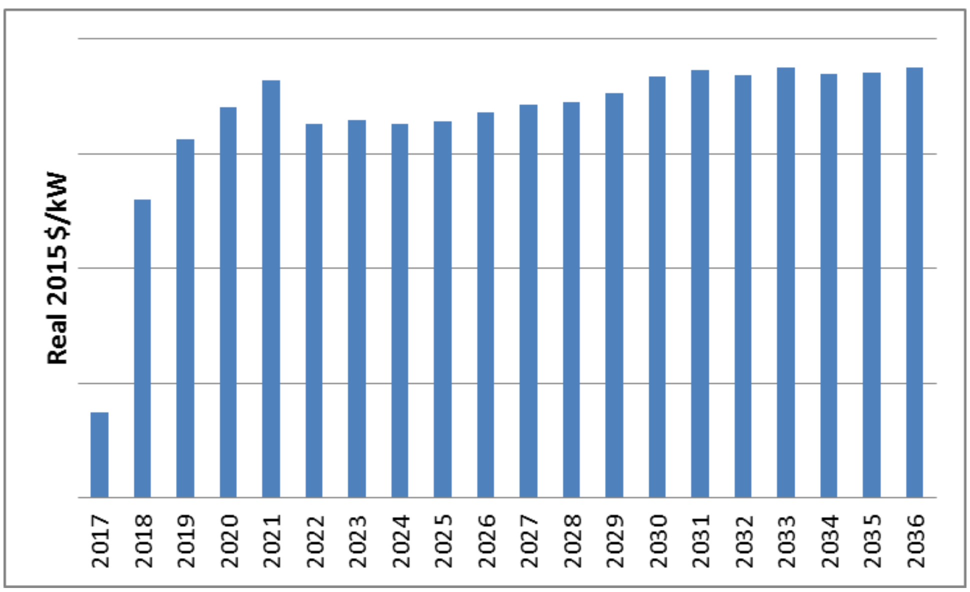
Figure 7.6 – IPL Peak and Energy Load Forecast





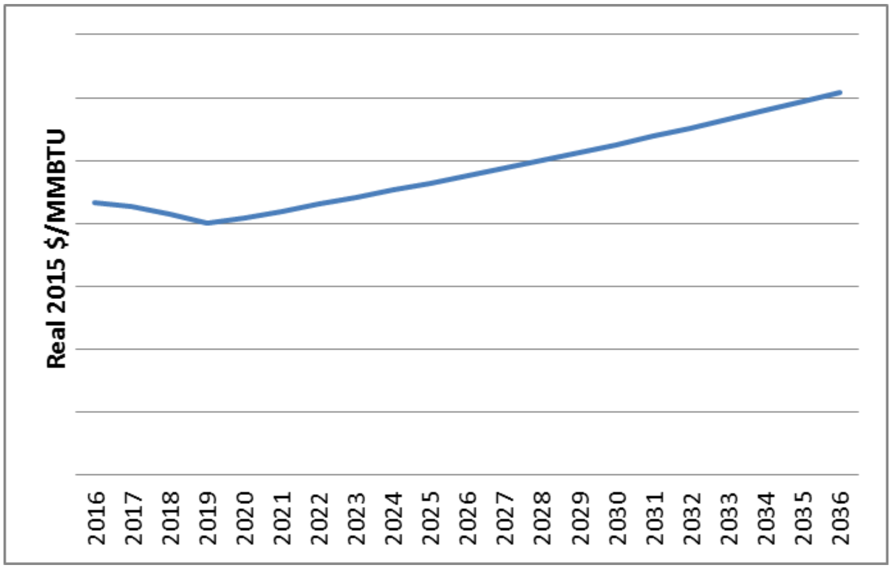
Capacity Prices: Capacity prices for Zone 6 of the MISO market, which IPL is located, have increased each year of MISO's Planning Resource Auction ("PRA"). As units in the MISO region retire, capacity prices are expected to rise toward CONE.

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

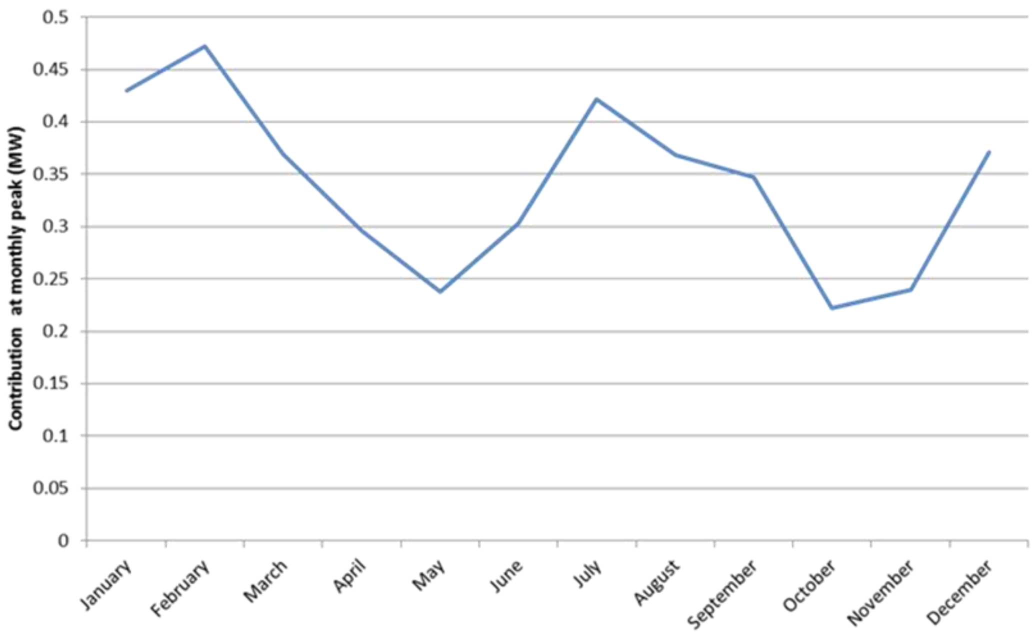
Section 5 described the process of creating DSM "bundles" that act as inputs into the Capacity Expansion Model. This section will continue that discussion by elaborating on how the Capacity Expansion Model evaluates these DSM bundles against supply-side resources.

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

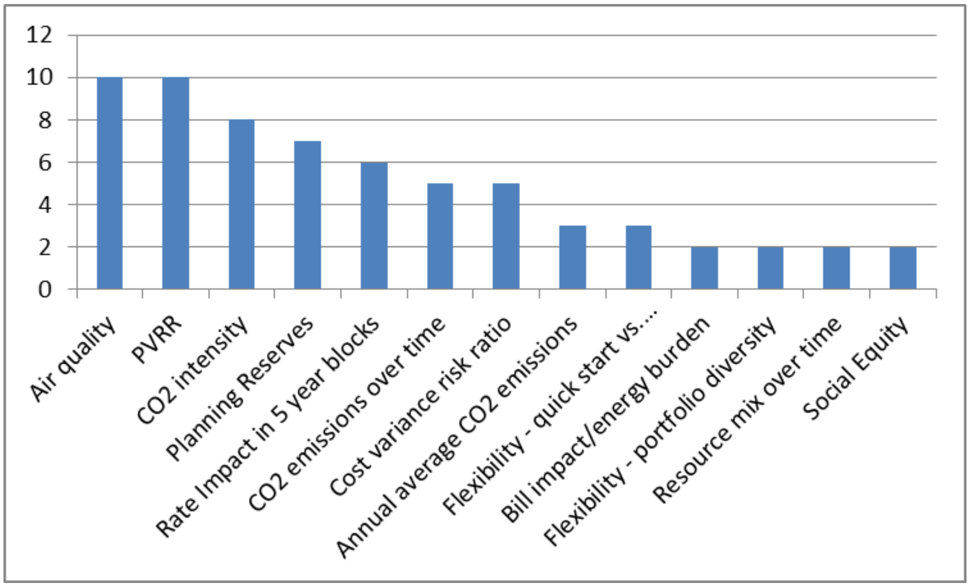
IPL proposed the use of several metrics under these four categories to stakeholders at the Public Advisory Meeting #2 and solicited stakeholder feedback and ideas for additional metrics. Stakeholders were divided into small groups and then given a chance to discuss the proposed metrics and to suggest 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	PVRR (20 year period) / 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	Sum of CO_2 tons emitted / # of years in the study period
	Annual average SO_2 emissions	tons/year	Sum of SO_2 tons emitted / # of years in the study period
	Annual average NO_X emissions	tons/year	Sum of NO_x tons emitted / # of years in the study period
	CO_2 intensity	tons/MWh	Sum of CO_2 tons emitted / MWh energy generated
Resiliency	Planning Reserves as a percent of load forecast	%	IPL's resources (MW) – peak utility load forecast (MW) / peak utility load forecast
	Distributed Energy Generation	%	Distributed generation supply (MW) / IPL resources (MW)
	Market reliance energy	%	MWh of market purchases / 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)

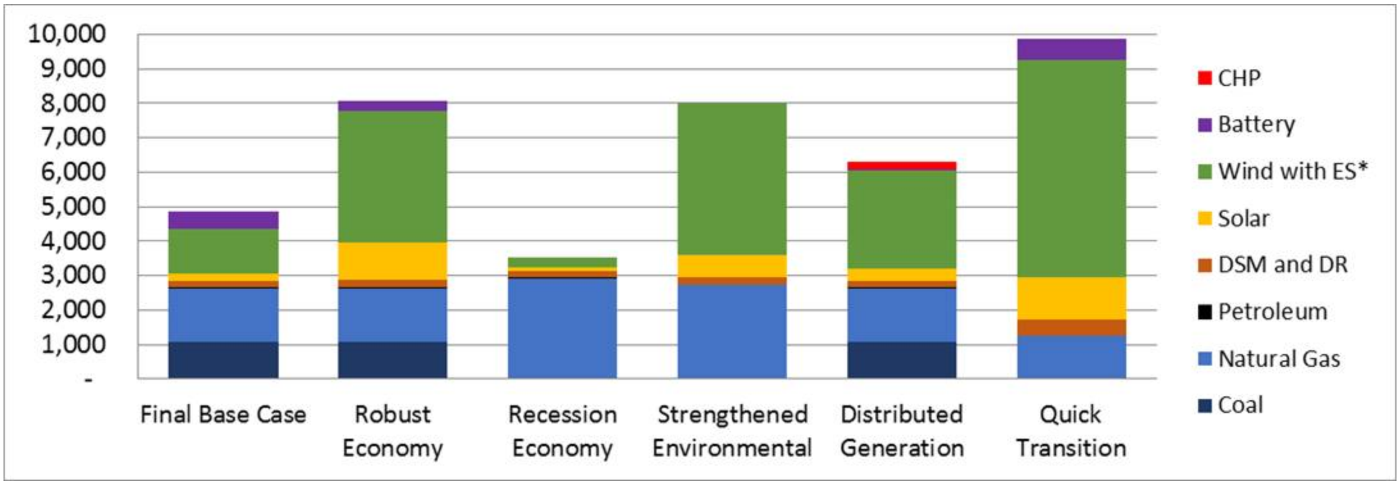


Figure 8.2 shows the operating capacity of supply side resource additions and retirements for each year of the study period for each scenario. The net demand side resource additions are shown in separate table for ease of reading.

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.

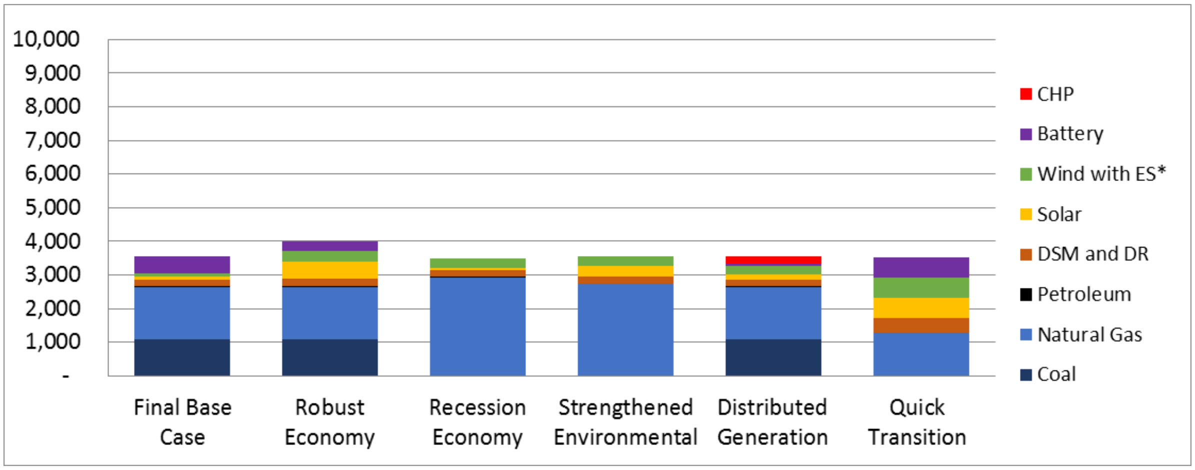
Figure 8.3 – Net Annual Incremental DSM (MW)

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

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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

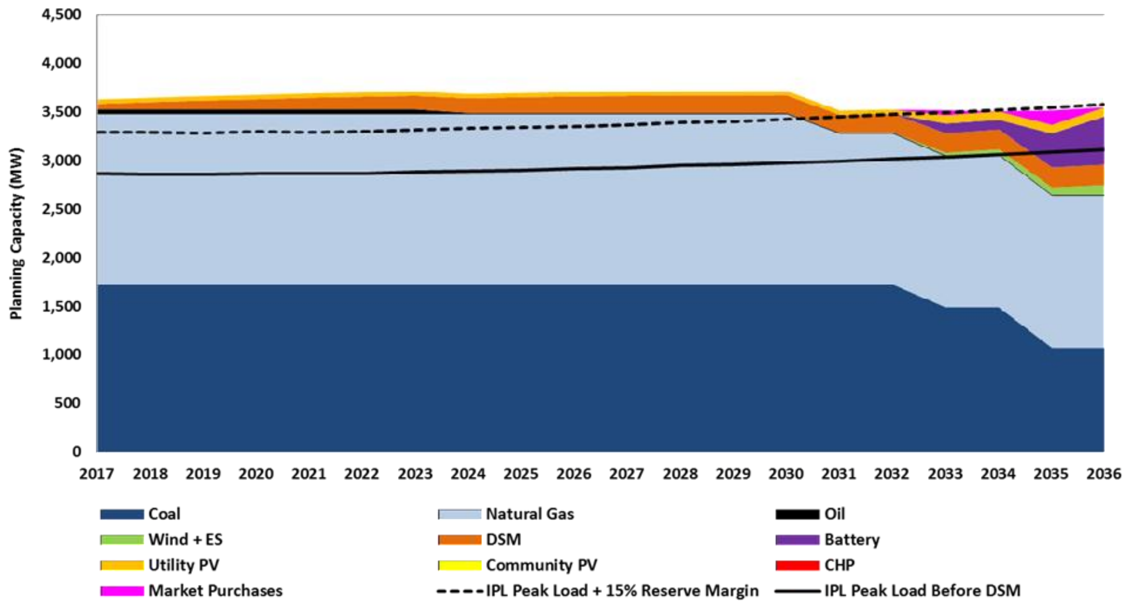


Figure 8.6 – Base Case Operating Capacity Additions

	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

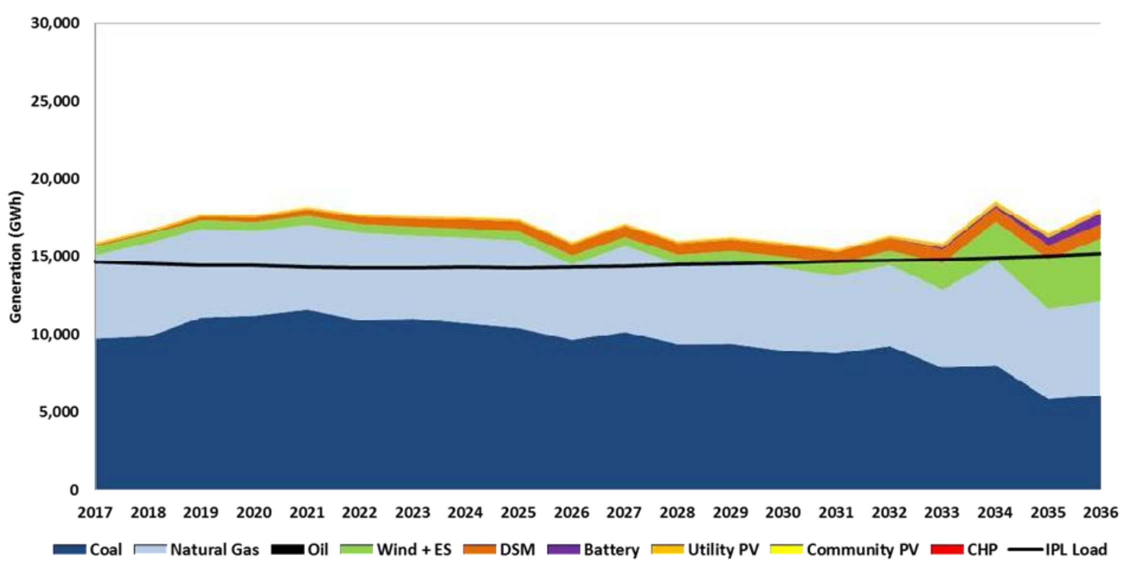
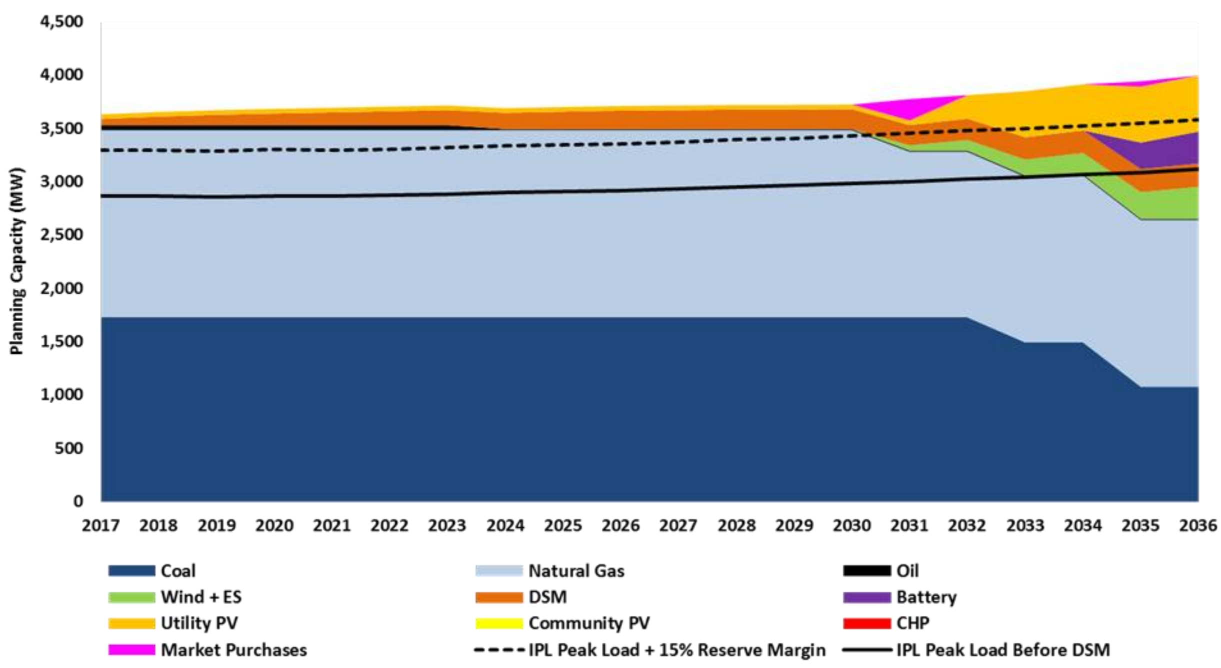


Figure 8.7 shows the forecasted energy results for the Base Case portfolio for 2017–2036. For this case, annual generation shows that the base case has enough resources each year to meet the load requirements designated by the black line. However, this figure does not show that on an hourly basis, there 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

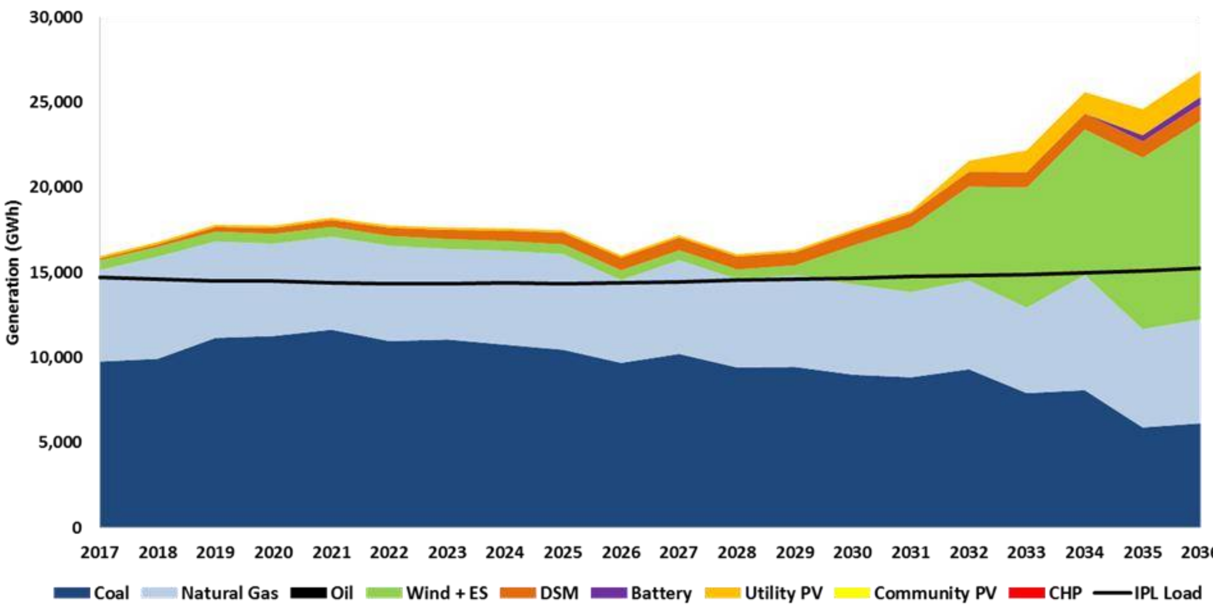


Figure 8.10 shows the Robust Economy portfolio energy mix as modeled against Base Case assumptions in the ABB Production Cost model. As explained in Section 7, IPL models each portfolio against the Base Case assumptions to assess how each portfolio would perform in the most likely future landscape. Hence, 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

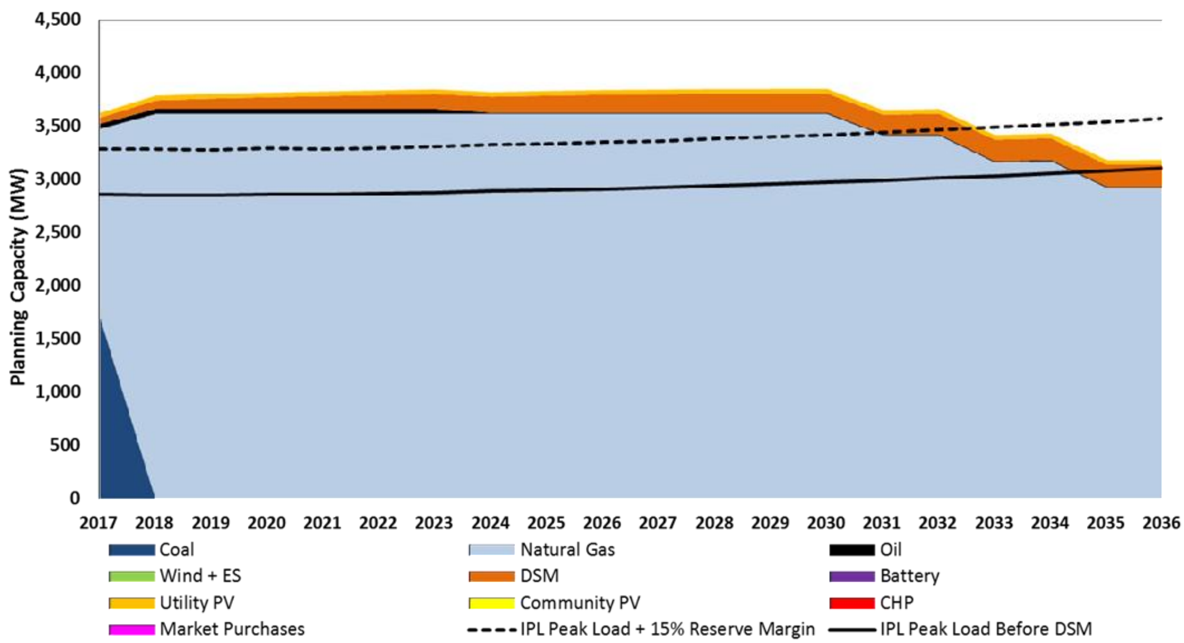
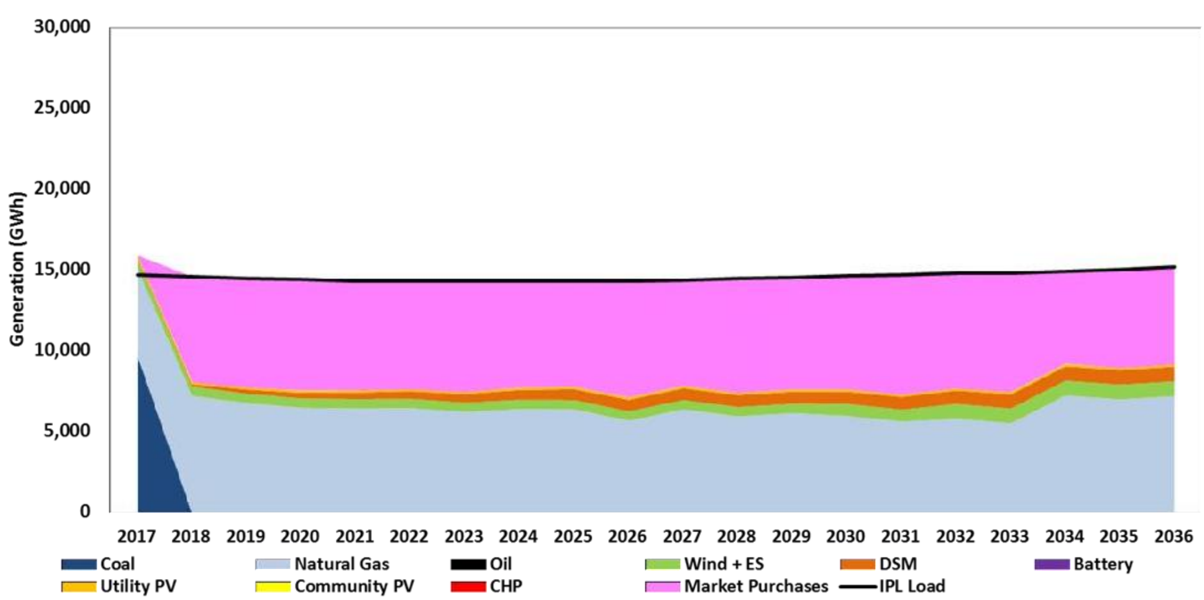


Figure 8.13 shows the Recession Economy portfolio energy mix as modeled against Base Case assumptions in the ABB Production Cost model. Hence, the load in this figure is the Base Case load. Figure 8.11 shows that a Recession Economy portfolio would under-build capacity as compared to the capacity needed 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

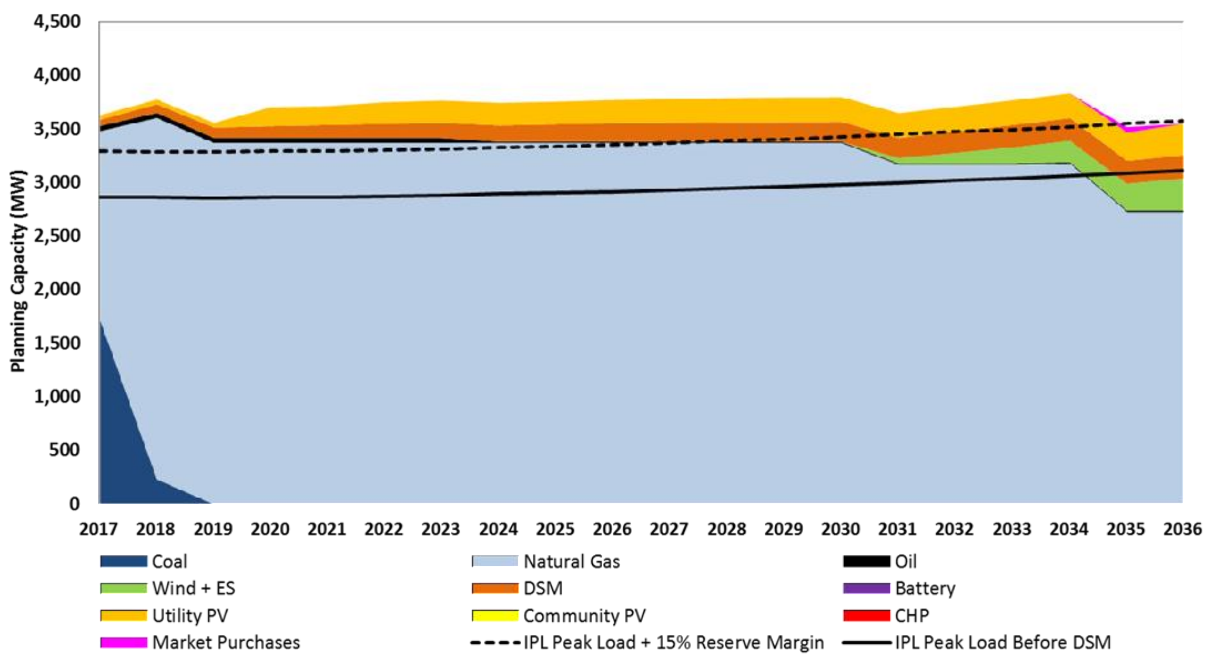
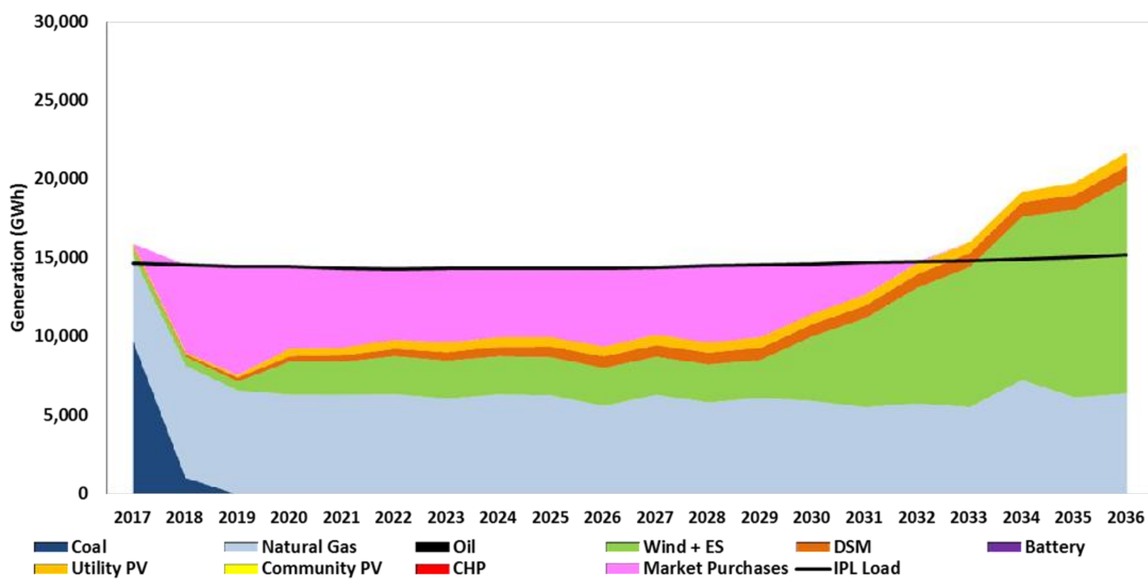


Figure 8.15 – Strengthened Environmental Operating Capacity Additions

	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

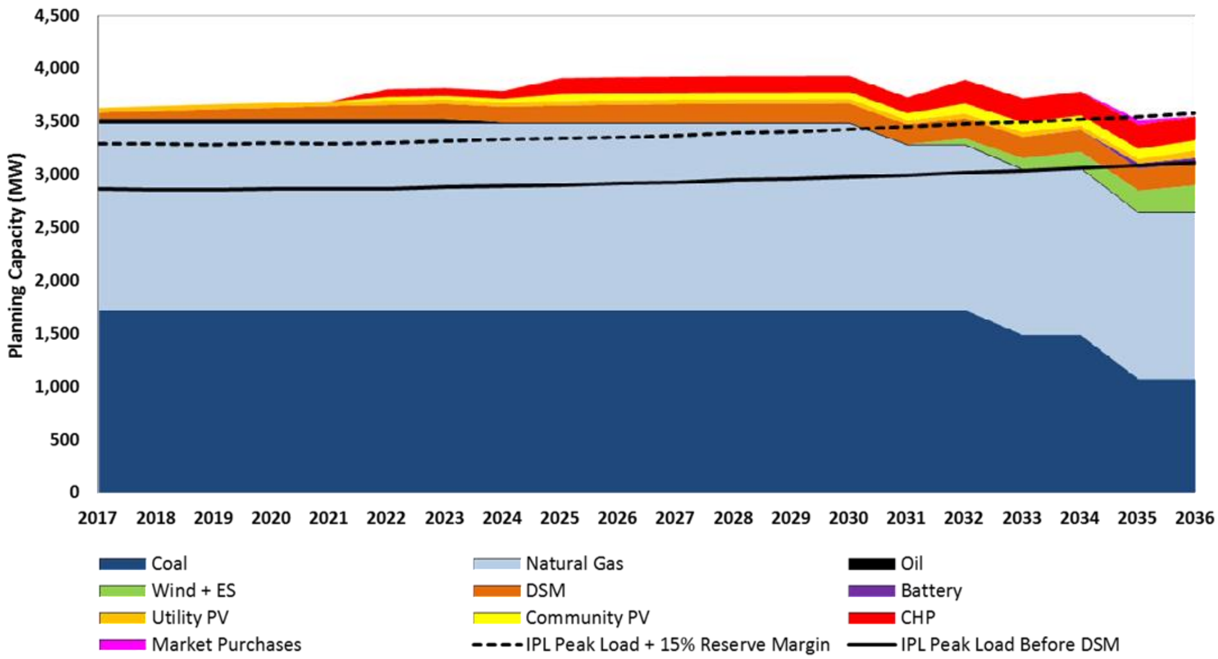
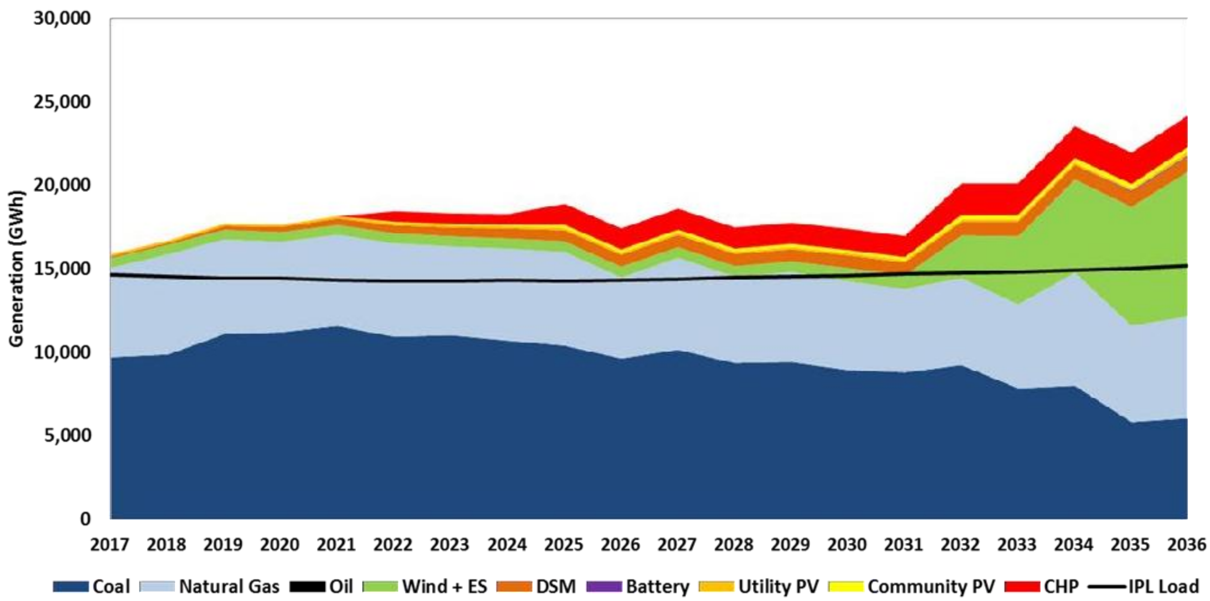


Figure 8.18 – High Customer Adoption of DG Operating Capacity Additions

	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

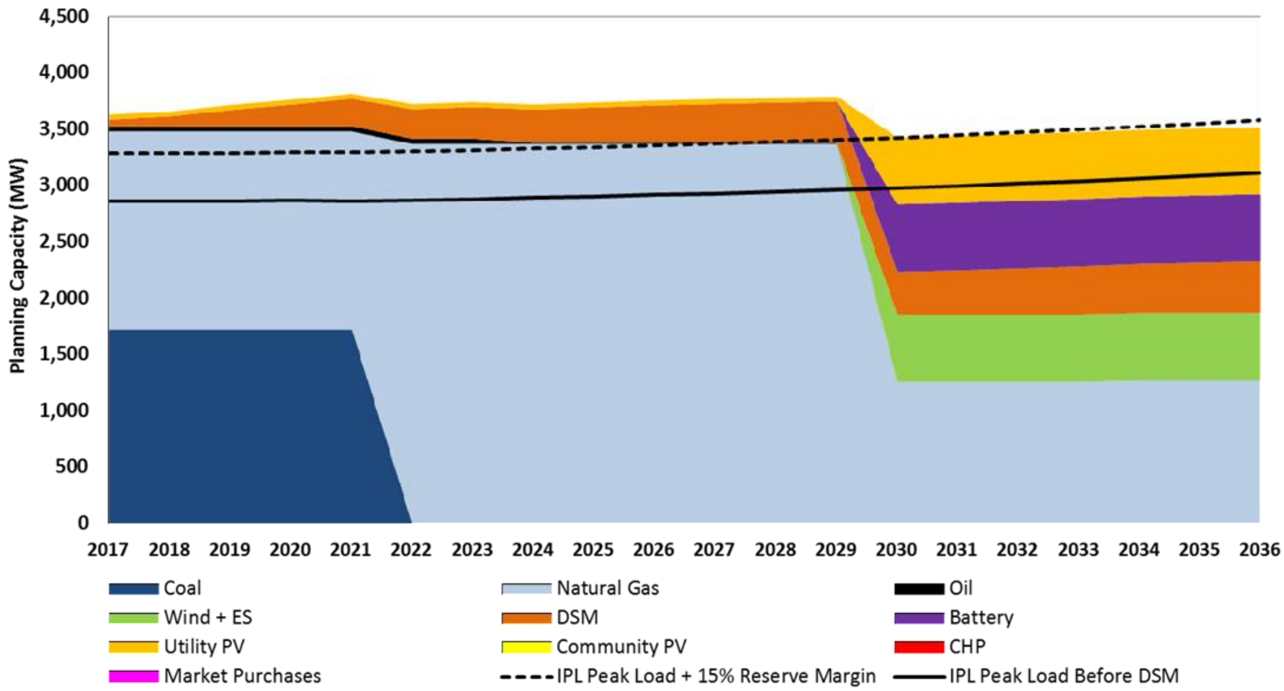
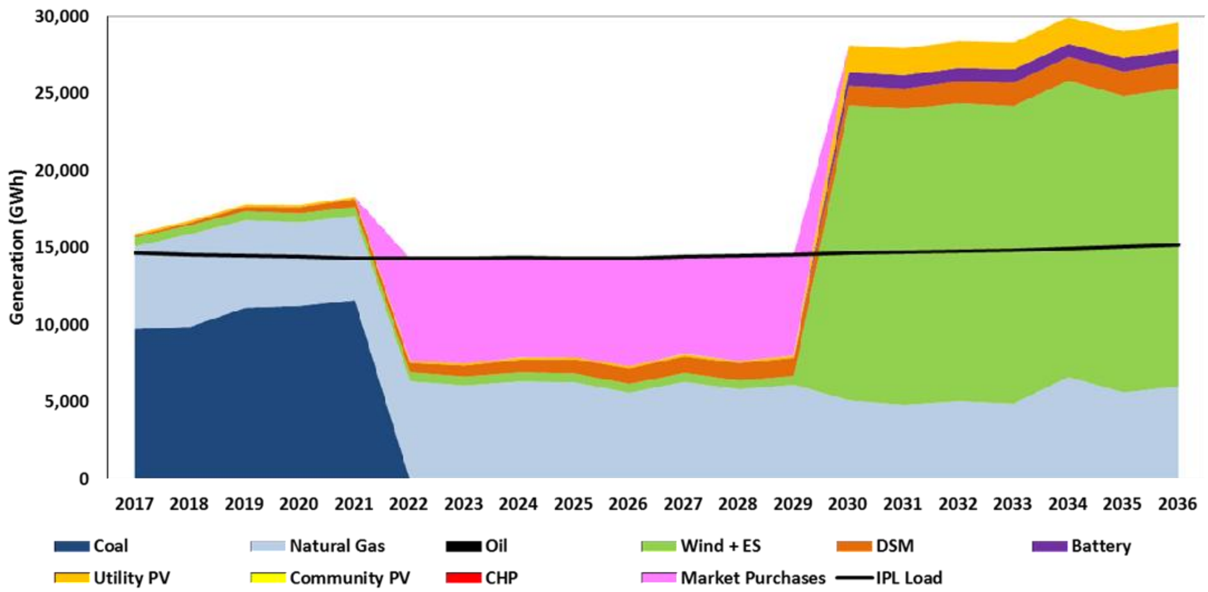


Figure 8.21 – Transition Operating Capacity Additions

	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

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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.

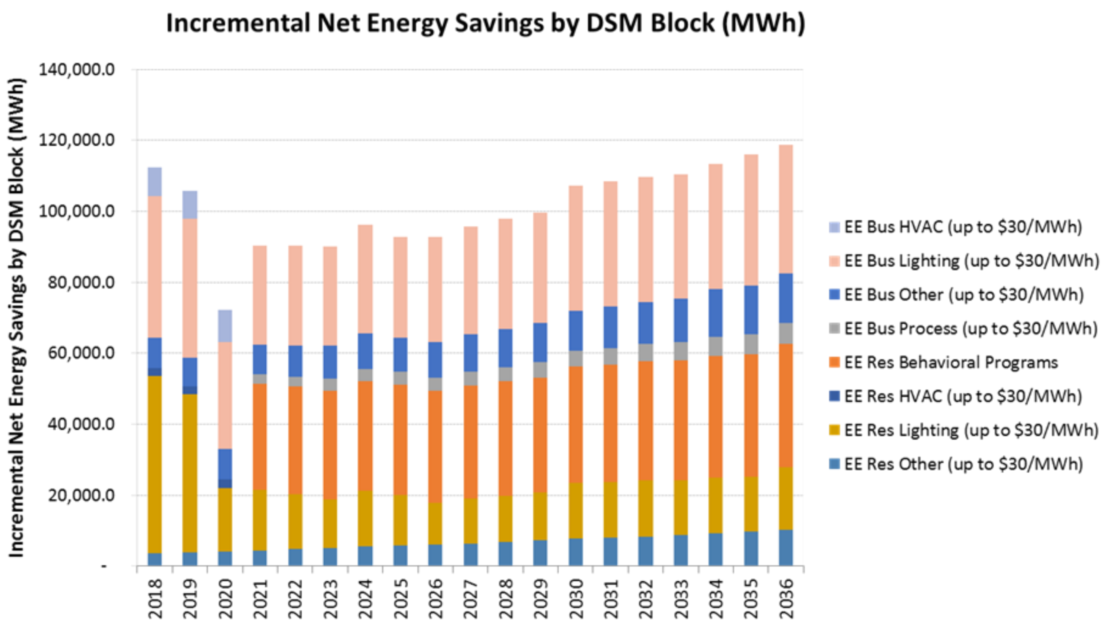
Target demand and energy savings by year for each scenario are presented below. The DSM selected by the Capacity Expansion model is at the measure (rather than at the Program level); therefore, DSM does not have certain of the metrics at this time (estimated bill reduction, participation incentive, and 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.

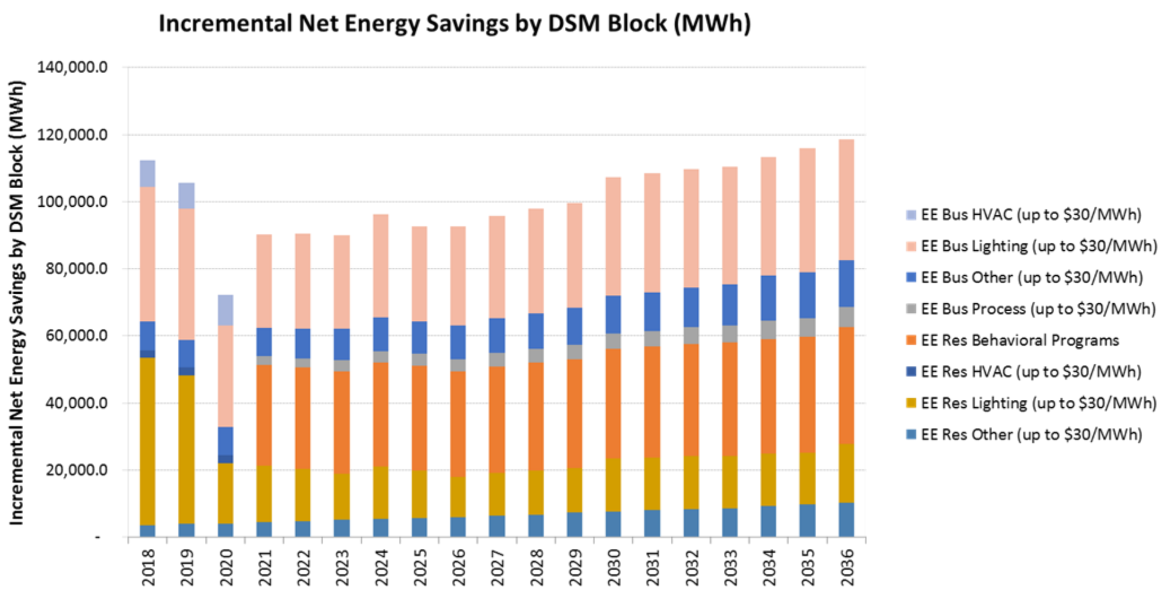
Figure 8.25 – Base Case DSM Results



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.

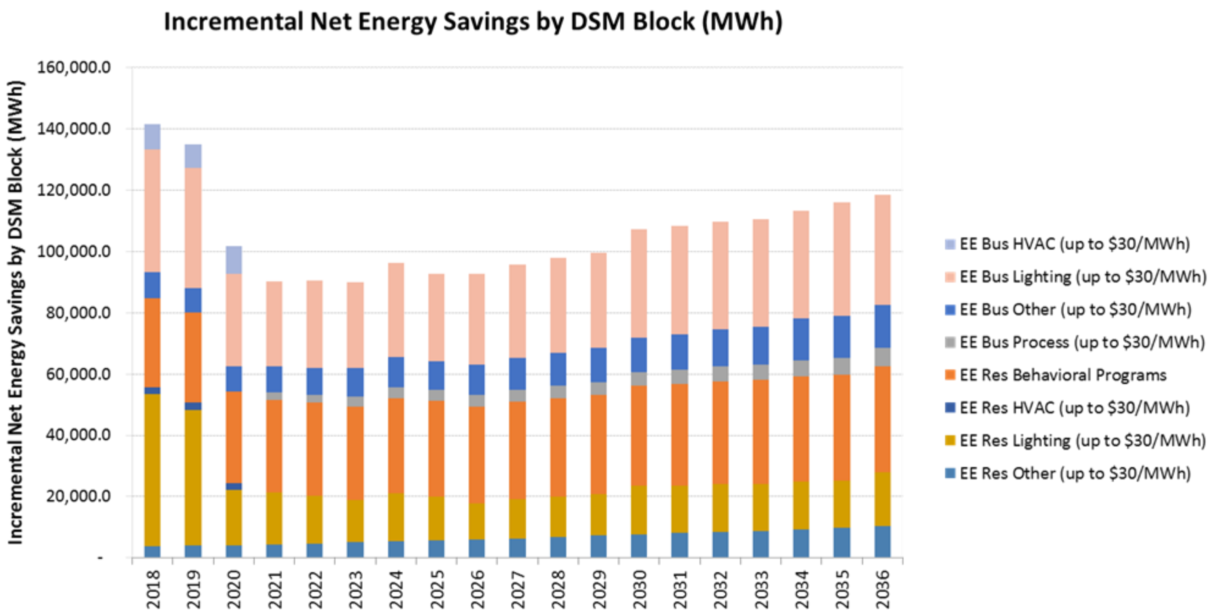
Figure 8.26 – Robust Economy DSM Results



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.

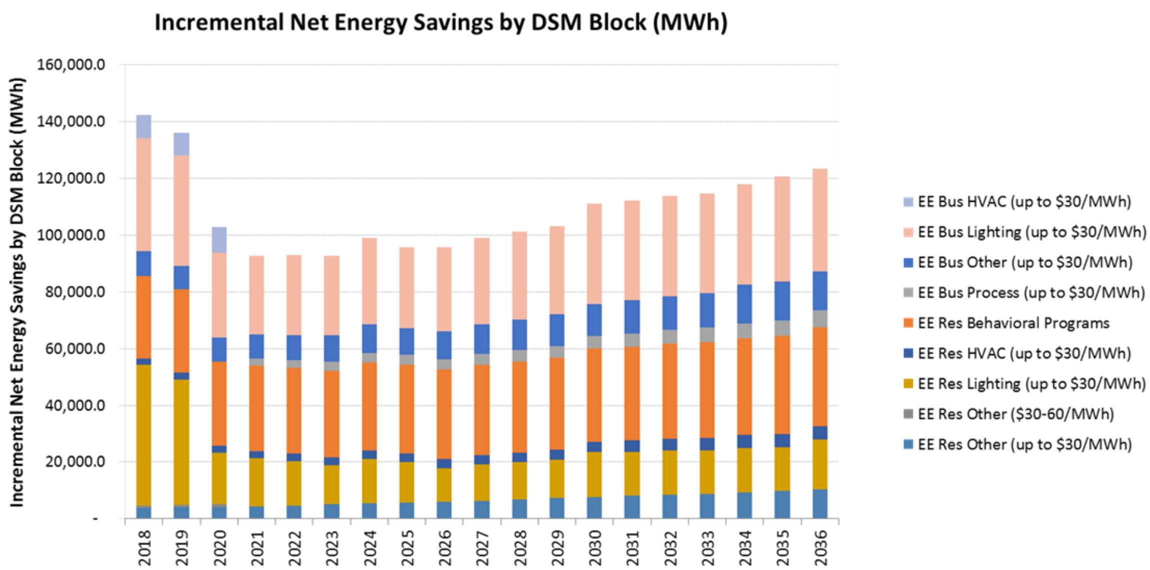
Figure 8.27 – Recession Economy DSM Results



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.

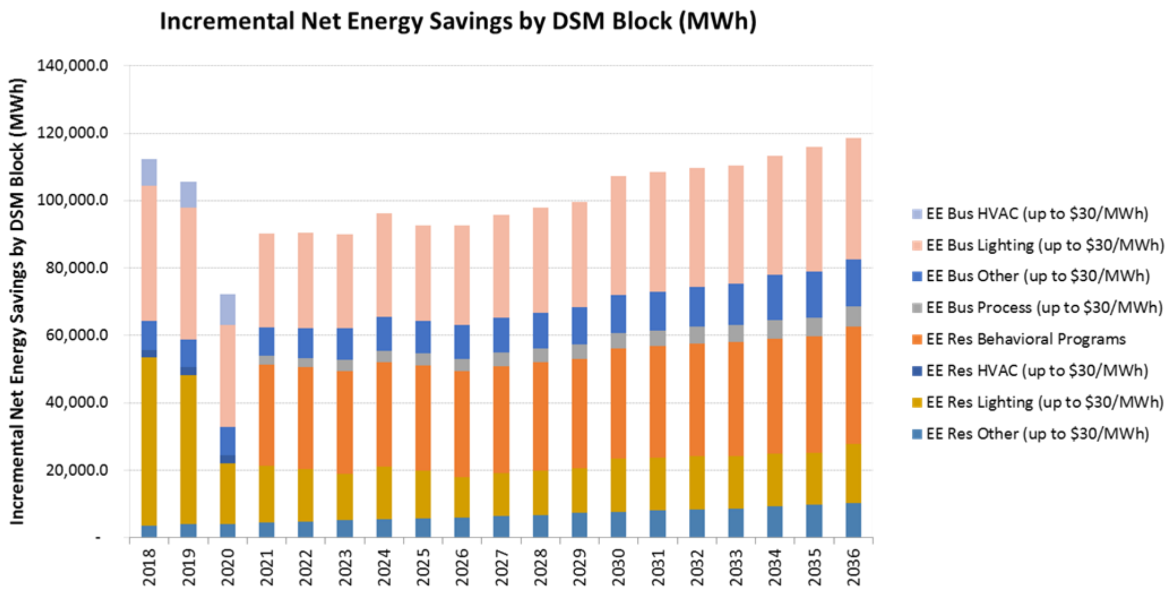
Figure 8.28 – Strengthened Environmental DSM Results



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.

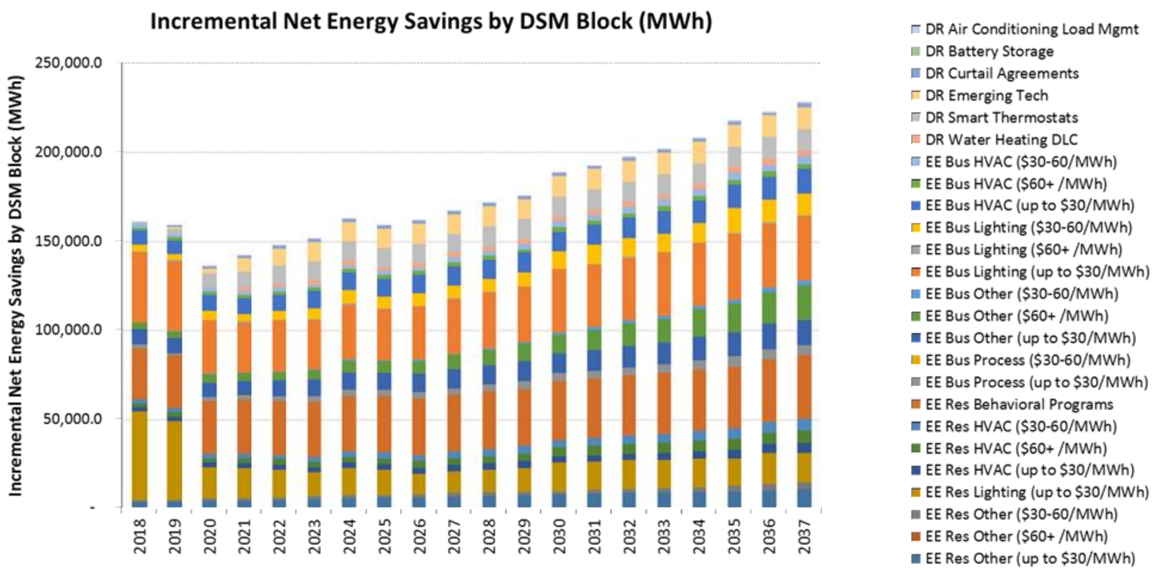
Figure 8.29 – High Customer Adoption of DG DSM Results



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)

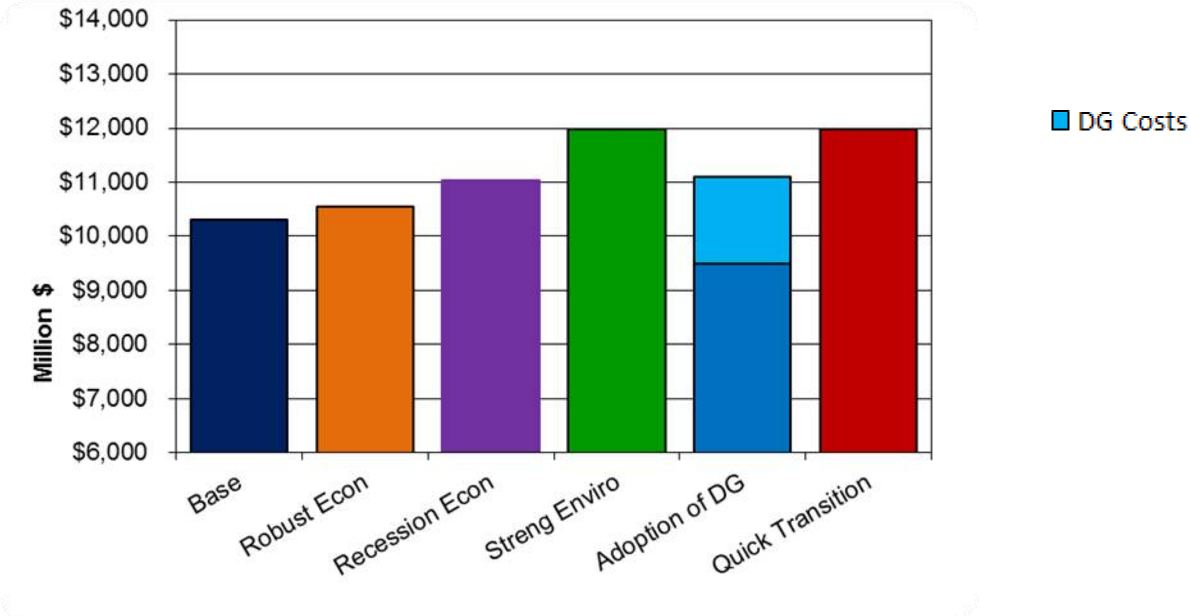
Figure 8.31 – PVRR Results (2017-2036) shows the deterministic PVRR for each scenario under Base Case assumptions. The Production Cost model took each portfolio produced by the Capacity Expansion Model and applied it to Base Case assumptions including natural gas, power prices, carbon prices, and load 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

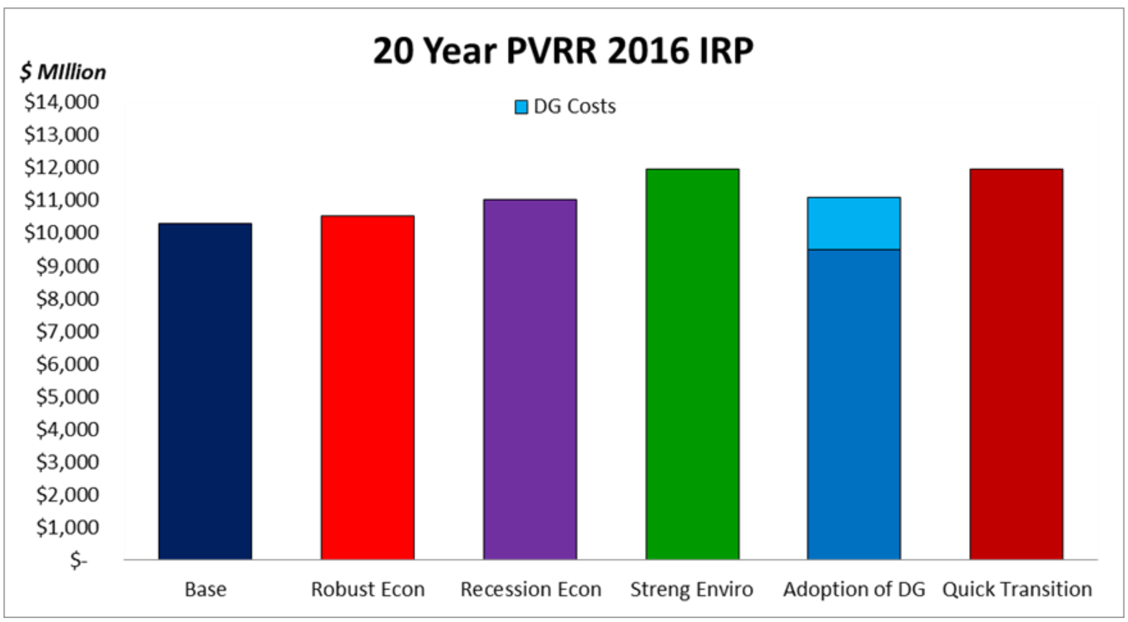
The Adoption of DG scenario includes estimated DG costs for 450 MW. These costs are represented in the light blue block below. The Production Cost model used the same technology costs and IPL's capital structure for DG, but actual customer costs may vary according to the customer's own financial situation 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

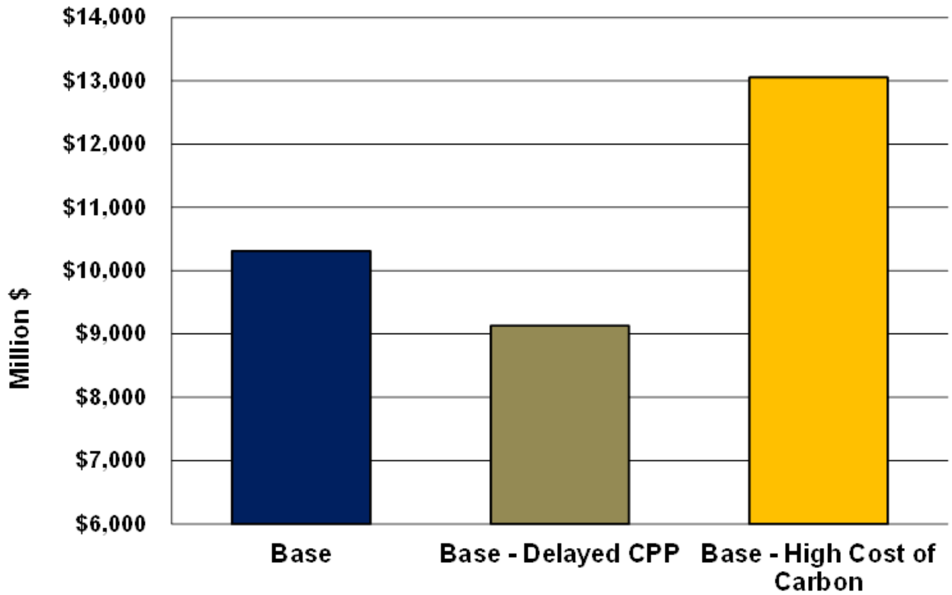
Base Case Deterministic Sensitivity 2 –"High Cost of Carbon" - More Stringent Clean Power Plan

- 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)



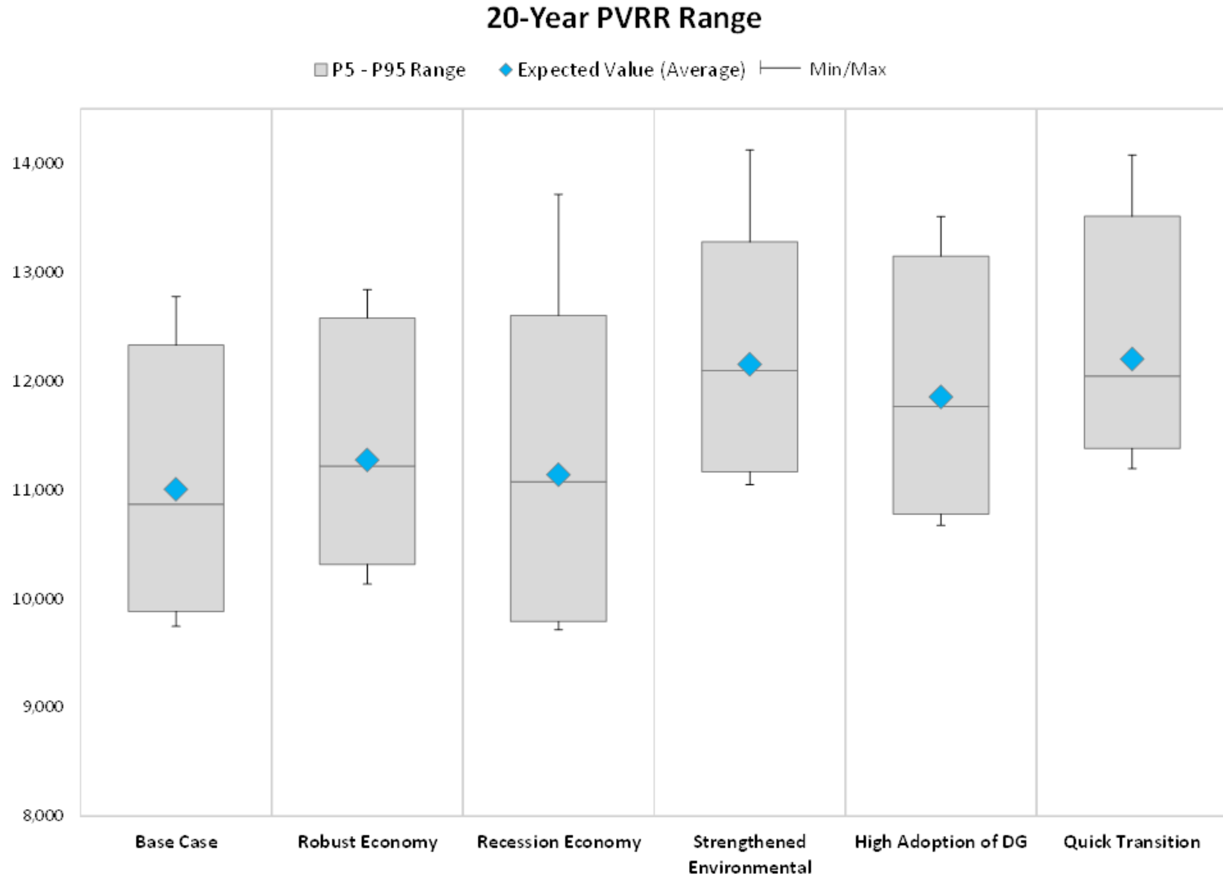
8.2.2. Stochastic Analyses Results for All Scenario Portfolios

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.

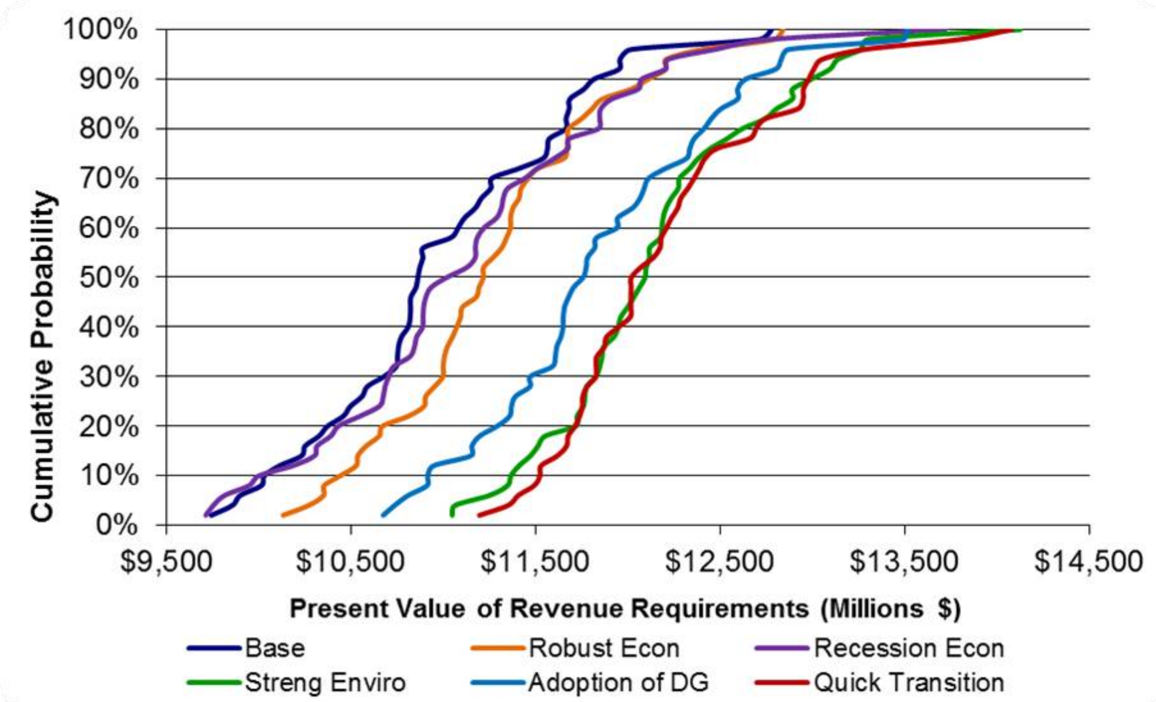
Figure 8.35 that follows contains a summary of the range of PVRRs for each portfolio based on results from the stochastic model. The gray box represents the range of PVRRs between the 5th and 95th percentiles, which means that 90% of the PVRR outcomes fell in this range. The horizontal bar within that 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



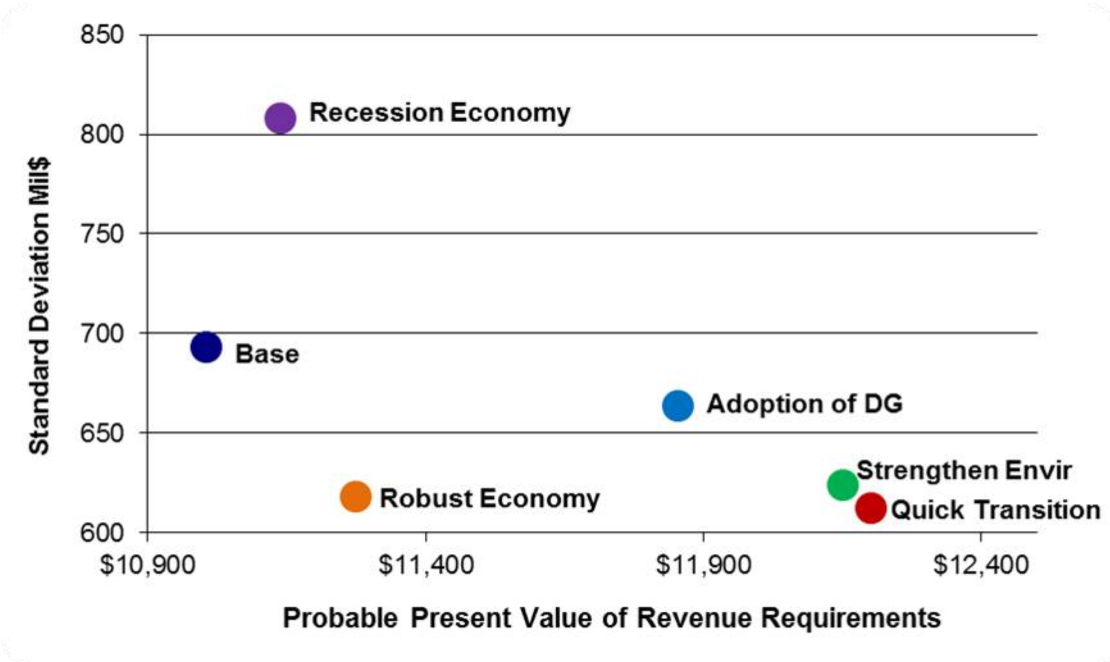
Another useful took to compare the portfolios is a risk profile chart, or a cumulative probability chart. The risk profile shows the distribution of PVRR outcomes from the fifty stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%. Figure 8.36 contains 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)

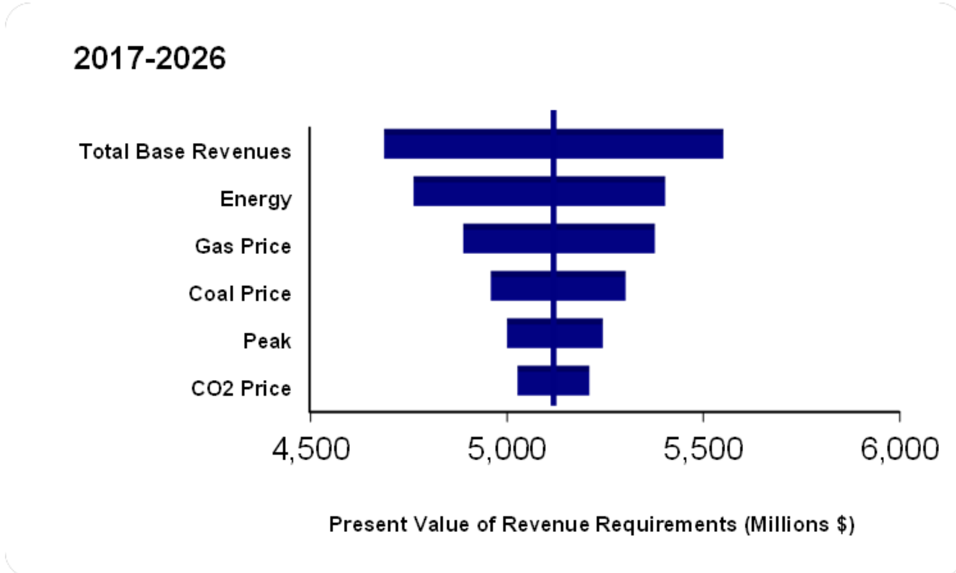


Figure 8.39 – Final Base Plan - Tornado Chart (2027-2036)

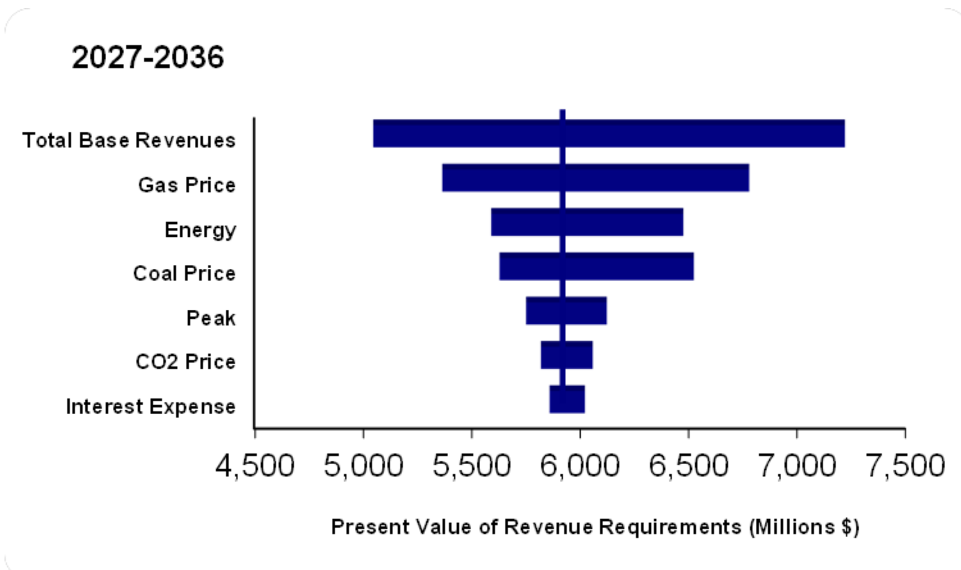


Figure 8.40 – Robust Economy - Tornado Chart (2017-2026)

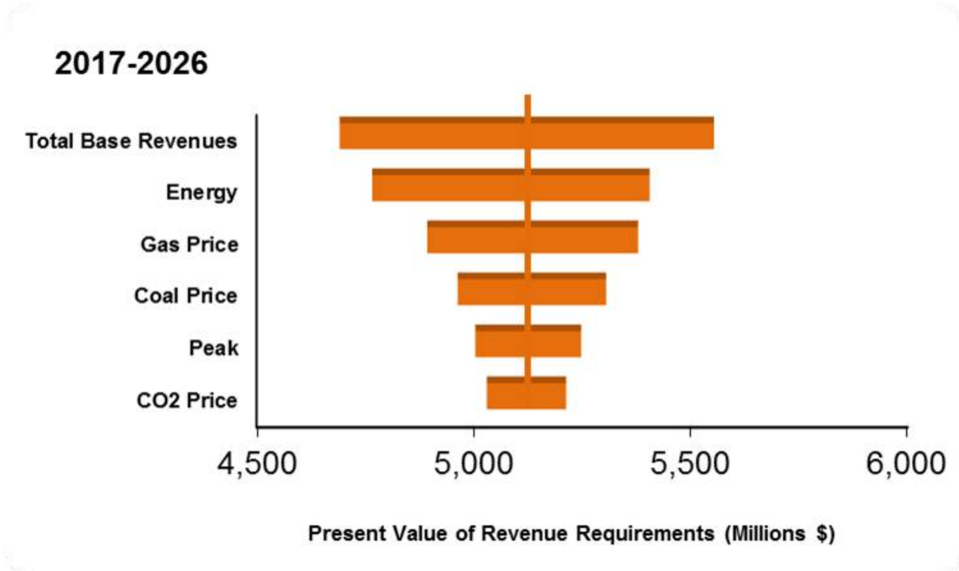


Figure 8.41 – Robust Economy - Tornado Chart (2027-2036)

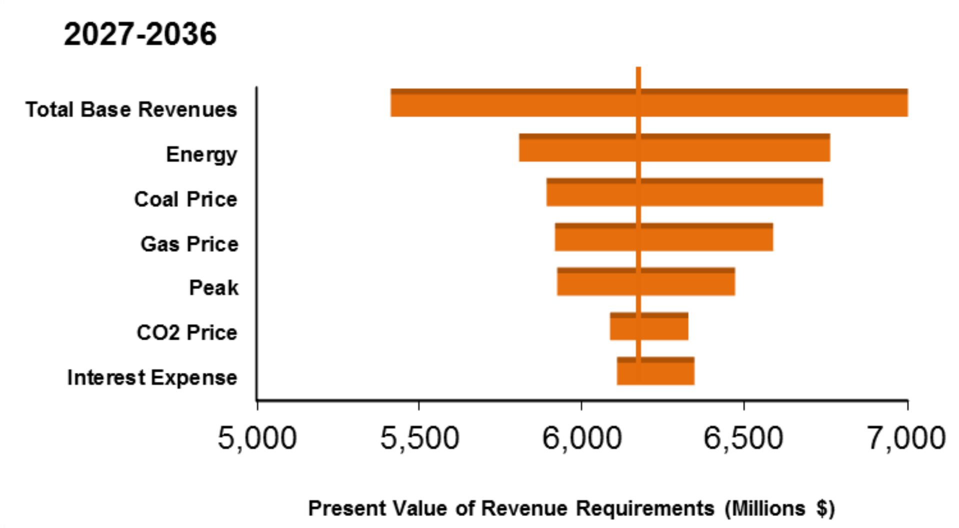


Figure 8.42 – Recession Economy - Tornado Chart (2017-2026)

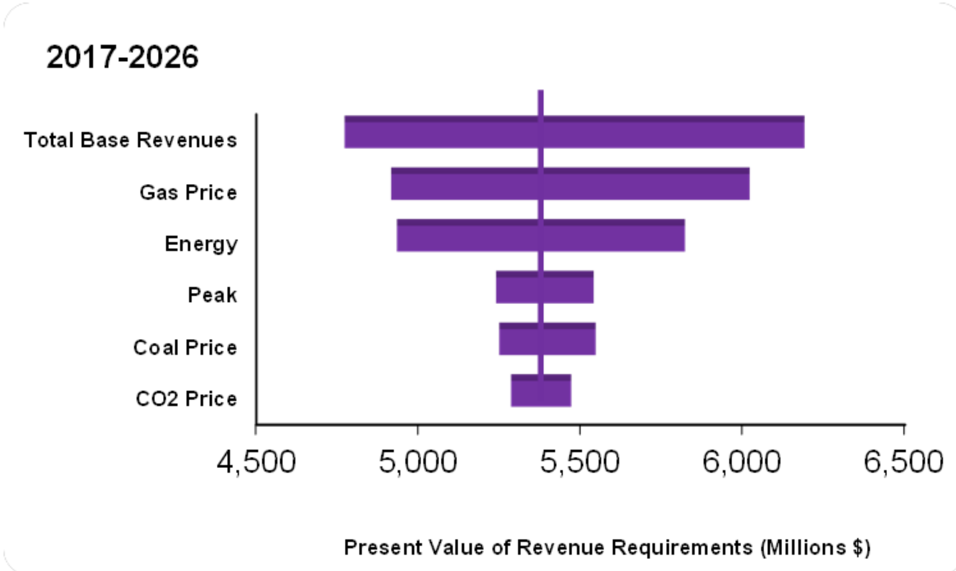


Figure 8.43 – Recession Economy - Tornado Chart (2027-2036)

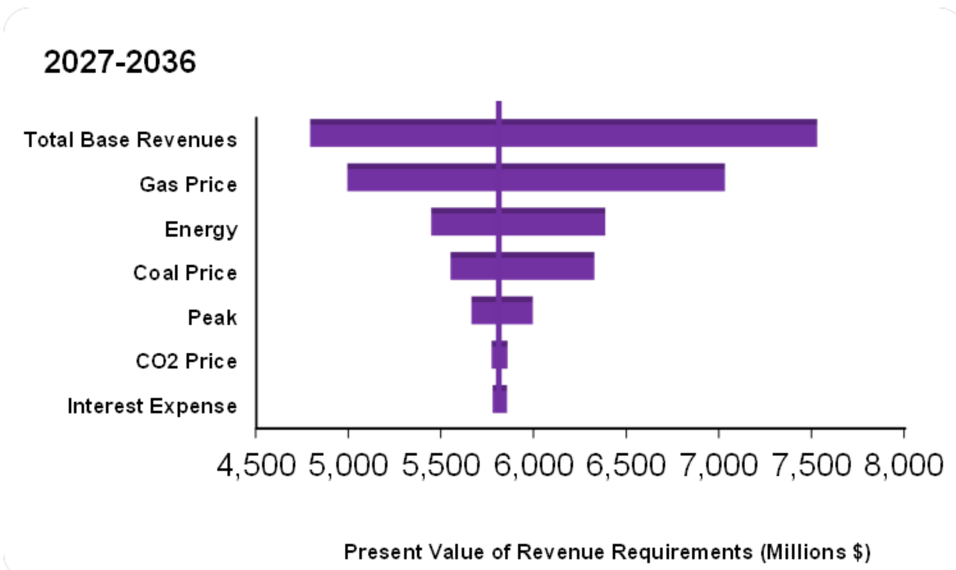


Figure 8.44 – Strengthened Environmental - Tornado Chart (2017-2026)

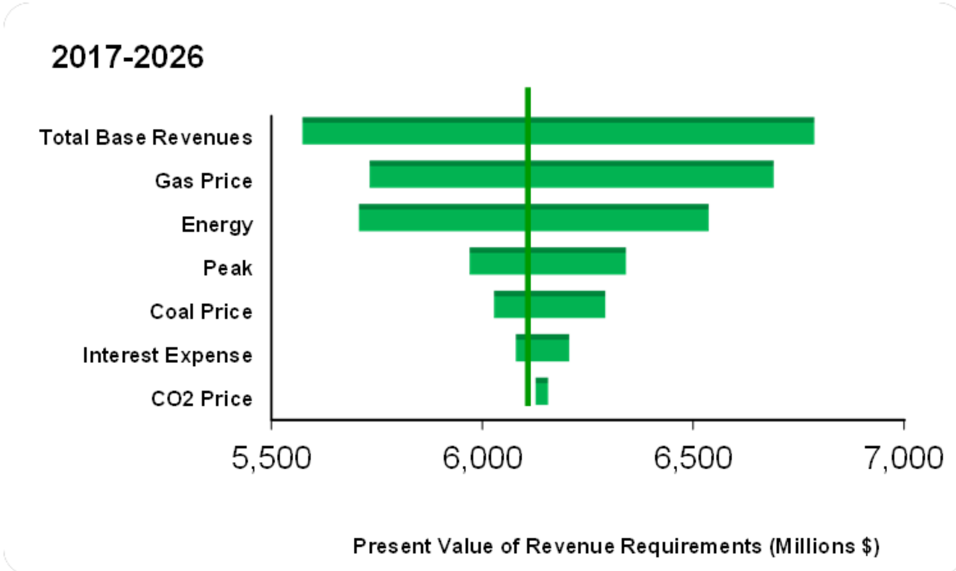


Figure 8.45 – Strengthened Environmental - Tornado Chart (2027-2036)

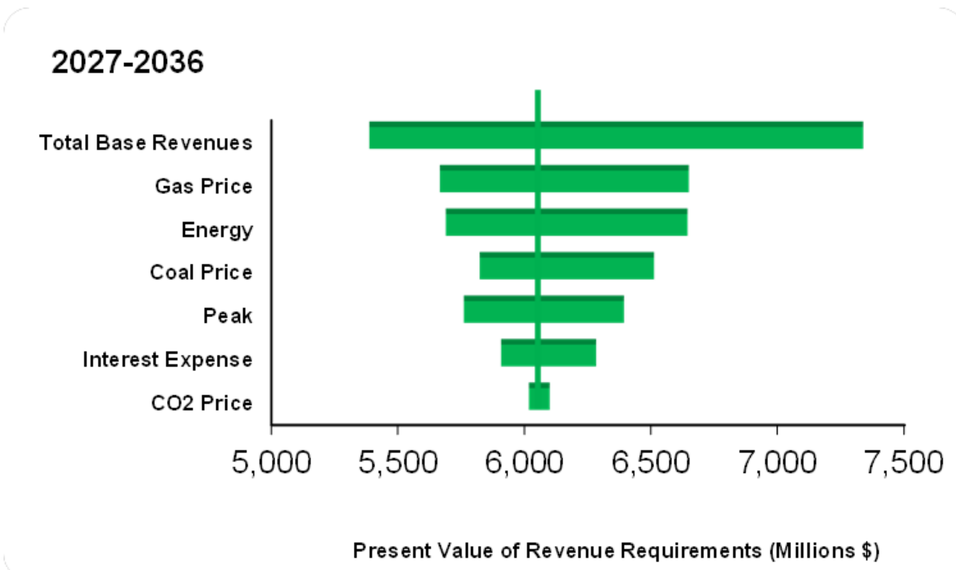


Figure 8.46 – Adoption of DG, Tornado Chart (2017-2026)

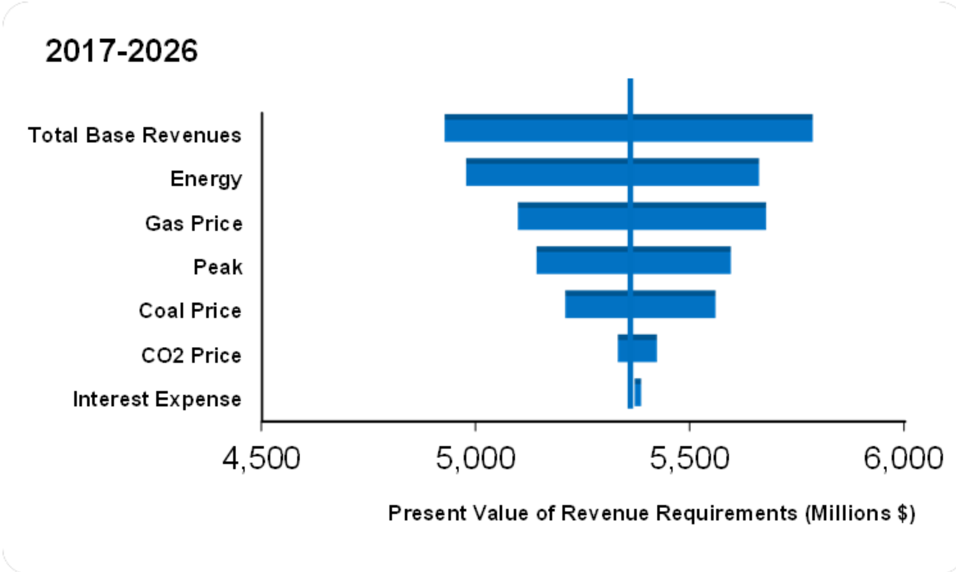


Figure 8.47 – Adoption of DG - Tornado Chart (2027-2036)

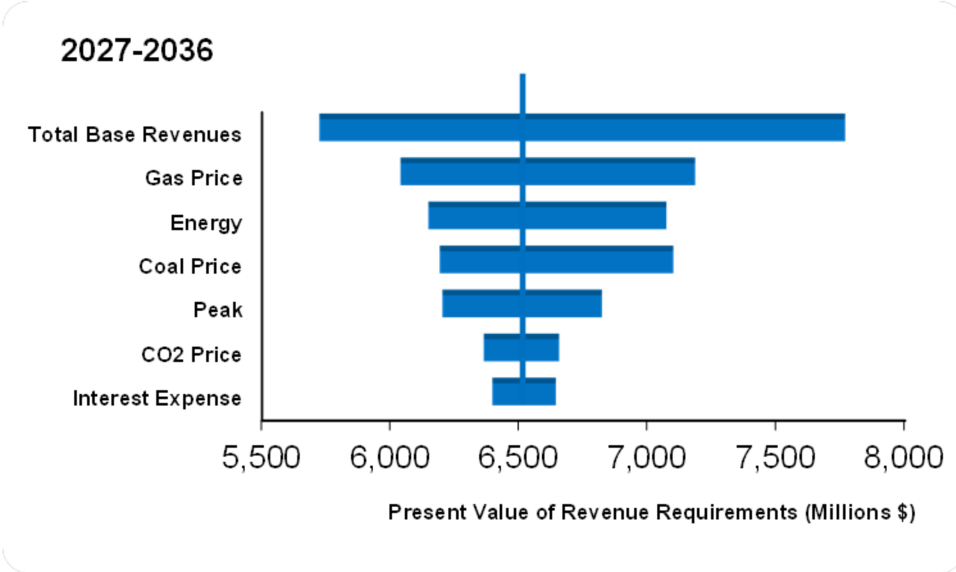


Figure 8.48 – Quick Transition - Tornado Chart (2017-2026)

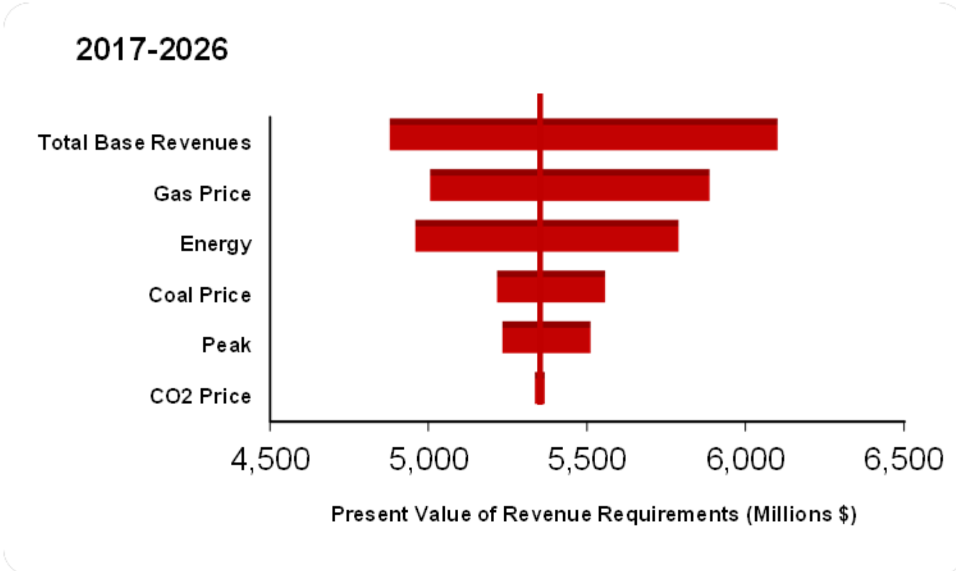
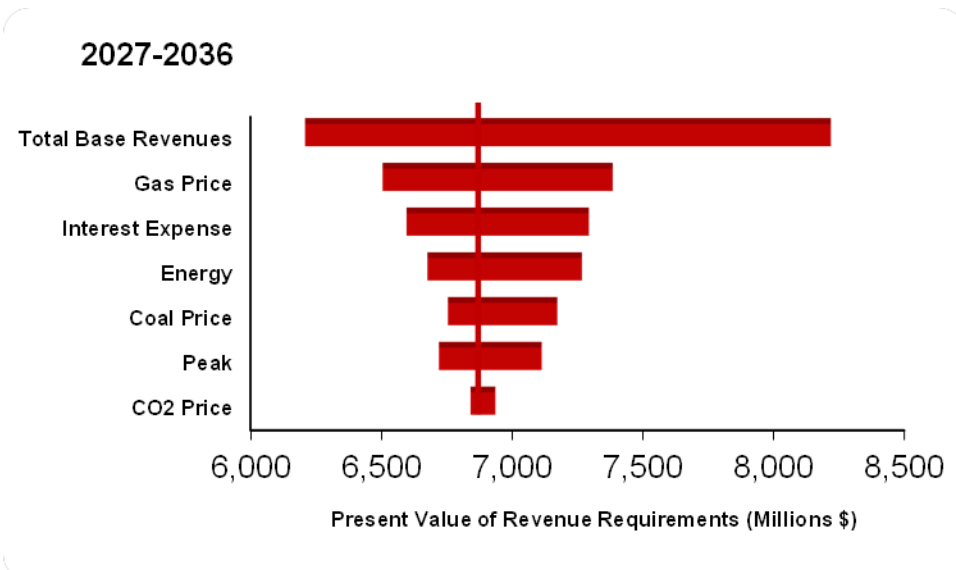


Figure 8.49 – Quick Transition - Tornado Chart (2027-2036)



8.3. Scenario Metrics Results

170 IAC 4-7-8(b)(2)

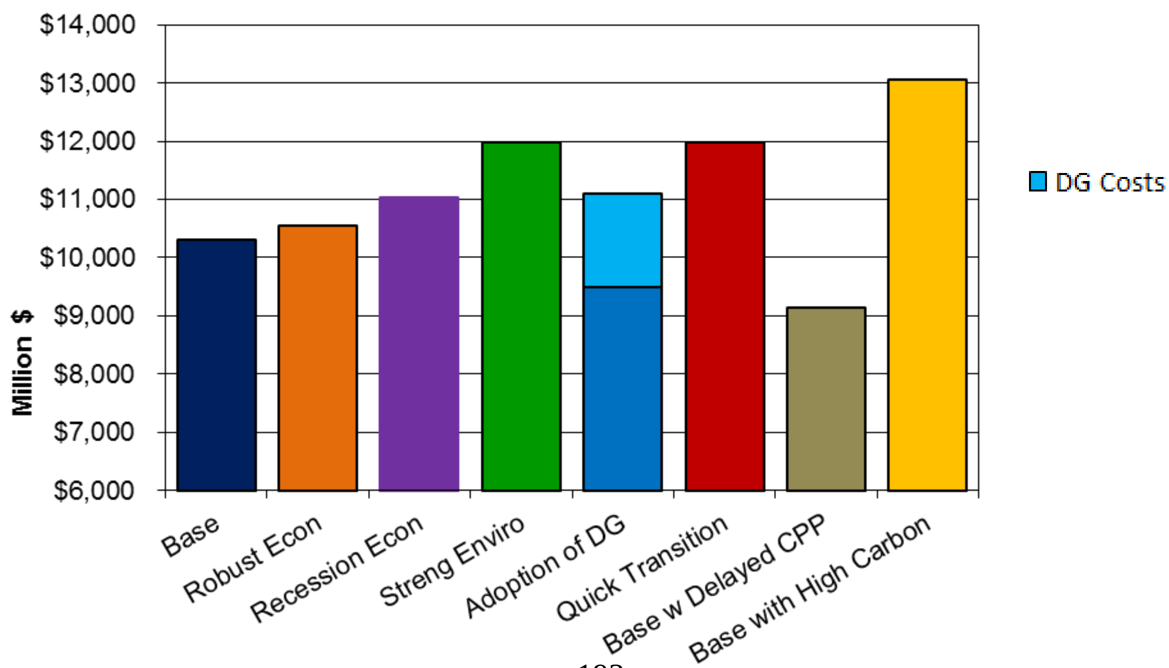
As explained in Section 7, IPL used four categories of metrics to compare the portfolios: Cost, Financial Risk, Environmental Stewardship, and Resiliency. The results of the eleven IPL metrics in the four metrics categories are summarized below. As explained in Section 7, metrics are not meant to provide 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

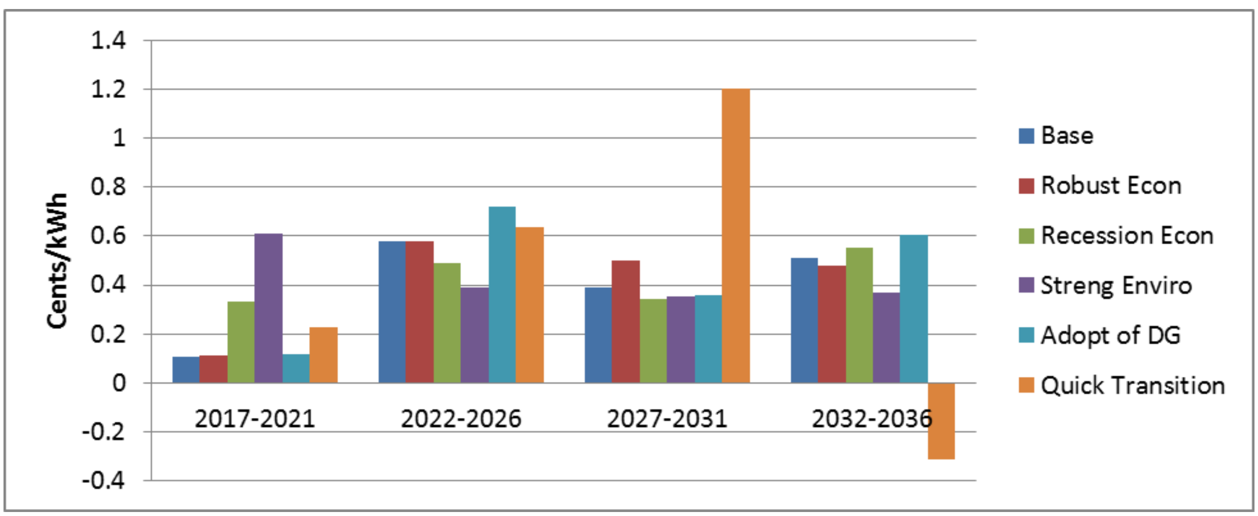


8.3.1.2 *Metric 2: Rate Impact*

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.

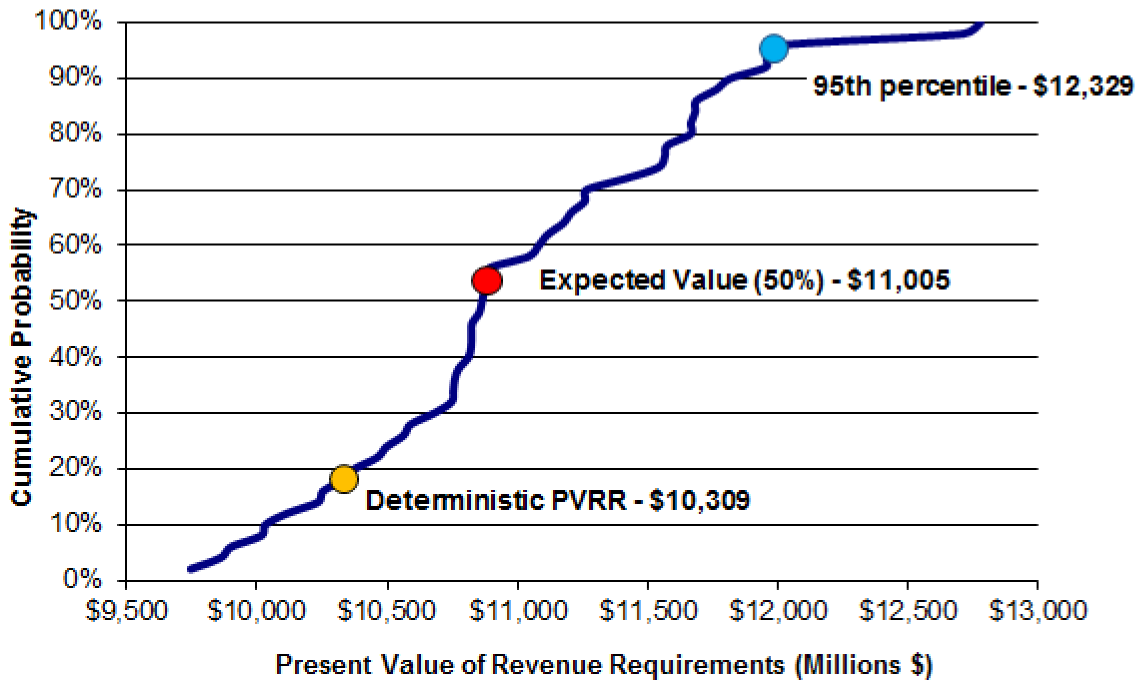
8.3.2. Financial Risk Category

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*

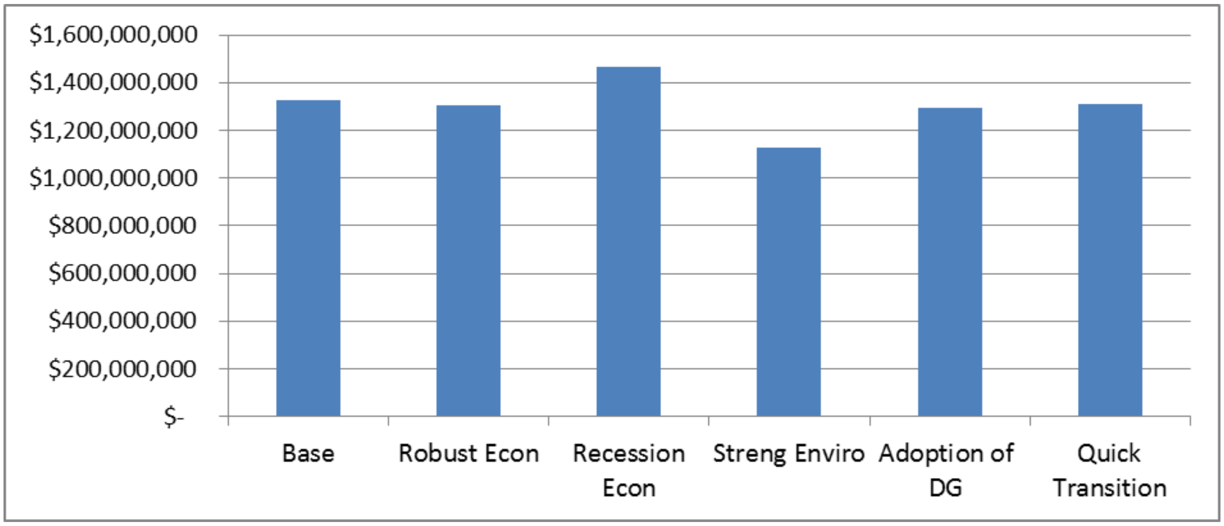
The Risk Exposure metric calculates risk exposure by subtracting the PVRR at the Expected Value from the PVRR at the 95th percentile. Figure 8.52 shows the risk profile for the Base Case and illustrates how this metric is calculated, and Figure 8.52 shows the results of the Risk Exposure metric for each 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



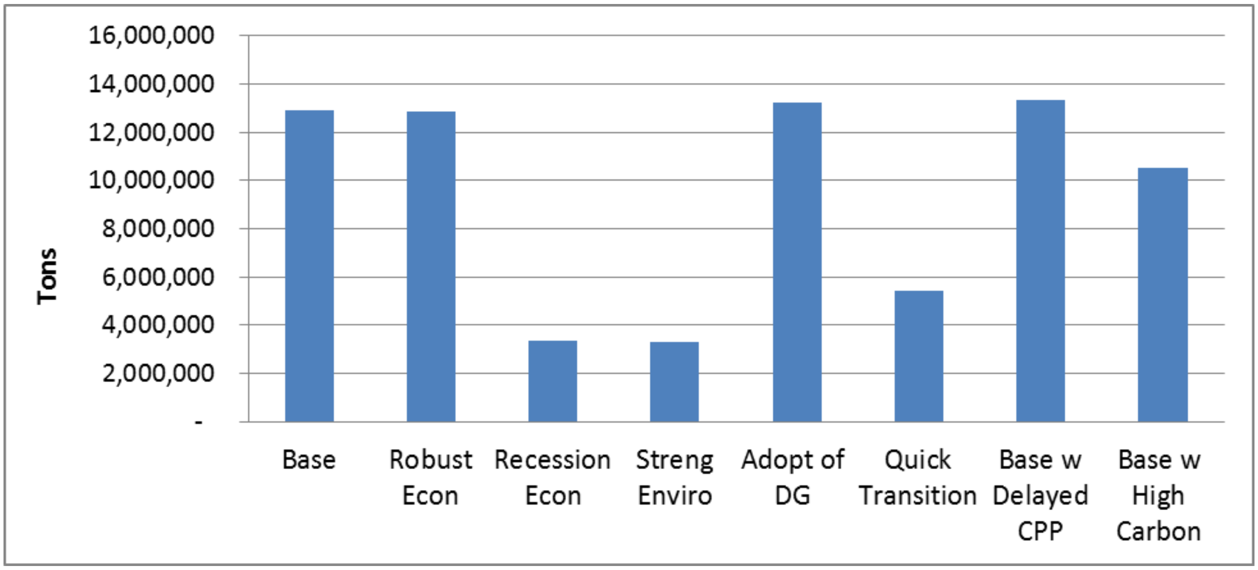
8.3.3. Environmental Stewardship Category

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*

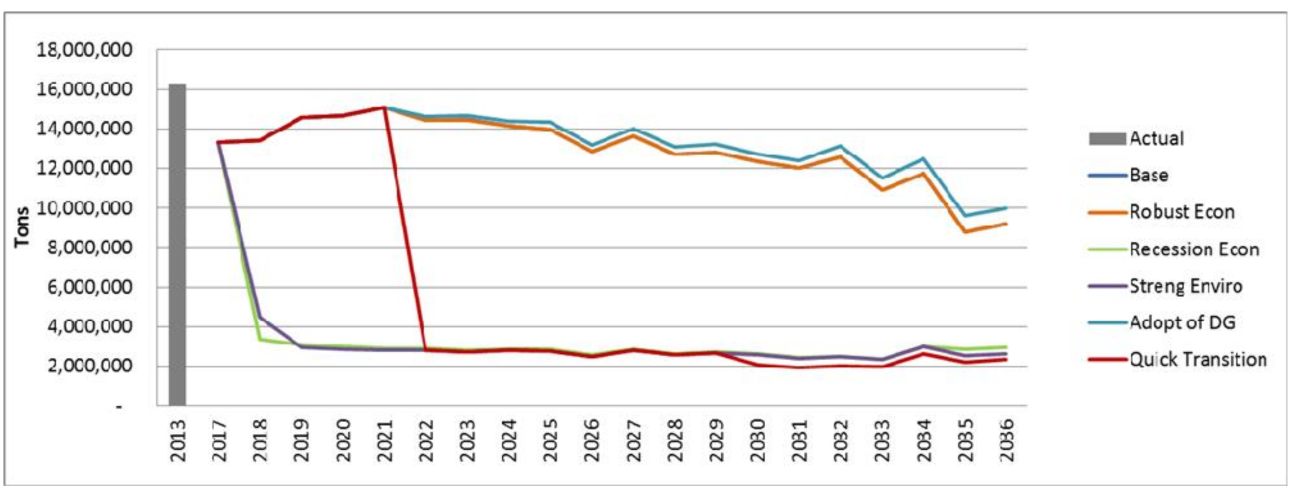
Figure 8.54 shows the annual average CO_2 emissions by scenario. These results were calculated by taking the total CO_2 emissions over the study period and dividing them by 20, the number of years in the study period.

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

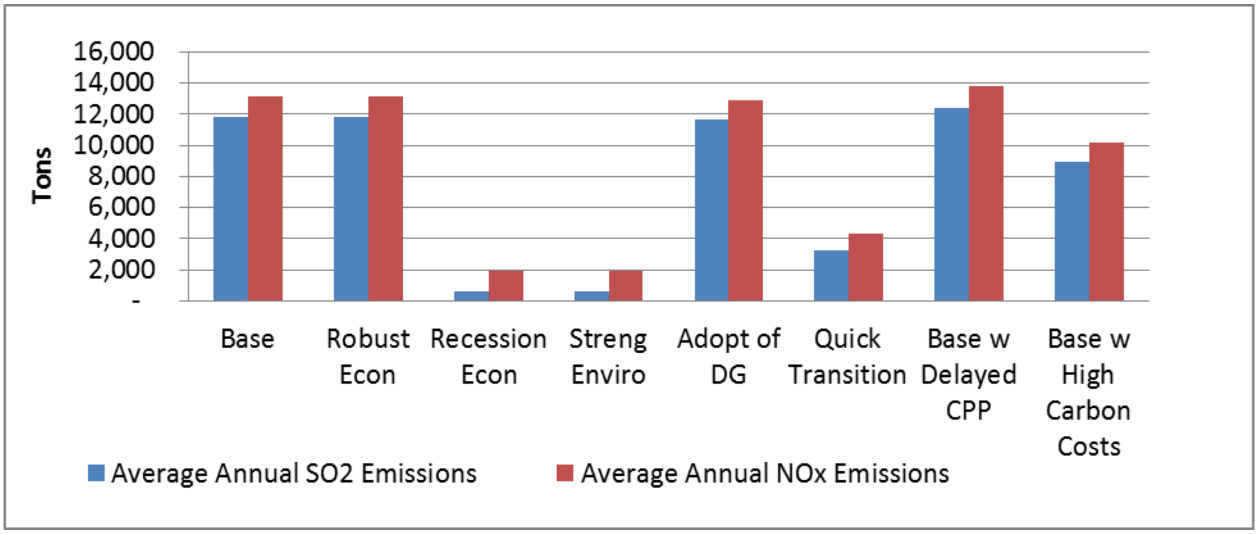


Figure 8.57 and Figure 8.58 show the projected annual emissions for each scenario compared to the 2013 annual NO_x and SO_2 emissions. Scenarios in which Pete units retire early or refuel to natural gas also have lower SO_2 and NO_x emissions. The Quick Transition scenario, in which Pete 1-4 use coal 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

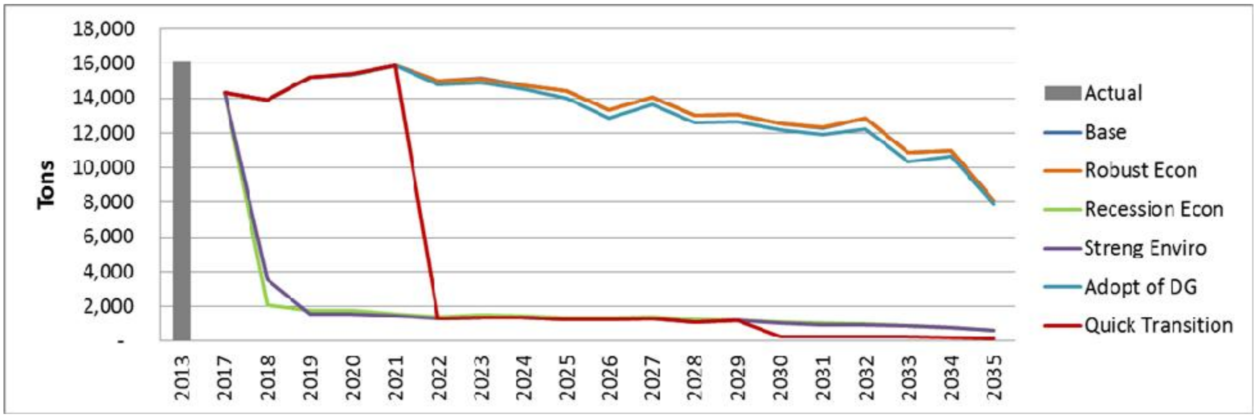
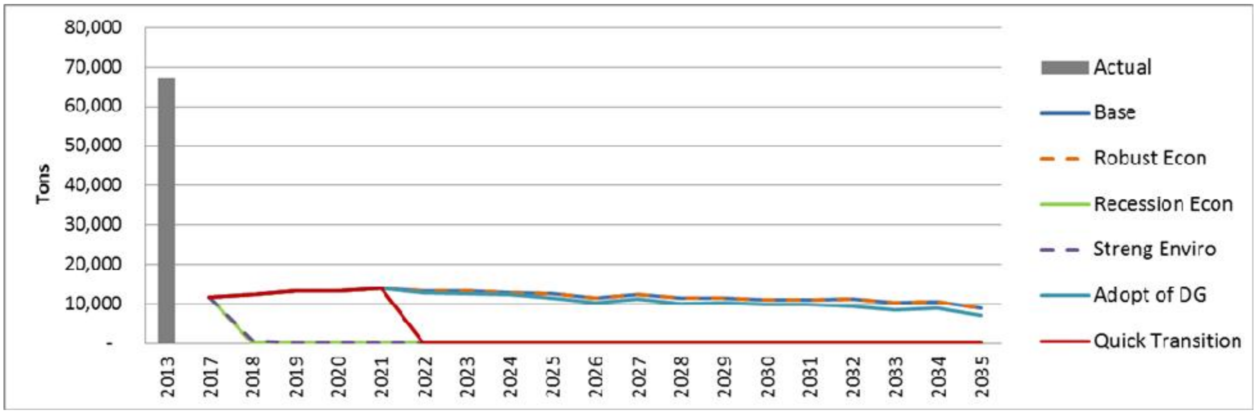


Figure 8.58 – Historical and Forecasted IPL Annual SO_2 Emissions

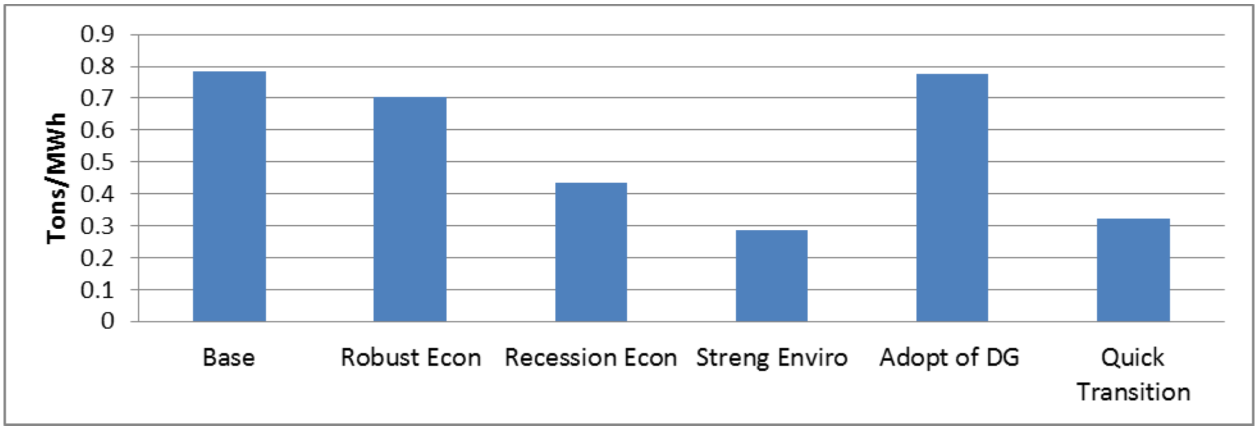


The Production Cost model shows the Base Case and Adoption of DG portfolios resulting in similar NO_x and SO_2 emissions. Not only do the two scenarios result in similar portfolios throughout most of the study period, but 225 MW of CHP is added to the Adoption of DG scenario. As modeled in the 2016 IRP, 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



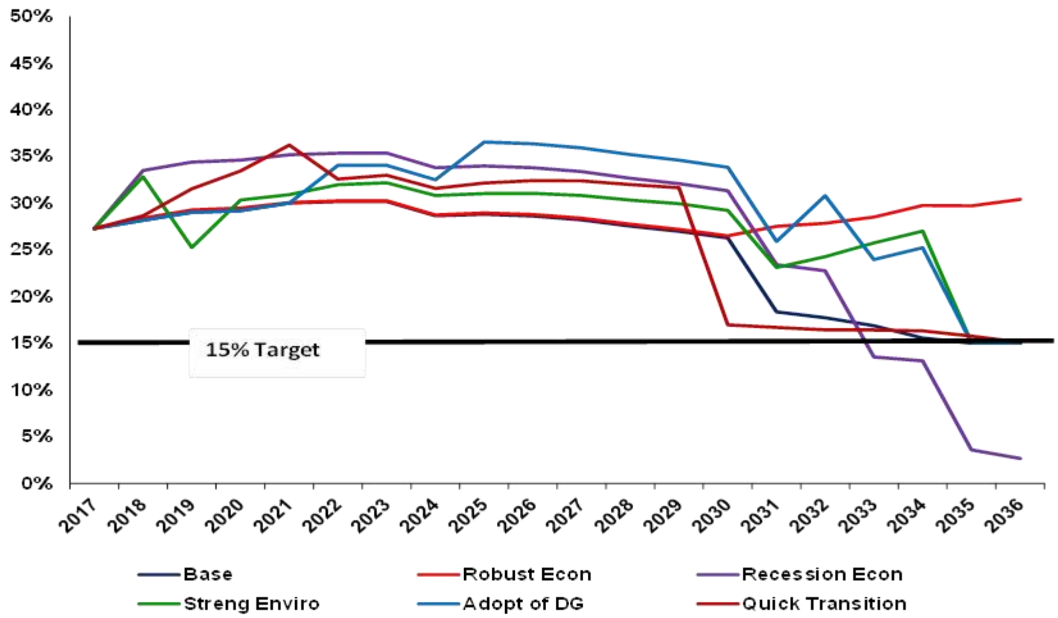
8.3.4. Resiliency

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")

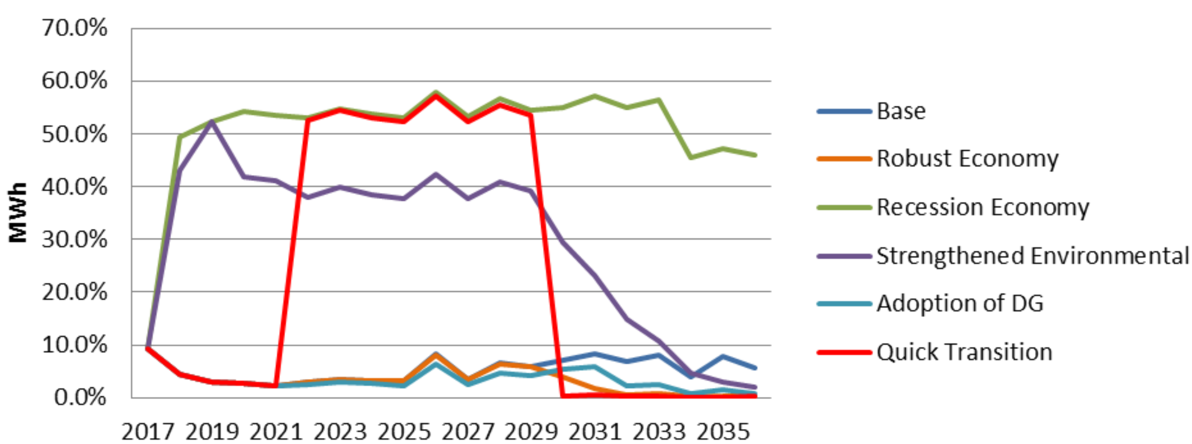
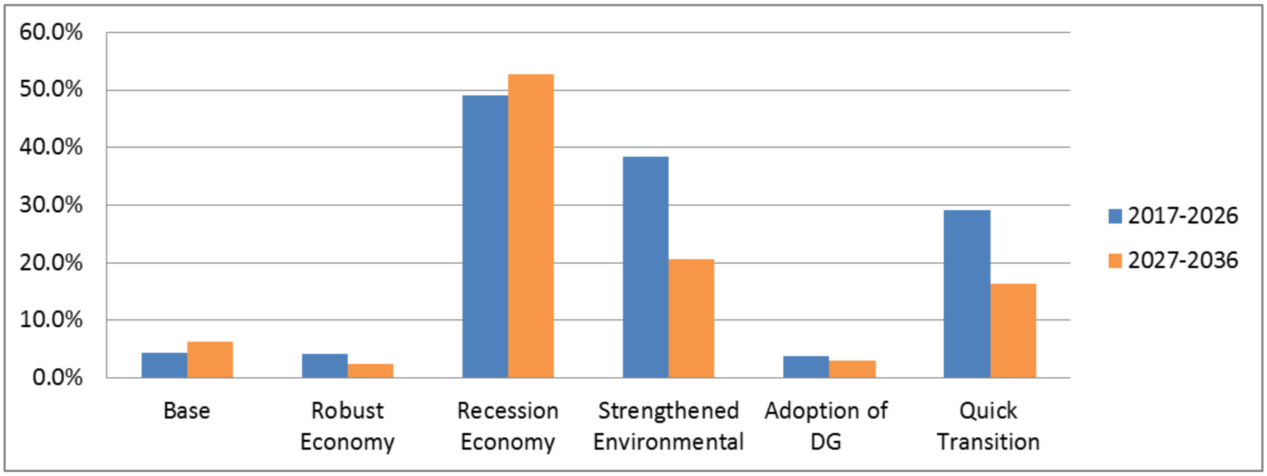


Figure 8.63 shows ten year averages of market reliance for each scenario. Based on ten year averages, the Recession Economy scenario has the high market reliance for energy, which shows that converting Pete to natural gas and then adding very few resources will expose IPL to a high level of market volatility 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.

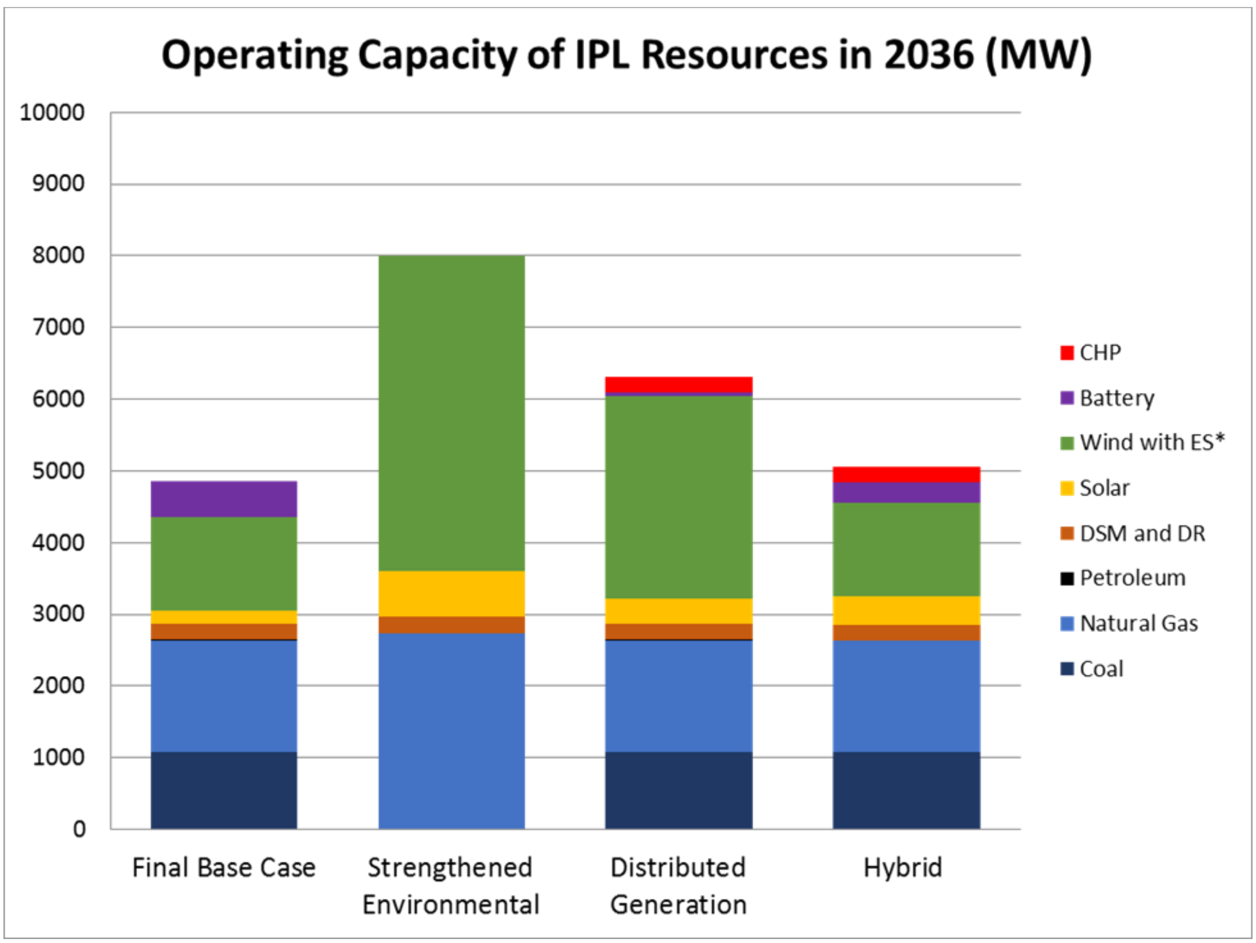
A hybrid portfolio in 2036 may include two Pete coal units, minimum natural gas generation for local system reliability, wind to serve load during non-peak periods, and an average of DSM, solar, energy storage levels from the three scenarios as summarized in Figure 8.66 and Figure 8.67 below.

[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)***

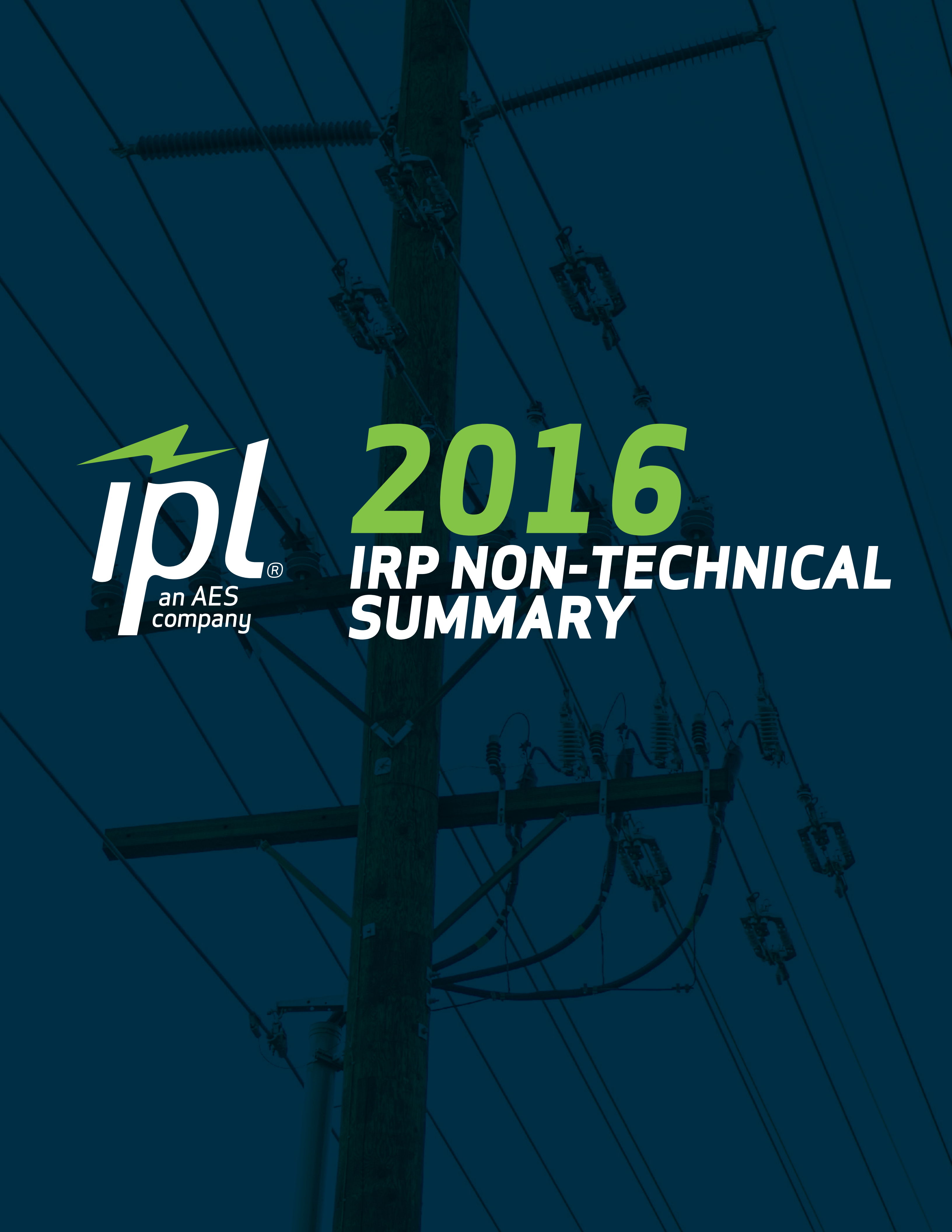
Confidential Attachment 5.10 (Avoided Cost Calculation) **170 IAC 4-7-4(b)(12) 170 IAC 4-7-6(b)(2) 170 IAC 4-7-8(b)(6)(C)**

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)**



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2016 IRP NON-TECHNICAL SUMMARY

BACKGROUND

Indianapolis Power & Light Company ("IPL") is committed to improving lives by providing safe, reliable, and sustainable energy solutions 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, which is 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 Operator ("MISO").

Effective planning is integral to serving customers , including anticipating and reacting to 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. Every two years, IPL submits an IRP to the Indiana Utility Regulatory Commission ("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 propose candidate resource portfolios 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.

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 throughout the study period giving due consideration to potential risks and stakeholder input.

IRP Process

IPL   starts the IRP process by modeling its existing resource mix and forecasts customer energy and peak requirements. The existing resources include Demand Side Management (DSM), approximately 2,700 MW of generating resources, and long term contracts known as purchase power agreements ("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.

However, IPL reserves the right to use RECs to meet any future environmental requirement, such as the EPA's Clean Power Plan ("CPP").

Figure 1 highlights IPL's service territory and resources.

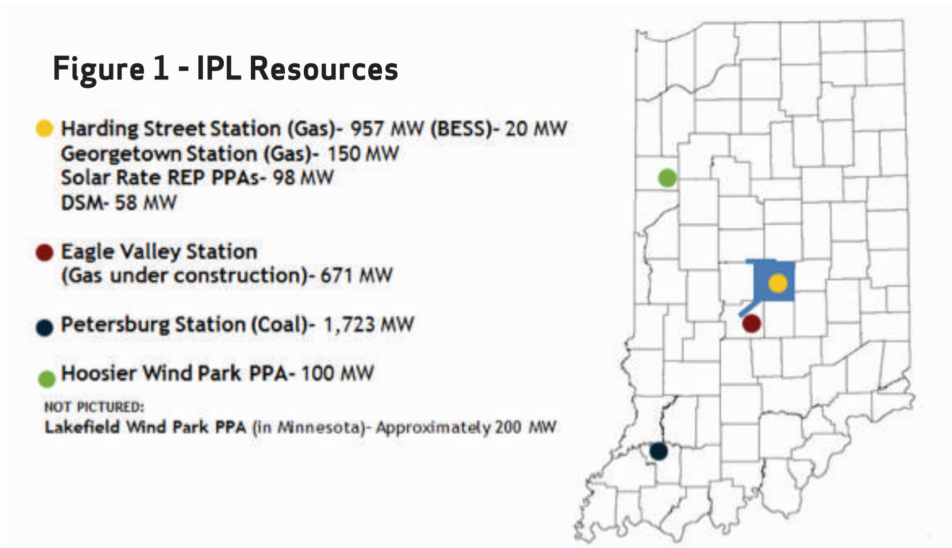

Figure 1 - IPL Resources

Since 2007, IPL has been a leader in moving towards cleaner resources as shown in Figure 2.

Figure 2 - IPL Resources

IPL identifies potential supply-side resources such as wind, solar, energy storage, or natural gas generation, and demand-side resources such as additional energy efficiency programs , for the IRP model to select to meet future customer energy requirements.

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*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."

The electric utility industry continues to evolve through technology advancements, fluctuations in customer consumption, changes in state and federal energy policies, uncertainty of long-term fuel supply and prices, and a multitude of other factors. Since the impacts these factors will have on the future utility industry landscape remains largely uncertain, IPL models multiple possible scenarios to evaluate various futures. In this IRP, IPL incorporated potential risks quantitatively and qualitatively in six scenarios summarized in Figure 3.

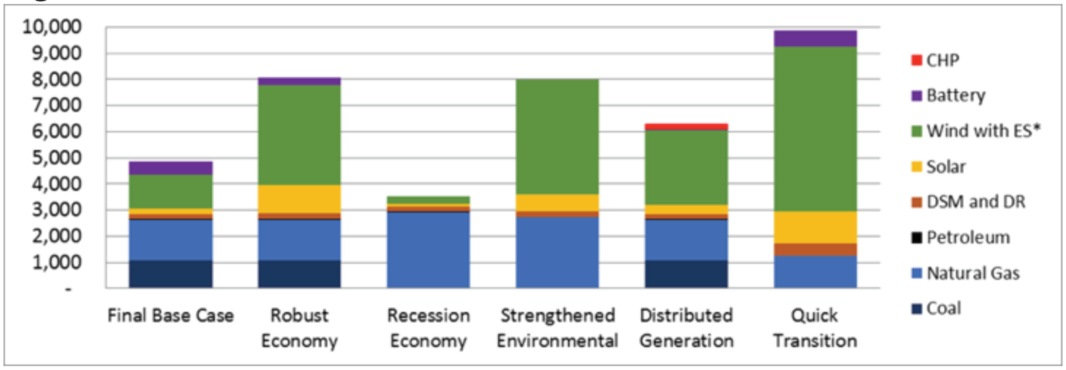
Figure 3 - IRP Scenario Drivers

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	CPP starting in 2022, Low cost environmental regulations	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 cost CPP and environmental regulations**	Base Case
5	**Distributed Generation**	Base Case	Base Case	Base Case	**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**

The IRP model produces potential candidate future resource portfolios in light of uncertainties and risk factors identified to date. "Unknown unknowns", such as public policy changes not yet proposed or unexpected future environmental regulations are not included, which could affect 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.

The candidate resource portfolios resulting from each scenario at the end of the 20 year IRP study period are shown in Figure 4.

Figure 4 - Candidate Resource Portfolios (MW in 2036)



The "Preferred Resource Portfolio" represents what IPL believes to be the most likely based on factors known at the time of the IRP filing. 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 the traditional customer cost metric of PVRR, 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 5.

Figure 5 - 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 prompted further developments which lead 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.

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 regulation. . 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.

Given that a blend of variables from the base case, strengthened environmental and DG scenarios appear likely to come to fruition , IPL contends that, at this point, a hybrid preferred resource portfolio may be a more appropriate solution.

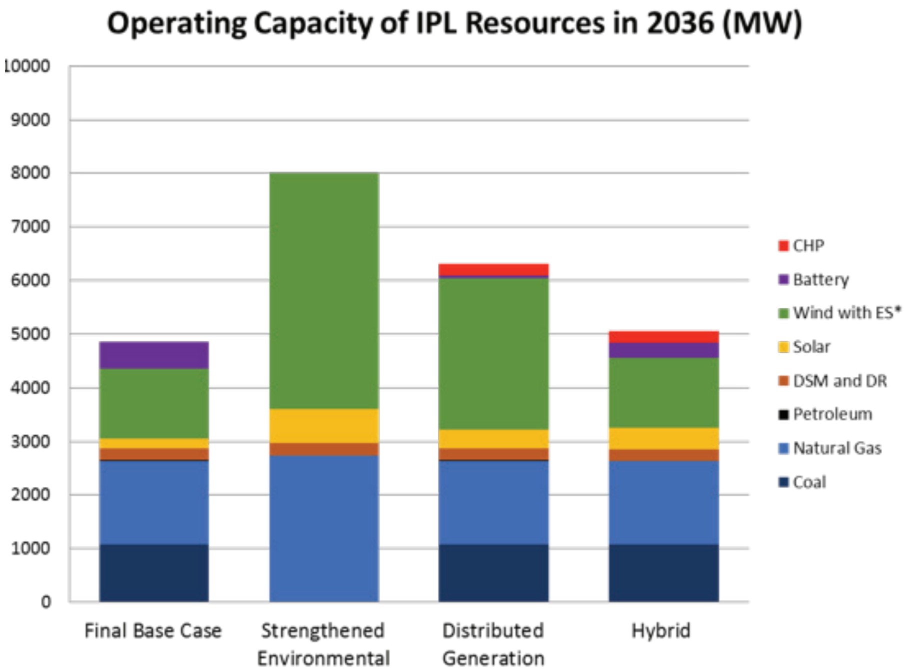
Under this scenario, a hybrid portfolio in 2036 could include two Pete coal units, (although these units would not necessarily serve as baseload generation but could be utilized more as a capacity resource), natural gas generation focused on local system reliability, wind to serve load during non-peak periods, and an average of DSM, solar, energy storage levels from the three scenarios as summarized in Figures 6 and 7.

Figure 6 – Summary of Resources (MW 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 7 – Candidate Resource Portfolios including Hybrid Option



IPL anticipates that additional potential changes not easily modeled may affect future resource portfolios such as the impacts of pending local gubernatorial and national Presidential election results, 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, 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.

PUBLIC ADVISORY PROCESS

IPL hosted four Public Advisory meetings to discuss the IRP process with interested parties and solicit feedback from stakeholders. The meeting agendas from each meeting are highlighted in the box below. For all meeting notes, presentations and other materials see IPL's IRP webpage at IPLpower.com/irp.

Meeting #1

- Introduction to IPL's IRP Process
- Selectable Supply-side and Demand-side Resource Options
- Discussion of Risks
- Scenario Development

Meeting #2

- Stakeholder Presentations
- Resource Adequacy
- Transmission & Distribution
- Load Forecast
- Environmental Risks
- Modeling Update

Meeting #3

- Draft Model Results for all Scenarios

Meeting #4

- Final Model Results
    - Preferred Resource Portfolio
    - Metrics & Sensitivity Analysis Results
- Short Term Action Plan

IPL incorporated feedback from stakeholders to shape the scenarios develop metrics and clarify the data presented. IPL is planning an additional public meeting in early 2017 to listen to stakeholders feedback about the final IRP document.

2016 Short Term Action Plan

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

CONCLUSION

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. IPL plans to conduct a public meeting to address questions and comments related to this IRP.

Integrated Resource Plan Public Advisory Meeting #1

April 11, 2016

Welcome and Safety Message

Bill Henley, VP of Regulatory and Government Affairs

Meeting Guidelines and Stakeholder Process

Dr. Marty Rozelle, Facilitator

Agenda for today

8:30	Registration
9:00	Welcome
9:15	Agenda Review and Meeting Guidelines
9:30	Introduction to IPL's IRP Process
10:00	Supply Side & Distributed Resources
10:30	Demand Side Resources
11:15	Demand Side Management (DSM) Modeling
12:00	Lunch
12:45	Discussion of Risks
1:45	Discussion of Scenarios
2:45	Next Steps

Objectives

- Listen to diverse stakeholders
- Describe IRP planning process
- Engage in meaningful dialogue
- Continue relationship built on trust, respect and confidence

Note: IPL will use publicly available data as much as possible

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Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions on risks and scenarios
- The phone line will be muted. During the allotted questions, press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
- Use WebEx online tool for questions during meeting
- Email additional questions or comments by April 18
- IPL will respond via website by May 2

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Meeting #2

- Date: June 14, 2016
- In response to your request,
  ~60 to 90 minutes will be reserved for listening to stakeholders' points of view.
- Let us know by May 17 if you plan to speak by emailing ipl.irp@aes.com
- Pre-registered speakers will split allocated time

Introduction to IPL's IRP

Joan Soller, Director of Resource Planning

Introduction to IPL

Quick facts
- 480,000 customers
- 1,400 employees
- 528 sq. miles territory
- 144 substations
- ~3,300 MW of Resources
- Serving Indianapolis reliably since 1929

IPL 2016 Resource Mix based upon capacity

Indianapolis area assets 1,222 MW
- **Harding Street Station (HS) –** 977 MW
- **Georgetown Station –** 150 MW
- **Solar PPAs* –** 95 MW

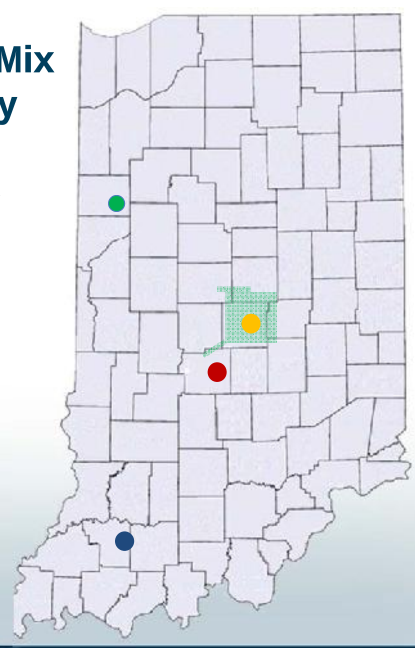
Eagle Valley (EV) Generating Station
- Retiring 263 MW coal in April 2016
- Constructing 671 MW Combined Cycle Gas Turbine (CCGT) for Spring 2017 operation

Petersburg Generating Station – 1,697 MW

Hoosier Wind Park PPA – 100 MW

Lakefield Wind Park PPA – 200 MW
(In Minnesota – Not pictured)

*PPAs = Power Purchase Agreements



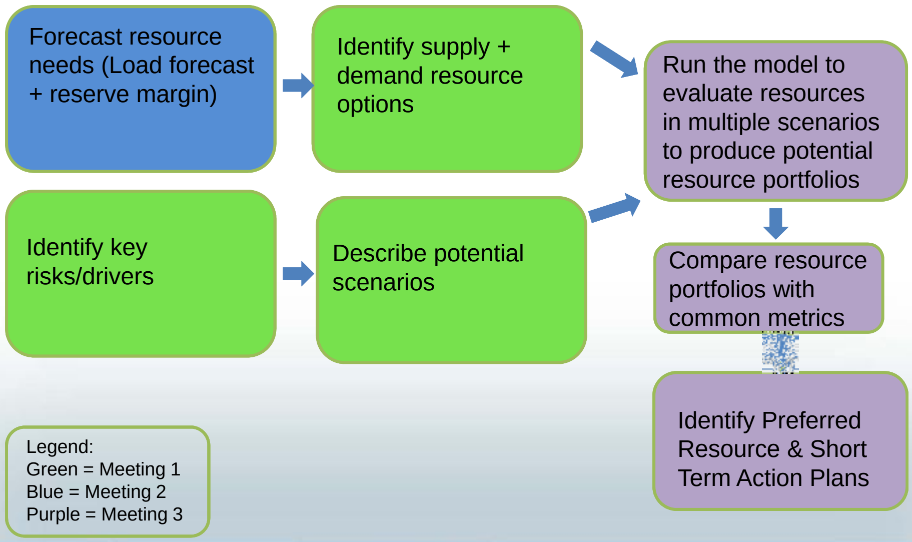
What is an IRP?

- An Integrated Resource Plan represents how a utility expects to provide its customers
  - reasonable least cost service
  - for a 20 year period
  - utilizing existing and future supply and demand side resources
  - following an analysis of multiple potential future scenarios.

Joint IRP 101 meeting

- Indiana utilities co-hosted IRP 101 session on Feb 3, 2016
- Included general information about the planning process
- Review materials at this link:
  https://www.iplpower.com/IRP/?terms=IRP

IRP process overview



IPL's IRP Objective

- To identify a portfolio to provide
  - safe
  - reliable
  - reasonable least cost energy service
  - to IPL customers from 2017-2036
  - measured in terms of Present Value Revenue Requirement (PVRR)
  - giving due consideration to potential risks and stakeholder input.

Actions since 2014 IRP

- Implemented short term action plan
  - Transmission expansion projects
  - DSM program implementation
  - MISO capacity purchases
  - Mercury and Air Toxics Standard (MATS) compliance
  - EV CCGT 671 MW
  - Blue Indy implementation
  - National Pollutant Discharge Elimination System (NPDES) compliance
  - Harding Street 5, 6 & 7 refuel/conversion to NG
  - Retire EV units 3 - 6

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Proposed enhancements based on feedback

	2014 IRP Feedback	IPL Response/Planned Improvements
1	Constrained Risk Analysis	Stakeholder discussion about risks will occur early in the 2016 IRP process.
2	Load Forecasting Improvements Needed	IPL is reviewing load forecast to enhance data in the 2016 IRP.
3	DSM Modeling not robust enough	IPL has piloted modeling DSM as a selectable resource and will discuss this in public meetings.
4	Customer-Owned and Distributed Generation lacked significant growth	IPL will develop DG growth sensitivities to understand varying adoption rate impacts.
5	Incorporation of Probabilistic Methods	IPL will incorporate probabilistic modeling in 2016 IRP.
6	Enhance Stakeholder Process	IPL participated in joint education session with other utilities to develop foundational reference materials. We will incorporate more interactive exercises in 2016.

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2016 IRP timeline

Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016
Pilot DSM modeling	Conduct IRP 101 session Identify risks	Hold 1st IRP meeting	Continue modeling & narrative	Finalize and file IRP
Initiate scenario development	Initiate DSM MPS	Complete DSM MPS	Perform Sensitivity Analyses	
Research DG resources		Complete load forecast	Hold 2nd & 3rd IRP meetings	
Update Reference case data		Initiate narrative & modeling		

Questions?

Supply Side Resources

Joan Soller, Director of Resource Planning

Supply side resources

- Model inputs include:
  - Nameplate capacity
  - Capital construction costs
  - Fixed Operating and Maintenance (O&M) costs
  - Variable O&M costs
  - Operating characteristics
  - Typical availability

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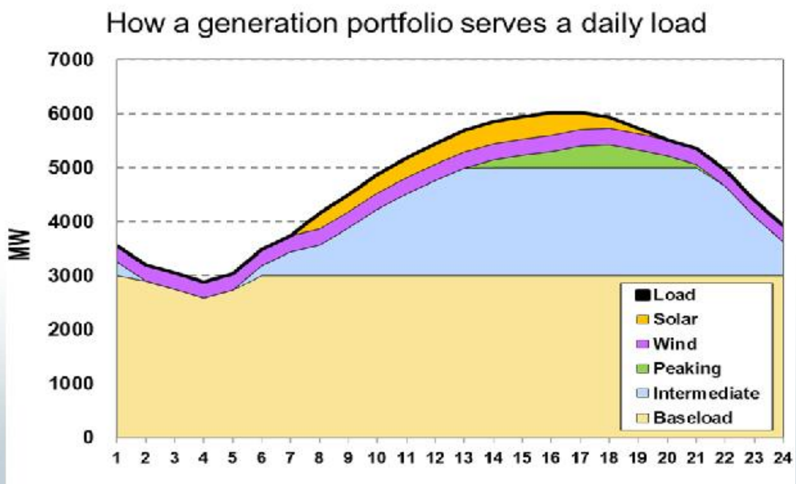
Typical summer load & resource mix



Supply side resource alternatives

IRP Resource Technology Options			
	MW Capacity	Performance Attributes	Representative Cost per Installed KW
Simple Cycle Gas Turbine[1]	160	Peaker	$676
Combined Cycle Gas Turbine - H-Class[1]	200	Base	$1,023
Nuclear[1]	200	Base	$5,530
Wind[2,3]	50	Variable	$2,213
Solar[4]	> 5 MW	Variable	$2,270
Energy Storage[5]	20	Flexible	~ $1,000
CHP – industrial site (steam turbine)[6]	10	Base	Ranges from ~ $670 to $1,100
Other?			

Sources for IRP resource technology options

[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

Distributed Resources Discussion

John Haselden, Principal Engineer

Customer-Sited Generation

- Typically diesel generators
- Usually not synchronous with IPL
- Size: 100 kW – 20 MW
- EPA regulations restrict availability to run during non-emergencies
- Indy area resources
  - 2010: 40.1 MW
  - 2014: 31.7 MW
  - 2016: 0 MW
- Quick start, high variable cost, limited run time

Combined Heat & Power (CHP)

- Combined Heat and Power
  - Usually customer sited and owned
  - Thermal requirements
- 5 MW – 100 MW
- Technology options
  - Conventional
    - Natural gas reciprocating engines
    - Natural gas turbines
  - Advanced
    - Fuel cell
    - Microturbine
    - Micro-CHP

Wind

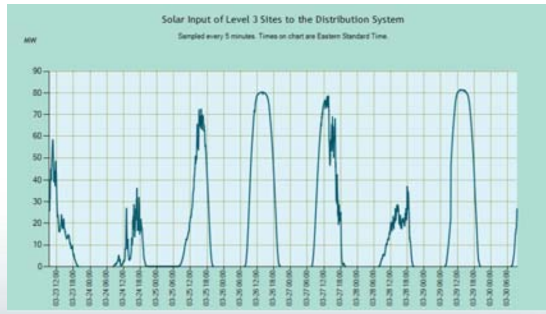
- Poor wind resource in this area – low energy output
- Height is important for production
- 5 kW – 1.5 MW
- Siting/zoning issues
- Noise
- Low coincidence with system peak, variable production
- Higher production costs than might otherwise be expected

Biomass

- Includes anaerobic digesters and combustion of organic products
- Siting and zoning issues
- Usually base load generation
- Customer choice to install
- Fuel transportation and emissions are a challenge

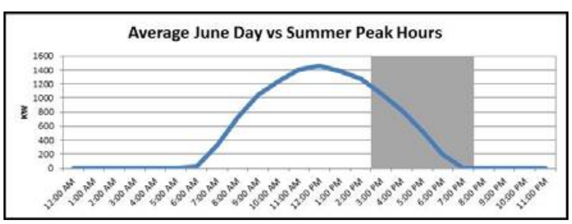
Solar Photovoltaic

- Permitting and construction are usually quick and not complicated
- Location determined by others
- Requires large spaces – 5-7 acres/MW
- Low capacity factor – 15-18%
- Variable production



Solar Photovoltaic (cont.)

- Some coincidence with system peak

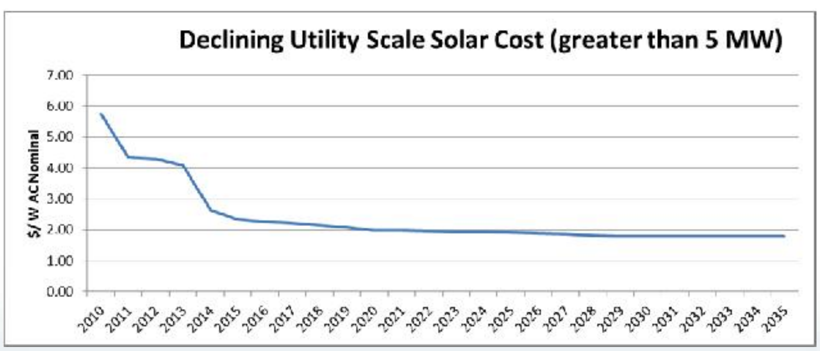


- Solar Renewable Energy Credit (SREC) value is variable and a short-term market

IPL experience with Solar PV

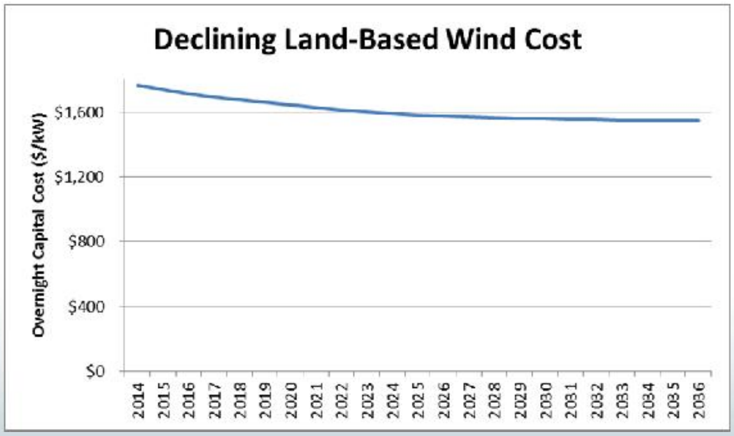
- Net metering
  - Small projects – Total capacity 1.45 MW
- Renewable Energy Production (REP) Rate
  - 95 MW operating solar
  - Approximately 45 MW contribution to capacity

Solar cost trend



Source: 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

Wind cost trend



Source: Discussion Draft of NREL 2016 Annual Technology Baseline Now Available for Review. Retrieved from http://www.nrel.gov/analysis/data_tech_baseline.html

Other Distributed Resources

- Technology innovation is impacting the industry
  - "Distributed Resources" go beyond "Distributed Generation" and will be considered as they mature
  - Microgrids
  - Energy storage
  - Voltage controls
  - Electric vehicles

Questions?

Demand Side Resources

Jake Allen, DSM Program Development Manager

Section Overview

- Demand side management (DSM) definition
- IPL's DSM Experience
- Current DSM programs (2015-2016)
- Update of DSM "Action Plan" for 2017
- Anticipated filing schedule for approvals to continue to offer DSM programs
- New Market Potential Study (MPS) underway

Demand Side Management

- Encompasses both:
  - Energy Efficiency – reduced energy use for a comparable or imposed level of energy service (kWh)
  - Demand Response – a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions (kW)

Demand side resource alternatives

Demand Side Resource Examples			
	2015 MWh Savings	Performance Attributes	Representative First Year Cost per kWh (on net basis)
Energy Efficiency programs			
- Residential Lighting	15,908	Dependent upon customer participation	$ 0.19/kWh
- Small Business Direct Install	4,407		$0.30/ kWh
	MW Savings	Performance Attributes	Representative Cost per Installed KW
Demand Response programs – - Air Conditioning Load Management (ACLM)	30	Peak Use	$300
- Conservation Voltage Reduction	20	Peak Use	Field assets are in place for this capacity

How do supply and demand side resources compare?

Characteristic	Supply	Demand
Size in terms of capacity	+++ (10-700 MW)	+ (1-10 MW)
Flexible response to capacity need	+	+++
Initial Costs	+++	+ to ++
Ongoing Costs	++	+
Lead time	++	+
Dispatchability	+++	+ to ++
Dependent upon customer behavior	+	+++

+ reflects relative scale

IPL's DSM experience

- IPL has offered DSM since 1993
- Commission Generic Order issued in 2009 (covered 2010-2014)
- Currently offering DSM Programs for a two year period (2015-2016)
  - pursuant to approvals in Cause No. 44497
- Current DSM efficiency goal is approximately 1.1% of total sales

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Current DSM programs

Current Program Offerings
Residential
Air Conditioning Load Management
Appliance Recycling
Home Energy Assessment
Income Qualified Weatherization
Lighting
Multi-Family Direct Install
Online Assessment w/ Kit
Peer Comparison Reports
School Education w/ Kit
Business (C&I)
Air Conditioning Load Management
Custom Projects
Prescriptive
Small Business Direct Install

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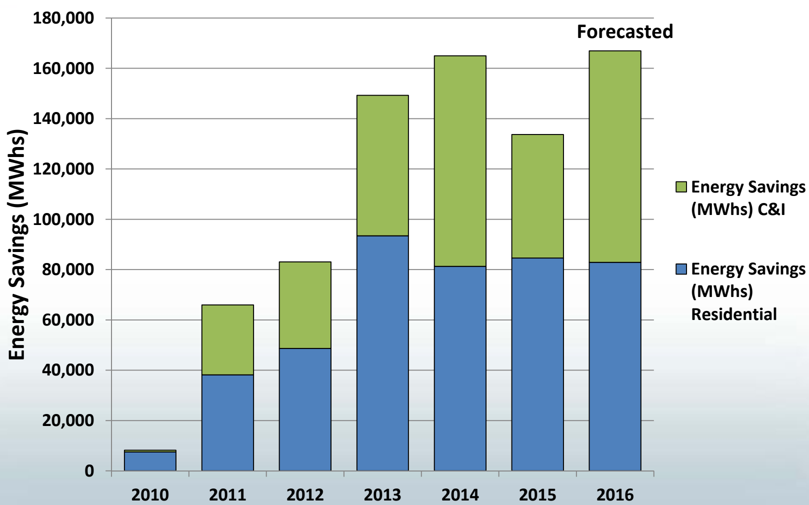
DSM program achievement



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DSM guiding principles

- Offer programs that:
  - Are inclusive for customers in all rate classes
  - Are appropriate for our market and customer base
  - Are cost effective
  - Modify customer behavior
  - Provide continuity from year to year

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Other planning considerations

- Large Commercial and Industrial Customer Opt out
  - Customers with demand > 1 MW may elect to opt-out of utility sponsored DSM programs
  - Customers representing approximately 26% of IPL's sales are eligible to opt-out
  - Approximately 81% of eligible customers have opted out
- Cost effectiveness challenges due to changing baselines – e.g. lighting

DSM Market Potential Study (MPS)

- 1st step in DSM planning
- Underway for 2018-2037
- Initial Kick Off Meeting was held late February
- Screening analysis to prepare for IRP modeling inputs completed by May

DSM planning - 2017

- Expect to propose one-year extension of current programs
  - Approvals would allow us to continue delivery of DSM programs in 2017
  - While the current IRP modeling is completed
  - IPL plans a filing with the Commission in May 2016
  - Updating previously filed 2015-2017 DSM Action Plan for 2017

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Future planning - beyond 2017

- Develop a three year DSM Action Plan (2018-2020) consistent with the 2016 IRP
  - New Market Potential Study (2018-2037)
  - Identify blocks of DSM as a selectable resource for modeling in the IRP
  - DSM will be evaluated in multiple scenarios
  - With the expectation of making a filing in early 2017 for a three-year approval

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Questions?

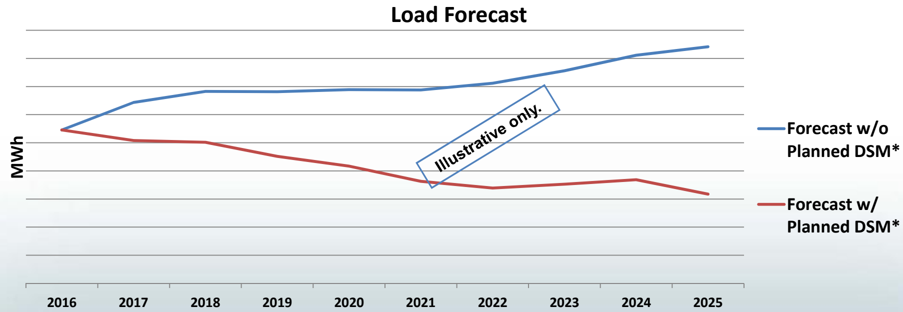
DSM Modeling Options

Erik Miller, Senior Research Analyst

DSM modeling options

Historical IRP Approach

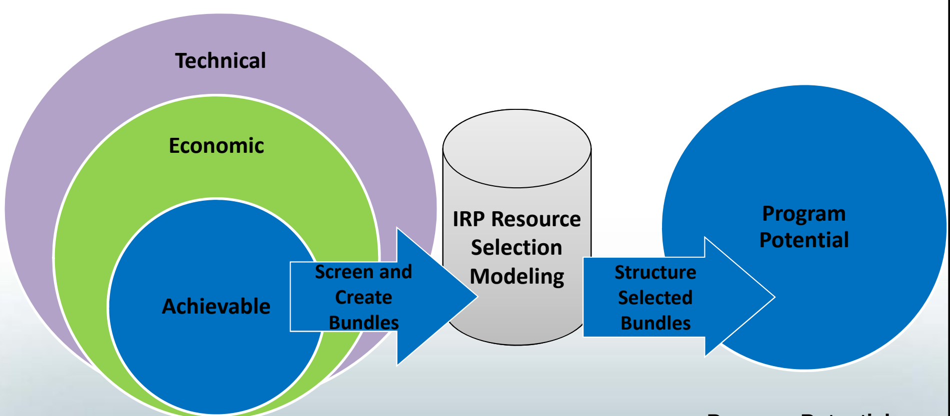
Market Potential Study determines cost effective DSM Action Plan
DSM Action Plan reduced from load forecast



*Past DSM performance and organic efficiency included in forecast.

DSM modeling options

DSM as a Selectable Resource



Market Potential

IPL's IRP modeling

Program Potential in Action Plan

Creating a DSM selectable resource

Different Bundling Approaches

Simple Cycle Gas Turbine
160 MW
Low capacity factor
Peaker

HEA Program Bundle
Measures include:
CFLs
LEDs
Low Flow Showerheads
Faucet Aerators
Programmable Thermostat
Energy Assessments

Portfolio Bundle
Home Assessment Program
Multifamily Program
Peer Comparison Program
Residential Lighting Program
School Education Program
Appliance Recycling Program

"CT" Power Plant

DSM "Program" Bundle

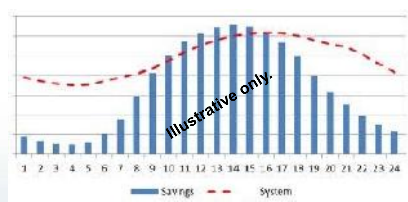
DSM "Portfolio" Bundle

Creating a DSM selectable resource

Similar Measure "HVAC" Bundle
Air Conditioners
Heat Pumps
Ductless Heat Pumps
AC Tune Up
ECM
Programmable Thermostats

DSM "Similar Measure" Bundle

"HVAC" Bundle Load Shape



Creating a DSM selectable resource

- Create a "bundle" of Energy Efficiency or Demand Response that resembles a power plant
- Bundle Characteristics
  - Cost to "build"/implement
  - Installed cost ($/kWh)
  - Load shape (8,760 hours)
  - Timing for implementation
  - Ramp rate
- Sectors
  - Residential
  - Commercial & Industrial

IRP/DSM pilot runs

- Objectives
  - Identify a potential approach for DSM block structures
  - Understand how the resource assessment model handles DSM
- Approach
  - Modeled individual residential program blocks based on 2015 DSM programs
  - DSMore model was used to create block load shapes
  - Load shapes were inputs in the resource assessment model
- Findings
  - Limited program offerings in early years
  - Staggered program selections
  - Less "cost effective" programs don't get selected
  - Program bundles contribute to staggered offerings

Questions?

Lunch Break

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Risk Discussion

Joan Soller, Director of Resource Planning

Risks include internal and external factors

- Planning Risks
  - Environmental Regulations
  - Fuel Costs
  - MISO Market Changes
    e.g. capacity auction, fast ramp products
  - Economic Load Impacts
  - Weather
  - Customer Adoption of DG
  - Technology Advancements
    e.g. solar and wind costs
- Operational Risks
  - Fuel Supply
  - Generation Availability
  - Construction Costs
  - Production Cost Risk
  - Access to Capital
  - Regulatory Risk

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Environmental Regulations

- Recent Environmental Regulations/Projects
  - Mercury and Air Toxics Standard (MATS)
  - National Pollutant Discharge Elimination System (NPDES) Water Discharge Permits
  - Cross State Air Pollution Rule (CSAPR)
- Future Environmental Regulations
  - Coal Combustion Residuals (CCR)
  - National Ambient Air Quality Standards (NAAQS)
  - Effluent Limitations Guidelines (ELG) Rule
  - 316(b) – Cooling water intake structures
  - Office of Surface Mining
  - Clean Power Plan (CPP)

Exercise

- Seek stakeholder feedback regarding risk likelihoods and/or importance

Scenario Discussion

Ted Leffler, Senior Risk Management Analyst

Planning under uncertainty

- Uncertainty = Potential for change
  - Examples:
    - Environmental Regulations
    - Commodity Prices
    - Load
    - Renewables Penetration
    - Distributed Generation Penetration
- Scenarios and sensitivity analysis are two forms of uncertainty analysis used in resource planning

Scenarios

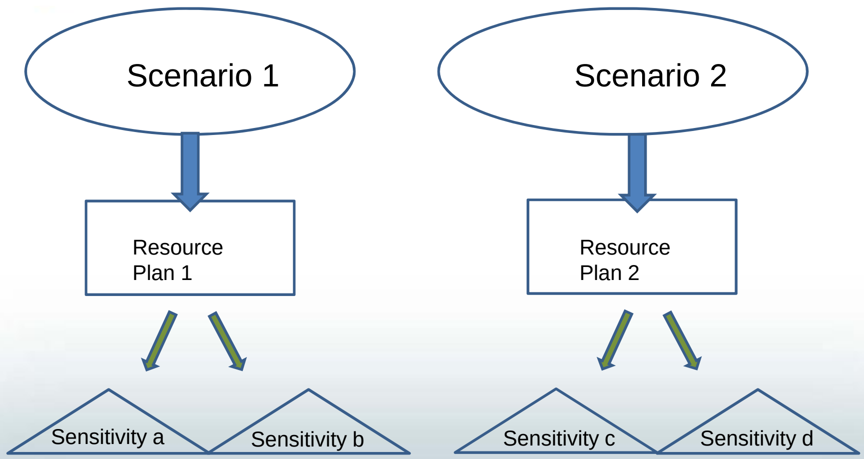
- *"A scenario is*
  - a simulation of a future world technical, regulatory and load environment."*
- *A scenario is not…*
  - A resource plan
  - A sensitivity
  - Not a representation of preferred outcome
- Base Case Scenario
  - "The base case [scenario] should describe the utility's best judgment (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 use and resources."*

*2015 Director's Report

What is a Sensitivity?

- A sensitivity measures how a resource plan performs across a range of possibilities for a specific risk or variable

Scenarios and Sensitivities



Scenario development process

- Cross functional IPL team considered future risks
- Reviewed other utilities IRP scenarios
- Reviewed MISO MTEP 2017 scenarios
- Qualitatively discussed recent trends/significant changes and impact likelihoods

Scenario development process

- Developed a list of risks or ‘major forces that might move the world in different directions’*
  - Economic Growth
  - Change in electricity use
  - Commodity Prices
  - Capital Costs
  - CO_2 regulation
  - Other environmental regulation
  - Change in Renewable & Storage Costs
  - Distributed Generation Adoption

* Source: Electric Power Resource Planning Under Uncertainty: Critical Review and Best Practices, White Paper, November 2014 Prepared by Adam Borison

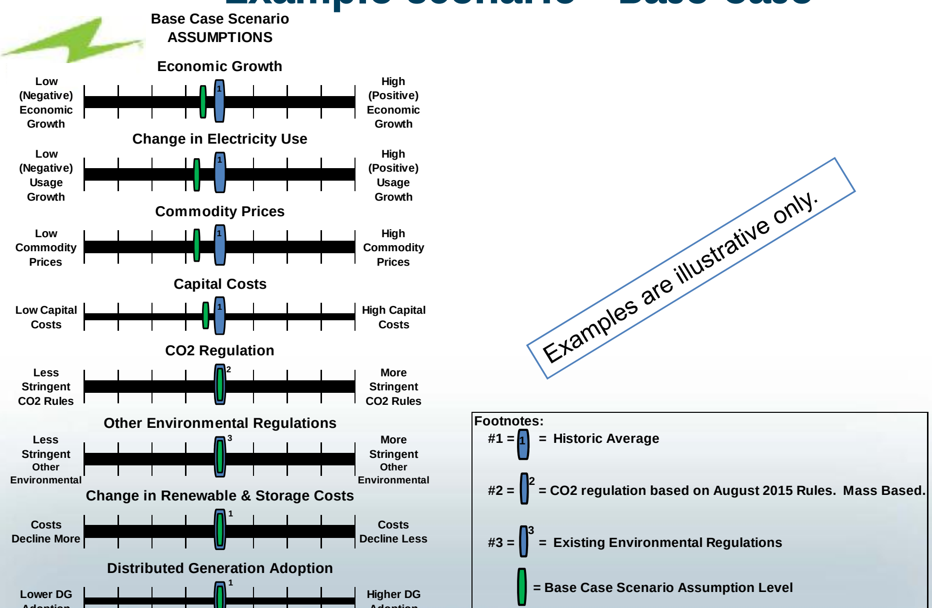
Scenario development process

- Developed a list of potential futures
  - Base Case
  - Robust Economy
  - Recession Economy
  - Strengthened Environmental Rules
  - High Customer Adoption of Distributed Generation (DG)

Potential Scenarios

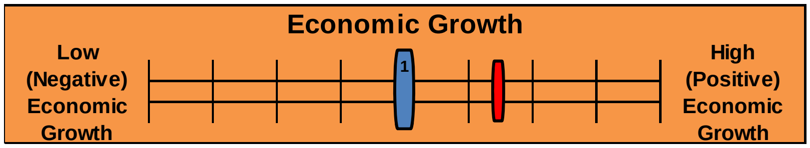
- Base Case
  - Only known events and expected trends
  - Commodity prices influenced by Clean Power Plan (CPP) beginning in 2022
  - Existing environmental regulations realized
  - Moderate decreases in technology costs for renewables and storage
- Robust Economy
  - High local and national economic growth
- Recession Economy
  - National and local economic downturns
- Strengthened Environmental Rules
  - Higher compliance costs for known regulations including CO_2 + RPS
- High Adoption of Distributed Generation
  - Customers adopt DG with lower technology costs

Example Scenario – Base Case



Example Scenario - Robust Economy

Robust Economy Case Scenario
ASSUMPTIONS

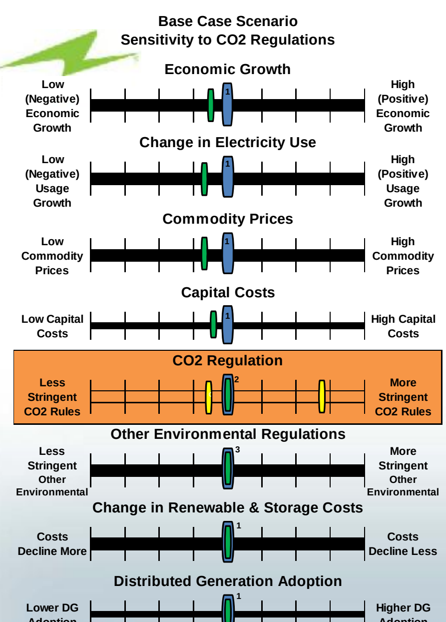


Other risks / major driver levels = Base Case Levels

Examples are illustrative only.

Footnotes:
#1 = 1 = Historic Average
= Robust Economy Case Scenario Assumption Level

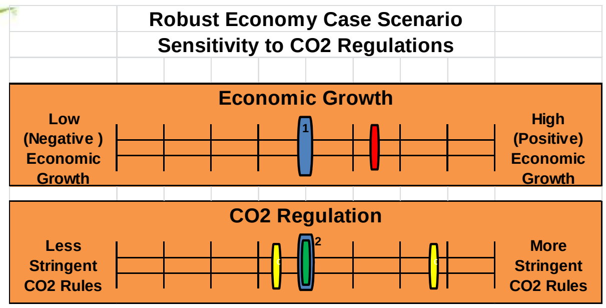
Example Sensitivity - Base to CO2



Examples are illustrative only.

Footnotes:
#1 = 1 = Historic Average
#2 = 2 = CO2 regulation based on August 2015 Rules. Mass Based.
#3 = 3 = Existing Environmental Regulations
= Base Case Scenario Assumption Level
= CO2 Sensitivity Levels

Example Sensitivity – Robust Economy to CO2



Other risks / major driver levels = Base Case Levels

Examples are illustrative only.

Footnotes:
#1 = 1 = Historic Average
#2 = 2 = CO2 regulation based on August 2015 Rules. Mass Based.
= Base Case & Robust Economy Scenario Assumption Level
= Robust Economy Case Scenario Assumption Level
= CO2 Sensitivity Levels

Exercise

- Seek stakeholder feedback regarding scenarios

Next Steps

Dr. Marty Rozelle, Facilitator

Next meetings

June 14, 2016

- Stakeholder Points of View presentations
- Load Forecast and Forecasting Methodology
- RTO/ MISO/Resource Adequacy
- Transmission & Distribution
- Environmental Risks including Clean Power Plan
- Modeling Parameters

September 16, 2016

- Resource Portfolio results
- Sensitivities
- Preferred Resource Plan
- Short Term Action Plan

Written comments and feedback

- Deadline to send written comments and questions regarding this meeting to ipl.irp@aes.com is Monday, April 18
- All IPL responses will be posted on the IPL IRP website by Monday, May 2

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Thank you!

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Integrated Resource Plan Public Advisory Meeting #2

June 14, 2016

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Welcome & Safety Message

Bill Henley, VP of Regulatory and Government Affairs

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Meeting Guidelines

Dr. Marty Rozelle, Facilitator

Agenda for today

9:00am Welcome
- Meeting Agenda and Guidelines
- Summary & Feedback from IRP Public Advisory Meeting #1
- Stakeholder Presentations

10:25am Break
- Portfolio Comparison based on Metrics
- Metrics Exercise
- Resource Adequacy

12:00 – 12:30pm Lunch
- Transmission & Distribution
- Load Forecast
- Environmental Risks

2:00pm Break
- Modeling Update
- Portfolio Exercise
- Closing Remarks & Next Steps

3:15pm Meeting Concludes

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions
- The phone line will be muted. During the allotted questions, press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
- Use WebEx online tool for questions during meeting
- Email additional questions or comments by June 21
- IPL will respond via website by July 5

Active Cases before the Commission

- Cause No. 42170, ECR-26
- Cause No. 44121, Green Power (GPR 9)
- Cause No. 43623, DSM 13
- Cause No. 44576, Rates (under appeal)
- Cause No. 44792, DSM 2017 Plan
- Cause No. 44794, SO_2 NAAQS and CCR
- Cause No. 44795, Capacity and Off System Sales Riders

Summary & Feedback from IRP Public Advisory Meeting #1

Joan Soller, Director of Resource Planning

Topics covered in Meeting #1

- IPL's IRP process and objective
- Supply side, distributed and demand side resources
- Modeling Demand Side Management (DSM) as a selectable resource
- Planning risks
- Scenario development with interactive exercise

Scenarios Exercise from Meeting #1 - Base Case

Scenario	Agree	Disagree	Proposed Integration
Base Case	• CPP – how specifically will it be included? • Pretty much agree with it.	• Smart homes should be included as a technology. • Why not include utility- owned DG? • Fuel prices including natural gas will increase more than indicated. Where is this reflected in the scenarios? (Can run sensitivities for this.)	• CPP will be modeled as mass-based • IPL will incorporate energy management and its technology-based smart thermostat pilot in DSM blocks • DG will be an input and may be customer or utility owned • IPL will run high/low sensitivities on commodities

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Scenarios Exercise from Meeting #1 - Robust Economy

Scenario	Agree	Disagree	Proposed Integration
Robust Economy	• Could happen, would be nice if it did. • Agree that it's a potential future, but would not necessarily lead to increased electricity use. • Could lead to higher DG adoption.	• May not lead to increased use of electricity. • Capital costs might go up due to higher costs of materials.	• The load forecast will be a sensitivity in this scenario. • Still thinking about how to address varying capital costs for supply side resources.

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Scenarios Exercise from Meeting #1 - Recession Economy

Scenario	Agree	Disagree	Proposed Integration
Recession Economy	• Hope it doesn't happen but it could – depends on things outside of our control, e.g. exodus or influx of people to Indiana. • A possibility. Question of whether shrinking industrial base is unique to this scenario – could happen in others.	• N/A	• Will likely run high/low load forecast sensitivities in other scenarios to incorporate potential recession effects

Scenarios Exercise from Meeting #1 - Strengthened Environmental Rules

Scenario	Agree	Disagree	Proposed Integration
Strengthened Environmental Rules	• Carbon tax is possible	• What if the Renewable Portfolio was federal or state? Could be part of the CPP. (Would probably have about the same impact.)	• In this scenario, there will be a 20% RPS in 2022 based on a national average. This could be federal or state proposed.

Scenarios Exercise from Meeting #1 – High Customer Adoption of DG

Scenario	Agree	Disagree	Proposed Integration
High Customer Adoption of DG	• There are reasons other than economic to go to DG. Residents seem to be more attracted, businesses less attracted. • Possible. If it's cost-effective there would be more community solar.	• N/A	• There will be some DG embedded in this scenario as a proxy for customers who will choose DG for reasons in addition to economics.

Additional stakeholder interaction

- Since the April meeting, IPL met with the following stakeholders:
  – IURC
  – OUCC
  – CAC
  – Sierra Club
  – Citizens Energy

Additional stakeholder interaction (cont'd)

- Continue to involve stakeholders in developing assumptions
- Consider C&I customer input in load forecast
- Consider discrete DSM bundles
- Coordinate planning efforts with Citizens Energy
- Consider more expansive sensitivities

Meeting #1 materials

- Approximately 20 stakeholders participated
- Presentation materials, audio recording, acronym list, and meeting notes are available on IPL's IRP webpage here: https://www.iplpower.com/irp/

Questions?

Stakeholder Presentations

Presenter #1: Denise Abdul-Rahman, Environmental Climate Justice Chair, NAACP Indiana

Presenter #2: Dr. Stephen Jay, Professor,
IU Fairbanks School of Public Health

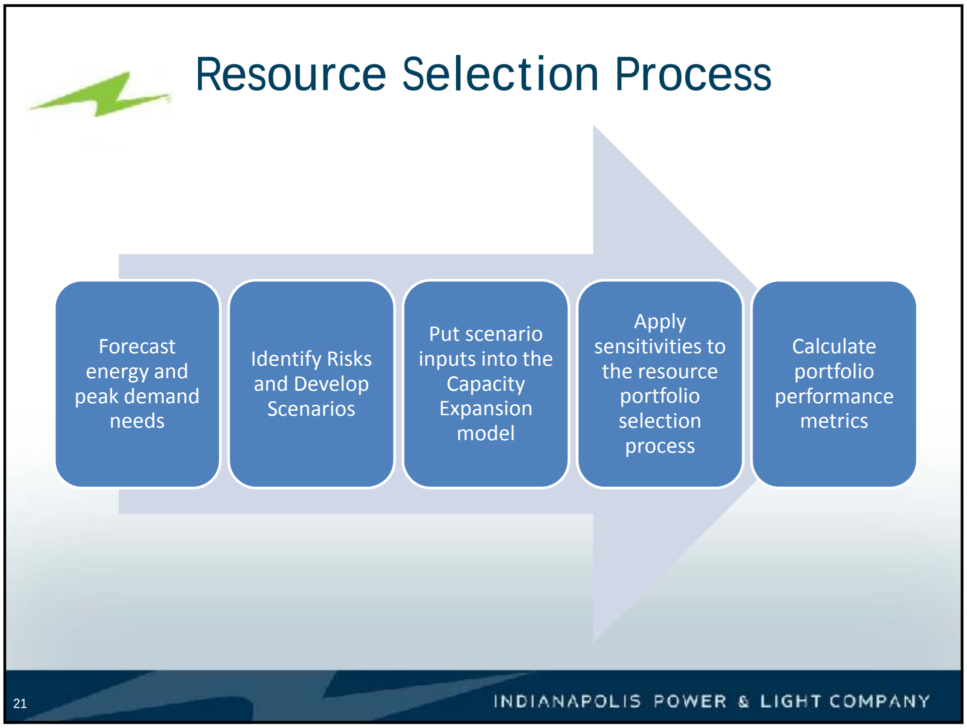
Presenter #3: Larry Kleiman, Executive Director, Hoosier Interfaith Power & Light

Presenter #4: Jodi Perras, Indiana Campaign Representative, Sierra Club Beyond Coal

Short Break

Portfolio Comparison based on Metrics

Megan Ottesen, Regulatory Analyst


Resource Selection Process
Forecast energy and peak demand needs
Identify Risks and Develop Scenarios
Put scenario inputs into the Capacity Expansion model
Apply sensitivities to the resource portfolio selection process
Calculate portfolio performance metrics
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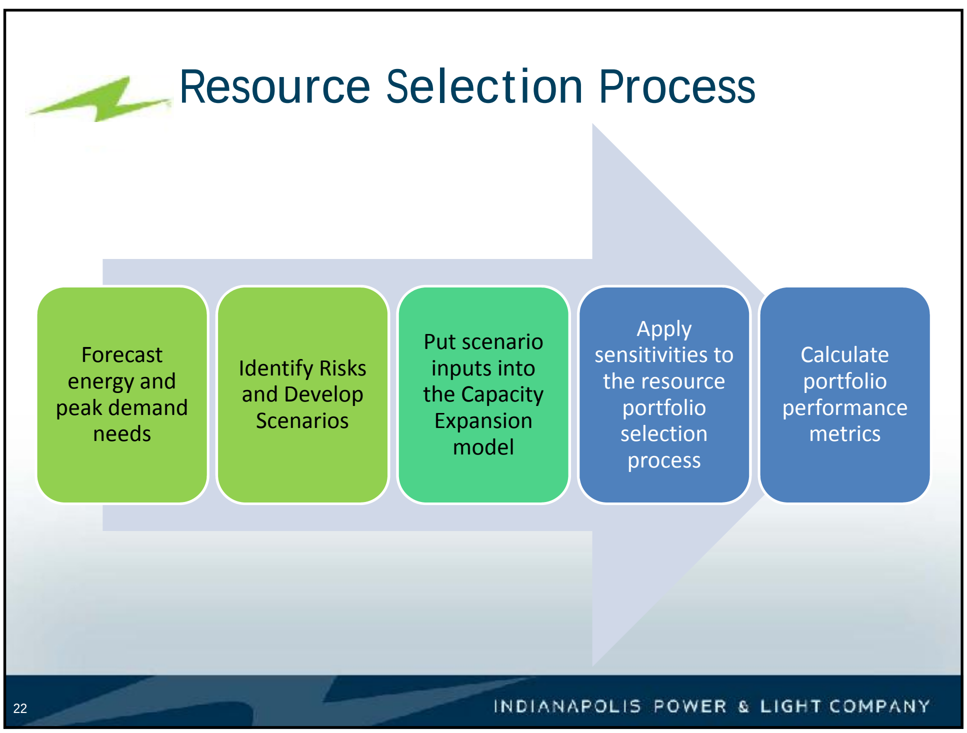
Resource Selection Process
Forecast energy and peak demand needs
Identify Risks and Develop Scenarios
Put scenario inputs into the Capacity Expansion model
Apply sensitivities to the resource portfolio selection process
Calculate portfolio performance metrics
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Portfolios will result from each of these scenarios

- Base Case
- Robust Economy
- Recession Economy
- Strengthened Environmental Rules
- High Customer Adoption of Distributed Generation

Introduction to metrics

- IPL will use several metrics to compare the benefits and costs of each scenario's portfolios
- In past IRPs, IPL primarily evaluated portfolios in costs measured by Present Value Revenue Requirement (PVRR)
- In addition to cost, IPL is considering the following categories to measure portfolio performances:
  - Financial risk
  - Environmental stewardship
  - Reliability

Metrics to consider

Cost	Financial Risk	Environmental Stewardship	Reliability
• Present Value Revenue Requirement (PVRR) • Rate Impact	• Cost Variance Risk Ratio	• Annual average CO_2 emissions • CO_2 intensity	• Planning Reserves • Flexibility

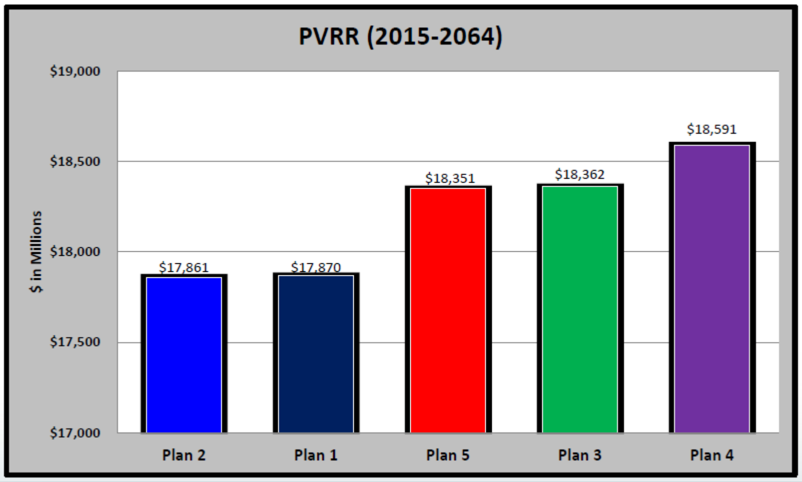
Cost Metrics

Present Value Revenue Requirement (PVRR):

– The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period

PVRR = Present Value of Revenue Requirements over the study period

PVRR Example



Source: IPL 2014 IRP

Cost Metrics

Present Value Revenue Requirement (PVRR):

– The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period

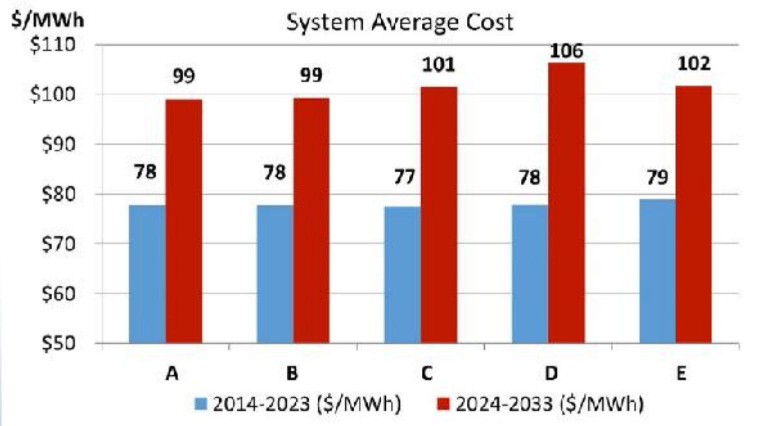
PVRR = Present Value of Revenue Requirements over the study period

Rate Impact:

– expressed in terms of cents/kWh for years 1-10 and 11-20
– Levelized average system cost

Rate Impact = $\frac{\text{\$ Total Revenue Requirements (10 yr period)}}{\text{Total kWh Sales (10 yr period)}}$

Rate Impact Example



Source: TVA 2015 IRP

Financial Risk Metrics

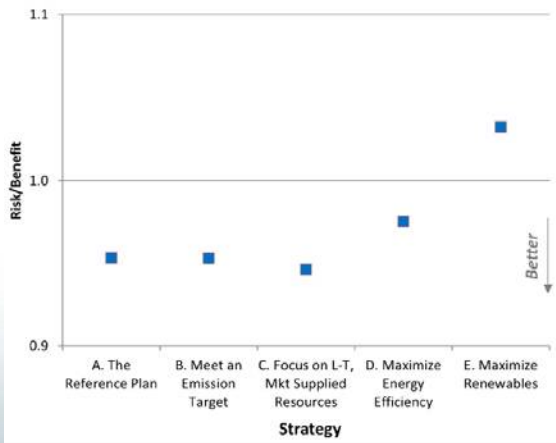
Cost Variance Risk Ratio:

- Shows how likely costs are to be higher or lower than the expected cost
- Ratio of how high costs could be to how low costs could be
- Calculated based on
  - Mean PVRR
  - Range of possible costs higher than mean PVRR
  - Range of possible costs lower than mean PVRR

Cost Variance Risk Ratio = $\dfrac{95^{th}\text{ Percentile (PVRR)} - \text{Mean (PVRR)}}{\text{Mean (PVRR)} - 5^{th}\text{ Percentile (PVRR)}}$

- Score less than 1.0: costs are more likely to be **lower** than mean PVRR
- Score greater than 1.0: costs are more likely to be **higher** than mean PVRR

Cost Variance Risk Ratio
(lower has less risk)



Source: TVA 2015 IRP

Strategy = Portfolio

Environmental Stewardship Metrics

Annual Average CO_2 emissions (tons)

– the annual average tons of CO_2 emitted over the study period

$$\text{Annual Average } CO_2 \text{ Emissions} = \frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$$

CO_2 intensity (tons/MWh)

– CO_2 Intensity for study period

$$CO_2 \text{ Intensity for study period} = \frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{MWh energy generated}}$$

Reliability Metrics

Planning Reserves:

- MW of supply above peak forecast

Planning Reserves = IPL's resources (MW) - utility load forecast (MW)

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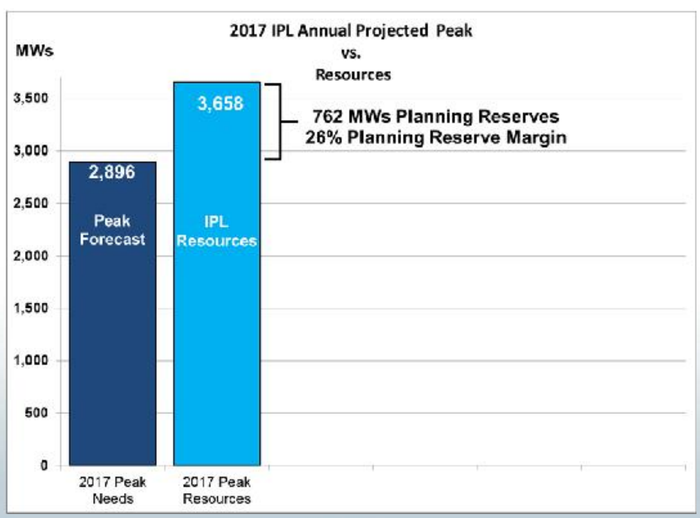
Planning Reserves for IPL



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Reliability Metrics

Planning Reserves:

- MW of supply above peak forecast

Planning Reserves = IPL's resources (MW) - utility load forecast (MW)

Flexibility:

- Ability of IPL's system to respond to load changes

Calculation = TBD open to input

Flexibility: (higher is more flexible)

Source: TVA 2015 IRP

Questions?

Cost
- Present Value Revenue Requirement (PVRR)
- Rate Impact

Financial Risk
- Cost Variance Risk Ratio

Environmental Stewardship
- Annual average CO_2 emissions
- CO_2 intensity

Reliability
- Planning Reserves
- Flexibility

Metrics Exercise

Resource Adequacy

Ted Leffler, Senior Risk Management Analyst

Introduction

- IRP process focuses on the future portfolio of resources needed to meet the
  - peak and
  - energy
  - needs of our customers.
- Resource Adequacy (RA) focuses on peak needs
- Resource Adequacy is the responsibility of the regulated utilities (part of the obligation to serve)
- MISO administers a short term Resource Adequacy construct
  - MISO is not responsible for Resource Adequacy
  - MISO's construct is focused on existing not future resources

Definitions (1 of 5)

- **Resource Adequacy**
  - ensuring that IPL has sufficient Resources to meet anticipated peak demand requirements plus an appropriate planning reserve
- **RA Time Horizon**
  - Resource Adequacy = > year out
- **MWs**
  - Measure of power
  - 1 MW = 1,340 Horsepower

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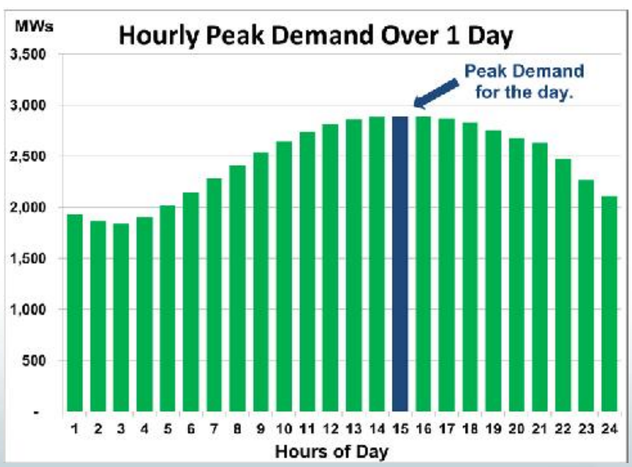
Definitions (2 of 5)

- **Peak Demand**
  - Instantaneous measure of the highest usage for a given period of time
  - Measured in MWs
    - MISO peak demand for summer 2017 estimate at about 123,000 MWs (165 million horsepower)
    - IPL peak demand for summer of 2017 estimate at about 2,900 MWs (3.9 million horsepower)



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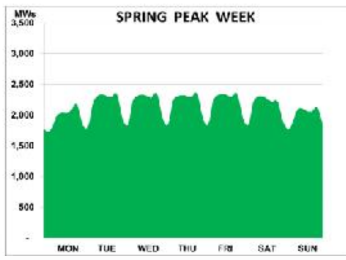
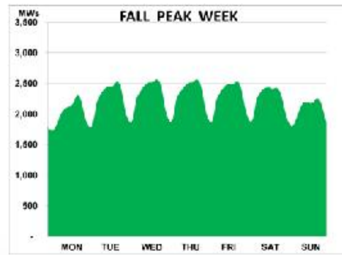
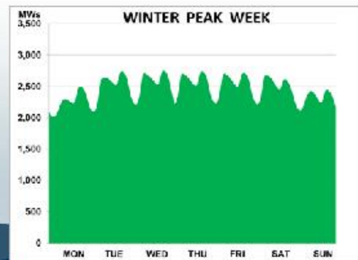
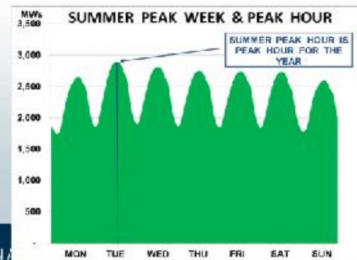
Definitions (3 of 5)

- **Peak Demand**
  – Instantaneous measure of the highest usage for a given period of time
  – In the Midwest and at IPL the peak demand typically occurs in the summer



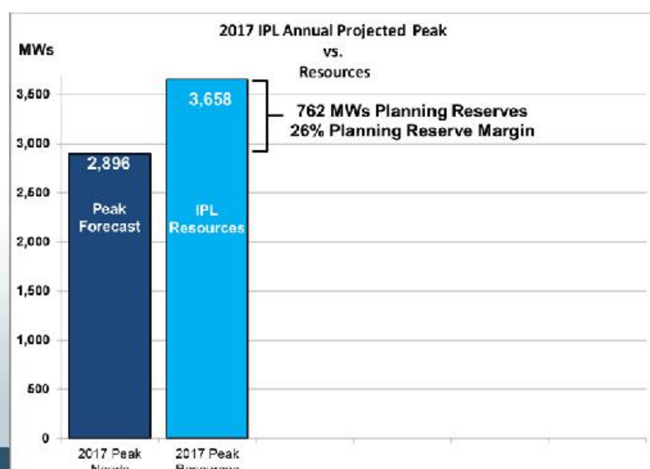






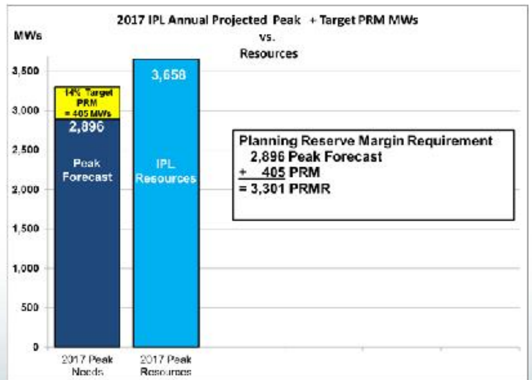
Definitions (4 of 5)

- Planning Reserve MWs
  – MW difference between the Peak forecast and generating unit availability
- Planning Reserve Margin (PRM)
  – The percentage of resources above the Peak forecast



Definitions (5 of 5)

- Target Planning Reserve Margin (Target PRM)
  - The percentage of resources above the Peak forecast needed to cover forecast and unit availability uncertainty
  - Calculated by MISO each November for the following summer
  - Result of the "Loss of Load Expectation Study"
  - This analysis produces a PRM that is expected to result in a loss of load event once every 10 years
- Planning Reserve Margin Requirement (PRMR)
  - MWs needed to meet the Peak forecast plus minimum MWs needed to cover potential for higher than normal peaks and lower than normal generating unit availability
  - PRMR = PEAK LOAD FORECAST X (1+Target PRM)
  - Calculated by MISO each November for the following summer
  - Typically around 14%: 7% for forecast uncertainty, 7% for availability uncertainty



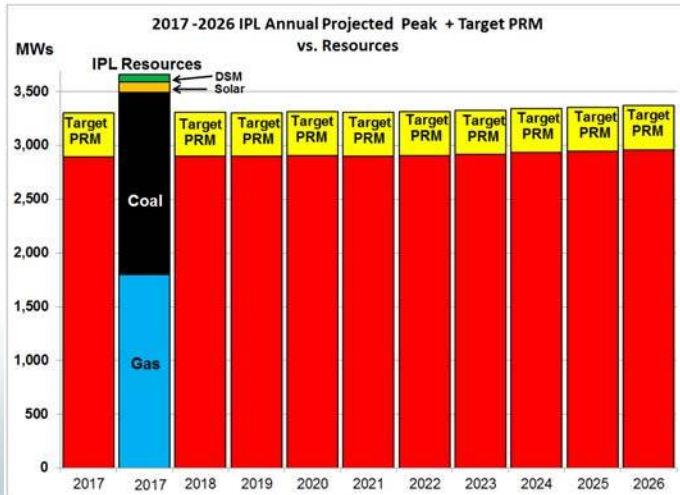
Planning to Provide Resource Adequacy

- IPL plans to meet the peak plus reserves with the following:
  - Demand Side Management Programs
  - IPL Generating Assets
  - Long Term Contracted Generating Assets
  - Balance of needs or excesses are purchased or sold in MISO capacity markets[1]

Footnote 1:
- Each year, prior to the summer, resource owners in MISO test the capacity level for each resource
- MISO populates an accounting system with 1 capacity credit for each MW of capacity
- Capacity credits can be purchased and sold
- Capacity credit sales do not impact energy sales
- Each utility with load must have capacity credits equal to its PRMR in the accounting system prior to the summer

IRP RA Process

- Resource Adequacy (RA) Process
  - Given current portfolio of resources
    - and future projected peak needs
    - and future projected energy needs
  - What portfolio of resources will be used to meet those needs?



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MISO's RA Process

- In Indiana, RA Process is the responsibility of the Utilities
- IRP process and the certificate of need process are regulated by the State, and the responsibility of the 'obligation to serve' resides with the utilities
- MISO has a Resource Adequacy process but MISO is not responsible for Resource Adequacy
- IRP process is focused on the long term (several years out)
  - Focus is on future portfolio of resources
- The MISO Resource Adequacy process is focused on the short term: less than a year out
  - Focused on existing resources

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MISO's role is an administrator of a reserving sharing pool

- This reserve sharing pool allows utilities to benefit from the diversity of resources across MISO
- Investments in and deployment of resources is lumpy
- Some utilities are slightly short, others slightly long of meeting their RA targets
- MISO's RA construct allows utilities that are temporarily short of meeting their RA target to purchase capacity credits from utilities that have more than enough resources to meet their short term RA targets
- Capacity credits are based on existing resources
- MISO capacity credits do not reflect the future value of adding resources or DSM

Key Takeaways

- IRP process must consider the future peak and energy needs of our customers
- Resource Adequacy (RA) focuses on peak needs
- Resource Adequacy is the responsibility of the regulated utilities (part of the obligation to serve)
- MISO administers a short term Resource Adequacy construct
  - MISO is not responsible for Resource Adequacy
  - MISO's construct is focused on existing not future resources

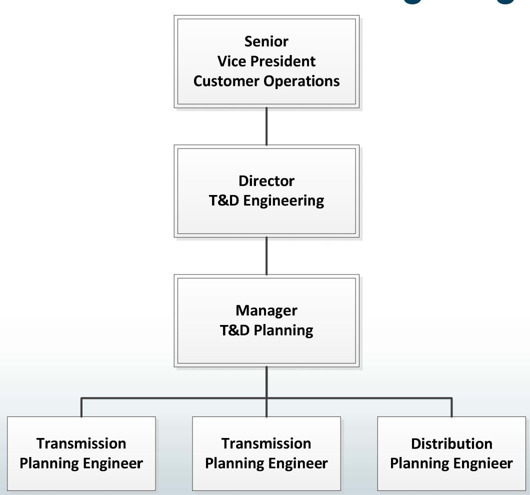
Questions?

Lunch Break

Transmission & Distribution

Mike Holtsclaw, Director of Engineering

Transmission Planning Organization



IPL has a dedicated Transmission Planning group within the Customer Operations Organization

IPL Transmission Planning

- IPL performs near term system studies for 1-5 years out and long term reliability planning studies for 10 years out
  - Studies are performed for on peak load, off peak load, and sensitivity cases looking for deficiencies on the transmission system
  - Steady state Power Flow studies show thermal (Rating) and voltage limits of the IPL transmission system
- Dynamic studies (0 to 20 seconds) show how the system performs to events
- IPL must also comply with the mandatory NERC Reliability Standards

IPL Transmission Planning (cont'd)

- The results of the studies are analyzed for deficiencies in the system such as thermal ratings that are exceeded on equipment such as transmission lines or transformers
- For the dynamic studies, voltage recovery times, and generation synchronization are analyzed to see that they meet IPL's planning criteria

MISO Transmission Planning Coordination

- MISO performs various planning studies for the full MISO footprint and for the three planning regions
- IPL is part of the MISO Central Planning region
- MISO will identify market efficiency projects and reliability projects for possible inclusion in their MISO Transmission Expansion Plan (MTEP)
- IPL participates in the MTEP studies and stakeholder groups to advocate solutions for customers

Recent IPL Transmission System Upgrades

- **Projects to Improve Reliability for Summer 2016**
  - Upgraded 345/138 kV auto transformer from 275 MVA to 500 MVA, included 138 kV bus modification to a ring bus arrangement
  - Installed the 275 MVA 345/138 kV auto transformer at another substation
  - Installed a 138 kV Static VAR Compensator +300/-100 MVAR for transient voltage support

Recent IPL Transmission System Upgrades (cont'd)

- **Projects to Support New Eagle Valley CCGT (COD Spring 2017)**
  - New 23 mile 138 kV line (Eagle Valley – Franklin Twp)
  - 138 kV Breaker Upgrades (Mooresville, Southport)
  - 138 kV Line Rating Upgrades
    - Eagle Valley – Southport
    - Eagle Valley – Glenns Valley
  - New 138 kV Capacitor Bank
- **MISO MTEP** – Upgrade Petersburg – AEP Sullivan 345 kV line

Distribution Planning

- Continuously reviews distribution system and develops a 5 year construction plan for new primary feeder circuits and substation capacity additions
- While distribution system load growth is relatively flat, neighborhood and commercial revitalization serves as a catalyst to improve existing circuits or extend new facilities
- Distributed Generation (DG) is also incorporated into the planning process through interconnection studies
- IPL has flexibility to switch loads due to compact service territory
- Recent distribution automation/smart grid deployment of >95% of the system supports remote switching operation

Smart Grid Project served as a catalyst

- Leveraged Department of Energy $20m grant toward $52m cost from 2010 to 2013
- Integrated holistic approach to include metering, distribution automation projects and customer facing technologies
- Sustainable solutions

U.S. DEPARTMENT OF ENERGY

Customer Systems have been deployed

- Customer Energy Management
  - Online Energy Feedback (PowerView®) for all customers
- Electric Vehicle Support
  - ~160 home, business & public chargers
  - Special rates
- Customer Web Engagement Tools
  - Smart grid education and outage reporting
  - Program enrollment for DSM

Distribution Automation Devices Currently Used Daily (1 of 3)

1. Central Business District Network Relays & Fault Indicators
   - Relays provide better protection
   - Fault indicators speed fault location and reduces cable damage
2. Digital Feeder Relays
   - Allows integration of DG onto the feeder
   - Reduced O&M costs by allowing reclosing to be turned off remotely
   - Provides 3 Phase currents, for better utilization of capacity
   - Distance to fault, reduces outage time
   - Feeder VAR readings integrated with capacitor control system to minimize substation and feeder losses

Distribution Automation Devices Currently Used Daily (2 of 3)

3. Recloser Installations on Primary Circuits
   - Reduces number of complete circuit lockouts
   - Reduces number of customers affected by an outage
   - Speeds restoration as they can be controlled remotely through the dSCADA system

4. Smart Capacitor Bank Controls
   - Better voltage regulation on distribution feeders
   - Ability to change setting from central locations

Distribution Automation Devices Currently Used Daily (3 of 3)

5. Load Tap Changer Controls
   - Key to Conservation Voltage Reduction (CVR) program settings can be changed remotely
   - CVR program is 20 MW of capacity
   - Tap changer operations recorded in historical database
6. Transformer On-line Monitoring
   - Improved asset health monitoring
   - Quicker indication of possible problems
7. Substation Security & Infrared Monitoring
   - Improved security and allows for quicker response when intruders are detected
   - Infrared Monitoring provides continuous monitoring of critical equipment

Smart Energy Project Successes

- Increased reliability from mid-point reclosers which reduce circuit lockouts and number of customers affected
- Improved personnel safety through remote operation of overhead and underground equipment
- Leverage data for distribution asset management
- Avoided truck rolls in 2015 total over 91,000
- Better information for operational and long-term decision making

Questions?

Load Forecast

Eric Fox, Director Forecast Solutions, Itron Inc.

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Forecast Overview

1. Energy Trends – Why the disconnect between economic growth (GDP) and electricity use
2. Long-term Forecast Approach
   – Capturing end-use efficiency improvements
3. Forecast Model and Base Case Forecast Overview
   1. Residential
   2. Commercial
   3. Industrial
   4. Energy and Peak
4. Forecast Sensitivity
5. Summary

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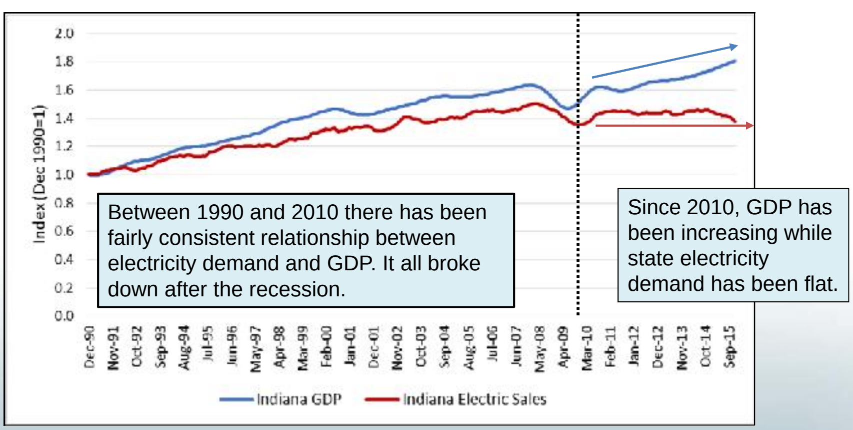
Top-Level Look

- Indiana GDP vs. Electricity Consumption



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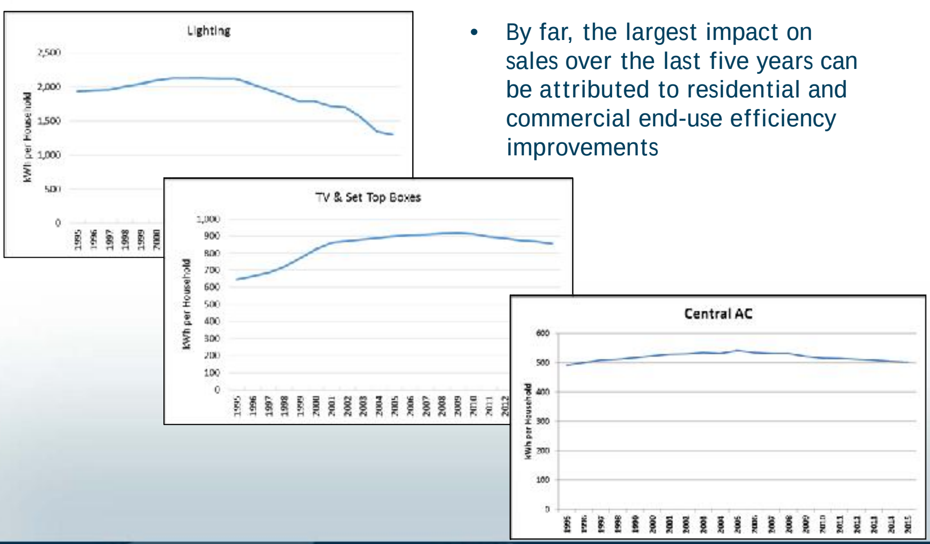
Why the disconnect?

- Strong residential appliance and commercial equipment efficiency improvements
  - Implementation of new end-use efficiency standards
- Increase in utility and state sponsored efficiency program activity
- Increasing share of less energy-intensive industries
- Smaller home square footage – increasing share of multifamily homes
- Changing demographics – smaller families and slower household formation growth
- Slower household income growth

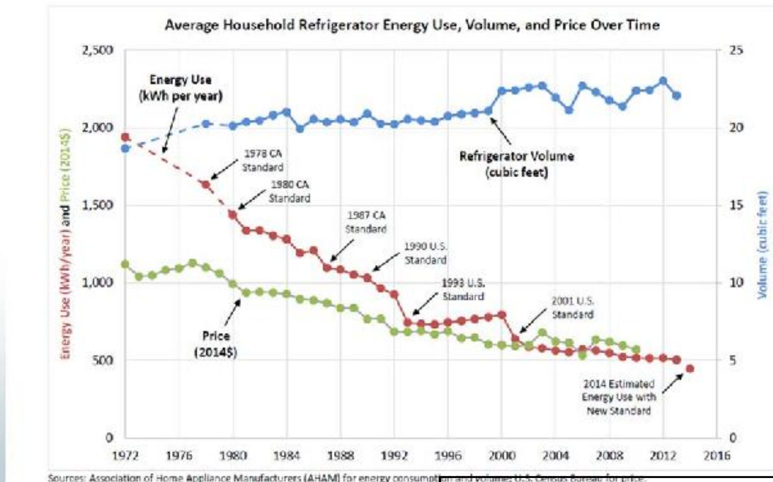
End-Use Efficiency Impact



- By far, the largest impact on sales over the last five years can be attributed to residential and commercial end-use efficiency improvements

Refrigerator Usage Trend

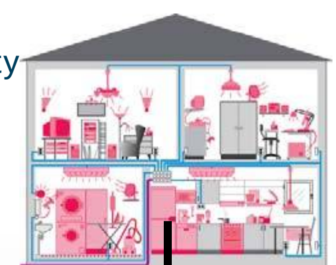
ASAP | APPLIANCE STANDARDS AWARENESS PROJECT



http://www.appliance-standards.org/

The Problem with using GDP as a Primary Forecast Driver

- GDP is correlated with electric sales, but GDP does not cause electric sales
- We use the stuff that uses electricity
  - We light our homes
  - We refrigerate and cook our food
  - We vacuum up after the kids and dog
  - We dry our clothes
  - We watch TV

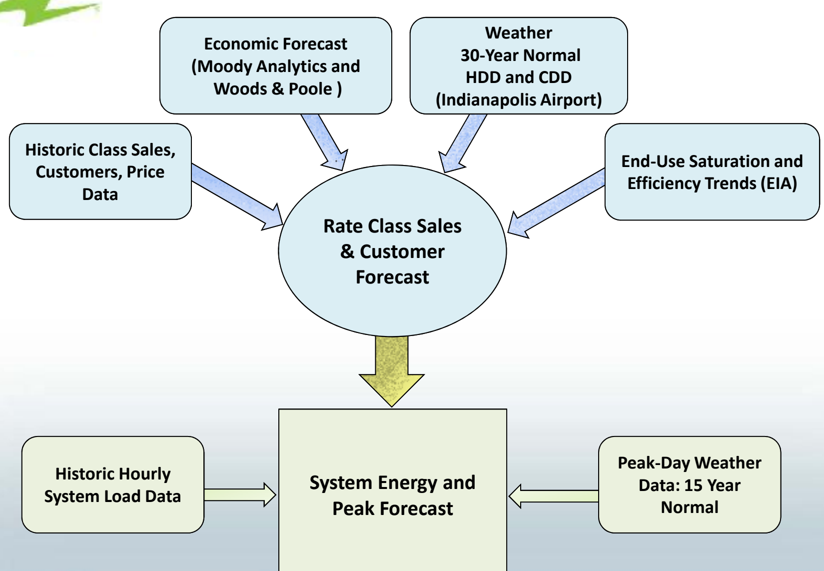


It's the other way around. Electricity generation and the things we buy are inputs into GDP

A Better Approach

- To the extent possible, we want to estimate forecast models of causation and not correlation
- That means understanding how changes in the technology we use at home and at work impacts our energy needs
- In addition to GDP as an economic variable

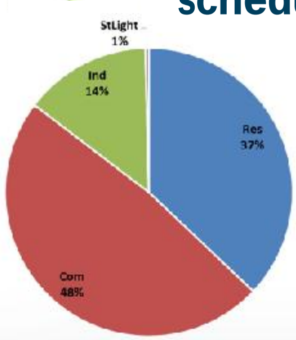
Forecast Modeling Framework



Forecast Models

- Forecasts are based on monthly regression models using ten-years of billed sales and customer data (January 2005 to March 2016)
- Sales Models
  - Residential and commercial models estimated using a blended end-use/econometric modeling framework
  - Industrial sales are estimated with a generalized econometric model
  - Small rate classes such as process heating, security lighting, and street lighting are estimated using simple trend and seasonal models
- Demand Model
  - Monthly system peak model based on heating, cooling, and base-use energy requirements derived from the sales forecast models

Models estimated at rate schedule level

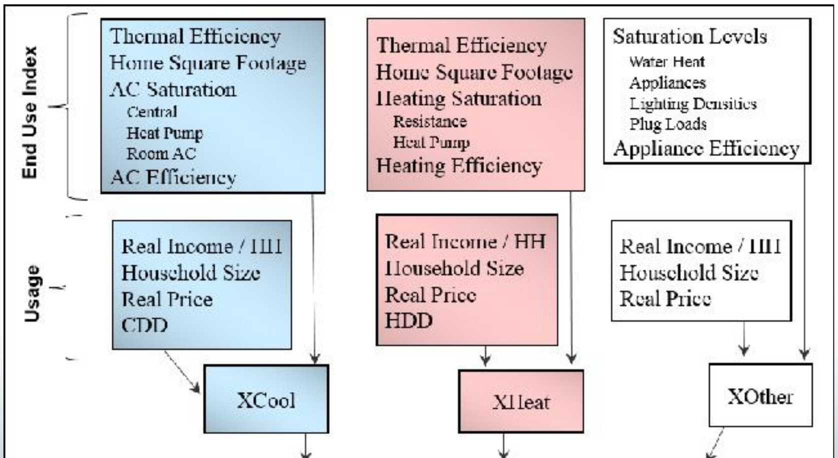


Percentage of 2015 Annual Sales

2015 Sales and Average Annual Customers

Rate Class	Rate Schedule	Definition	Customers	MWh	Avg_kWh
RES	RS	General Service	246481	2342108	9,502
RES	RH	Electric Heat	150498	2,323,908	15,441
RES	RC	Electric Water Heat	32022	406,586	12,697
Sml Com	SS	General Service	46,153	1,228,878	26,626
Sml Com	SH	GS All Electric	4,035	562,864	139,495
Sml Com	SE	GS Electric Heat	3,357	19,383	5,774
Sml Com	CB	GS Water Heat (Controlled)	95	432	4,549
Sml Com	UW	GS Water Heat (Uncontrolled)	84	1,506	17,923
Sml Com	APL	GS Security Lighting	364	31,620	86,868
Lrg Com	SL	Secondary Service	4,539	3,504,652	772,120
Lrg Com	PL	Primary Service	142	1,260,060	8,873,662
IND	HL1	High Load Factor 1	28	1,373,248	49,044,571
IND	HL2	High Load Factor 2	5	225,376	45,075,200
IND	HL3	High Load Factor 3	3	345,920	115,306,667
IND	APL	Ind Security Light	364	5,725	15,728
Other	ST	Street Lighting		53,280	
Total			488,170	13,685,546	28,034

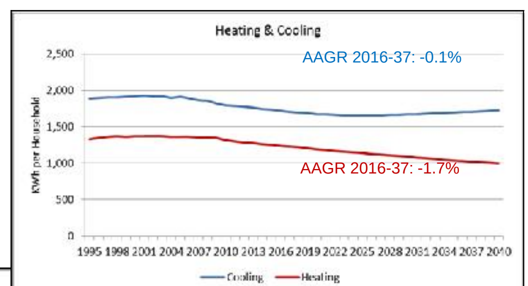
Residential Model

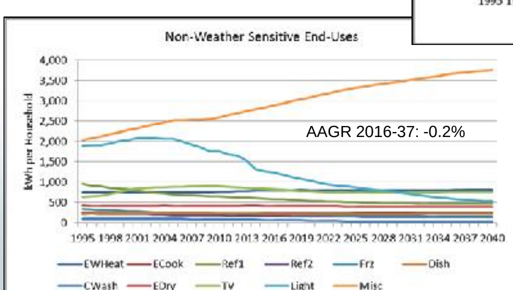


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + e_m$$

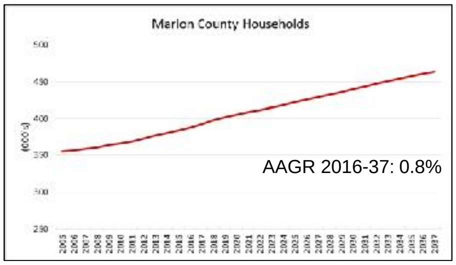
Residential End-Use Intensity Trends

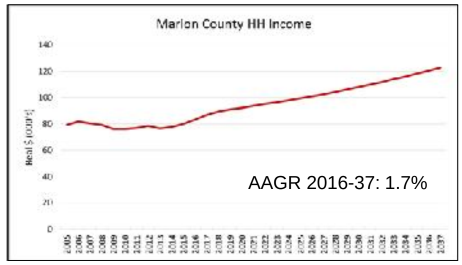
- Energy intensities derived from the EIA 2015 Annual Energy Outlook for the East North Central Census Division



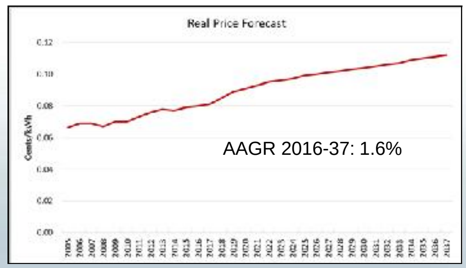


Residential Economic Drivers



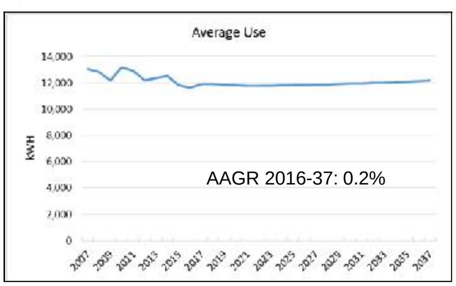


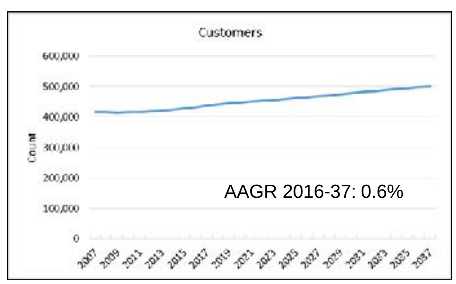
- Marion County Economic Forecast
- Blended Woods & Poole near-term forecast with Moody Analytics long-term forecast
- Price projections developed by IPL

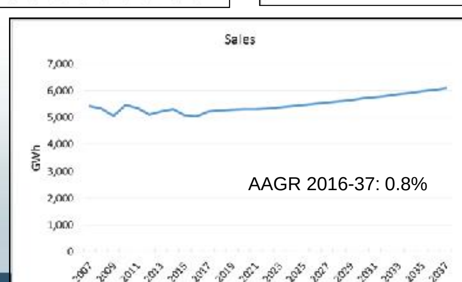


*AAGR=Average Annual Growth Rate

Residential Forecast

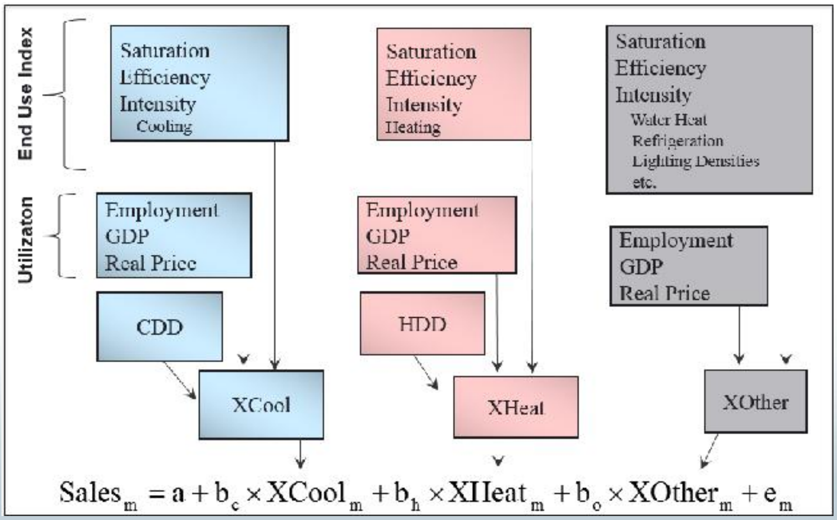






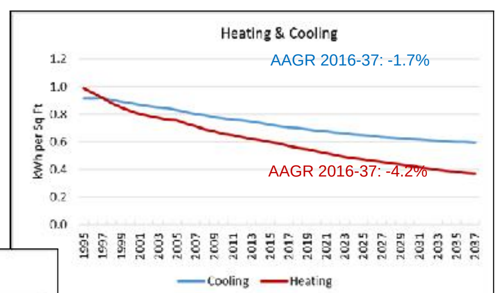
*AAGR=Average Annual Growth Rate

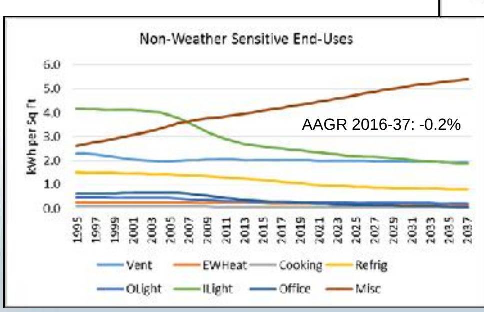
Commercial Model Framework



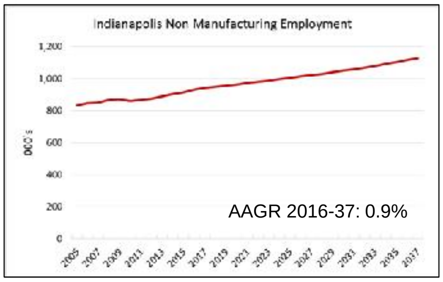
Commercial End-Use Intensities

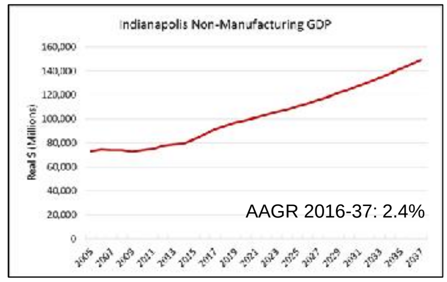
- Energy intensities derived from the EIA 2015 Annual Energy Outlook for the East North Central Census Division



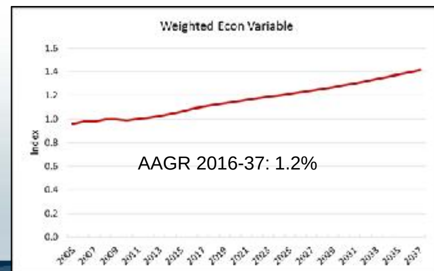


Commercial Economic Drivers





- Indianapolis MSA
- Blended Woods & Poole (in the near-term) and Moody Analytics in the long-term)
- Weighted economic variable: 80% employment/20% GDP



*AAGR=Average Annual Growth Rate

Industrial Model Framework

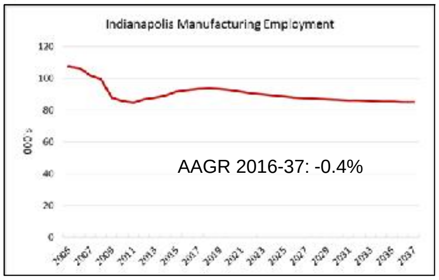
- Industrial sales are estimated with a generalized econometric model

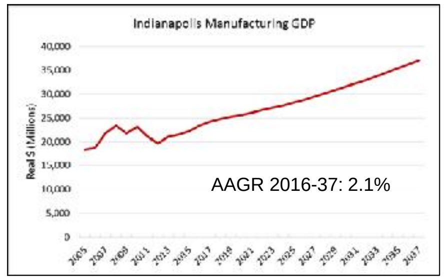
Cooling Degree Days

Manufacturing Employment
Manufacturing Output
Price

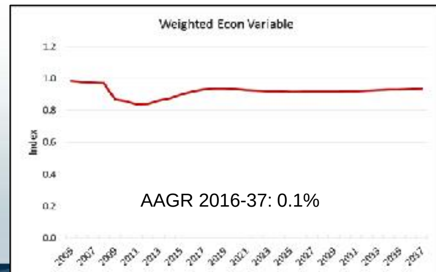
$$Sales_m = a + b_{cdd} \times CDD_m + b_{Econ} \times EconVariable_m + e_m$$

Industrial Economic Drivers



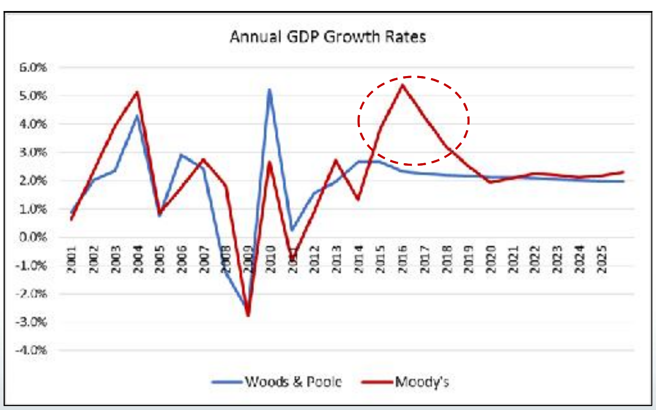


- Indianapolis MSA
- Blended Woods & Poole (near-term) and Moody Analytics long-term
- Strong employment weighting



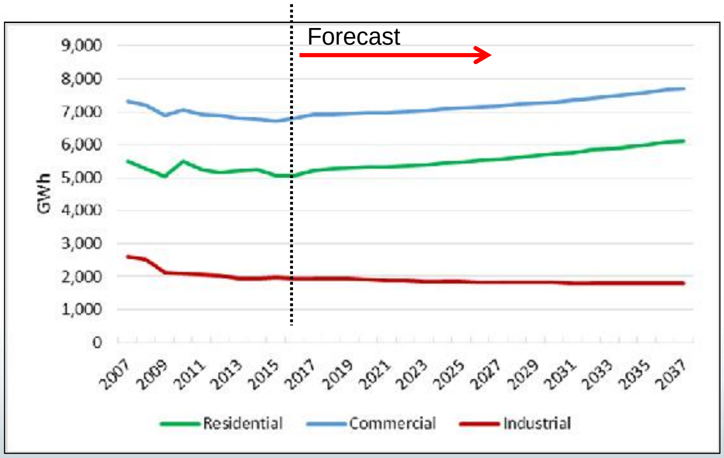
*AAGR=Average Annual Growth Rate

Comparison of GDP forecasts - Indianapolis Metropolitan Statistical Area (MSA)



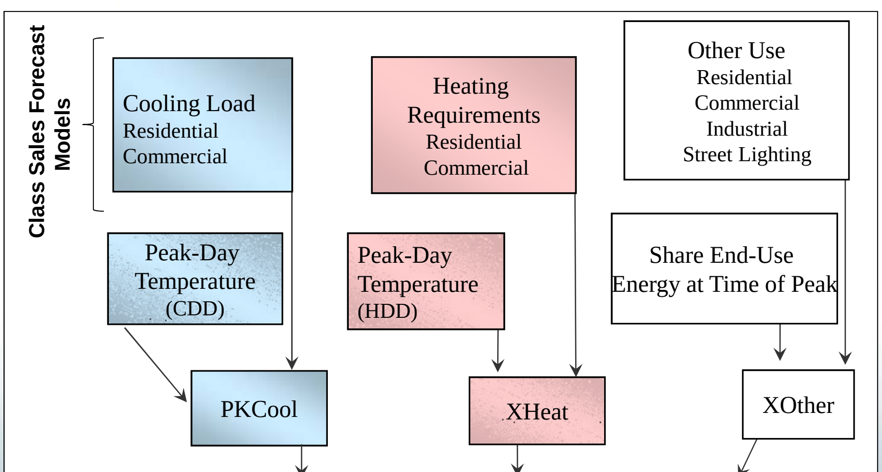
- Near-Term based on Woods & Poole GDP Forecasted Growth

Class Sales Forecast (before EE program savings)



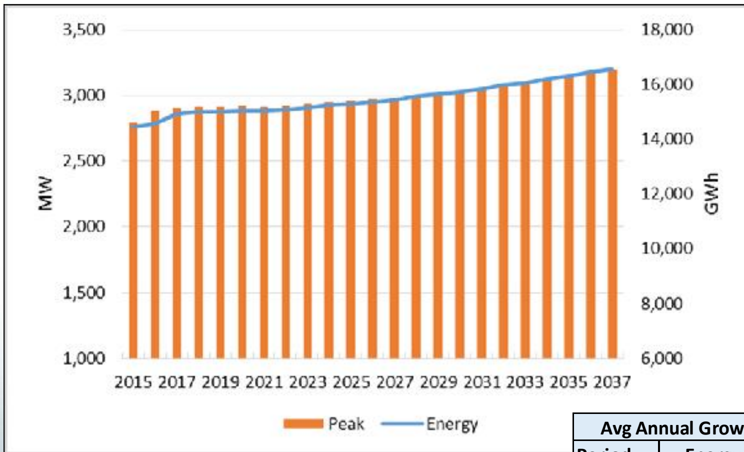
Avg Annual Growth Rate			
Period	Residential	Commercial	Industrial
2016-37	0.8%	0.5%	-0.4%

Peak Model



$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_o \times PKOther_m + e_m$$

Energy & Peak Forecast

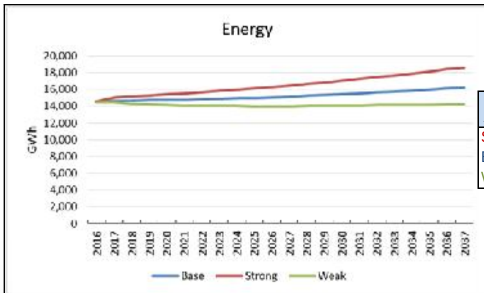


Avg Annual Growth Rate		
Period	Energy	Peaks
2016-37	0.5%	0.4%

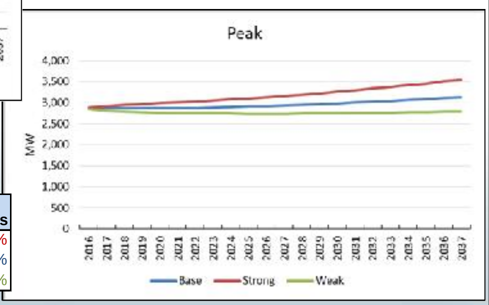
Forecast Sensitivity

- "Strong Economy"
  - Based on Moody Analytics "stronger near-term rebound" scenario for the Indianapolis MSA
- "Weak Economy"
  - Based on Moody Analytics "protracted slump" scenario for the Indianapolis MSA

Sensitivity Comparison



Avg Annual Growth Rates	
Strong	1.2%
Base	0.5%
Weak	-0.1%



Avg Annual Growth Rates	
Strong	1.0%
Base	0.4%
Weak	-0.1%

Summary

- Relatively strong customer growth and business activity
- But slow energy and demand growth
  - Sales growth is mitigated by continued improvement in end-use efficiency coupled with IPL's energy efficiency program activity
- The blended end-use/econometric model works extremely well in capturing the impact of improvements in end-use efficiency as well as customer and economic growth

Questions?

Environmental Risks

Angelique Collier, Director of Environmental Policy

INDIANAPOLIS POWER & LIGHT COMPANY

Current Environmental Controls for Coal-Fired Generation

Unit	In Service Date	Generating Capacity (MW)	SO_2 Control	NO_x Control	PM Control	Hg Controls
Petersburg 1	1967	232	Scrubber (1996)	LNB (1995)	ESP (1967)	ACI (2015) SI (2015)
Petersburg 2	1969	435	Scrubber (1996)	LNB (1994) SCR (2004)	Baghouse (2015)	ACI (2015) SI (2015)
Petersburg 3	1977	540	Scrubber (1977)	SCR (2004)	ESP (1986) Baghouse (2016)	ACI (2016) SI (2016)
Petersburg 4	1986	545	Scrubber (1986)	LNB (2001)	ESP (1986)	ACI (2016) SI (2016)

SO_2 = Sulfur dioxide
NO_x = Nitrogen oxides
MW = Mega Watts
ACI = Activated Carbon Injection

ESP = Electricstatic Precipitator
SCR = Selective catalytic reduction
LNB = Low NO_x Burners
SI = Sorbent Injection

Environmental Regulations

- Recent Environmental Regulations/Projects
  - Mercury and Air Toxics Standard (MATS)
  - NPDES Water Discharge Permits
  - Cross State Air Pollution Rule (CSAPR)
- Future Environmental Regulations
  - 316(b) – Cooling water intake structures
  - Office of Surface Mining
  - Clean Power Plan (CPP)
  - Coal Combustion Residuals (CCR)
  - Effluent Limitations Guidelines (ELG) Rule
  - National Ambient Air Quality Standards (NAAQS)

NPDES= National Pollutant Discharge Elimination System

Recent Environmental Regulations

- MATS
  - Mercury and other air toxics from utilities
  - Compliance date: April 2016
  - Ceased coal-combustion on older, smaller coal-fired units
  - $450 million in new and upgraded air pollution controls at Petersburg
- NPDES
  - New metal limits for Harding Street and Petersburg
  - Compliance date: September 2017
  - Cease coal-combustion at Harding Street Unit 7
  - Scrubber wastewater treatment system and dry fly ash handling at Petersburg
  - $250 million in wastewater treatment
- CSAPR
  - Phase I effective January 2015; Phase II January 2017
  - Existing controls and purchase of allowances on the open market

Future Environmental Regulations – NAAQS and CSAPR

- National Ambient Air Quality Standards (NAAQS)
  - PM2.5 and Ozone
    - Lowered standards
    - IPL areas designated or expected to be designated at attainment
- Cross State Air Pollution Rule Ozone Update
  - Proposed December 3, 2015
  - Would address lowered 2008 Ozone standard
  - Lower Ozone Season allowances allocated
  - Compliance through additional purchase of allowances or additional NO_x controls

NAAQS = National Ambient Air Quality Standards
CAIR = Clean Air Interstate Rule
$PM_{2.5}$ = Particulate Matter less than 2.5 microns in diameter
SO_2 = Sulfur Dioxide
SCR = Selective catalytic reduction
EPA = Environmental Protection Agency

Future Environmental Regulations - Cooling Water Intake Structures Rule

- Final Rule published August 2014
- Regulates environmental impact from cooling water intake structures (CWIS)
  - Impingement and entrainment of aquatic species
  - Closed cycle cooling systems may be required
- Studies underway to determine impact
  - Eagle Valley and Harding Street already equipped with closed cycle cooling.
  - Two of four Petersburg units fully equipped with closed cycle cooling
- Compliance required in 2020 or later

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Future Environmental Regulations - Office of Surface Mining Rule

- Proposed Rule expected in 2016
- Would regulate placement of ash as backfill in mines
- If backfill prohibited, IPL Petersburg may require expansion of onsite landfill

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Future Environmental Regulations – Clean Power Plan

- Final Rule published August 23, 2015
- Requires carbon dioxide emissions reductions
  - Indiana must develop a State Plan or be subject to Federal Plan
  - May be achieved through
    - Heat rate improvements;
    - Re-dispatch from coal to new renewables or existing NGCCs; or
    - Other measures.
- New Eagle Valley NGCC not subject to Rule
- Harding Street will comply by combusting natural gas
- Rule stayed by SCOTUS pending legal resolution
  - Initial State Plan deadline of September 6, 2016 no longer in place
  - Compliance deadline likely delayed by 18 months or longer

NGCC = Natural Gas Combined Cycle
SCOTUS = Supreme Court of the U.S.

Future Environmental Regulations – Clean Power Plan Allocations

Plant Name	Boiler ID	Unit's First Period Allocation (short tons) 2022-2024	Unit's Second Period Allocation (short tons) 2025-2027	Unit's Third Period Allocation (short tons) 2028-2029	Unit's Final Allocation (short tons) 2030-2031
Harding Street	50	397,900	382,078	359,864	346,958
Harding Street	60	365,218	350,695	330,305	318,460
Harding Street	70	1,712,557	1,644,458	1,548,847	1,493,304
Petersburg	1	968,248	929,747	875,690	844,287
Petersburg	2	1,808,953	1,737,021	1,636,028	1,577,359
Petersburg	3	2,356,018	2,262,332	2,130,797	2,054,384
Petersburg	4	2,222,084	2,133,724	2,009,666	1,937,597
Total		9,830,978	9,440,055	8,891,197	8,572,349

Model Assumptions and Inputs

Potential Impacts of Environmental Regulations

Regulation	Expected Implementation Year	Cost Range Estimate ($MM)	Assumed Technology
Office of Surface Mining	2018	0-15	Onsite Landfill
Cooling Water Intake Structure	2020	10-160	Closed Cycle Cooling
Ozone National Ambient Air Quality Standards	2020	0-150	Selective Catalytic Reduction

Questions?
Part 1

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Short Break

Upcoming Environmental Regulations – Coal Combustion Residuals (CCR) Rule

- Final rule published April 2015
- Regulates ash as non-hazardous waste
  - Minimum criteria for ash ponds
  - Closure and post-closure requirements
- HS and EV ponds will be closed because ceased coal combustion
- Petersburg ponds must meet minimum criteria or cease use and close
  - Pond closure would require system to handle bottom ash
  - Closed-loop bottom ash handling system

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Future Environmental Regulations – Effluent Limitations Guidelines (ELG) Rule

- Final rule published November 2015
- Technology-based standard regulating wastewater
  - Scrubber wastewater treatment
  - Dry fly ash handling
  - Dry or closed-loop bottom ash handling
- No impact at Harding Street or Eagle Valley
- Petersburg compliant due to other requirements
  - NPDES
  - CCR

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Upcoming Environmental Regulations – SO_2 NAAQS

- HS and EV comply by combusting natural gas
- Compliance required in 2017
- More stringent limits at Petersburg will require improved SO_2 control
  - Dibasic acid injection
  - Emergency ball mill
  - Emergency limestone conveyance
  - Unit 1 & 2 switch gear

NAAQS = National Ambient Air Quality Standards
SO_2 = Sulfur Dioxide

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Model Assumptions and Inputs

Upcoming Impacts of Environmental Regulations

Regulation	Expected Implementation Year	Cost Estimate ($MM)	Assumed Technology
Effluent Limitations Guidelines	2018	0	None
Coal Combustion Residuals	2018	47	Bottom Ash Dewatering System
SO_2 National Ambient Air Quality Standards	2017	48	FGD Improvements

Questions?
Part 2

Short Break

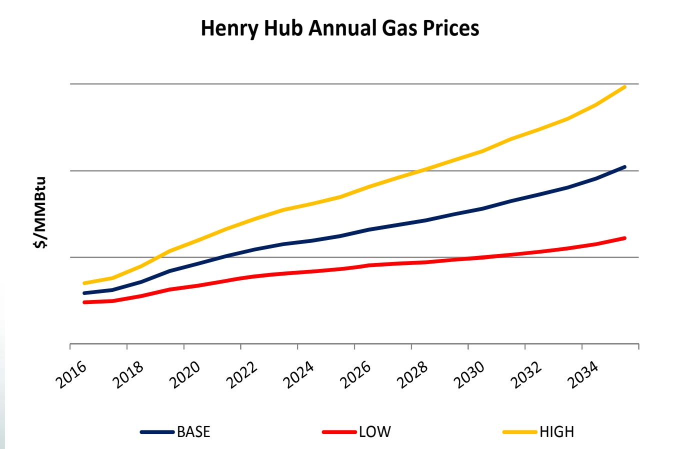
Modeling Update

Joan Soller, Director of Resource Planning

Modeling work continues

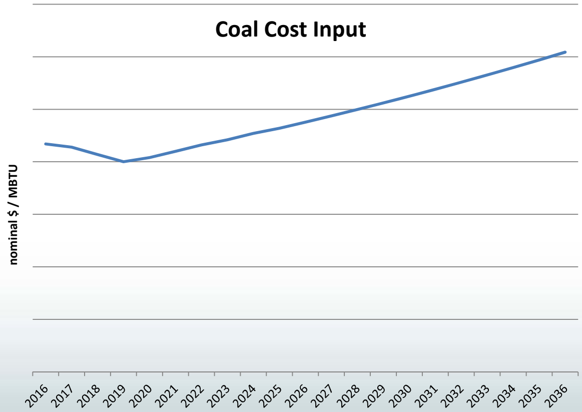
- Updated NG, market price, capacity cost and environmental inputs
- Refreshed existing resource information
- Fine-tuned supply resource parameters
- Created DSM bundles
- Updated load forecast
- Ran initial base case scenario

Natural gas inputs



Source: ABB 2015 Fall Reference Case in nominal dollars

Coal cost inputs



Source: IPL Forecast

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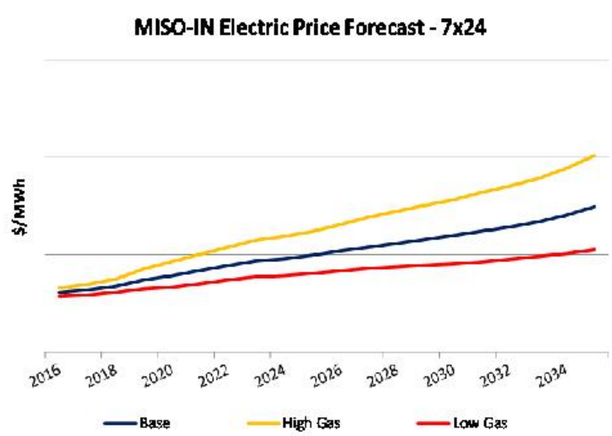
Market price inputs



Source: ABB 2015 Fall Reference Case in nominal dollars

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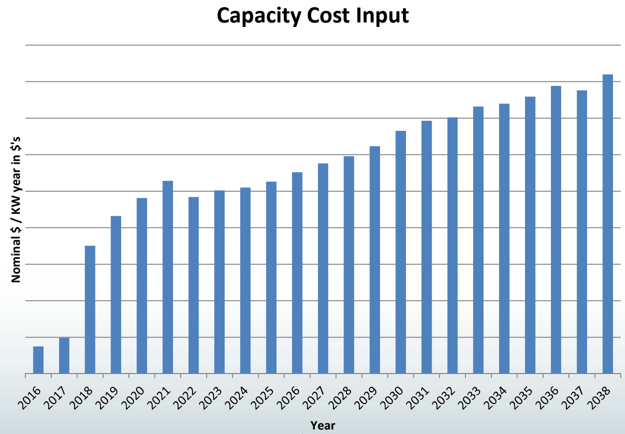
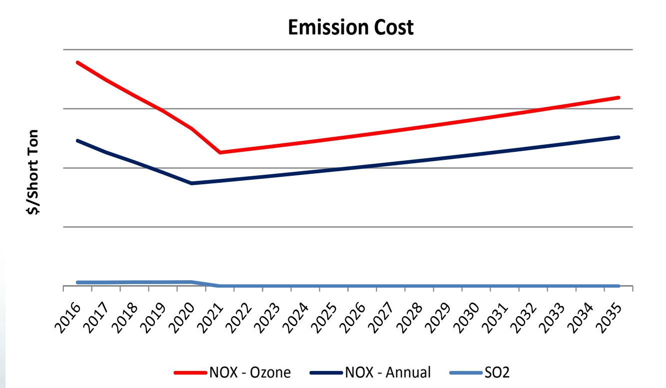
Capacity cost inputs



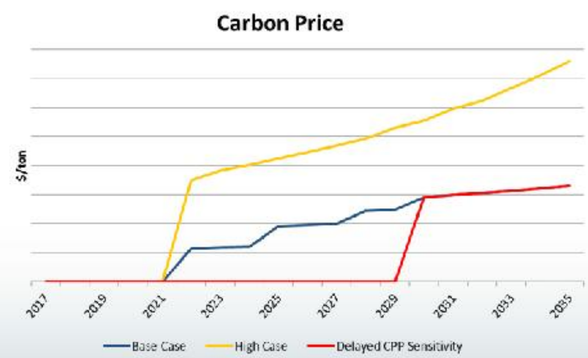
Source: Market Transactions and ABB 2015 Fall Reference Case

Emission cost inputs



Source: ABB 2015 Fall Reference Case in nominal dollars

Carbon cost inputs



Source: ABB Fall 2015 Reference Case and ICF Federal Legislation

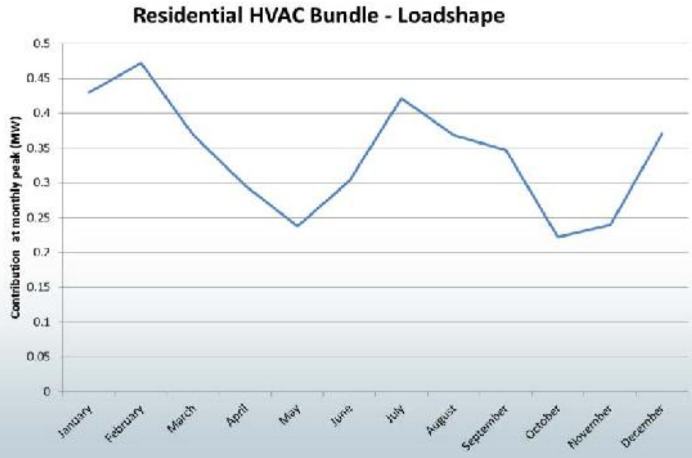
*Price is in nominal dollars

DSM bundles from Market Potential Study

1. EE Res Other (up to $30/MWh)
2. EE Res Other ($60+ /MWh)
3. EE Res Other ($30-60/MWh)
4. EE Res Lighting (up to $30/MWh)
5. EE Res HVAC (up to $30/MWh)
6. EE Res HVAC ($60+ /MWh)
7. EE Res HVAC ($30-60/MWh)
8. EE Res Behavioral Programs
9. EE Bus Process (up to $30/MWh)
10. EE Bus Process ($30-60/MWh)
11. EE Bus Other (up to $30/MWh)
12. EE Bus Other ($60+ /MWh)
13. EE Bus Other ($30-60/MWh)
14. EE Bus Lighting (up to $30/MWh)
15. EE Bus Lighting ($60+ /MWh)
16. EE Bus Lighting ($30-60/MWh)
17. EE Bus HVAC (up to $30/MWh)
18. EE Bus HVAC ($60+ /MWh)
19. EE Bus HVAC ($30-60/MWh)
20. DR Water Heating DLC
21. DR Smart Thermostats
22. DR Emerging Tech
23. DR Curtail Agreements
24. DR Battery Storage
25. DR Air Conditioning Load Mgmt

EE = Energy Efficiency
DR = Demand Response

DSM sample monthly load shape



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Initial base model run results

DRAFT RESULTS – NOT FINAL

YEAR	Base*
2017	DSM - 21 MW
2018	DSM - 23 MW
2019	DSM - 17 MW
2020	DSM - 13 MW
2021	DSM - 12 MW
2022	DSM - 12 MW
2023	**Retire HS GT 1 & 2 (-32 MW) Oil** DSM - 12 MW
2024	DSM -13 MW
2025	DSM - 13 MW
2026	DSM - 11 MW
2027	DSM - 6 MW
2028	DSM - 7 MW
2029	DSM - 3 MW
2030	DSM - 4 MW
2031	**Retire HS 5 & 6 (-200 MW) NG** DSM - 5 MW
2032	**Retire Pete 1 (-227 MW) Coal** DSM - 12 MW
2033	**Retire HS 7 (-430 MW) NG** DSM - 11 MW Battery 140 MW PV 20 MW
2034	**Retire Pete 2 (-410 MW) Coal** DSM - 5 MW Battery 460 MW
2035	DSM - 5 MW CC 200 MW Battery 240 MW
2036	DSM - 5 MW CC 200 MW Battery 60 MW

*Batteries were modeled as "peakers" without additional grid benefits. Technology and market changes may affect implementation timing.

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Initial findings

- The base scenario model results include environmental compliance capital expenditures at Petersburg
- Incremental DSM additions were selected each year starting at ~1% of forecasted sales
- Supply side additions of batteries and solar occur near the unit retirements
- CCGT is selected in later years of study period

Modeling work will continue

- Review base case including inherent DSM
- Run Capacity Expansion model for the other 4 scenarios
- Run Production Cost model for all scenarios
- Calculate PVRRs
- Calculate metrics
- Share results

Questions?

Portfolio Exercise

Joan Soller, Director of Resource Planning
Dr. Marty Rozelle, Facilitator

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Stakeholders draft portfolios

- Consider mix of supply and demand resources to meet ~3000 MW peak load requirement
- Recall representative costs from the April meeting on the next slide
- We are interested in your points of view

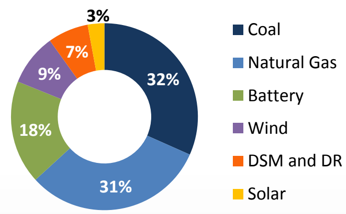
Supply side resource alternatives (from Meeting #1)

IRP Resource Technology Options*			
	MW Capacity	Performance Attributes	Representative Cost per Installed KW
Simple Cycle Gas Turbine	160	Peaker	$676
Combined Cycle Gas Turbine - H-Class	200	Base	$1,023
Nuclear	200	Base	$5,530
Wind	50	Variable	$2,213
Solar	> 5 MW	Variable	$2,270
Energy Storage	20	Flexible	~ $1,000
CHP – industrial site (steam turbine)	10	Base	Ranges from ~ $670 to $1,100
Other?			

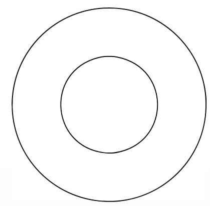
*See Meeting #1 presentation for sources

Exercise worksheet

Potential IPL 2034 portfolio
(nameplate capacity)



"My" portfolio



- ☐ coal ____%
- ☐ battery ___%
- ☐ DSM and DR ____%
- ☐ natural gas ____%
- ☐ oil _____%
- ☐ solar ______%
- ☐ wind ____%
- ☐ other ____%

Discussion

Next Steps

Dr. Marty Rozelle, Facilitator

Written comments and feedback

- Deadline to send written comments and questions regarding this meeting to ipl.irp@aes.com is Tuesday, June 21
- All IPL responses will be posted on the IPL IRP website by Tuesday, July 5
- IPL is considering a webinar to share modeling results in August

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Next scheduled meeting

Friday, September 16, 2016

- Resource Portfolio results
- Sensitivities
- Preferred Resource Plan
- Short Term Action Plan

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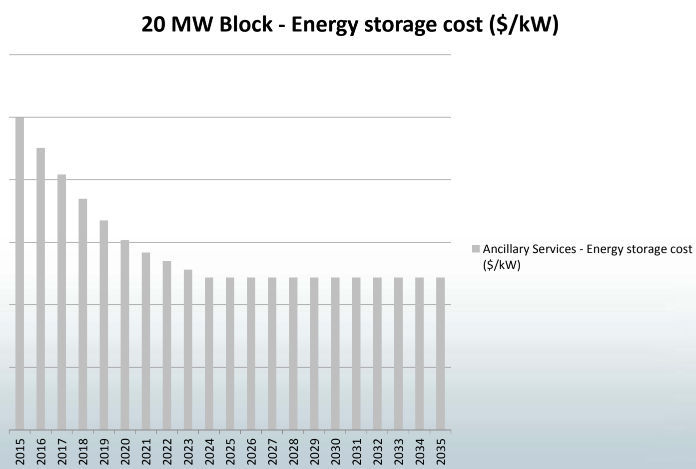
Thank you!

We value your input and appreciate your participation. Please submit your feedback form and recycle your nametag at the registration table as you leave the meeting today.

June 14 Appendix

Capacity reserves exceed min requirement of ~14% in draft base case

Energy storage cost forecast



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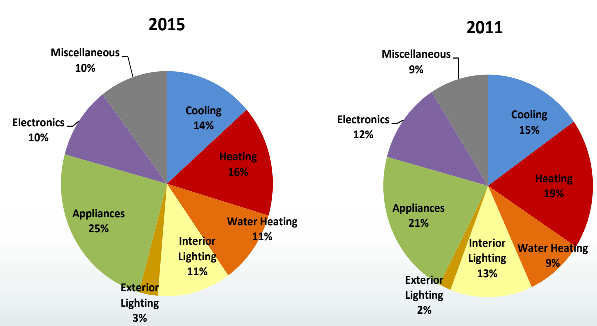
IPL residential market profile



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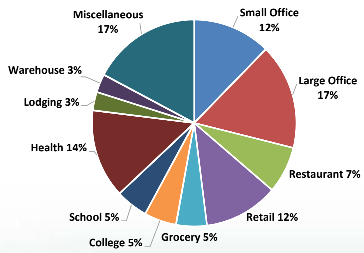
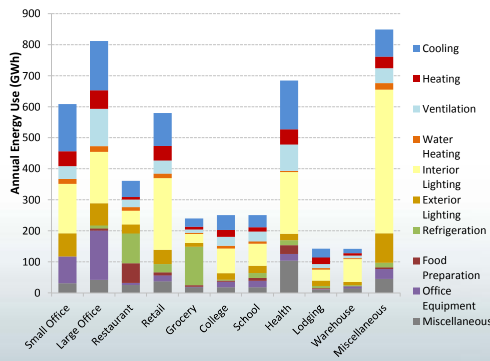
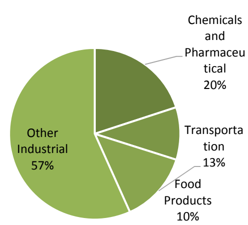
IPL commercial market profile



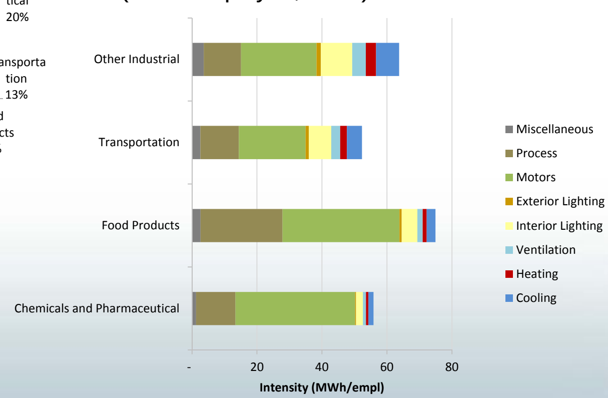
Electricity Consumption by End Use and Segment (GWh, 2015)



IPL Industrial market profile



Electric Intensity by End Use and Segment (MWh/employee, 2015)



REVISED 9-6-16

- DSM appendix slides - real $ noted
- Added slides 50 - 56

Integrated Resource Plan Public Advisory Meeting #3

August 16, 2016

INDIANAPOLIS POWER & LIGHT COMPANY

Welcome & Safety Message

Bill Henley, VP of Regulatory and Government Affairs

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Meeting Guidelines

Joan Soller, Director of Resource Planning

Agenda for today

9:30am Welcome
- Meeting Agenda and Guidelines
- Summary & Feedback from IRP Public Advisory Meeting #2

9:45am IRP modeling update
- Updates to modeling
- Draft model results for all scenarios

10:30am Stakeholder Feedback

10:45am Sensitivity analysis setup

11:30am Conclusion

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions
- Three ways to participate remotely:
  - The phone line will be muted. Press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
  - Use WebEx online tool for questions during meeting
  - Email additional questions or comments to ipl.irp@aes.com
- All may email questions/comments by August 23 for IPL to respond via website by September 6

Active cases before the commission

- Cause No. 42170, ECR-26
- Cause No. 44121, Green Power (GPR 9)
- Cause No. 43623, DSM 13
- Cause No. 44576, Rates (under appeal)
- Cause No. 44792, DSM 2017 Plan
- Cause No. 44794, SO_2 NAAQS and CCR
- Cause No. 44795, Capacity and Off System Sales Riders

Summary & Feedback from IRP Public Advisory Meeting #2

Joan Soller, Director of Resource Planning

Topics covered in Meeting #2

- Stakeholder presentations
- Portfolio Comparison based on Metrics
- Transmission & Distribution
- Load Forecast
- Environmental Risks
- Portfolio and Metrics Exercises
- Draft base case results

- Presentation materials, audio recording, acronym list, and meeting notes are available on IPL's IRP webpage here: https://www.iplpower.com/irp/

Stakeholder interaction continues

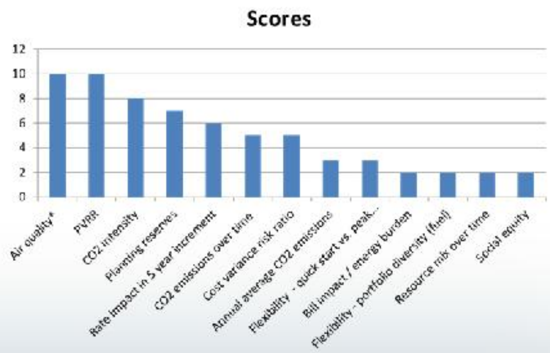
- Since the June meeting, IPL has reached out to the following stakeholders:
  - Citizens Energy
  - Hoosier Interfaith Power & Light (HIPL)
  - IPL Advisory Board
  - National Association for the Advancement of Colored People (NAACP)

Stakeholder portfolio exercise feedback

Resource	Potential IPL 2034 Portfolio June 2016	Range of Stakeholder Preferred Capacity Percentage
Coal	32%	0 – 30%
Natural Gas	31%	0 – 35%
Battery	18%	5 – 18%
Wind	9%	9 – 30%
DSM	7%	7 – 20%
Solar	3%	6 – 30%
Oil	0%	0 – 10%

Stakeholder metrics exercise feedback

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

Questions?

IRP Modeling Update

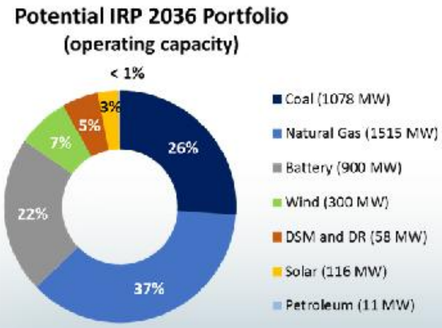
Joan Soller, Director of Resource Planning

Base case has evolved since last meeting

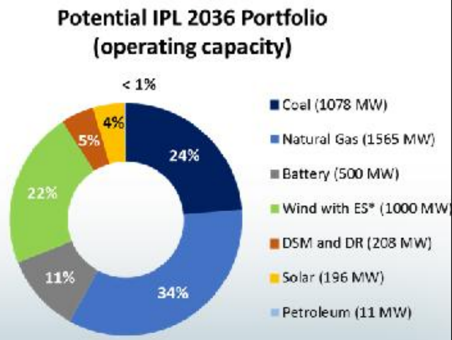
- Incorporated NERC standards voltage stability requirements
  - Minimum 450 MW baseload on 138 kV in addition to EV CCGT
- Adjusted battery capacity credit to 25% to represent 4 hour energy output durations
- Added wind parameters
  - Capacity credit in 2022 as a proxy for expected transmission expansion
  - Frequency response (via energy storage) per proposed order in FERC docket RM 16-6 and reactive power (via quick capacitors) provisions per recent FERC Order 827
  - Limit 250 MW per year and total of 1000 MW to mirror minimum loads

Base case comparison

Initial Base Case (June 2016)

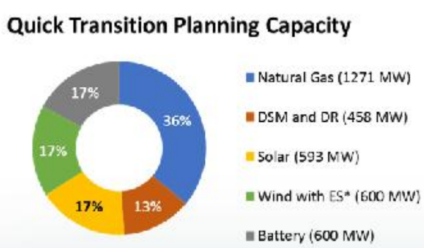


Final Base Case (Aug 2016)



*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

IPL created a Quick Transition Scenario to reflect Stakeholder feedback



Inputs:
- All coal units retire by 2030
- Retain minimum NG on local 138 kV system to meet NERC standards
- Adopt maximum achievable DSM
- Balance comprised of solar, wind and storage

*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

Summary of scenarios

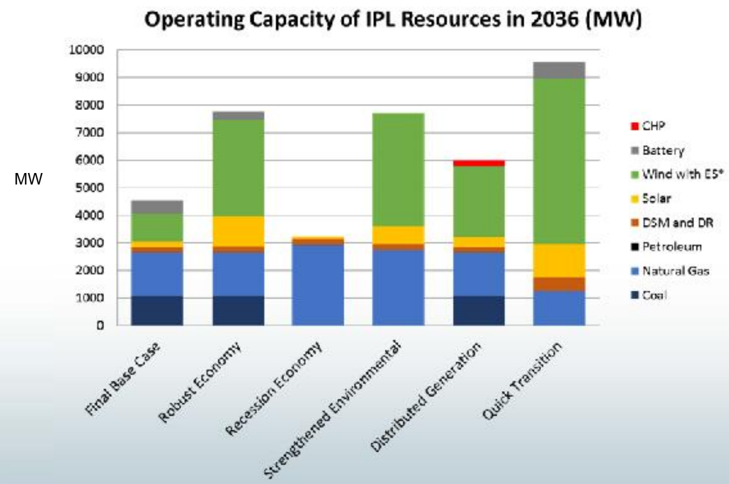
1. Base Case
2. Robust Economy
3. Recession Economy
4. Strengthened Environmental Rules
5. High Adoption of Distributed Generation
6. Quick Transition

Scenario Characteristics/Variable 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	ABB Mass-based CPP Scenario	Mass-based CPP starting in 2022. Low cost environmental regulations: ozone, 316b, NSR, 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, NSR*	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	Base Case	Base Case	Base Case	Fixed portfolio to retire coal, add max DSM, minimum baseload (NG), plus solar, wind and storage*

*Purple font indicates changes.

Scenarios produce varied expansion plans

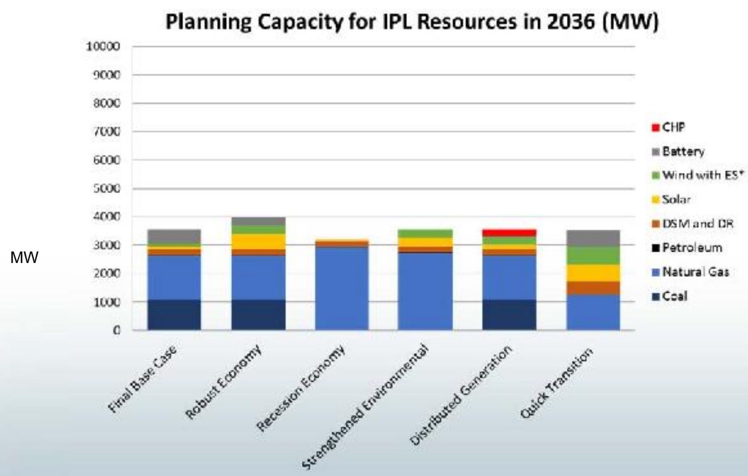


*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

Scenario observations

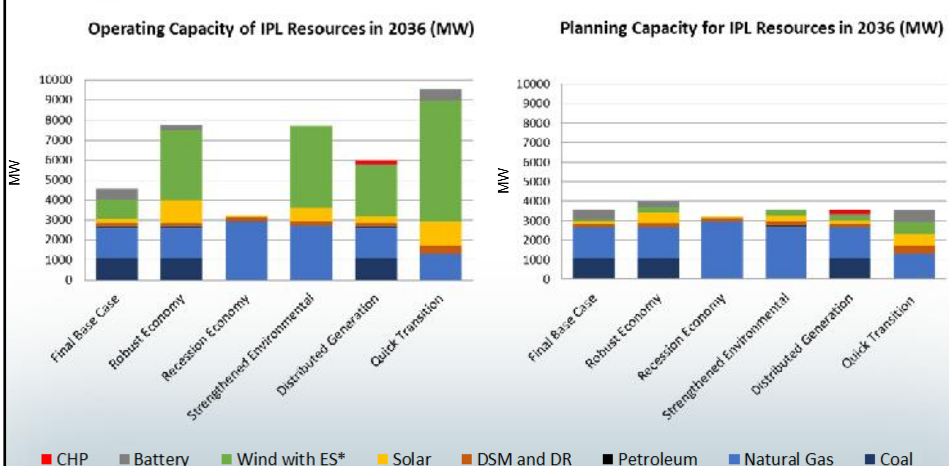
Base Case	Assumes existing units operate through their estimated useful life.
Robust Economy	Load increased by ~370 MW with higher NG prices.
Recession Economy	Load decreased by ~300 MW, lower NG, includes Pete 1-4 refuel early.
Strengthened Environmental	Higher costs for CO_2, 316 b, NAAQS ozone, OSM, and NSR. Includes P1 retirement, P2-4 refuel.
Distributed Generation	Customers choose DG for reasons other than economics totaling ~450 MW or ~15% of IPL load.
Quick Transition	Asset additions are "lumpy" in 2030 when there is an inflection point in Clean Power Plan compliance. The Maximum Achievable Potential DSM was added.

Planning capacity provides resource adequacy in MISO



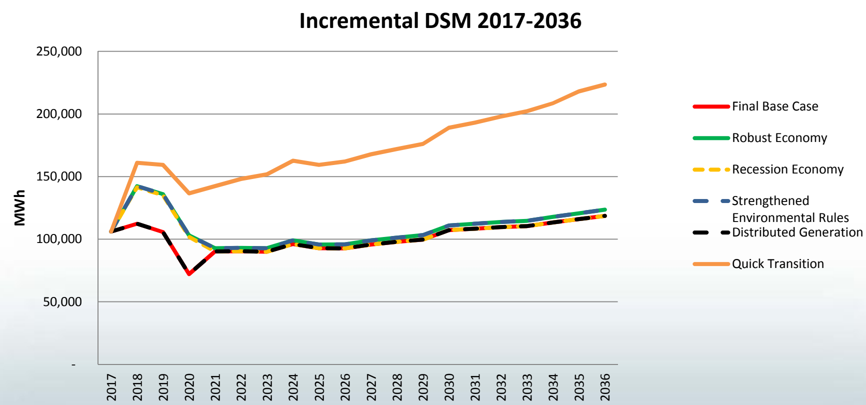
*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

Planning capacity for renewables is lower than operating capacity

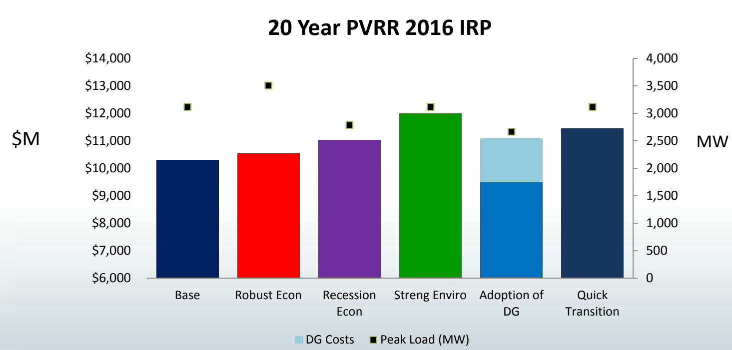


*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

DSM varies by scenario



Costs are shown as Present Value Revenue Requirement (PVRR) 2017 - 2036



*Light blue DG costs are estimated for 450 MW. Customer DG costs will vary.

Questions?

Sensitivity Analysis Setup

Patrick Maguire
Director, Corporate Planning & Analysis

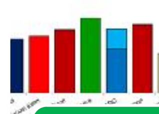
Sensitivity analysis plan

- Two deterministic carbon sensitivities for the base case
  - Delayed CPP from 2022 to 2030
  - High carbon cost for CPP
- Stochastic modeling for all portfolios
  - Multiple inputs varied in each model run
    - Examples: Load (peak and energy), commodity prices, carbon prices, capital costs, forced outage rates

IRP modeling process

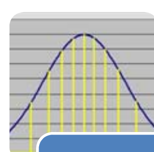
Deterministic Capacity Expansion Model

Complete



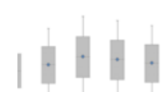
Production Cost Model Run with Base Assumptions for All Portfolios

Complete



Stochastic Parameter Setup

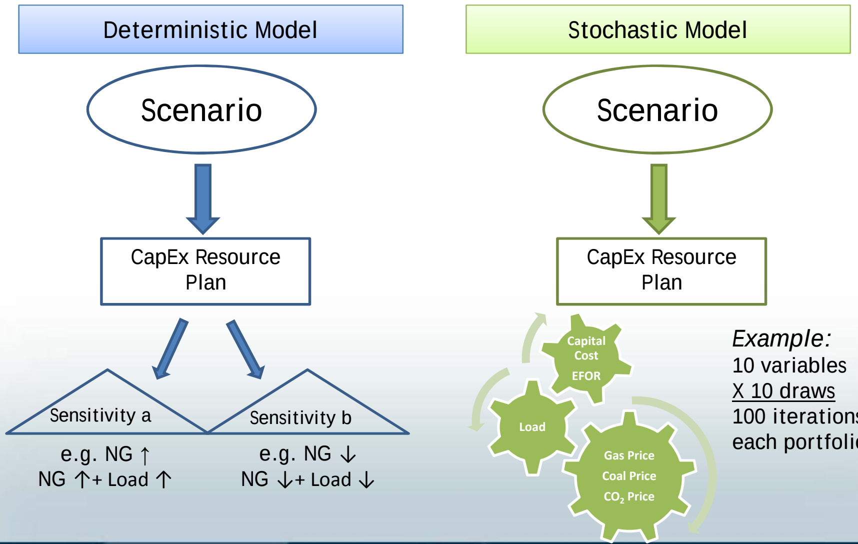
In Progress



Stochastic Modeling and Risk Analysis

In Progress

Two modeling approaches



Example:
10 variables
X 10 draws
100 iterations for each portfolio

Why model stochastically?

Deterministic Model

Advantages

- Easy to administer with no formal probability calculations
- Can be comprehensive with the right amount and combination of variables

Shortcomings

- More qualitative setup, e.g. variables changed by user-defined known and fixed amounts
- Difficult to capture correlations between variables

Stochastic Model

Advantages

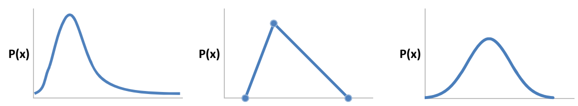
- More robust accounting for interrelatedness and correlation between variables
- Well-established statistical principles and common use guide the setup

Shortcomings

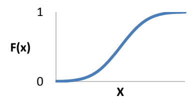
- Difficult to perform and consolidate statistical probability data and correlations
- All variable iterations fed into Integrated Model to generate power prices => significantly higher amount of model simulation time

Parameter setup

Define the distribution



Determine Cumulative Distribution

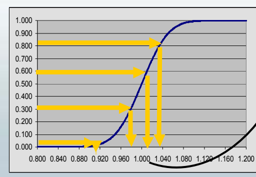


Pick a random number

Use random number to get to multiplier

Account for specific variable characteristics:

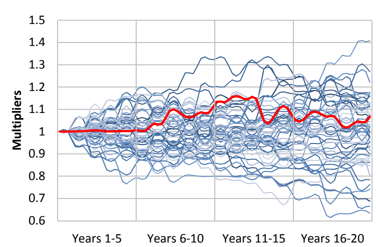
- *Random Walking*
- *Mean Reversion*
- *Seasonality*
- *Skewness*
- *Kurtosis*



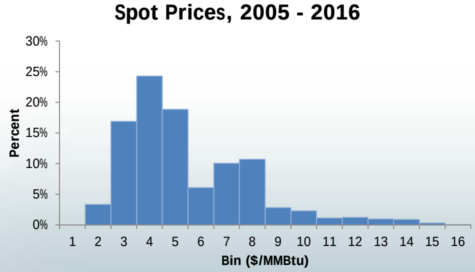
1.037
0.980
0.952
1.005
1.002
1.013
1.003

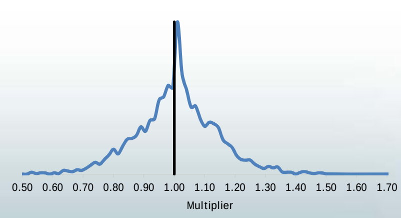
Stochastic Parameter: Gas

Well established market with extensive historical data



Histogram of Historical Henry Hub Spot Prices, 2005 - 2016

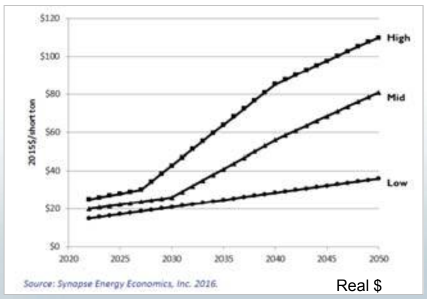


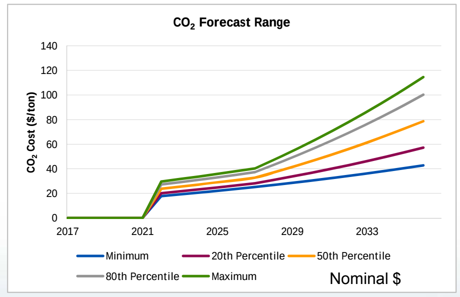


Stochastic Parameter: CO_2

Lack of historical pricing complicates variable setup

Synapse forecasts guided the range of outcomes





Use of Stochastic Parameters

ILLUSTRATIVE PURPOSES ONLY

Variable Multipliers

Draw	Gas Price	Coal Price	Demand	etc.
1	1.10	1.00	1.15	...
2	1.18	1.06	1.01	...
3	1.15	1.08	1.14	...
4	0.97	0.97	1.03	...
5	1.06	1.04	1.08	...
6	1.04	0.98	1.11	...
7	1.07	0.95	1.11	...
8	1.09	1.07	0.95	...
9	1.10	1.00	1.00	...
10	1.06	1.07	0.99	...
11	0.97	1.04	1.15	...
12	1.15	1.08	0.97	...
13	1.15	1.01	1.14	...
14	1.01	1.04	1.10	...
15	1.18	1.03	1.10	...

Fundamental Forecasts

Market Price Model

Draw	Power Price
1	$40.50
2	$37.97
3	$51.53
4	$31.25
5	$37.35
6	$36.09
7	$35.60
8	$34.20
9	$34.09
10	$35.22
11	$36.99
12	$37.36
13	$41.81
14	$36.73
15	$41.87

Strategic Planning Model

PVRR ($ in Billions)

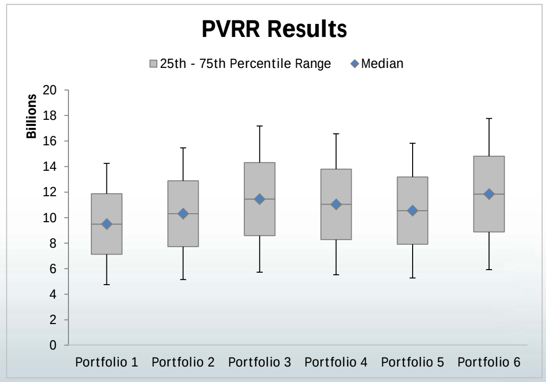
Draw	Portfolio 1	Portfolio 2	Portfolio 3
1	$9.6	$10.8	$10.4
2	$10.1	$10.6	$7.7
3	$10.9	$12.2	$8.6
4	$8.7	$9.4	$10.6
5	$9.2	$12.8	$7.6
6	$8.4	$10.8	$9.7
7	$10.3	$12.4	$10.9
8	$11.2	$11.1	$8.9
9	$7.9	$8.3	$10.0
10	$8.8	$12.5	$8.6
11	$7.9	$9.8	$11.4
12	$11.9	$9.0	$9.1
13	$9.5	$11.9	$9.5
14	$7.5	$8.1	$8.5
15	$11.0	$12.2	$11.4

Model Results and Application

Stochastic results will guide the formation of the metrics

- Provides a range of results (PVRR, carbon emissions, etc.) across all iterations

ILLUSTRATIVE PURPOSES ONLY



35

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Questions?

36

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Next Steps

Joan Soller, Director of Resource Planning

Written comments and feedback

- Deadline to send written comments and questions regarding this meeting to ipl.irp@aes.com is Tuesday, August 23
- All IPL responses will be posted on the IPL IRP website by Tuesday, September 6

Final 2016 IPL IRP Public Advisory Meeting

Friday, September 16, 2016

- Final model results
- Sensitivity analyses results
- Preferred Resource Plan
- Short-term Action Plan

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Thank you!

We value your input and appreciate your participation. Please submit your feedback form and recycle your nametag at the registration table as you leave the meeting today.

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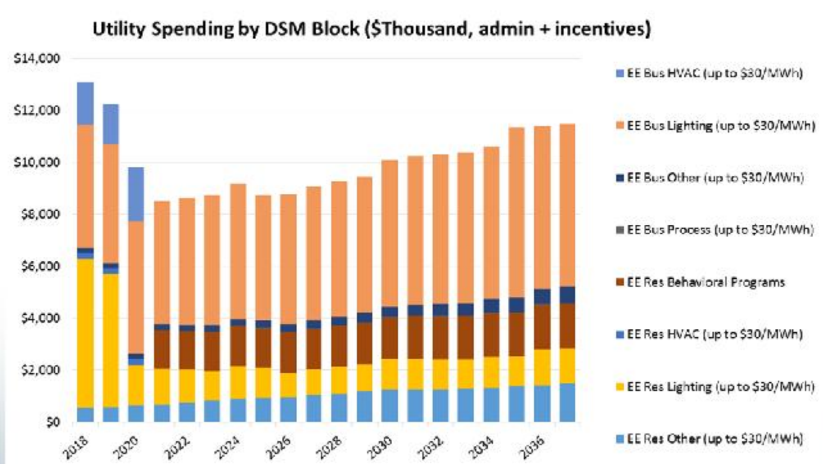
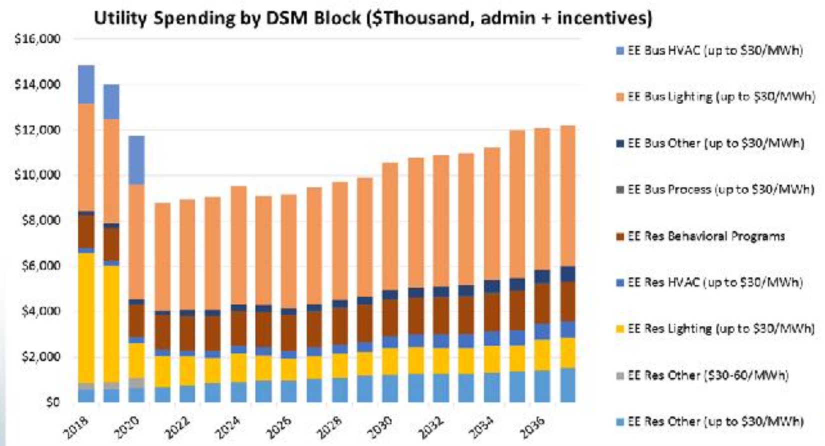
APPENDIX – DSM DETAILS

Base case



in real $

Robust economy



in real $

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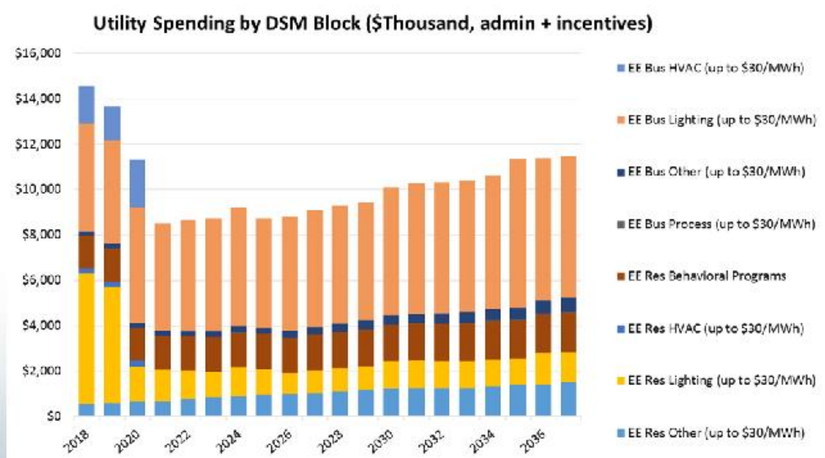
Recession economy



in real $

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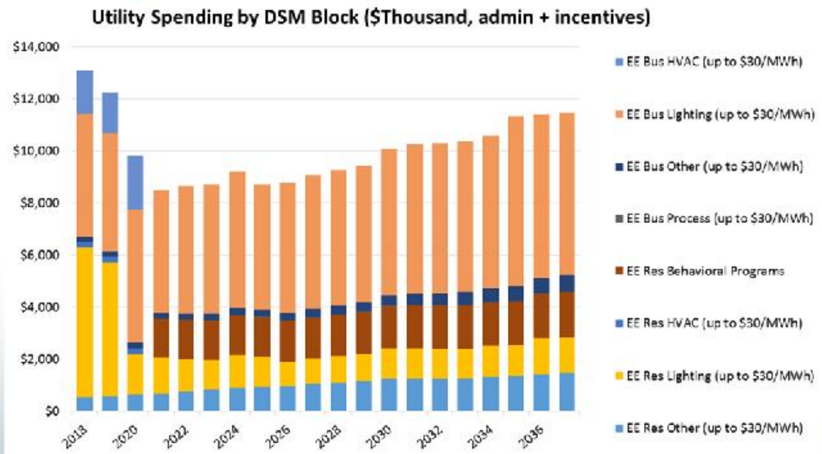
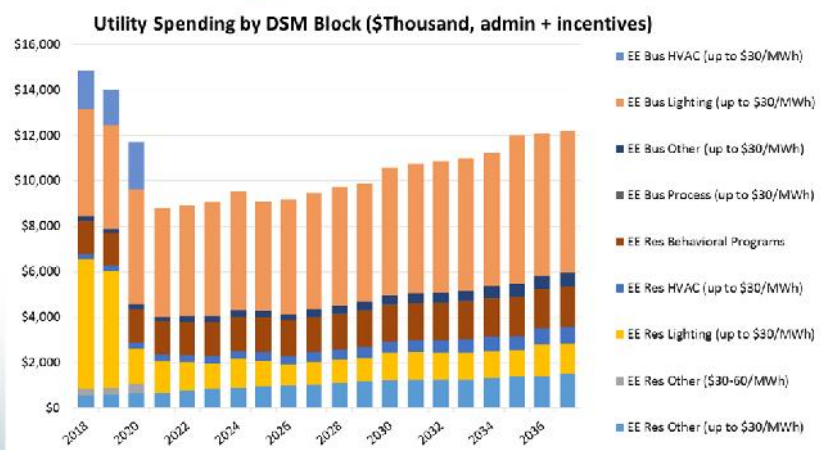
Adoption of distributed generation



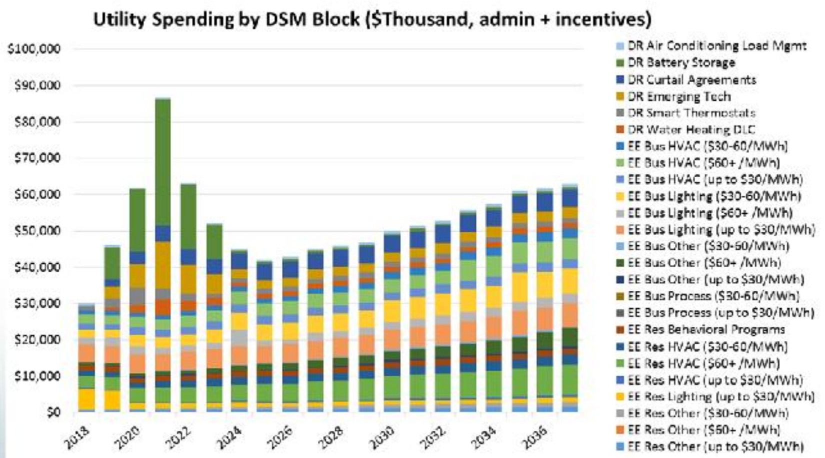
in real $

Strengthened environmental



in real $

Quick transition



in real $

DSM building blocks selected

(based upon maximum achievable)

DSM Blocks Selected	Final Base Case	Robust Economy	Recession Economy	Strengthened Environmental	Distributed Generation
Res Other up to $30MWh 2018-2020	X	X	X	X	X
Res Other $30-60MWh 2018-2020		X		X	
Res Lighting up to $30MWh 2018-2020	X	X	X	X	X
Res HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Behavioral Program 2018-2020		X	X	X	
Bus Other up to $30MWh 2018-2020	X	X	X	X	X
Bus Lighting up to $30MWh 2018-2020	X	X	X	X	X
Bus HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Other up to $30MWh 2021+	X	X	X	X	X
Res Lighting up to $30MWh 2021+	X	X	X	X	X
Res HVAC up to $30MWh 2021+		X		X	
Res Behavioral Programs 2021+	X	X	X	X	X
Bus Process up to $30MWh 2021+	X	X	X	X	X
Bus Other up to $30MWh 2021+	X	X	X	X	X
Bus Lighting up to $30MWh 2021+	X	X	X	X	X

Quick Transition DSM

DSM Blocks	2018-2020	2021-2037
EE Res Other (up to $30/MWh)	X	X
EE Res Other ($60+ /MWh)	X	X
EE Res Other ($30-60/MWh)	X	X
EE Res Lighting (up to $30/MWh)	X	X
EE Res HVAC (up to $30/MWh)	X	X
EE Res HVAC ($60+ /MWh)	X	X
EE Res HVAC ($30-60/MWh)	X	X
EE Res Behavioral Programs	X	X
EE Bus Process (up to $30/MWh)	X	X
EE Bus Process ($30-60/MWh)	X	X
EE Bus Other (up to $30/MWh)	X	X
EE Bus Other ($60+ /MWh)	X	X
EE Bus Other ($30-60/MWh)	X	X
EE Bus Lighting (up to $30/MWh)	X	X
EE Bus Lighting ($60+ /MWh)	X	X
EE Bus Lighting ($30-60/MWh)	X	X
EE Bus HVAC (up to $30/MWh)	X	X
EE Bus HVAC ($60+ /MWh)	X	X
EE Bus HVAC ($30-60/MWh)	X	X
DR Water Heating DLC	X	X
DR Smart Thermostats	X	X
DR Emerging Tech	X	X
DR Curtail Agreements	X	X
DR Battery Storage	X	X
DR Air Conditioning Load Mgmt	X	X

ADDED 9-6-16

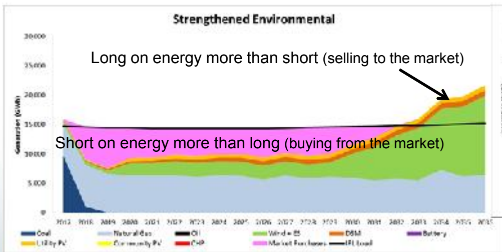
APPENDIX II– ENERGY MIX BY SCENARIO

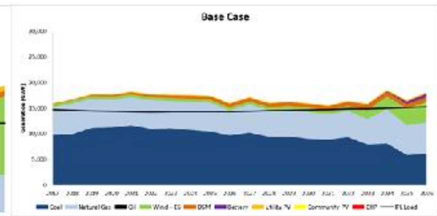
ADDED 9-6-16
Will be discussed at the 9-16-16 meeting

How to Read Energy Mix Slides

- “Long”= more generation in a single hour than load
  “Short”= more load in a single hour than generation
- IPL is long and short throughout the year at different times

These graphs will be shared again and discussed at the final public advisory meeting.

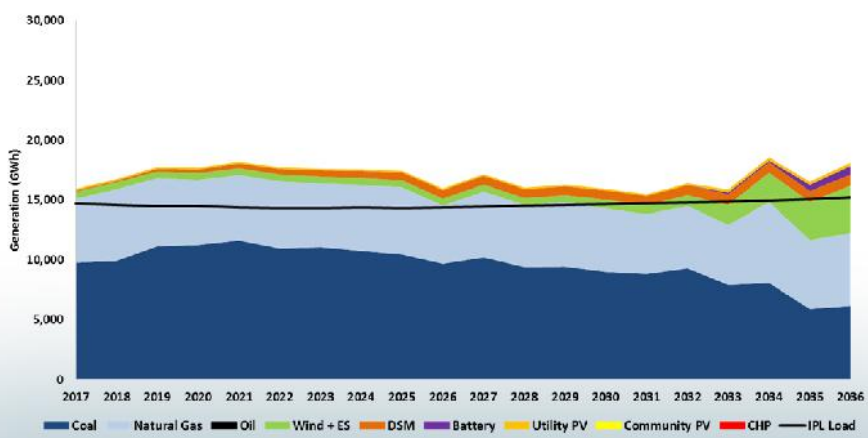




- Based on the nature of dispatching units, IPL will still buy and sell from the market in the base case

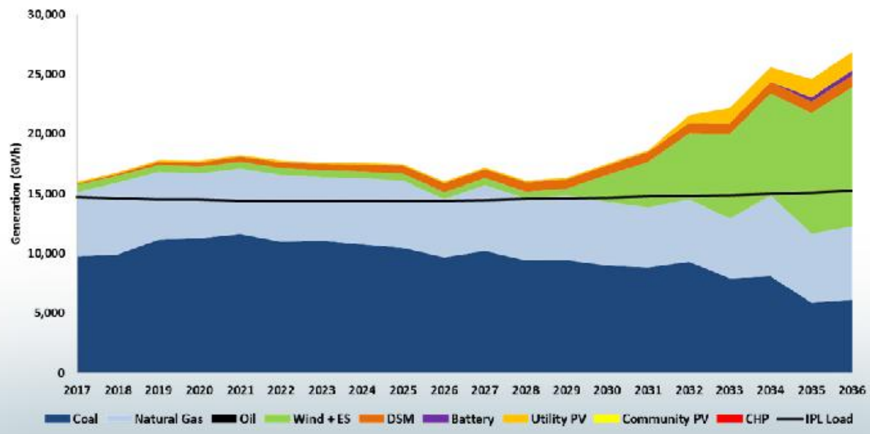
ADDED 9-6-16
Will be discussed at the 9-16-16 meeting

Base Case Energy



ADDED 9-6-16
Will be discussed at the 9-16-16 meeting

Robust Economy Energy



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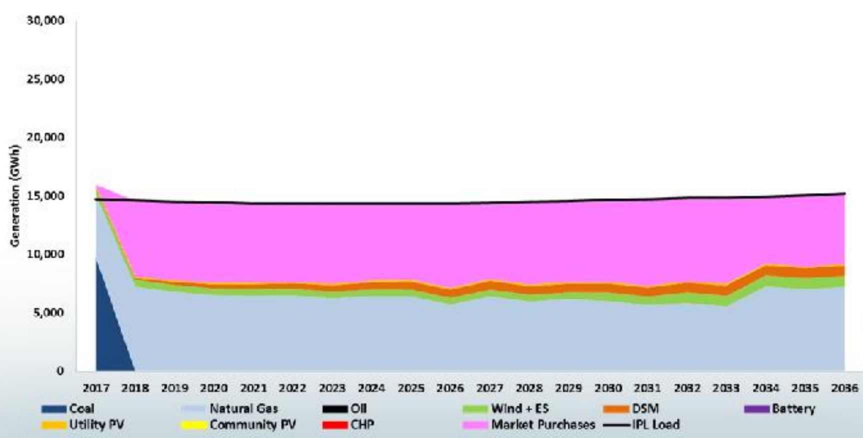
ADDED 9-6-16
Will be discussed at the 9-16-16 meeting

Recession Economy Energy



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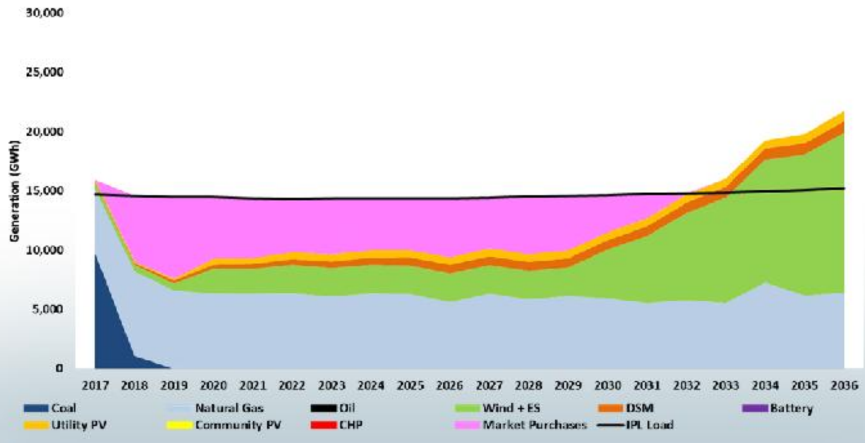
ADDED 9-6-16

Will be discussed at the 9-16-16 meeting

Strengthened Environmental Energy



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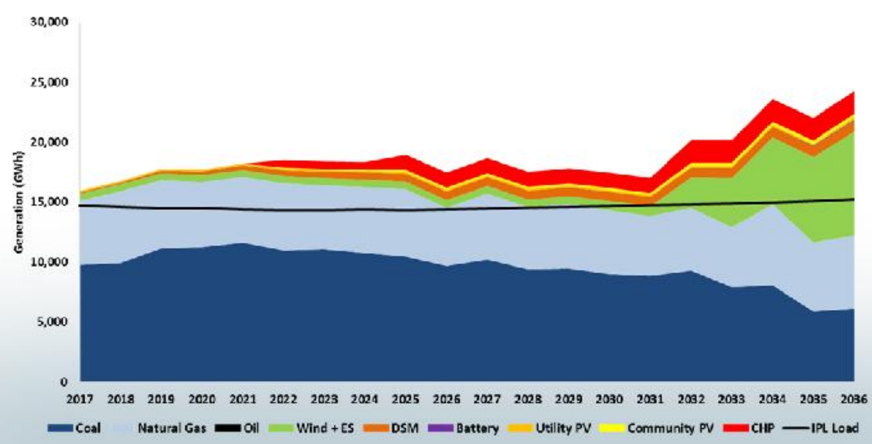
ADDED 9-6-16

Will be discussed at the 9-16-16 meeting

High Customer Adoption of DG Energy



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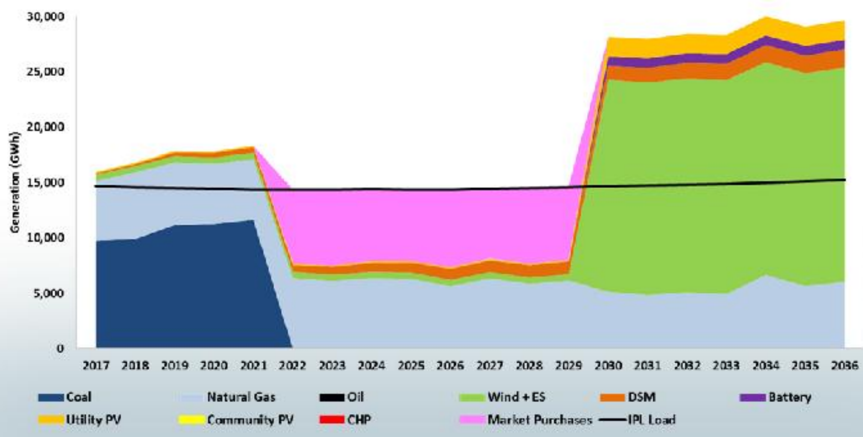
ADDED 9-6-16

Will be discussed at the 9-16-16 meeting

Final Quick Transition Energy



REVISED 10-06-16

Revised Slides 64 & 114

Integrated Resource Plan Public Advisory Meeting #4

September 16, 2016

Welcome & Safety Message

Bill Henley, VP of Regulatory and Government Affairs

Meeting Guidelines

Dr. Marty Rozelle, Facilitator

Agenda for today

9:00am Welcome

- Meeting Agenda and Guidelines
- Summary & Feedback from IRP Public Advisory Meeting #3
- Guiding Principles
- Final Model Results
- Preferred Resource Portfolio

10:25am Break

- Metrics & Sensitivity Analysis Results

11:45 – 12:30pm Lunch

- Analysis Observations
- Discussion of Results
- Short Term Action Plan
- IRP Public Advisory Process Feedback
- Concluding Remarks & Next Steps

2:30/3:00pm Meeting Concludes

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions
- The phone line will be muted. During the allotted questions, press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
- Use WebEx online tool for questions during meeting
- Email additional questions or comments by September 23
- IPL will respond via website by October 7

Active Cases before the Commission

- Cause No. 38703, FAC 113
- Cause No. 42170, ECR-27
- Cause No. 44576, Rates (under appeal)
- Cause No. 44792, DSM 2017 Plan
- Cause No. 44794, SO_2 NAAQS and CCR
- Cause No. 44808, MISO Rider

Summary & Feedback from IRP Public Advisory Meeting #3

Joan Soller, Director of Resource Planning

Topics covered in Meeting #3

- IRP modeling update
- Draft model results for all scenarios
- Stakeholder feedback
- Sensitivity analysis setup

Presentation materials, audio recording, acronym list, and meeting notes are available on IPL's IRP webpage here: https://www.iplpower.com/irp/

Scenario Characteristics/Variable 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	ABB Mass-based CPP Scenario	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 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*

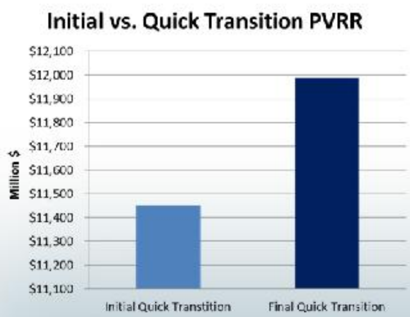
*Purple font indicates changes from the Base Case.

IPL response to feedback

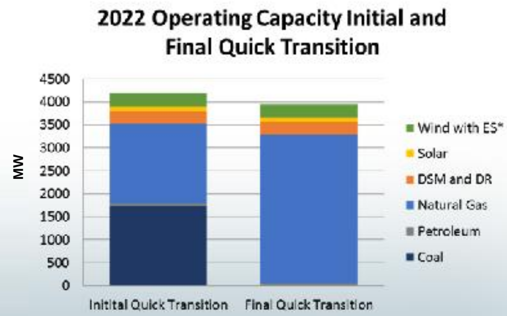
- IPL modified the Quick Transition scenario
  – Pete 1 retirement and Pete 2-4 refuel in 2018
  – Include maximum achievable DSM and balance of resources with solar, wind and batteries in 2030
  – Minimum NG resources stayed the same

Quick Transition results changed

PVRR (2017-2036) varied



Resources varied earlier



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Questions?

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Guiding Principles and Assumptions

Joan Soller

Guiding principles for IRP

- IPL will comply with IURC rules and orders, IAC requirements, NERC reliability standards and FERC approved MISO tariffs.
- Costs estimates for demand and supply side resources are based upon local economics and recent market experiences.
- IPL is agnostic to the resource mix comprising portfolio plans.
- The model is agnostic to resource ownership; however, IPL's capital structure is modeled to calculate costs.

IAC – Indiana Administrative Code, IURC – Indiana Utility Regulatory Commission, NERC – North American Electric Reliability Corporation, FERC – Federal Energy Regulatory Commission, MISO – Midwest Independent System Operator

DSM guiding principles

- Demand Side Management (DSM) is modeled as a selectable resource in this IRP which represents a change from previous IRPs.
- IPL plans to offer cost effective DSM programs that are inclusive for customers in all customer classes, appropriate for the market and customer base, modify customer behavior and provide continuity from year to year.

These assumptions are consistent in the study period

- IN regulatory framework
- MISO Capacity construct
- IPL engages in MISO stakeholder process
- Natural gas & market price correlation trends
- Distributed Generation (DG) is synchronized with the grid & not curtailed

These potential changes may affect future portfolios

- Technology enhancements
- Pending national election impacts on:
  - Pending environmental regulations
  - Public policy
  - Tax credits
- Stakeholder sustainability interests

Questions?

Final Model Results

Diane Crockett, Principal Consultant ABB

Portfolio Development Process

Metrix ND: develops high, low, and base load forecast

DSM Model: market potential study for DSM

ABB Reference Case: assumptions for gas, emissions and market prices

Capacity Expansion Module: develop scenario portfolios

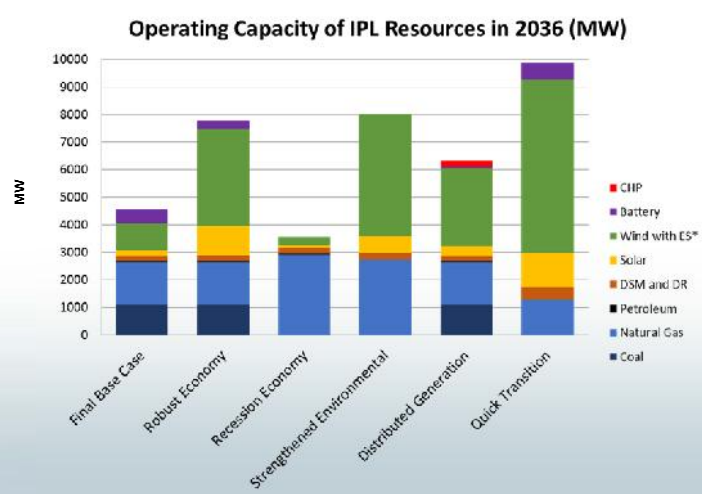
Strategic Planning Software: portfolio scenario evaluation and sensitivity analysis

Risk Module: stochastic portfolio performance metrics

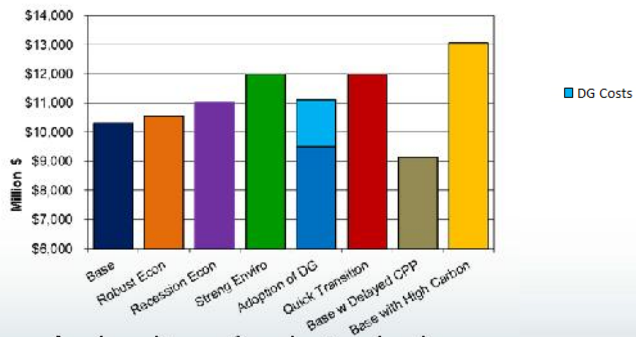
Review of resource alternatives

IRP Resource Technology Options	
	MW Capacity
Simple Cycle Gas Turbine	160
Combined Cycle Gas Turbine - H-Class	200
Nuclear	200
Wind	50
Solar	> 5 MW
Community Solar	1 MW
Energy Storage	20
CHP – industrial site (steam turbine)	10
DSM	Varies
Market purchases	Up to 200 MW

Scenario Capacity Mix in 2036

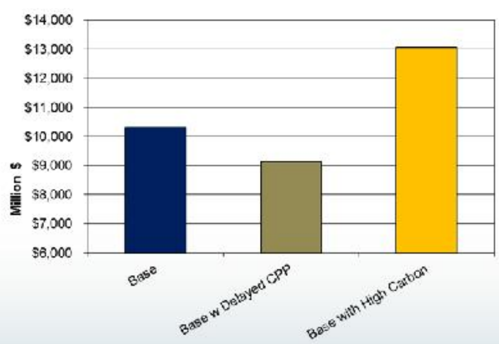


Scenario Present Value of Revenue Requirements (PVRR) 2017-2036



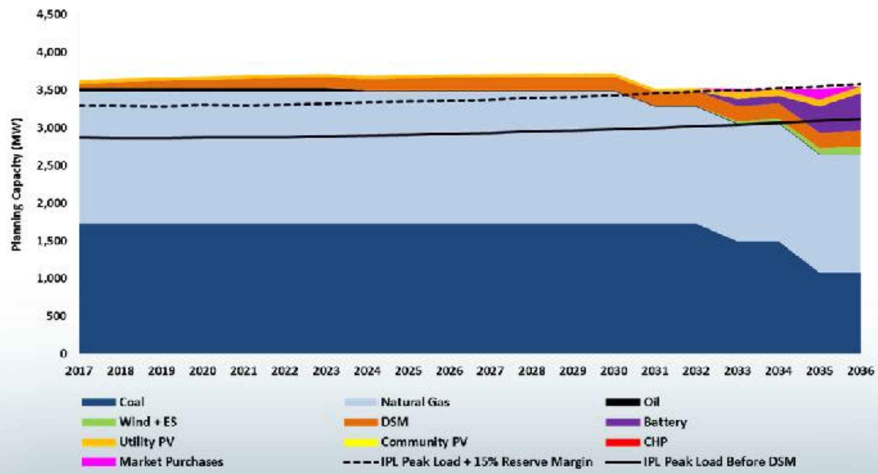
- Each portfolio was developed to perform best under the assumptions for that scenario
- Since assumptions vary between scenarios, not all portfolios are directly comparable
- This graph shows the PVRR of all portfolios *utilizing the base assumptions* prior to introducing stochastic uncertainty

Base Sensitivity PVRRs 2017-2036



- CPP starts in 2030 instead of 2022 for the delayed case
- More stringent CPP is represented by using high carbon cost scenario beginning in 2022

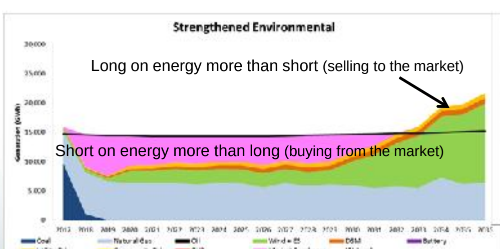
Base Case Capacity

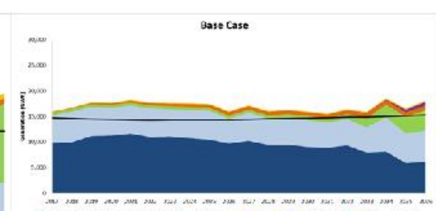


- Includes Petersburg upgrades for NAAQS, SO_2 and CCR

How to Read Energy Mix Slides

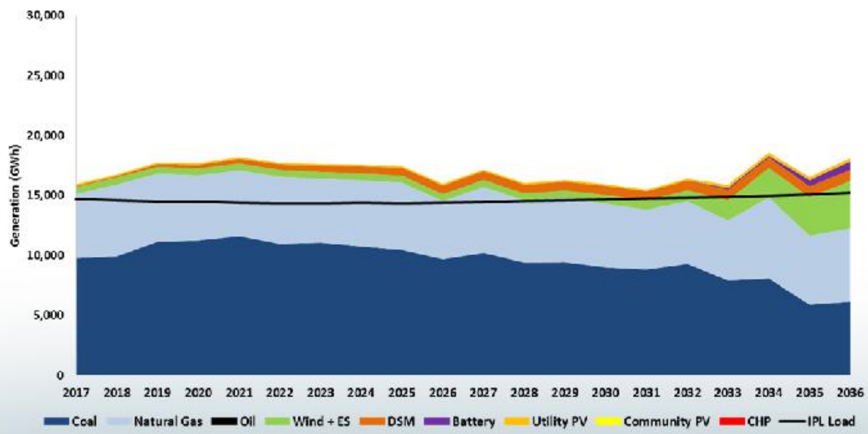
- "Long"= more generation in a single hour than load
  "Short"= more load in a single hour than generation
- IPL is long and short throughout the year at different times





- Based on the nature of dispatching units, IPL will still buy and sell from the market in the base case

Base Case Energy



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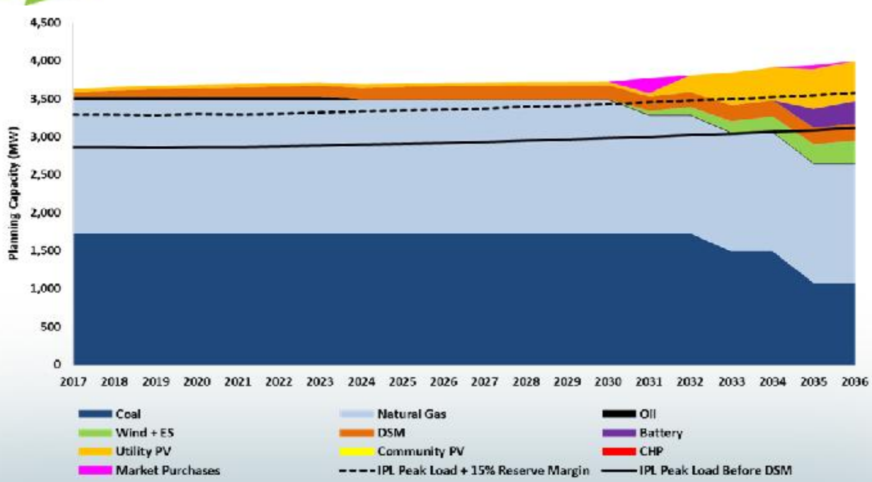
Robust Economy Capacity



- Includes upgrades for NAAQS, SO_2 and CCR
- High load capacity expansion plan under base load assumption

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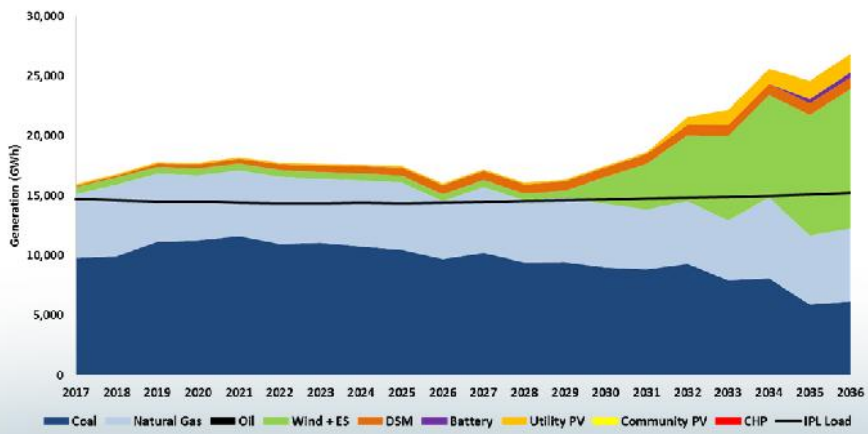
Robust Economy Energy



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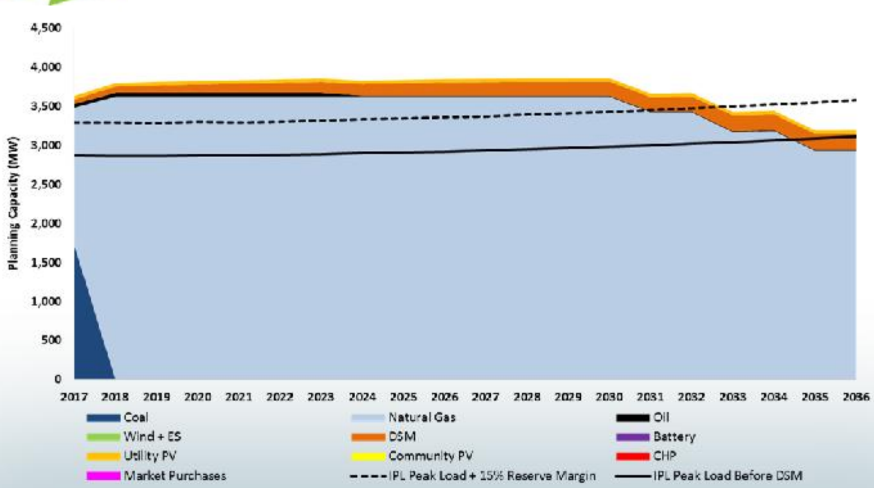
Recession Economy Capacity



- Refuel Pete 1-4
- Low load capacity expansion plan under base load assumption

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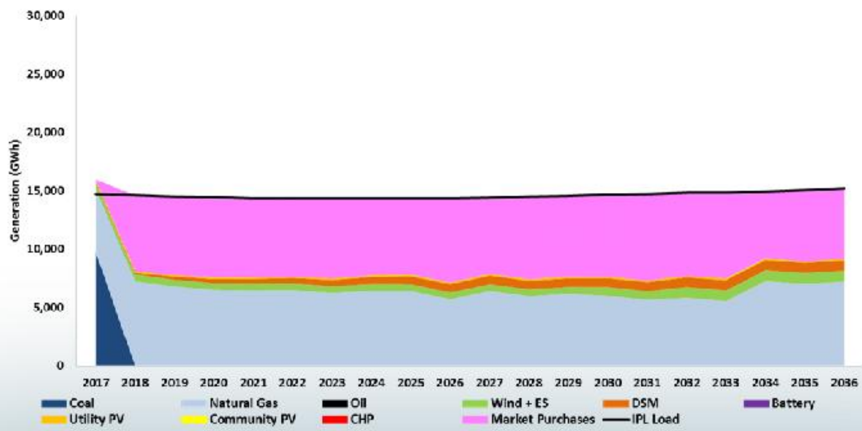
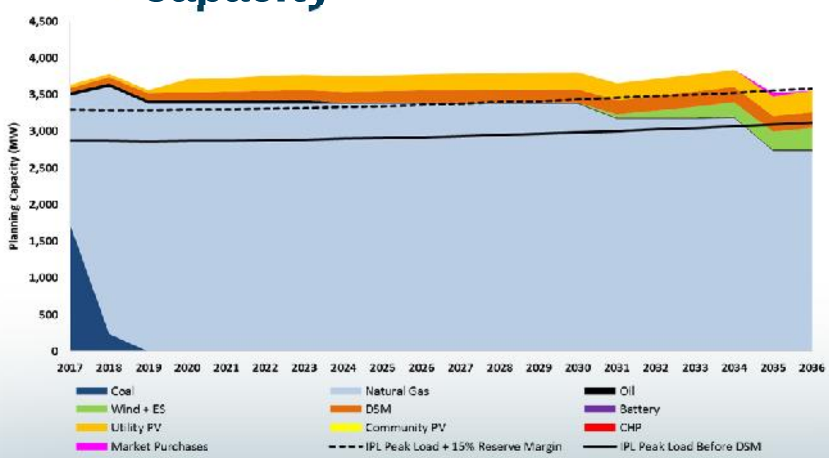
Recession Economy Energy



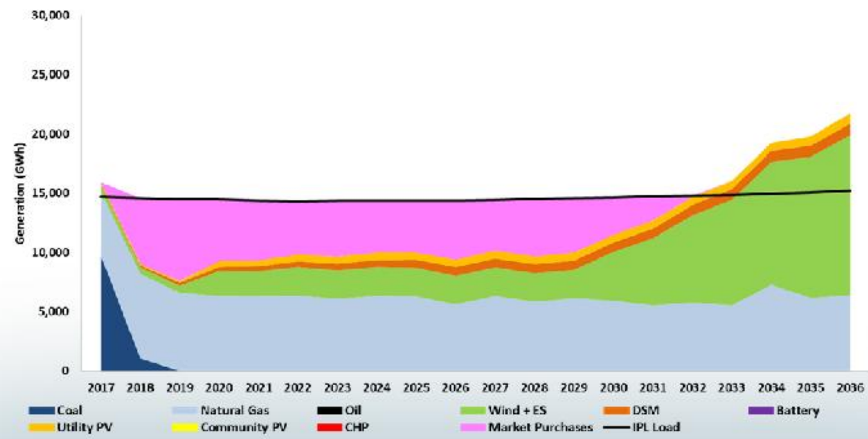
- Refuel Pete 1-4
- Low load capacity expansion plan under base load assumption

Strengthened Environmental Capacity



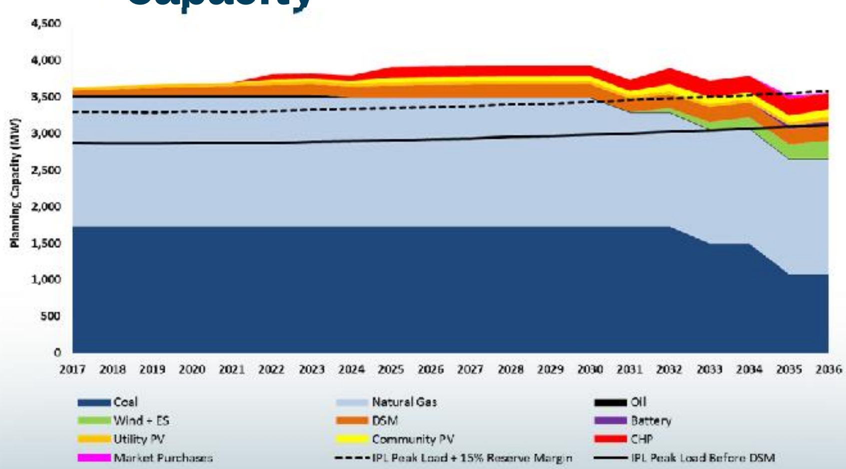
- Retire Pete 1
- Refuel Pete 2-4
- 20% Renewable Portfolio Standard by 2022

Strengthened Environmental Energy



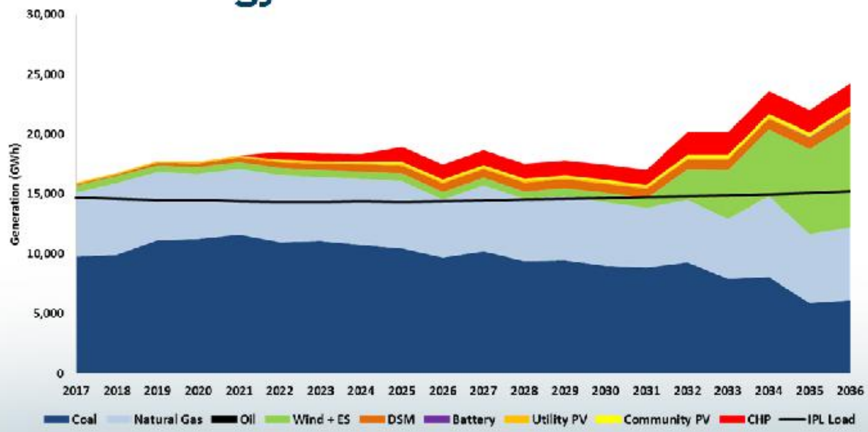
- Retire Pete 1
- Refuel Pete 2-4
- 20% Renewable Portfolio Standard by 2022

High Customer Adoption of DG Capacity



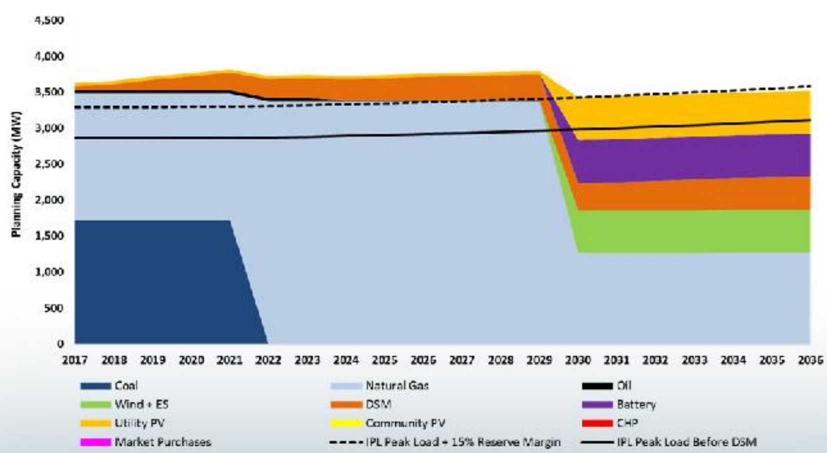
- Includes upgrades for NAAQS, SO_2 and CCR
- 10 MW of Wind, 65 MW of Community Solar and 75 MW of CHP in 2022, 2025 and 2032

High Customer Adoption of DG Energy



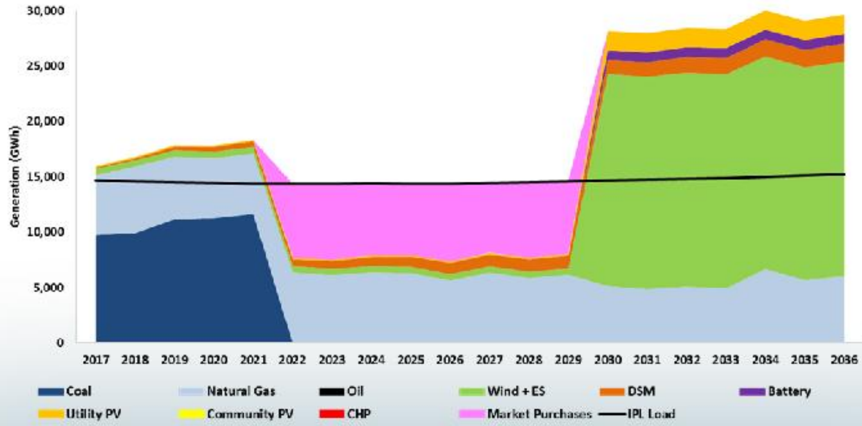
- 10 MW of Wind, 65 MW of Community Solar and 75 MW of CHP in 2022, 2025 and 2032

Quick Transition Capacity



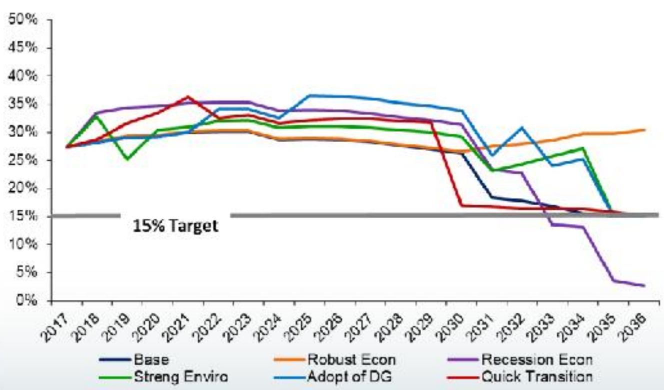
- Includes upgrades for NAAQS, SO_2 and CCR
- Retire Pete 1 and Refuel Pete 2-4 in 2022
- Retire Pete 2-4, HS GT 4-6, HS 5&6, HS IC1, Pete IC1-3 in 2030

Quick Transition Energy



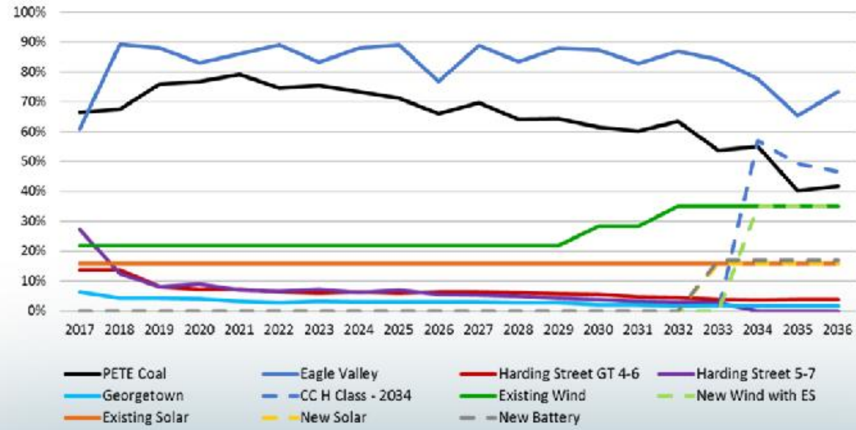
- Retire Pete 1 and Refuel Pete 2-4 in 2022
- Retire Pete 2-4, HS GT 4-6, HS 5&6, HS IC1, Pete IC1-3 in 2030

Reserve Margins



- This graph shows the Reserve Margin for all plans *utilizing the base load assumption*
- All portfolios optimized for the load forecast of the specific scenario
  - Example: Low load forecast was a driver in Recession Economy scenario. This chart shows the reserve margin if IPL planned for a low load forecast and the base load forecast materialized.

Capacity factors for Base Case



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Capacity factors for Strengthened Environmental

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Questions?

Preferred Resource Portfolio

Joan Soller, Director of Resource Planning

Rationale for determining the Preferred Resource Portfolio

- IPL's preferred resource portfolio reflects the most likely inputs and most probable risks known at this point in time.
- The primary selection criteria is the reasonable least cost to customers stated in terms of the Present Value Revenue Requirement (PVRR) metric.
- Other metrics including rate and environmental impacts, market reliance and risk exposure were considered but not equally weighted.

IPL's IRP Preferred Resource Portfolio

- The preferred resource portfolio is the Base Case in the 2016 IRP
- PVRR is the lowest
- Risk tradeoff between probable PVRR costs and variance is most favorable for customers
- Subsequent IRP analyses will consider changes to assumptions and risks
- IPL will continue to monitor risks associated with resource planning

Preferred Resource Portfolio summary

Final Base Case resource changes (2017 to 2036)

- Upgrade Pete units for NAAQS-SO_2 and CCR
- Implement 206 MW DSM
- Retire (32 MW oil) HS GT 1&2
- Retire (628 MW NG) HSS 5, 6, 7
- Retire (651 MW coal) Pete 1 & 2
- Purchase 200 MW capacity
- Add 1000 MW wind, 100 MW Solar, 500 MW Battery
- Add 450 MW CCGT

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Questions?

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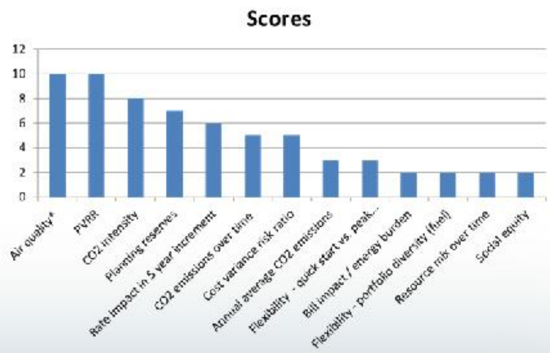
Short Break

Metrics & Sensitivity Analysis Results

Patrick Maguire, Director, Corporate Planning & Analysis
Megan Ottesen, Regulatory Analyst, Resource Planning

Recall stakeholder metrics exercise feedback

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*



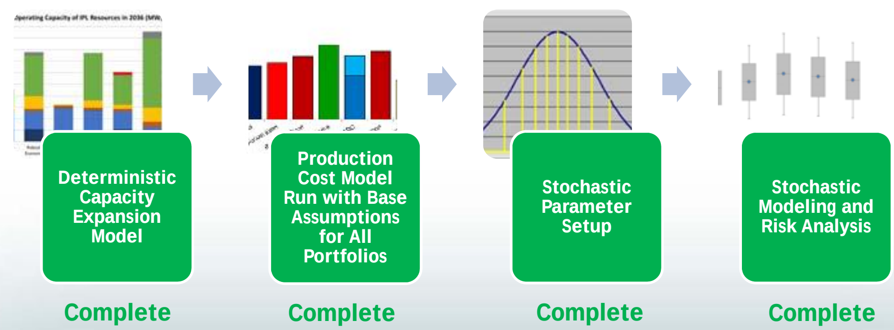
green = stakeholder proposed
blue= IPL proposed

*other pollutants including PM, NOx, SO2, methane emissions

Metrics developed with stakeholder input

Cost	Financial Risk	Environmental Stewardship	Resiliency
• Present Value Revenue Requirement (PVRR) • Rate Impact	• Risk Exposure	• Average annual CO_2 emissions • Average annual NO_x emissions • Average annual SO_2 emissions • CO_2 intensity	• Planning Reserves • Distributed Generation penetration • Market reliance (energy and capacity)

Recall sensitivity analysis setup from Meeting 3…



Metrics are based upon a blend of model results

Deterministic Model

- Change selected variables by a fixed and known amount
- Example:
  - Natural gas prices up 10%
  - Load up 10%
- Output
  - PVRR for each sensitivity
  - Change in emissions

Stochastic Model

- Subject multiple variables to randomness
- Ranges are bound by estimated probability distributions and statistical properties
- Output
  - 50 model iterations for each portfolio
  - Risk profiles
  - Financial metrics

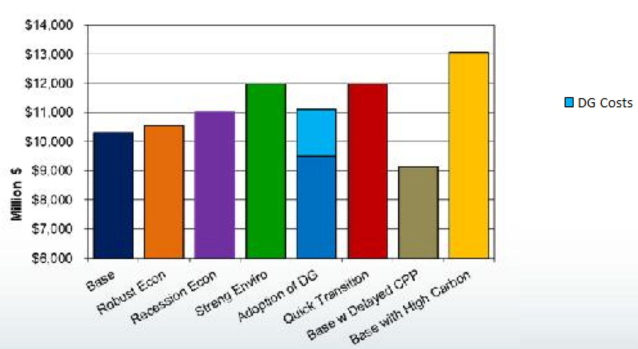
Cost Metric: PVRR

1. Present Value Revenue Requirement (PVRR):

– The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period

PVRR = Present Value of Revenue Requirements 2017-2036

PVRR for 2017-2036



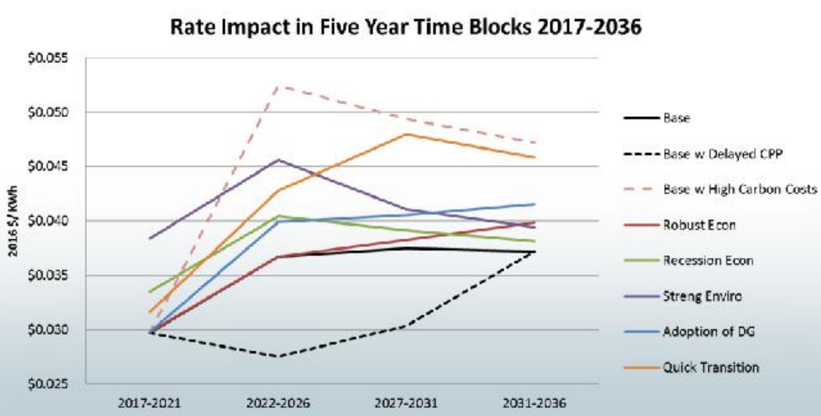
Cost metric: Rate Impact

2. Rate Impact:

- Shows the incremental impact of adding new resources to our rates
- This shows an aggregate rate impact and does not reflect rate design for different customer classes
- Expressed in terms of cents/kWh in five year time blocks
- Levelized average system cost

Rate Impact = $\frac{\text{Present Value of Revenue Requirements (5 year period)}}{\text{Total kWh Sales (5 year period)}}$

Incremental rate impact due to resource changes only



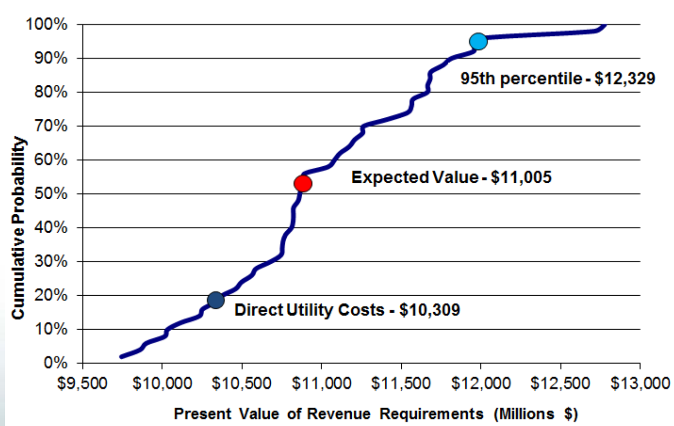
Financial Risk: Risk Exposure

3. Risk Exposure:

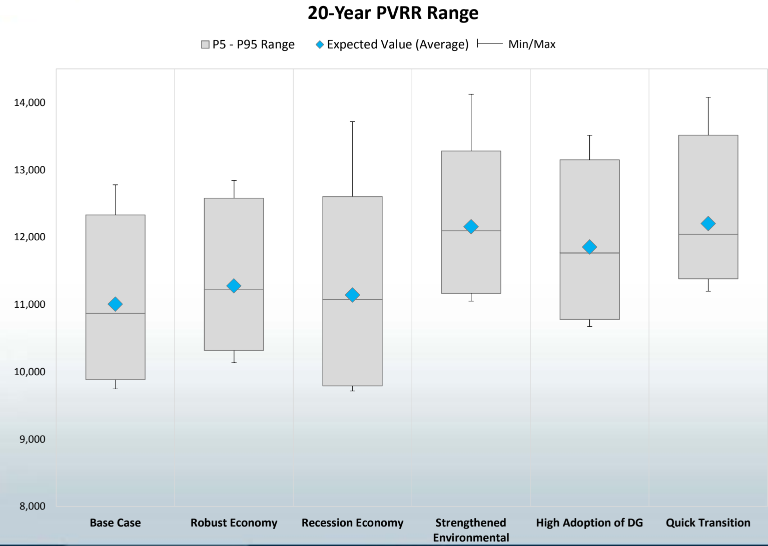
- The difference between the value at the 95th percentile of probability and the value at 50% percentile probability (expected value)
- In order to reflect risk, this metric utilizes results from stochastic modeling as opposed to deterministic results

Risk Exposure = The PVRR at the 95% probability – expected PVRR

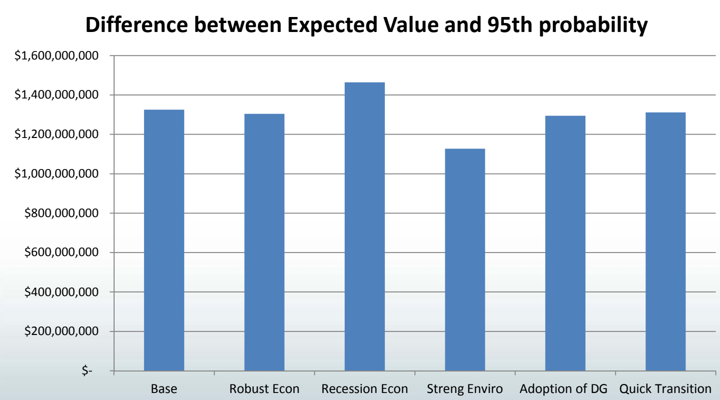
Risk Exposure – risk profile chart



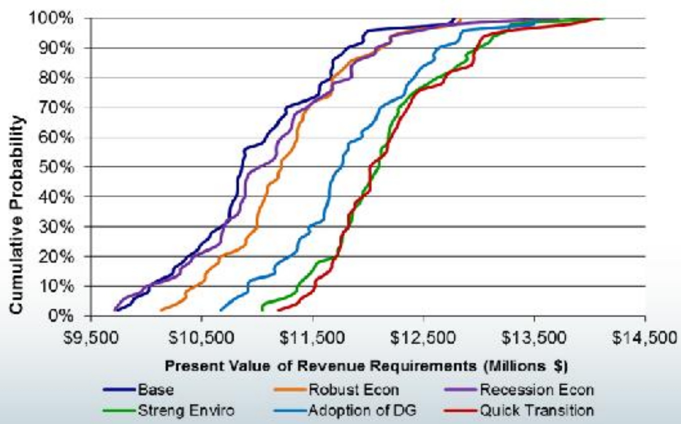
Risk Exposure range



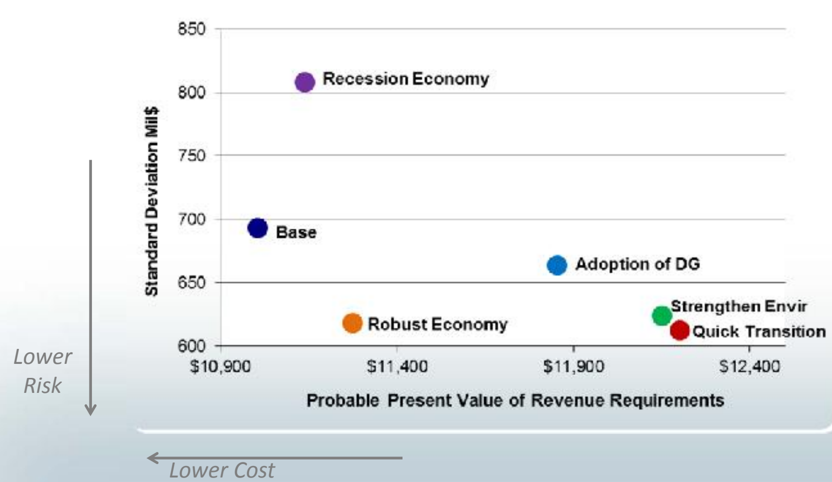
Risk Exposure



Combined Risk Profiles



Risk trade off diagram



Tornado charts show impacts of drivers

- Provide information on the driving factors that influence PVRR based on stochastic modeling
- Provide insights for risk mitigation
- Charts were prepared for each scenario
- 10 year blocks were used
- Total impact is a blended view, not the sum of the ranges

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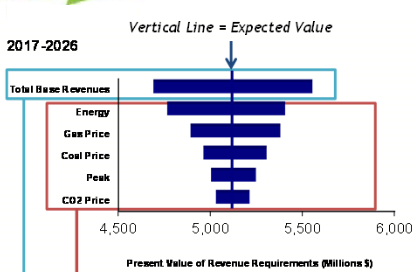
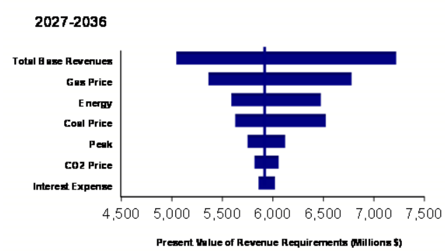
Base Case Tornado Chart



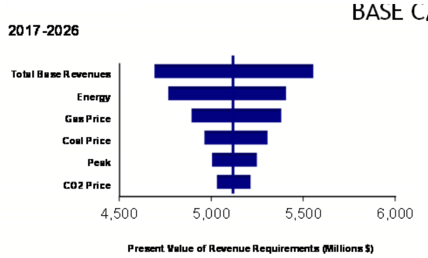


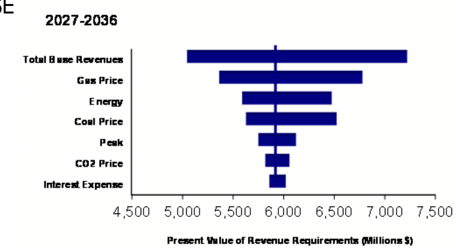
Dependent Variable: PVRR

Independent Variables: Which variables are driving the change in PVRR?

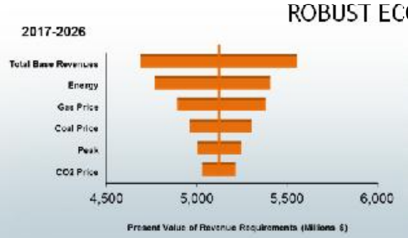
Tornado: Base Case and Robust Economy

BASE CASE





ROBUST ECONOMY



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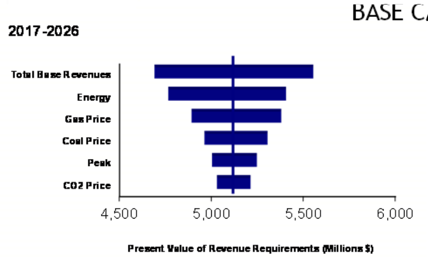
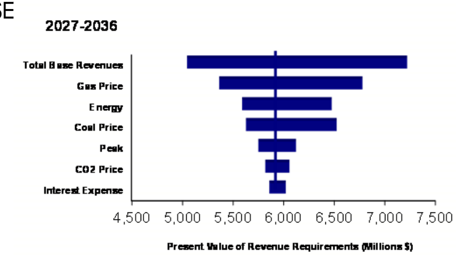
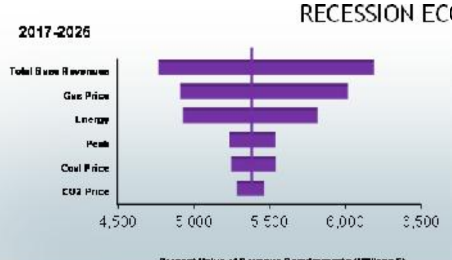
Tornado: Base Case and Recession Economy

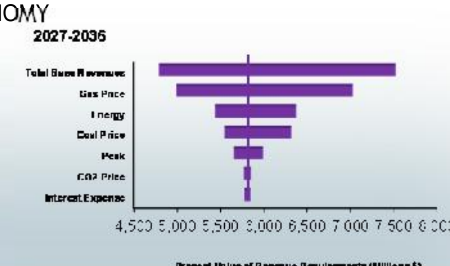
BASE CASE





RECESSION ECONOMY





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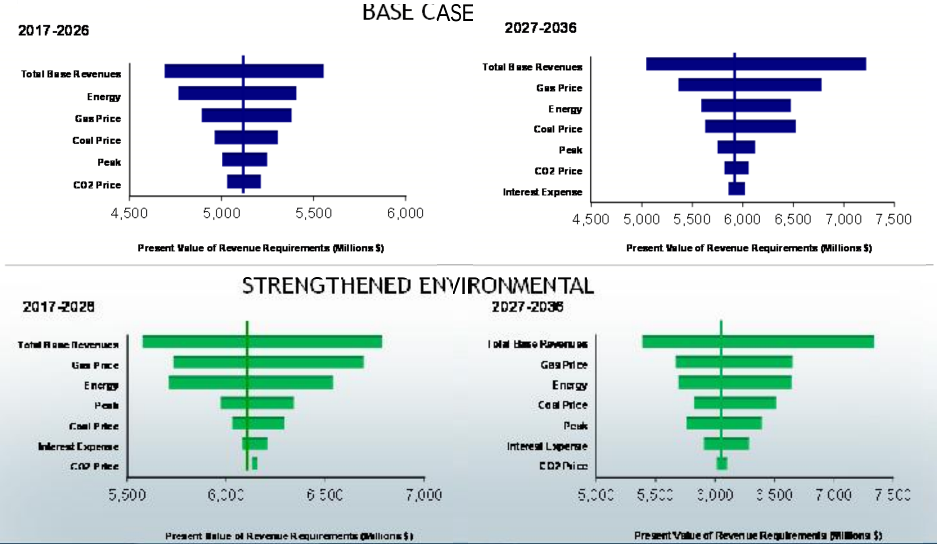
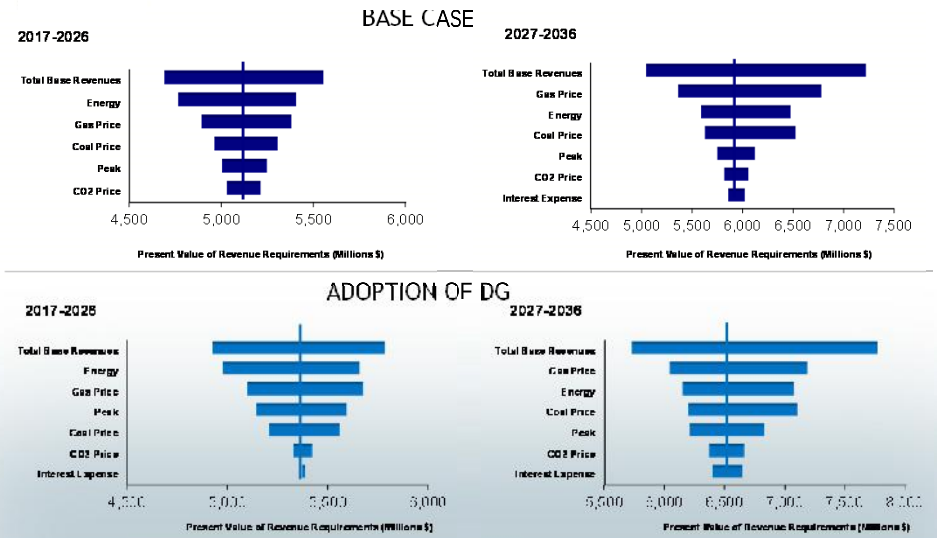
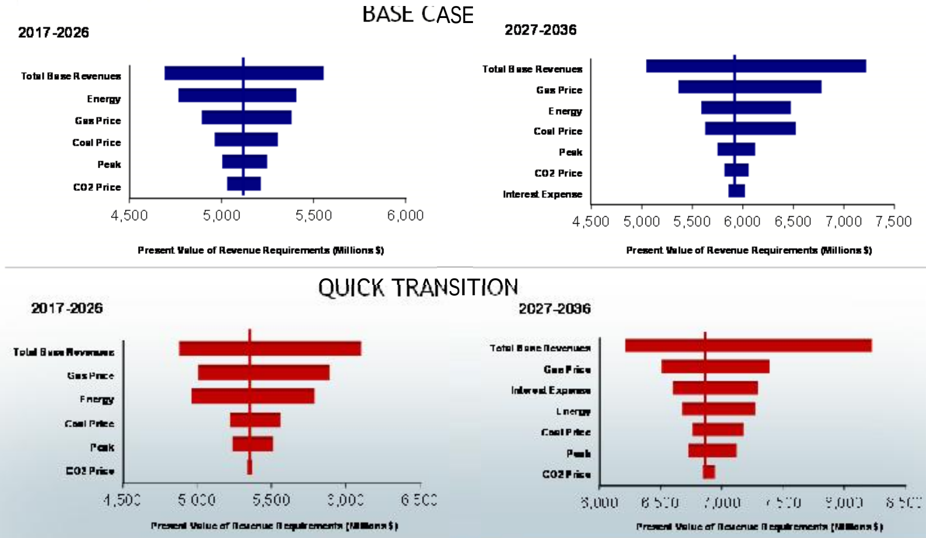
Tornado: Base Case and Strengthened Environmental



Tornado: Base Case and Adoption of DG



Tornado: Base Case and Quick Transition



Environmental Metrics: CO_2, SO_2, NOx

3. Average annual CO_2 emissions (tons)

Annual Average CO_2 Emissions = $\frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$

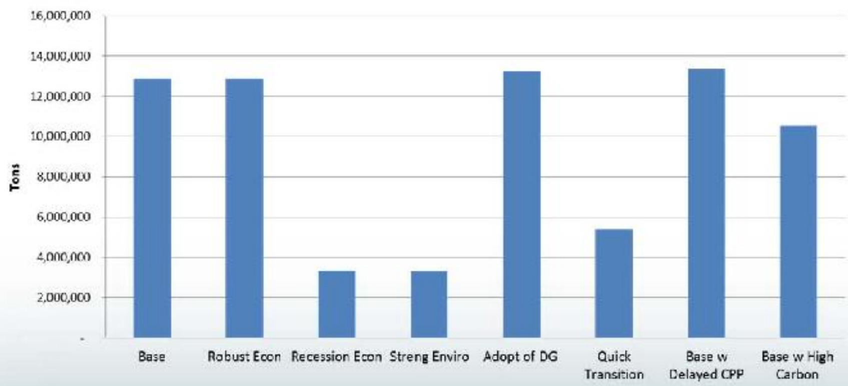
4. Average annual SO_2 emissions (tons)

Annual Average SO_2 Emissions = $\frac{\text{Sum of } SO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$

5. Average annual NO_x emissions (tons)

Annual Average NOx Emissions = $\frac{\text{Sum of } NO_x \text{ tons emitted}}{\text{\# of years in the study period}}$

Average annual CO_2 emissions (tons)



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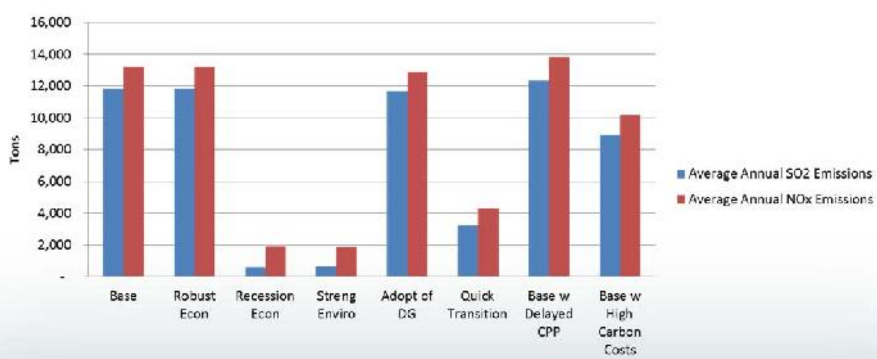
Average annual NO_x and SO_2 emissions



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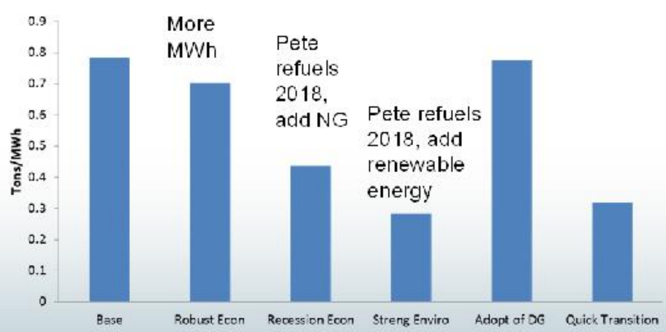
Environmental Metrics: CO_2 intensity

6. CO_2 intensity (tons/MWh)

CO_2 Intensity for study period = $\dfrac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{MWh energy generated}}$

CO_2 intensity for study period



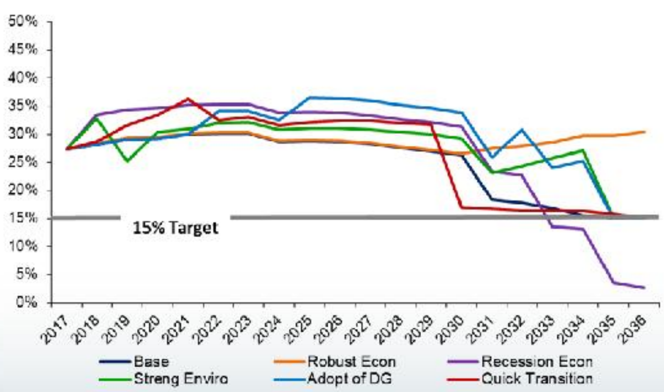
Reliability Metric: Planning Reserves

7. Planning Reserves

- Planning reserves are the MW of supply above peak forecast

Planning Reserves as a percent of load forecast	= <u>IPL's resources (MW) – peak utility load forecast (MW)</u> utility load forecast

Planning Reserves



- This graph shows the Reserve Margin for all plans *utilizing the base load assumption*
- All portfolios optimized for the load forecast of the specific scenario
  - Example: Low load forecast was a driver in Recession Economy scenario. This chart shows the reserve margin if IPL planned for a low load forecast and the base load forecast materialized.

Reliability metric: DG Penetration

8. DG Penetration

- Percent of IPL's resources that is distributed generation
- Includes IPL's existing 96 MW of solar and all new solar additions
- Shown in 5 year time blocks

DG Penetration = distributed generation supply (MW) / IPL resources (MW)

Reliability metric: DG penetration

In terms of 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%

Reliability Metric: market reliance

9. & 10. Market reliance – Energy and Capacity

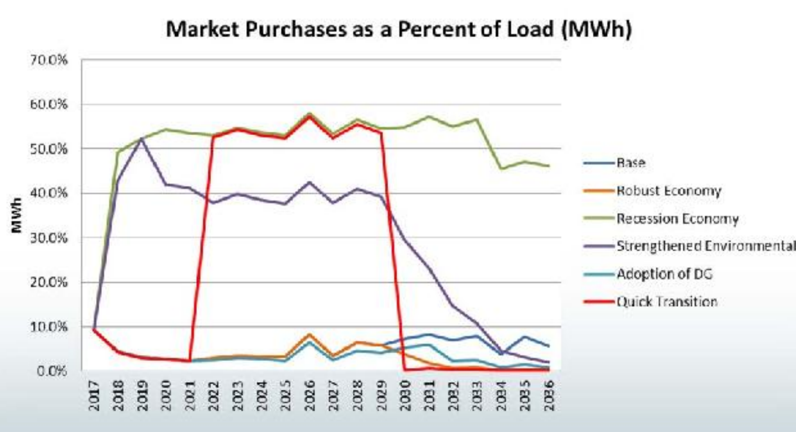
- Market reliance for energy: Percent of load met with market purchases

Market Reliance for energy = $\frac{\text{MWh of market purchases}}{\text{MWh of customer demand}}$

- Market reliance for capacity: Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin

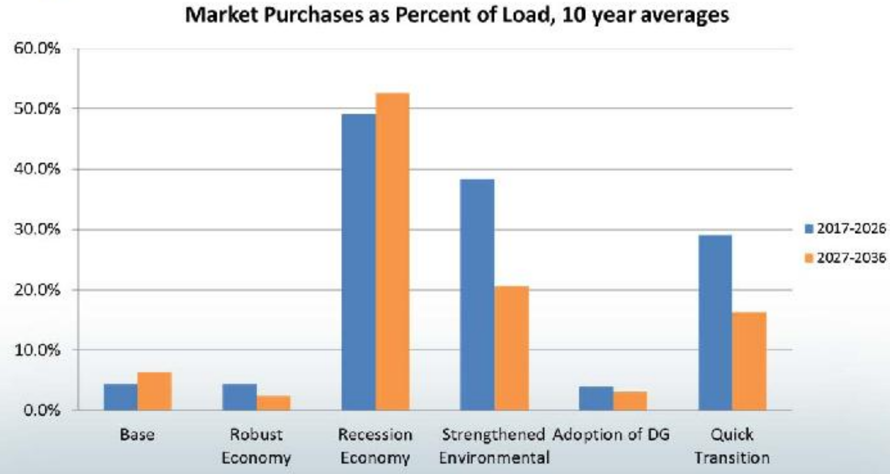
Market Reliance for capacity = total capacity purchases

Market Reliance



* Each scenario's portfolio is modeled with the Base Case load

Market Reliance - Energy



* Each scenario's portfolio is modeled with the Base Case load

Market Reliance – Capacity

	Base	Robust Economy	Recession Economy	Strengthened Environmental	Adoption of DG	Quick Transition
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031		200 MW				
2032						
2033	50 MW					
2034						
2035	150 MW	50 MW		50 MW	50 MW	
2036						

Metrics Summary

Scenarios	Cost		Financial Risk	Environmental Stewardship				Resiliency			
	20 yr PVRR ($ MN)	Rate Impact, 20 yr average ($/kWh)	Risk Exposure ($)	Average annual CO2 emissions (tons)	Average annual NOx emissions (tons)	Average annual SOx 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	$ 0.035	$ 1,461,856,693	12,883,603	13,181	11,808	0.510	15%	2%	9%	150
Robust Econ	$ 10,550	$ 0.036	$ 1,361,308,495	12,883,183	13,181	11,808	0.410	27%	2%	9%	200
Recession Econ	$ 11,042	$ 0.038	$ 1,529,366,806	3,334,067	1,925	593	0.284	3%	3%	58%	0
Streng Enviro	$ 11,990	$ 0.041	$ 1,183,639,662	3,309,326	1,910	629	0.150	15%	2%	52%	50
Adopt of DG	$ 11,092	$ 0.038	$ 1,382,467,346	13,159,800	13,332	11,808	0.459	15%	11%	9%	50
Quick Transition	$ 11,988	$ 0.042	$ 1,469,716,821	5,403,645	4,320	3,243	0.173	15%	3%	57%	0

* this Planning Reserves metric compares each scenario's resources to the Base Case peak load forecast.

Questions?

Lunch Break

Analysis Observations

Joan Soller, Director of Resource Planning

As proposed in meeting #1…

	2014 IRP Feedback	IPL Response/Planned Improvements
1	Constrained Risk Analysis	Stakeholder discussion about risks will occur early in the 2016 IRP process.
2	Load Forecasting Improvements Needed	IPL is reviewing load forecast to enhance data in the 2016 IRP.
3	DSM Modeling not robust enough	IPL has piloted modeling DSM as a selectable resource and will discuss this in public meetings.
4	Customer-Owned and Distributed Generation lacked significant growth	IPL will develop DG growth sensitivities to understand varying adoption rate impacts.
5	Incorporation of Probabilistic Methods	IPL will incorporate probabilistic modeling in 2016 IRP.
6	Enhance Stakeholder Process	IPL participated in joint education session with other utilities to develop foundational reference materials. We will incorporate more interactive exercises in 2016.

Analyses Observations

- Stakeholder input has shaped modeling process
- Metrics have informed discussions
- Scenario development and related economic modeling results produced varying portfolios
- The future may vary from this snapshot
- Transmission voltage stability analyses will continue

Analyses Observations (cont'd)

- The ultimate resource portfolio may differ from model results should assumptions vary from the Base Case (e.g. Strengthened Environmental with ~40% market reliance)
- Resources perform to meet the scenario parameters with varying capacity factors
- Wholesale energy & capacity sales offset revenue requirements
- More analysis of batteries with renewables is expected

Questions?

Discussion of Results

Reference handout for small group questions.

Short Term Action Plan

Joan Soller, Director of Resource Planning

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Short Term Action Plan Criteria Proposed in 170 IAC* 4-7

- Explanation of the previous short term action plan and differences based on what actually transpired
- 3 year view (2017 through 2019)
- Includes resource changes and major projects
- Description of preferred resource portfolio elements
- Implementation schedule

*IAC – Indiana Administrative Code

Status of 2014 IRP Short Term Action Plan (for 2015-2017)

- Completed Items
  - Retired Eagle Valley (EV) coal Units 3-6
  - Refueled Harding Street Station (HSS) units 5, 6 and 7 from coal to natural gas
  - Retrofitted Petersburg units for Mercury and Air Toxics Standards (MATS) regulation
  - Secured market capacity purchases for 2015-2017
  - Built HSS 20 MW Battery Energy Storage System

Status of 2014 Short Term Action Plan (cont'd)

- In progress
  - Implement DSM for 2015-2017
  - Construct EV Combined Cycle Gas Turbine (CCGT)
  - Retrofit Pete and HSS for National Pollutant Discharge Elimination System (NPDES) permit compliance
  - Complete transmission projects for EV CCGT
  - Support Blue Indy electric car sharing program (74 of 200 locations complete)

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2016 Short Term Action Plan Items (2017-2019)

Resource Changes	2017	Implement DSM proposed for 2017, draft and seek approval for 2018-2020 DSM action plan
	2017	Complete EV CCGT Construction
	2018	Complete CCR/NAAQS-SO2 Pete upgrades
Transmission	2017	Upgrade (1) 138 kV line, replace (1) auto-transformer
	2018	Upgrade 3 substations, (3) 138 kV lines, and replace breakers at 2 substations
	2019	Implement projects identified in 2017 & 2018

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Questions?

IRP Process Feedback

Dr. Marty Rozelle, Facilitator
Joan Soller, Director, Resource Planning

IPL's planned improvements to 2019 IRP process

1. Analyze smart meter data for more granular load forecasting
2. Refine Demand Side Management (DSM) modeling
3. Research MISO transmission congestion forecasts
4. Assess 138 kV voltage stability options
5. Refine frequency & reactive support requirements of new wind assets
6. Study firming benefits of batteries with renewables

Stakeholder process feedback

- Reference handout for large group questions.

Questions?

Concluding Remarks & Next Steps

Marty Rozelle, Meeting Facilitator
Joan Soller, Director of Resource Planning

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Next Steps

2016 IPL IRP Schedule	
September 23, 2016	Stakeholder comments due to IPL (ipl.irp@aes.com)
October 7, 2016	IRP Public Advisory Meeting #4 Notes and responses posted to IPL IRP Webpage
November 1, 2016	IPL files 2016 IRP with the IURC
90 days after filing: February 1, 2017	Interested Party Deadline to Submit Comments to the IURC. See 170 IAC 4-7-2* for details
120 days after filing: March 1, 2017	IURC Director's Draft Report publication expected

IAC – Indiana Administrative Code
*The draft proposed rule is available at: http://www.in.gov/iurc/2674.htm

Questions?

Thank you!

We value your input and appreciate your participation. Please submit your feedback form and recycle your nametag at the registration table as you leave the meeting today.

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Appendix

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Recession Economy summary

Resource changes (2017 to 2036)

- Refuel 1629 MW Pete 1-4 to NG
- Implement 208 MW DSM
- Retire (32 MW) HS GT
- Retire (628 MW) HSS 5, 6, 7
- No capacity purchases
- No wind, solar, or battery additions
- Add 450 MW CCGT

Robust Economy Summary

Resource changes (2017 to 2036)

- Upgrade Pete units for NAAQS-SO_2 and CCR
- Implement 218 MW DSM
- Retire (32) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- Retire (651 MW) Pete 1 & 2
- Purchase 250 MW capacity
- Add 3500 MW wind, 1006 MW Solar, 300 MW Battery
- Add 450 MW CCGT

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Strengthened Environmental Summary

Resource changes (2017 to 2036)

- Retire (224 MW) Pete 1
- Refuel 1403 MW Pete 2-4
- Implement 218 MW DSM
- Retire (32 MW) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- Purchase 50 MW capacity
- Add 4100 MW wind, 549 MW Solar
- Add 450 MW CCGT

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High Customer Adoption of DG Summary

Resource changes (2017 to 2036)

- Upgrade Pete units for NAAQS-SO_2 and CCR
- Implement 208 MW DSM
- Retire (32 MW) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- No capacity purchases
- Add 30 MW DG wind, 195 MW DG solar, 225 DG CHP
- Add 2500 MW utility wind, 157 MW utility solar, 50 MW battery
- Add 450 MW CCGT

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Quick Transition Summary

Resource changes (2017 to 2036)

- Retire (224 MW) Pete 1
- Refuel 1403 MW Pete 2-4 to NG
- Implement 458 MW DSM
- Retire (32 MW) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- No capacity purchases
- Add 6000 MW wind, 1146 MW solar, 600 MW battery
- Add 450 MW CCGT

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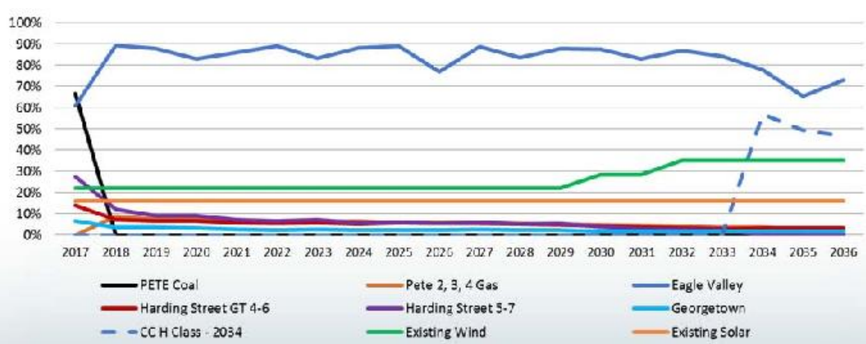
Capacity Factors for Recession Economy



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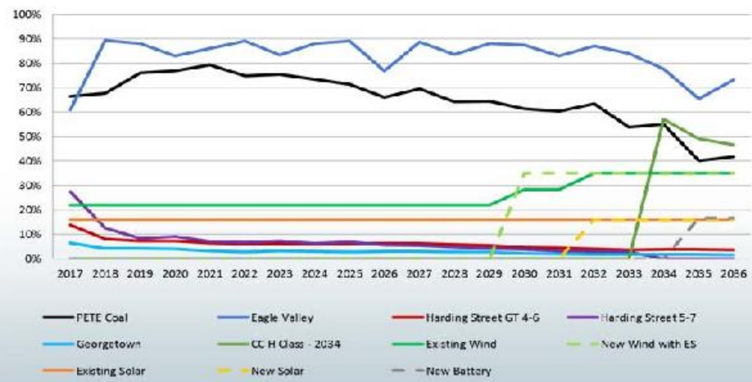
Capacity Factors for Robust Economy



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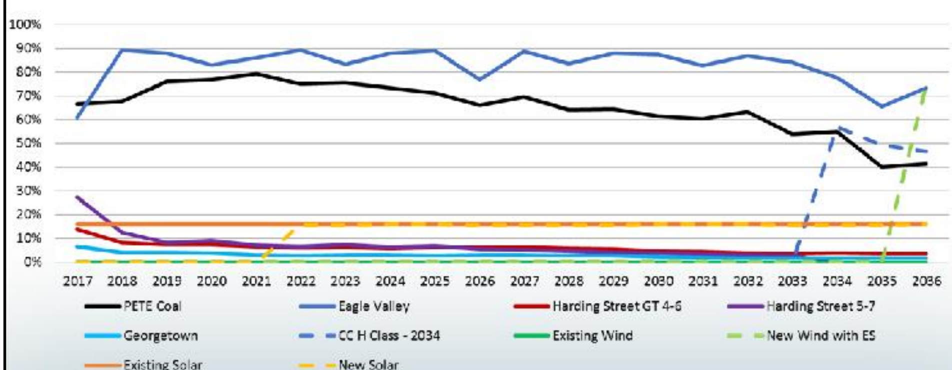
Capacity factors for High Customer Adoption of DG



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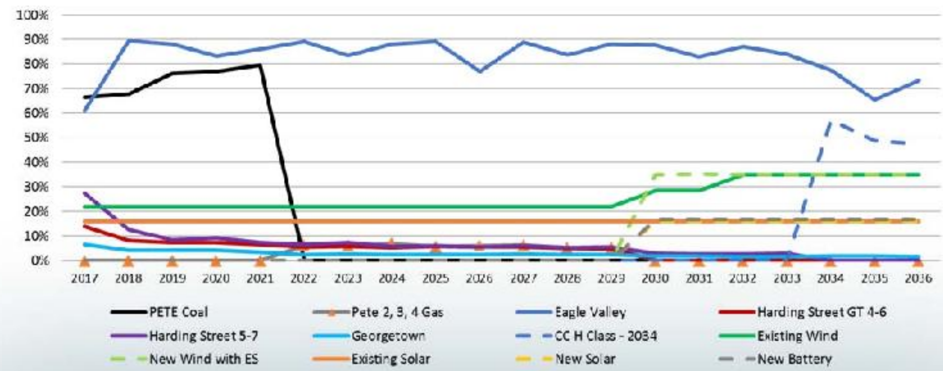
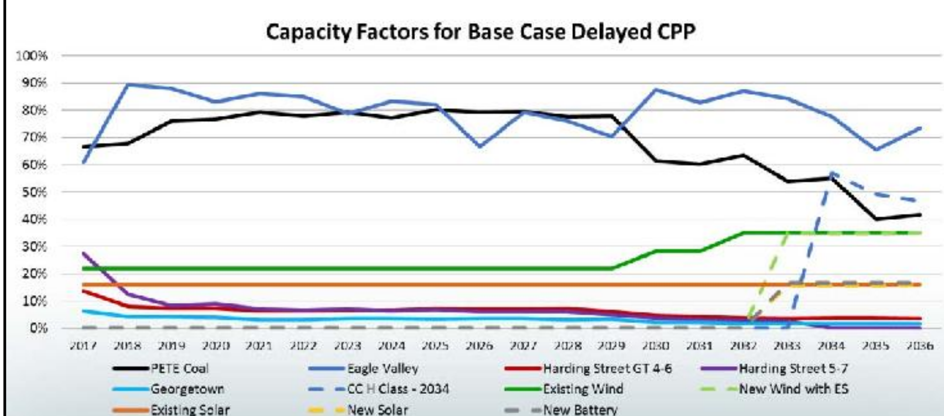
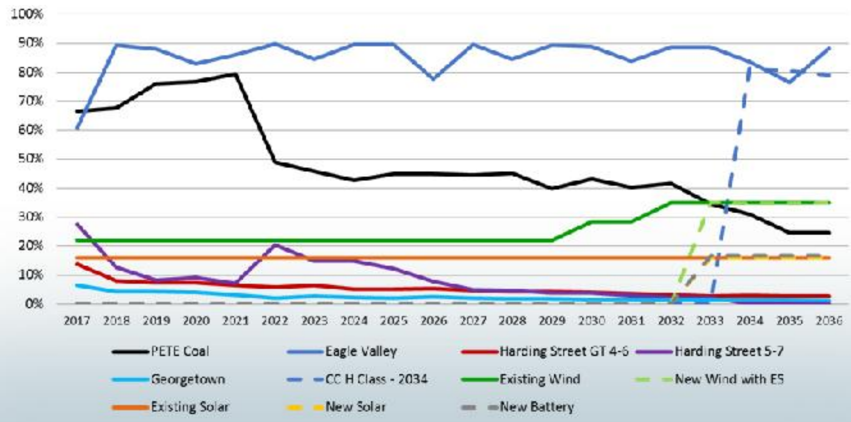
Capacity factors for Quick Transition



Capacity factors for Base Case Delayed CPP



Capacity Factors for Base Case High Costs of Carbon



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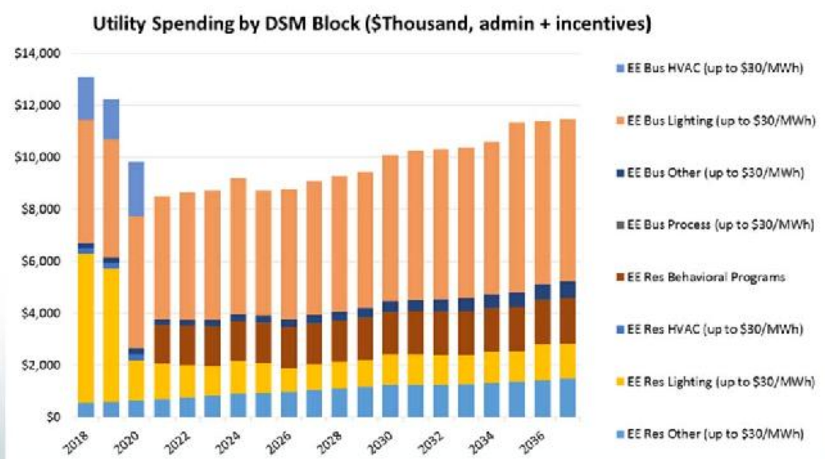
Base case



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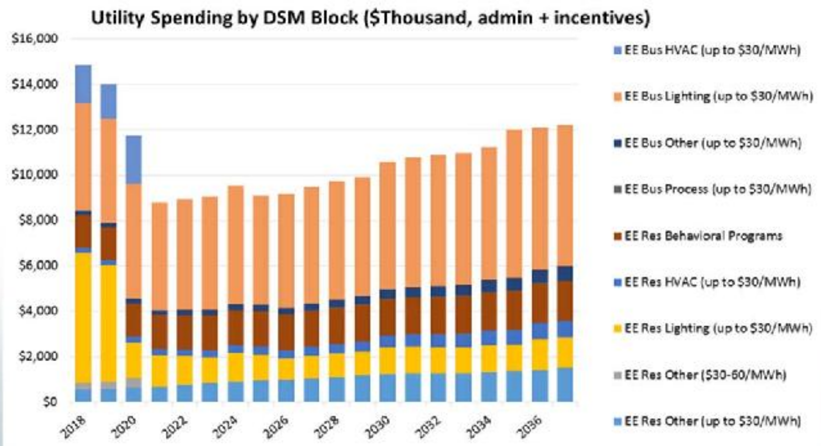
Robust economy



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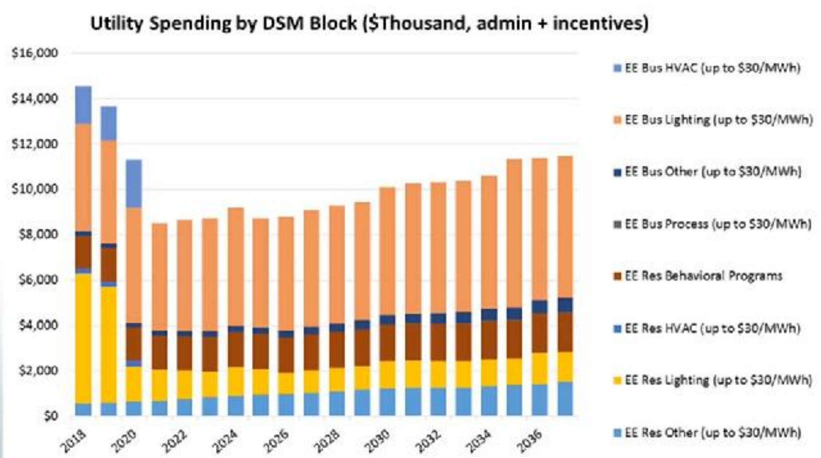
Recession economy



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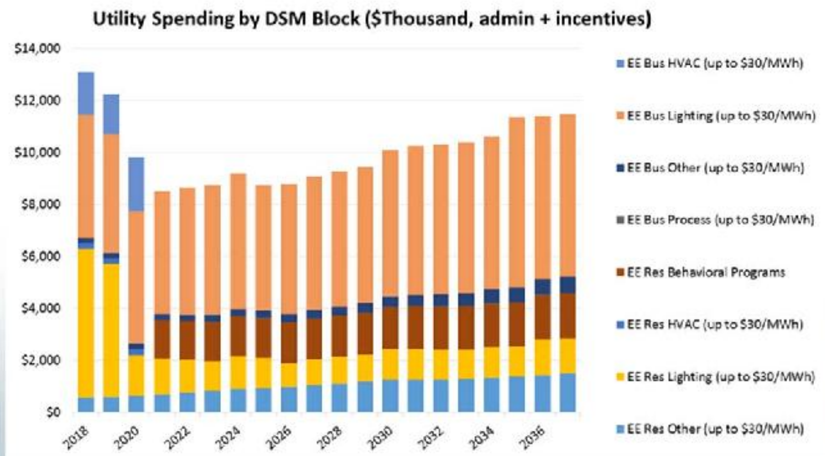
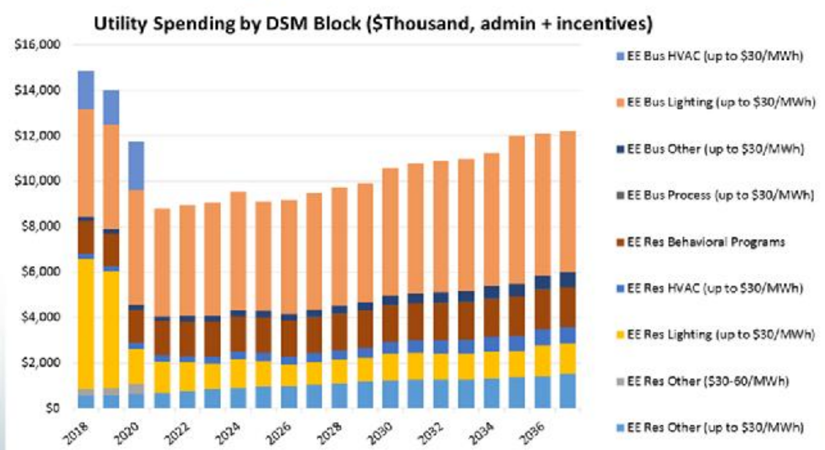
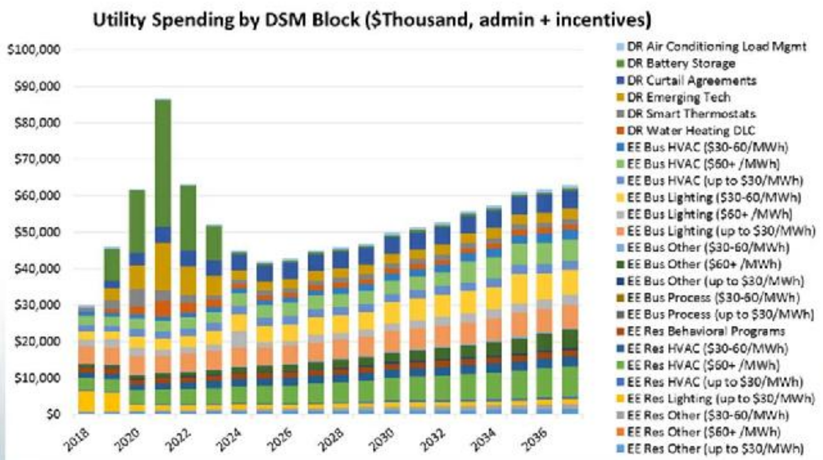
Adoption of distributed generation



Strengthened environmental



Quick transition



DSM building blocks selected

(based upon maximum achievable)

DSM Blocks Selected	Final Base Case	Robust Economy	Recession Economy	Strengthened Environmental	Distributed Generation
Res Other up to $30MWh 2018-2020	X	X	X	X	X
Res Other $30-60MWh 2018-2020		X		X	
Res Lighting up to $30MWh 2018-2020	X	X	X	X	X
Res HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Behavioral Program 2018-2020		X	X	X	
Bus Other up to $30MWh 2018-2020	X	X	X	X	X
Bus Lighting up to $30MWh 2018-2020	X	X	X	X	X
Bus HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Other up to $30MWh 2021+	X	X	X	X	X
Res Lighting up to $30MWh 2021+	X	X	X	X	X
Res HVAC up to $30MWh 2021+		X		X	
Res Behavioral Programs 2021+	X	X	X	X	X
Bus Process up to $30MWh 2021+	X	X	X	X	X
Bus Other up to $30MWh 2021+	X	X	X	X	X
Bus Lighting up to $30MWh 2021+	X	X	X	X	X

Quick Transition DSM

DSM Blocks	2018-2020	2021-2037
EE Res Other (up to $30/MWh)	x	x
EE Res Other ($60+ /MWh)	x	x
EE Res Other ($30-60/MWh)	x	x
EE Res Lighting (up to $30/MWh)	x	x
EE Res HVAC (up to $30/MWh)	x	x
EE Res HVAC ($60+ /MWh)	x	x
EE Res HVAC ($30-60/MWh)	x	x
EE Res Behavioral Programs	x	x
EE Bus Process (up to $30/MWh)	x	x
EE Bus Process ($30-60/MWh)	x	x
EE Bus Other (up to $30/MWh)	x	x
EE Bus Other ($60+ /MWh)	x	x
EE Bus Other ($30-60/MWh)	x	x
EE Bus Lighting (up to $30/MWh)	x	x
EE Bus Lighting ($60+ /MWh)	x	x
EE Bus Lighting ($30-60/MWh)	x	x
EE Bus HVAC (up to $30/MWh)	x	x
EE Bus HVAC ($60+ /MWh)	x	x
EE Bus HVAC ($30-60/MWh)	x	x
DR Water Heating DLC	x	x
DR Smart Thermostats	x	x
DR Emerging Tech	x	x
DR Curtail Agreements	x	x
DR Battery Storage	x	x
DR Air Conditioning Load Mgmt	x	x

2016 Integrated Resource Plan Modeling Summary

Prepared for:
Indianapolis Power & Light Company

Date Submitted:
September 22, 2016

Prepared by:
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Liability Note

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EXECUTIVE SUMMARY

ABB was retained by Indianapolis Power & Light Company (IPL) to provide analytical services to support its 2016 Integrated Resource Plan (IRP). ABB used the Midwest Fall 2015 Power Reference Case projection of natural gas, emission and energy prices. In addition, ABB forecasted gas and energy prices for the MISO-Indiana Power Market for additional scenarios and stochastic modeling.

Sections, tables and figures identified as "Confidential" are available in Volume 2 of IPL's full 2016 Integrated Resource Plan as Confidential Attachment 2.2.

ABB performed IPL portfolio expansion simulations using its Capacity Expansion Module to model demand side and supply side alternatives. The module did a complete numerical simulation of all possible combinations using mixed integer linear programming (MILP) while maintaining a minimum 15 percent reserve margin as required by MISO for the current planning year. While this minimum level is reviewed annually, IPL opted to assume a constant value in the study period. The decision criterion or objective function is to minimize the costs to customers presented in terms of present value of revenue requirements (PVRR). Study period was 2017-2036 with end effects through 2046.[1]

In addition, ABB used their Strategic Planning (SP) software to model the portfolio, financial and rate making simulations. ABB calibrated the operating characteristics of the IPL fleet consistent with the National Ambient Air Quality Standard for Sulfur Dioxide Emissions ("NAAQS-SO_2") and Coal Combustion Residuals ("CCR") Rule Compliance Project, and performed deterministic and scenario assessments for the plans.

Five sets of CO_2 prices were used for this analysis:

- Deterministic prices were used from ABB's 2015 Fall Reference Case for the CO_2 Tax Scenario.
- Deterministic prices were developed for the high/low gas scenarios with a CO_2 Tax.
- Deterministic prices were developed for IPL's high carbon cost forecast which was based on the data provided by its vendor ICF Federal Legislation data starting in 2022. A set of 50 stochastic prices for MISO-IN were developed using ABB's Integrated Model and its Smart Monte Carlo sampling program.

The six scenarios of the energy industry's future were modeled. Highlights for each scenario were:

Base: Base load forecast with CO_2 Tax reference case assumptions with implementation of national greenhouse gas legislation starting in 2022. A carbon tax serves as a proxy for future carbon regulation which may be allowance or tax based.

Robust Economy: High load forecast with high gas and market prices correlated with base CO_2 Tax.

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[1] The process within SP to capture end effects consists of running the simulation beyond the study period. When conducting integrated resource planning and active evaluation of constructing base load generating facilities, it is critical to properly evaluate the cost effectiveness of resource additions by extending the planning horizon

Recession Economy: Low load forecast with low gas and market prices correlated with base CO_2 Tax.

Strengthened Environmental Rules: Base load forecast with high carbon cost assumptions starting in 2022 with correlated gas and market prices. A Renewable Portfolio Standard of 20% was added in by 2022.

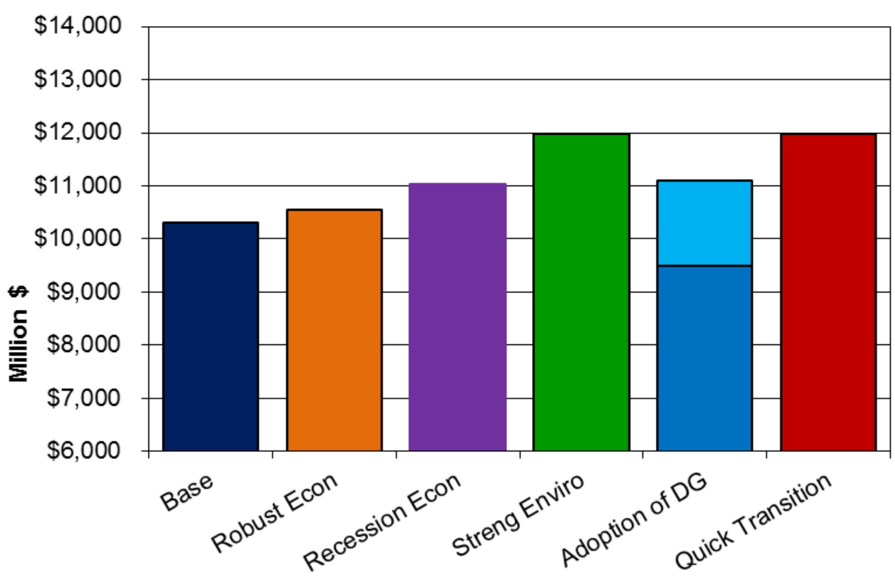
High Customer Adoption of Distributed Generation (DG): Same as Base Case with 150 MW of DG added in each of the three years: 2022, 2025 and 2032 to reflect potential customer choices.

Quick Transition: Same as base case with Pete 1 retirement and refueling Pete 2-4 in 2022 and maximum achievable Demand Side Management (DSM), and the balance of resources comprised of solar, wind and battery storage in 2030 based on stakeholder feedback.

ABB performed deterministic and risk analyses to evaluate IPL's scenarios under varying conditions, identifying a wide range of possible portfolios. . Figure 1-1 shows the 20 Year PVRR for the six scenarios. For the High Customer Adoption of DG Scenario, the light blue DG costs are estimated for 450 MW.

Figure 1-2 through Figure 1-4 illustrate the resource additions, reserve margin and annual aggregate incremental rate increases due to resource changes only for the six scenarios.

Figure 1-1
Scenario - PVRR Rankings (2017-2036)



(Source: ABB Advisors.)

Figure 1-2
Base Scenario Resource Plan Additions

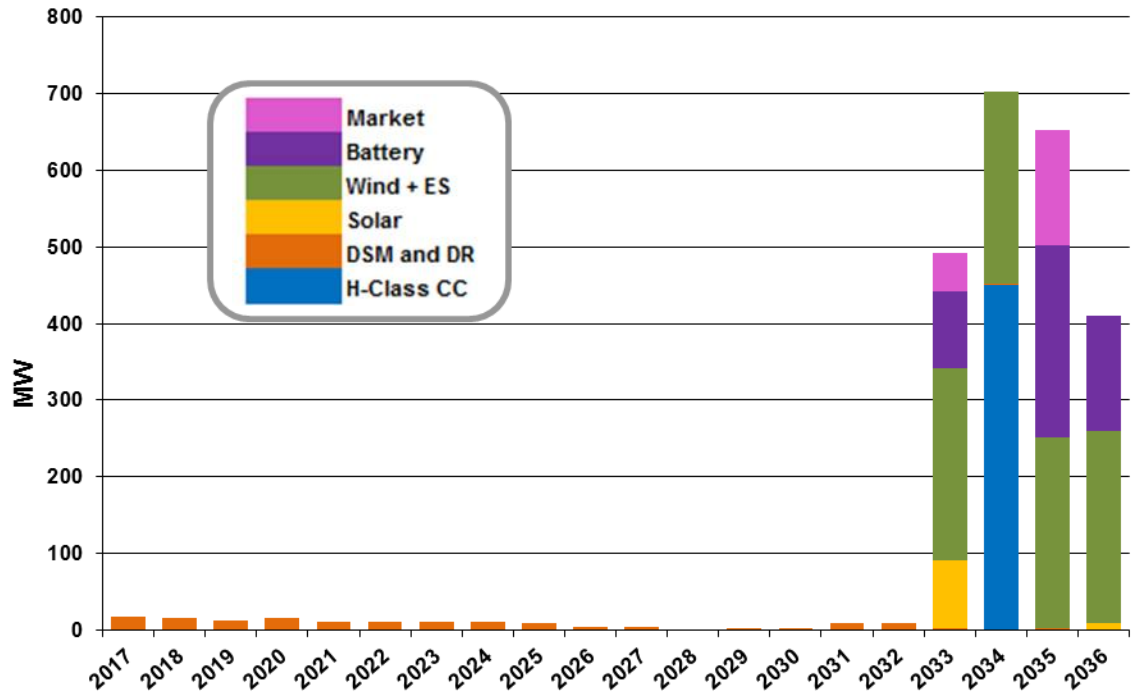
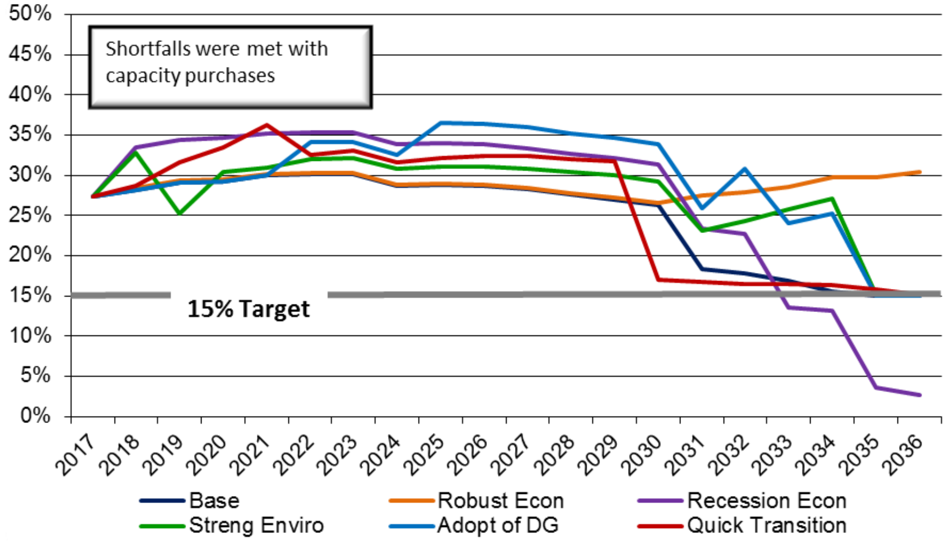
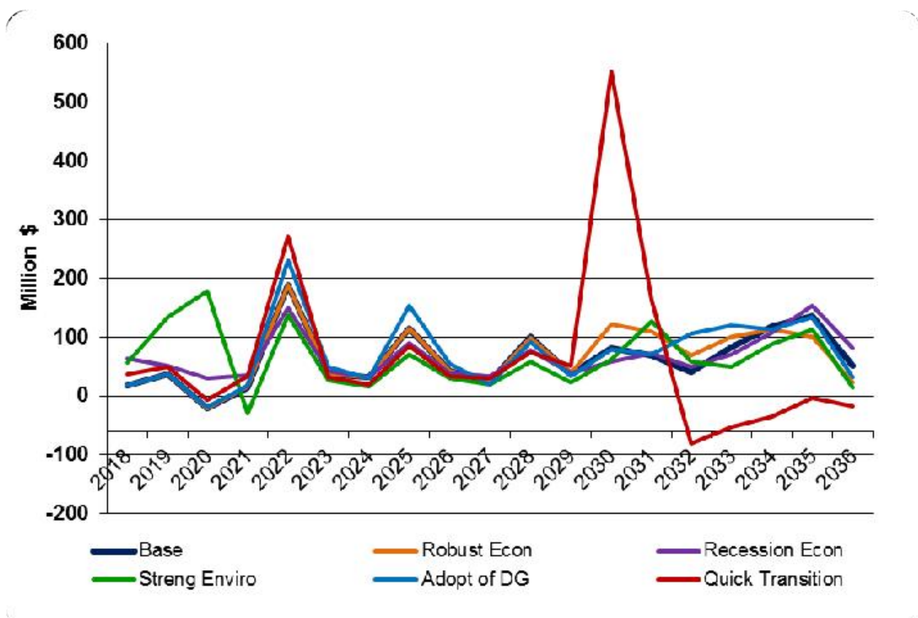


Figure 1-3
Resource Portfolios- Reserve Margin (IPL Installed Capacity). All plans utilize the base load assumption.



(Source: ABB Advisors.)

Figure 1-4
Scenario Annual Rate Increases[2]



(Source: ABB Advisors.)

[2] The Quick Transition portfolio was crafted from stakeholder input. The 2022, 2025 and 2030 asset additions align with CPP compliance periods. The lumpy additions in 2030 would likely be smoothed.

1 SCOPE OF PROJECT

ABB believes that the Resource Planning process and results need to be fully "owned" by the client. ABB provided consulting advice, oversight and analytics of IPL's current and projected resources. IPL provided portfolio information and approval of key assumptions. As such, the approach involved a combined ABB and IPL team as it relates to aspects of the engagement.

ABB utilized Strategic Planning (SP) *powered by MIDAS Gold™* in conjunction with the Capacity Expansion Module (CEM) to meet the needs of the resource planning study. SP and CEM allowed our consultants to quickly screen and optimize resource options and feedback the information to the client's portfolio. SP also allowed the capture of financial information that was not related to production results including, but not limited to, the financial aspects of a construction program, timing of cash and creation of rate base items. SP captured revenue requirements based on return on rate base.

IPL's expectations were the development of a detailed resource plan evaluation process which captures and quantifies the risk of certain events. To accomplish this, ABB performed the following scope of work:

<u>MISO-Indiana Market Simulation</u>

1. Forecasted Hourly Energy Prices. Five sets of prices were used for this analysis:

- Deterministic prices were used from ABB's 2015 Fall Reference Case for the Clean Power Plan (CPP) Carbon Tax Scenario.
- Deterministic prices were developed for the high/low gas scenarios with a CO_2 Tax.
- Deterministic prices were developed for ICFs Federal Legislation Scenario starting in 2022.
- A set of 50 stochastic prices for MISO-IN were developed using ABB's Integrated Model and its Smart Monte Carlo sampling program.

2. Forecasted Annual Capacity Prices. Provided a deterministic projection of MISO-Indiana 2017-2036 capacity prices from ABB's Fall Reference Case.

<u>IPL Portfolio (Capacity Expansion Module or CEM) Simulation</u>

1. Modeled supply-side alternatives including combustion gas turbines, combined cycles, nuclear, wind, battery storage and photovoltaic ownership options.
2. Modeled demand-side alternatives identified in IPL's 2016 DSM Market Potential Study (MPS) as selectable resources based on similar measure load shapes by rate class and cost. (e.g. Residential lighting under $30/MWh as a bundle.)
3. Allowed the model to retrofit/refuel or retire the Pete units in 2018.
4. Performed a complete numerical simulation of all possible combinations using mixed integer linear programming (MILP) while maintaining a minimum 15 percent reserve margin with a decision criterion of minimizing the present value of revenue requirements (PVRR). The results of the CEM screenings were passed to the Strategic Planning model as part of the portfolio, financial, and rate making simulations.

<u>IPL Portfolio Simulation</u>

1. Calibrated the operating characteristics of the IPL fleet (fuel type, variable cost, fixed cost, heat rate, minimum capacity, must run status, spinning reserve, maximum capacity, emission rates, starts). Calibration was based on National Ambient Air Quality Standard for Sulfur

Dioxide Emissions (“NAAQS-SO_2”) and Coal Combustion Residuals (“CCR”) Rule Compliance Project work recently completed. Modifications to the Pete Unit retrofit costs and unit capacity ratings were then adjusted. Base year was updated to 2016 dollars.

2. The IPL assets and load are dispatched competitively against the electricity market prices. This modeling more accurately mimics the implementation of the Midcontinent Independent Transmission System Operator (MISO) market, where IPL sells its generation into the MISO market and purchases its retail load requirements from the MISO market.
3. Performed deterministic and scenario simulations to assess the performance and risk associated with each resource plan.

<u>Scenario Based Market Price Simulation</u>

ABB utilized the CPP Carbon Tax market price scenario developed in our 2015 Fall Power Reference Case in addition to forecasting energy prices for the MISO-Indiana Power Market for the following additional scenarios.

1. The four scenarios are as follows:

Base (CPP Carbon Tax): The focus of the CPP Carbon Tax Scenario was to meet the national target reduction of 32 percent using a mass-based approach. ABB utilized its proprietary Integrated Model to determine a CO_2 tax that would be required to meet the 32 percent reduction by 2030. In addition, it was further refined to reflect the CO_2 tax that would be required to meet the interim targets. This scenario also included an uplift in the natural gas prices and reduced coal prices due to increased/reduced demand respectively.

Low Gas Price with CPP Carbon Tax: For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes (base), but also of probabilities around the projection. Accordingly, ABB developed upper and lower 10 percent confidence bands around the gas forecast. This means that there is a long-run 80 percent probability that future gas prices will occur within these bands and that 10% of the time gas prices can be lower than the projected low gas price. Market prices developed for this scenario are consistent with the low gas prices and a CO_2 tax.

High Gas Price: Again, this means that there is a long run 80 percent probability that future gas prices will occur within the upper and lower 10 percent confidence band and that 10% of the time gas prices can be higher than the projected high gas price. Market prices developed for this scenario are consistent with the high gas prices and a CO_2 tax.

High carbon costs: ABB developed gas and market prices that were correlated with the high carbon cost assumptions in $/ton starting in 2022.

2 REGIONAL MODELING ASSUMPTIONS

Introduction

ABB created a forward view of the MISO-Indiana regional electricity market, which includes IPL's portfolio. The database uses publicly available information through 2024 and is further extrapolated to 2036 using general trends for prices, demand growth and resource expansion.

The Forward View is a proprietary perspective of the future based on public or commercial information and experience in working in electricity markets. This fundamental approach relies on first identifying the basic components of electricity price: supply, transmission and demand, and using best available sources, project the components over time and geography.

Supply is disaggregated into types of generation, and further disaggregated into fuels (or drivers), operations of the resources (capacity, heat rates, planned outages, and forced outages), the amount of additions (and retirements) over time and other factors such as emissions from power generation.

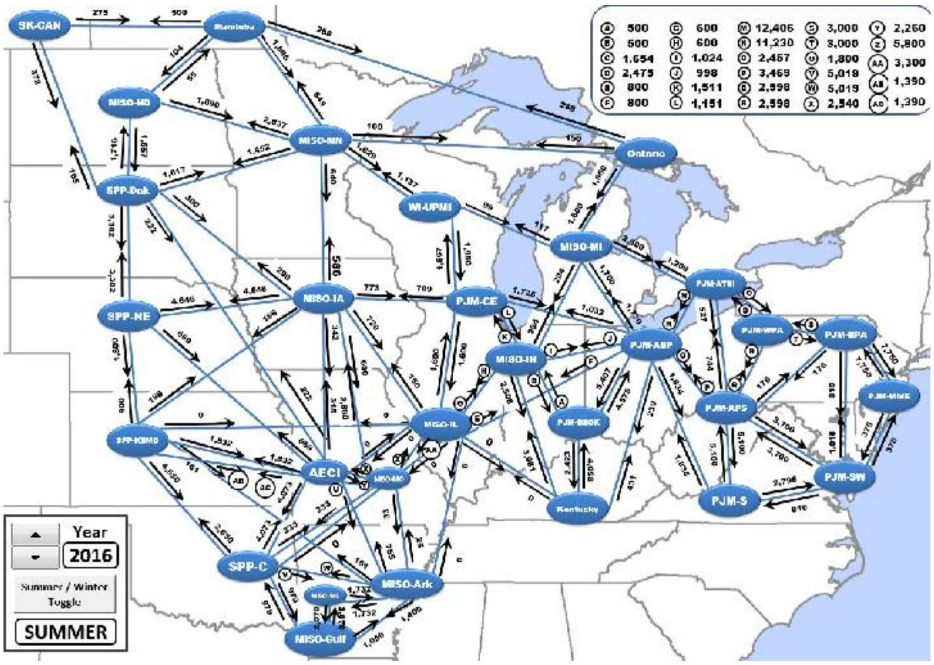
Demand is the demand for electricity by zone (191 zones in North America). Monthly peak and energy demand is forecast over a ten year period. Then, reference hourly demand of electricity is applied to forecasts to produce forecasts of hourly demand by region.

Mid-Continent Market Topology

The Midwest region covers nearly 2.3 million square miles and includes all or portions of 26 U.S states and the Canadian provinces of Saskatchewan and Manitoba. Almost 40% of the US and Canadian population live in this area, and approximately 470,000 MW of generating resources supply 1,796 TWh of energy annually. The Midwest is highly interconnected, and, with some limitation, generation from any area with in the Midwest can be used to meet load in any other area. These interconnections results in a highly interdependent Midwest electricity market.

To develop hourly energy prices for MISO-IN, ABB modeled the entire Eastern Interconnection with transmission interties and zonal price points. Figure 2-1 displays the transmission system with a focus on the mid-continent market.

Figure 2-1
Mid-Continent Market Configuration (MW Transfer Limit)



(Source: ABB Advisors.)

Market Price Formation

ABB used a fundamentals-based approach to calibrate unit performance, market prices, and power flows. ABB simulated the operation of each generating unit of the Eastern Interconnection. For each region, ABB's software models considered:

- Individual generating unit characteristics including heat rates, variable O&M, fixed O&M, and other technical characteristics;
- Transmission line interconnections, ratings, and wheeling rates;
- Resource additions and retirements;
- Nuclear unit outages and refuelings;
- Hourly loads for each utility or load serving entity in the region; and
- The cost of fuels that supply the plants.

ABB's models simulated the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The models are 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.

ABB's calibration methodology was to benchmark the models against observed:

- prime mover output within the market zones;
- market prices; and
- power flows.

Market Price Results

ABB created a forward view of the MISO-Indiana regional electricity market, which includes the IPL portfolio. The highly interconnected regions of the Eastern Interconnect (NPCC, SERC, FRCC, SPP, PJM, MISO and MRO) [3] required the demand, supply and transmission to be considered for the entire region. The database uses publicly available information through 2024 and is further extrapolated to 2036 using general trends for prices, demand growth and resource expansion.

Four sets of deterministic prices were used for this analysis:

- Prices from ABB's 2015 Fall Reference Case for the CO_2 Tax Scenario.
- Prices were developed for the high/low gas scenarios with a CO_2 Tax.
- Prices were developed for ICFs Federal Legislation Scenario.

The following describes the market prices used in each scenario.

Base: 2015 Fall Reference Case CO_2 Tax assumptions with implementation of national greenhouse gas legislation starting in 2022.

Robust Economy: High Gas: ABB's subjective view of 90th percentile of probability distribution that corresponds to limited shale supply scenario. Market prices developed for this scenario are consistent with the high gas prices and the Base CO_2 tax.

Recession Economy: Low Gas: ABB's subjective view of 10th percentile of probability distribution that corresponds to production costs for best shale plays. Base scenario CO_2 Tax. Market prices developed for this scenario are consistent with the low gas prices and the Base CO_2 tax.

Strengthened Environmental: Market and gas prices developed for ICF's assumption of implementation of national greenhouse gas legislation (Federal Legislation) starting in 2022.

High Customer Adoption of DG: Same as Base Case

Deterministic Results

Table 2-1 summarizes the base (CPP Carbon Tax) annual 5x16 (On-Peak), Wrap (Off-Peak) and 7x24 (Average) electricity prices for the MISO-Indiana region.

Table 2-1 – Confidential Table
Base (CO_2 Tax) Prices for the MISO-Indiana Region (Nominal $/MWh)

[3] Northeast Power Coordinating Council, SERC Reliability Corporation, Florida Reliability Coordinating Council, Southwest Power Pool, Pennsylvania-New Jersey-Maryland Interconnection, Midwest Independent System Operator and Midwest Reliability Organization

Base (CO_2 Tax) electricity prices for MISO-Indiana are summarized in Figure 2-2.

Figure 2-2 – Confidential Figure
Base (CO_2 Tax) Prices for MISO-Indiana Region (Nominal $/MWh)

Table 2-2 and Figure 2-3 summarize the average (7x24) electricity prices that were specifically developed for the IRP scenarios along with the Base (CO_2 Tax) market prices.

Table 2-2 – Confidential Table
7x24 Scenario Prices for the MISO-Indiana Region (Nominal $/MWh)

Figure 2-3 – Confidential Figure
7x24 Scenario Prices for MISO-Indiana (Nominal $/MWh)

Natural Gas, Oil Price, Coal Price and Emissions Write up – Confidential

Figure 2-4 – Confidential Figure
Fall 2015 Henry Hub Forecast Comparison (2015 $/MMBtu)

Table 2-3 – Confidential Table
CPP Carbon Tax Scenario Monthly Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)

Figure 2-5 – Confidential Figure
CPP Carbon Tax Scenario Henry Hub Natural Gas Forecast (Nominal $/MMBtu)

Table 2-4 summarizes the three approaches incorporated by ABB to produce the Reference Case natural gas price forecast.

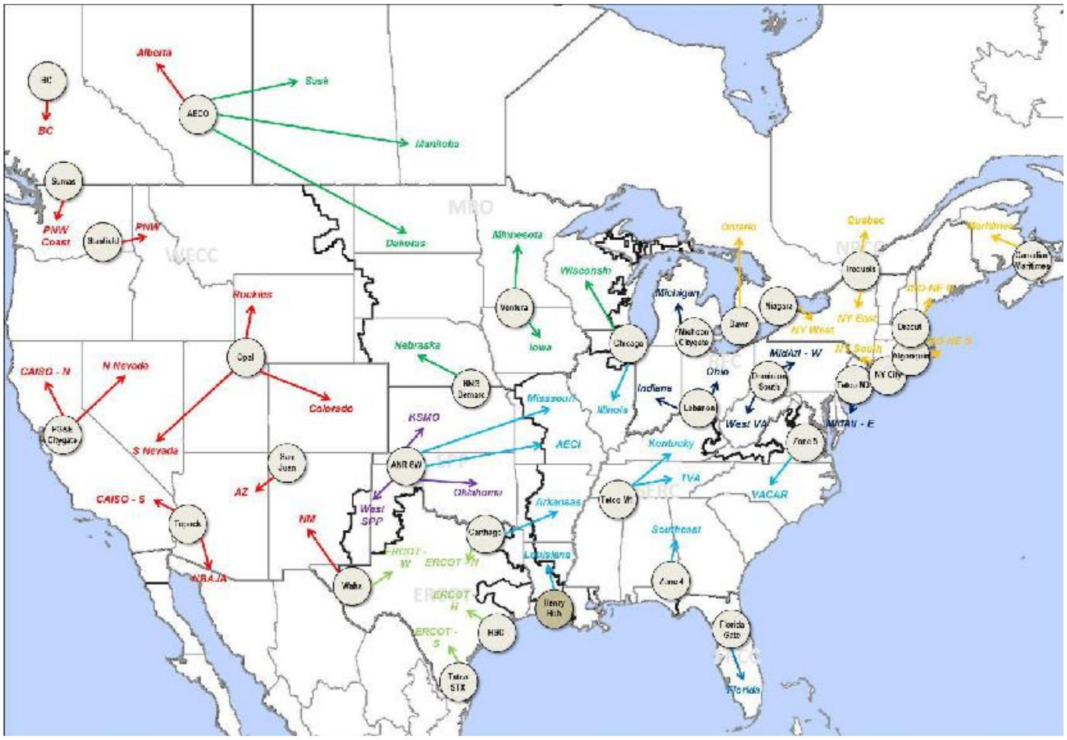
Table 2-4
Reference Case Gas Price Forecasting Phases

Forecast Phase	Period Length	Data Source	Forecast Technique
Futures Driven	First 24 Months	NYMEX Henry Hub futures and market differentials	Calculated Henry Hub and liquid market center differentials
Blend	Months 25-48	ABB Advisors and NYMEX/Velocity Suite	Linear process to gradually equate near-term to long-term fundamentals
Long-term Fundamentals	Remaining forecast period (to 2040)	ABB Advisors	Fundamental supply and demand analysis modeling

(Source: ABB Advisors.)

Figure 2-6 illustrates the liquid market centers that are used in the Fall 2015 Reference Case forecast.

Figure 2-6
Natural Gas Liquid Market Centers



(Source: ABB Advisors.)

Table 2-5 shows ABB's annual coal basin price forecast for US Basin Coal.

Table 2-5 - Confidential
ABB US Basin Coal Price Forecast (Nominal $MMBtu)

Table 2-6 contains the Reference Case emission prices for the MISO-Indiana transaction group in addition to the high carbon cost assumptions.

Figure 2-7 illustrates the CO_2 emissions cost for the two environmental scenarios.

Table 2-6 – Confidential
Emission Costs (Nominal $/Ton)

Figure 2-7 - Confidential
CO_2 Emission Costs (Nominal $/Ton)

3 PORTFOLIO MODELING ASSUMPTIONS

Natural Gas

The natural gas prices used for IPL's system include the forecast for the Henry Hub price plus $0.05/MMBtu delivery to Eagle Valley and $0.20/MMBtu delivery to Harding Street and Georgetown. **Table 3-1** summarizes the annual Henry Hub plus basis differential for all scenarios.

Table 3-1 - Confidential
Annual Natural Gas Prices for all Scenarios (Nominal $/MMBtu)

Inflation

A 2.5 percent escalation rate was used for the forecast period.

Discount Rate

Per IPL's direction, ABB assumed a 5.61 percent discount rate based on IPL's most recent rate case and all PVRR dollars amounts presented have been discounted back to 2016 dollars.

IPL Coal Price Forecast

IPL provided a Petersburg coal price forecast based upon local contract negotiation pricing for the first three years, followed by local projections for the next seven years, and then a fixed escalation rate for the remainder of the study period.

Table 3-2 - Confidential
IPL Coal Price Forecast (Nominal $/MMBtu)

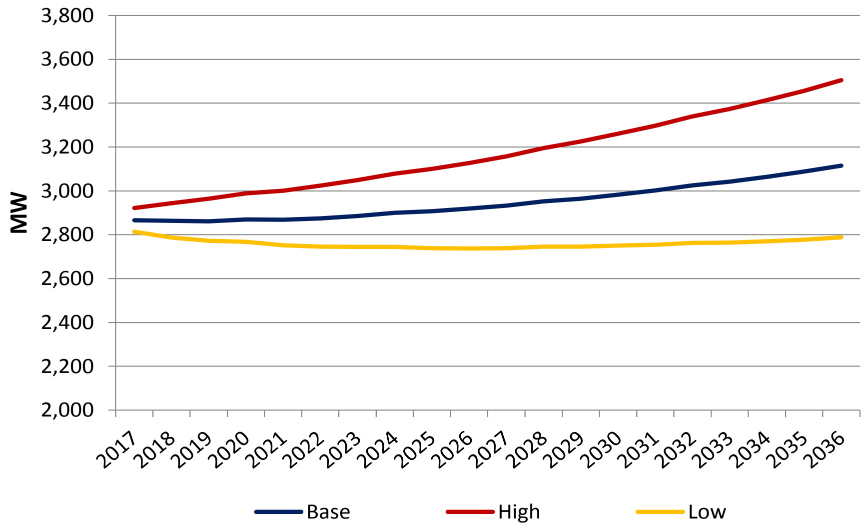
Unit Operating Characteristics

Operating characteristics of the IPL portfolio units were obtained from IPL-based on National Ambient Air Quality Standard for Sulfur Dioxide Emissions ("NAAQS-SO_2") and Coal Combustion Residuals ("CCR") Rule Compliance Project work that was completed in Q4 2015. Modifications to the Pete Unit retrofit costs and unit capacity ratings were then adjusted. Base year was updated to 2016.

IPL Load Forecast

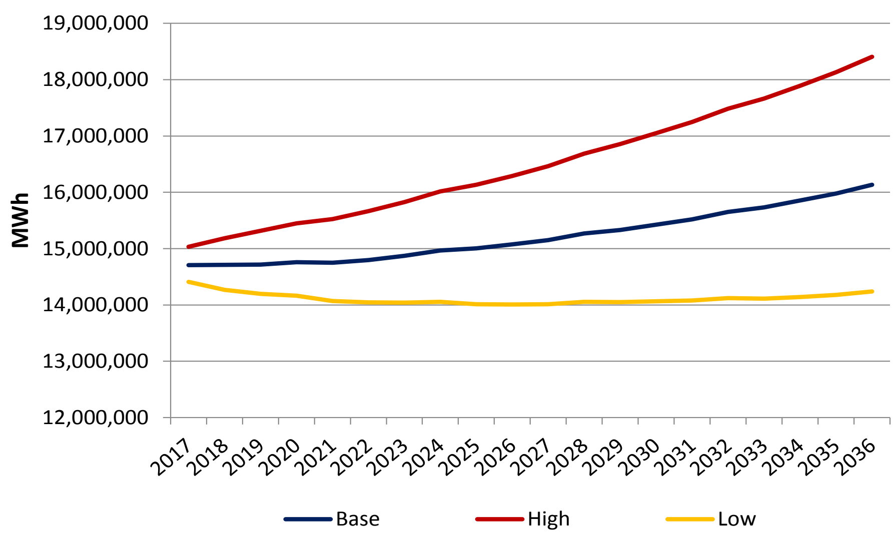
High, medium and low load forecast was supplied by IPL. Figure 3-1 & Figure 3-2 show the load forecast for both peak and energy for base, low and high ranges.

Figure 3-1
IPL Peak Forecast (2017-2036)



Source: IPL

Figure 3-2
IPL Energy Forecast (2017-2036)



Source: IPL

IPL Load and Resource Balance Report

Figure 3-3 contains IPL's Load and Resource Balance report for the period of 2017-2036 for the base plan. The capacity ratings are for planning based on MISO rules. Existing wind receives no planning capacity credit since the PPAs do not include firm transmission services. A 10% planning capacity was used for wind units starting in 2031 to reflect expected transmission system enhancements. A 45% planning factor was used for existing solar based on IPL's actual PPA data and a 48% planning factor was used for all new solar additions as allowable by MISO to reflect possible technology improvements or be located outside the IPL service territory with improved insolation performance.

Figure 3-3
Base Plan Load and Resource Balance Report

Indianapolis Power & Light
Load and Resource Balance Report

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	50	75	100
Solar Existing	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43	43	43	48
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	350	500
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	150	0
Total Resources	3575	3575	3575	3575	3575	3575	3575	3537	3537	3537	3537	3537	3537	3537	3335	3335	3320	3306	3315	3345
Original Peak Load	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	75	92	104	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2789	2770	2766	2749	2746	2746	2749	2746	2750	2758	2773	2785	2801	2817	2832	2840	2861	2882	2908
Reserve Margin	27.3%	28.2%	29.0%	29.2%	30.0%	30.2%	30.2%	28.7%	28.8%	28.6%	28.2%	27.6%	27.0%	26.3%	18.4%	17.8%	16.9%	15.6%	15.0%	15.0%

4 STOCHASTIC ASSUMPTIONS

Introduction

ABB's Integrated Model uses a structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission, and provides a solid basis for decision-making. Using a stratified Monte Carlo sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, unit availability, capital expansion cost, and emission price) and take into account statistical distributions, correlations, and volatilities.

Stratified sampling can be thought of as "smart" Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges and then a sample is taken from each range. By allowing these uncertainties to vary over a range of possible values, Strategic Planning develops a range or distribution of forecasted price.

Prices are derived using a rigorous probabilistic approach that does the following:

1. Quantifies the uncertainties that drive market price through a Stratified Monte Carlo sampling model;
2. Puts the uncertainties into a decision tree;
3. Evaluates multi-region, hourly market price for a set of consistently derived futures using Strategic Planning; and
4. Accumulates the information into expected forward price and volatility of the marketplace.

The uncertainty drivers developed for the specific MISO-IN market prices are also used when evaluating the portfolio. During the portfolio evaluation, the prices and the associated uncertainties provide sufficient information about the market to allow for proper evaluation of alternatives. For example, high gas prices would generally result in high on-peak prices. If the high gas prices were not used in conjunction with the high electric prices, resource evaluation would be biased.

Uncertainty Variables

For the regional price trajectories, ABB examines the impact of demand, fuel price, and supply on regional spot market prices. Additionally, for the portfolio analysis, we examine the uncertainty of resource capital cost provided by IP&L. Specifically, the following uncertainties are evaluated:

Demand

- Mid-Term Peak Demand by region
- Mid-Term Energy by region
- Long-Term Electric Demand Growth

Fuel Prices

- Mid-Term Gas Price
- Long-Term Gas Price
- Long-Term Coal Price
- Long-Term Oil Price

Emission Cost

- Long-Term CO_2 Price

Supply

- Mid-Term Coal Unit Availability by region
- Long-Term Combined Cycle Capital Cost
- Long-Term Wind and Solar Capital Cost
- Long-Term Utility Scale and Community Solar Cost
- Long-Term Battery Storage Cost

Stochastic Draws

Using Strategic Planning's Stratified Monte Carlo sampling program, ABB created 50 future scenarios for price development and portfolio evaluation. ABB has performed extensive market price trajectory simulations and has determined that 50 trajectories provide a reasonable balance between the number of scenarios to achieve a convergent solution and a manageable number of stochastic scenarios to be applied to many resource plan alternatives. Uncertainty draws were made for the capital cost of the resource additions in the portfolio evaluation. These capital cost draws are combined with the uncertainty draws from the price development runs.

Mid-Term Peak and Energy by Region

Monthly peak and monthly energy are constant variance variables (i.e. the variance remains constant over time) with normal probability distributions. For constant variance variables, monthly variability is expressed in terms of the normalized standard deviation (Std Dev/Mean) for the month. To derive the regional values for peak, ABB calculated the average standard deviation of the regional, growth-adjusted historical peaks by month. A parallel methodology is used to derive the standard deviations for monthly energy. Unique standard deviations are developed for all of the regions in the database. The correlation between the regional historical monthly peak and energy values are incorporated into the uncertainty analysis. The monthly correlations are calculated using the standard Excel correlation function.

Table 4-1 shows typical monthly normalized standard deviations for monthly peak and energy uncertainty variables for the MISO-IN transaction group. The correlation coefficients are also included.

Table 4-1
Peak and Energy Standard Deviations

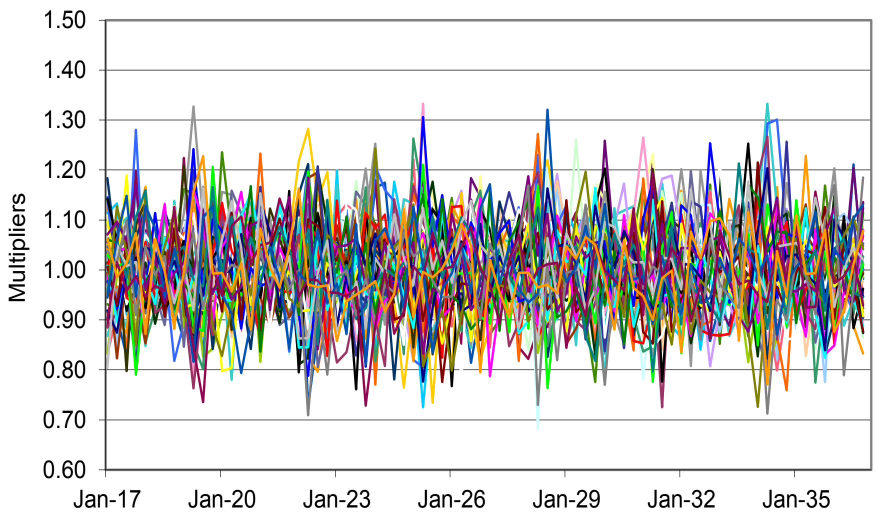
	Peak Standard Deviation	Energy Standard Deviation	Peak - Energy Correlation
Jan	0.082	0.071	0.897
Feb	0.073	0.073	0.964
Mar	0.079	0.082	0.940
Apr	0.096	0.081	0.916
May	0.094	0.081	0.851

Jun	0.060	0.069	0.764
Jul	0.067	0.068	0.899
Aug	0.079	0.084	0.924
Sep	0.092	0.096	0.897
Oct	0.130	0.098	0.759
Nov	0.095	0.088	0.980
Dec	0.083	0.087	0.902

(Source: ABB Advisors)

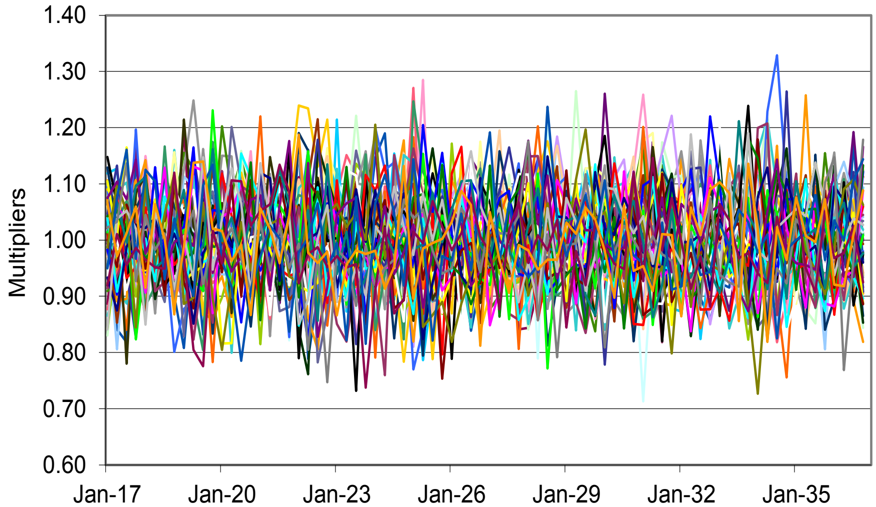
These parameters are used by ABB's Stratified Monte Carlo sampling program to develop a statistically consistent set of uncertainty multipliers. The resulting monthly peak and energy multipliers are then used to modify the input market area forecasts. MISO-IN peak and energy multipliers are shown in Figure 4-1 and Figure 4-2 The figures illustrate 50 draws per month. Alternatively, Figure 4-3 and Figure 4-4 show the peak and energy probability distribution of the multipliers. For each month, the correlated peak and energy draws are applied to the normalized peak and energy forecast by customer class.

Figure 4-1
MISO-IN Peak Multipliers



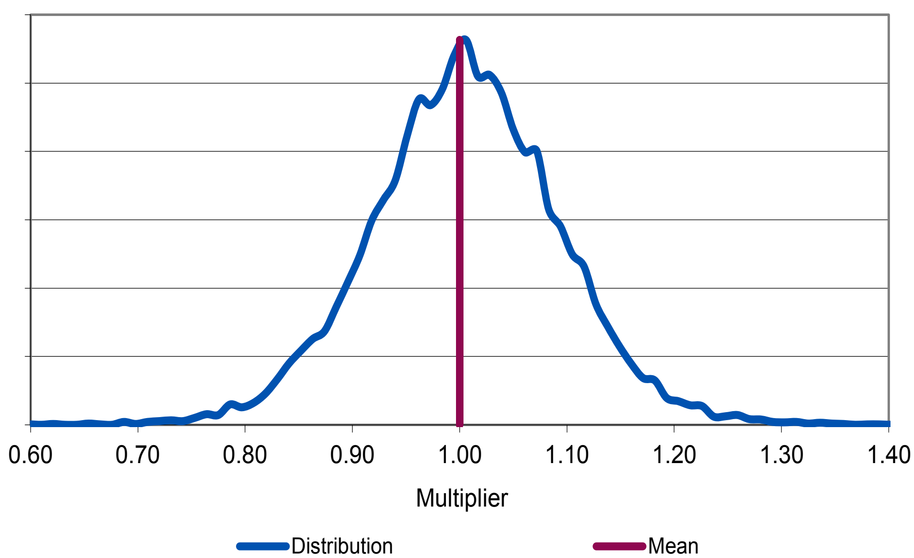
(Source: ABB Advisors)

Figure 4-2
MISO-IN Energy Multipliers



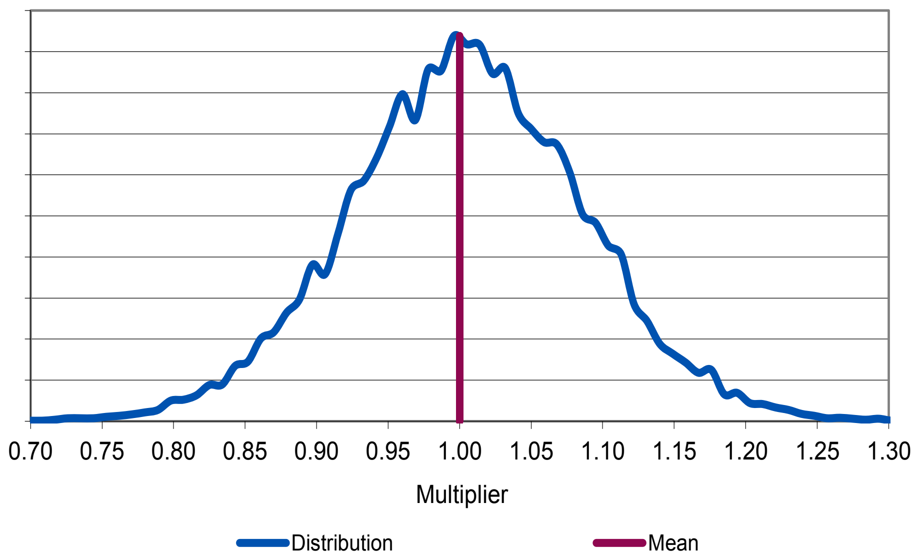
(Source: ABB Advisors)

Figure 4-3
MISO-IN Peak Distribution



(Source: ABB Advisors)

Figure 4-4
MISO-IN Energy Distribution

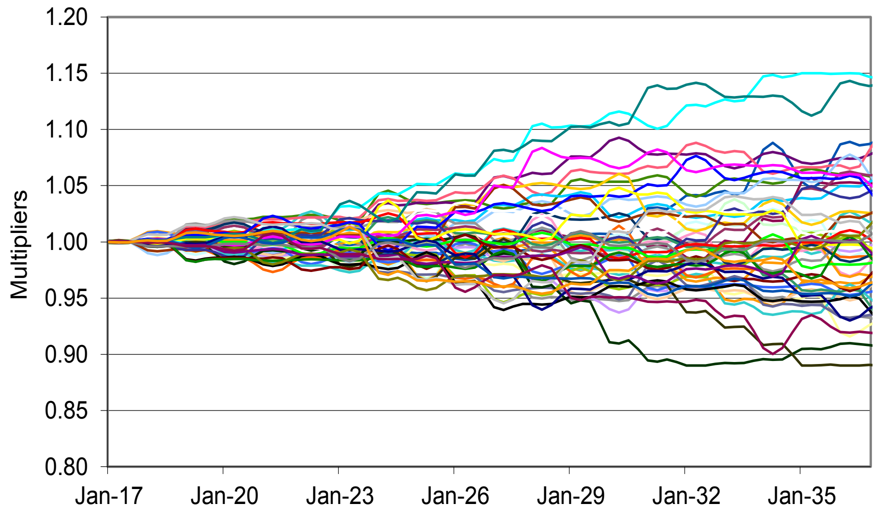


(Source: ABB Advisors)

Long-term Demand (to consider uncertainty in the rate of long-term load growth)

In order to consider the uncertainty in the rate of long-term load growth, demand multipliers are created to modify both peak and energy. The base assumption for the overall long-term growth rate is 0.55%, which is based on the Fall Reference case Midwest Peak and Energy Load Forecast in the MISO NERC Assessment Area. In the example below, volatility parameters are adjusted to consider a range of growth rates between -0.05% and 0.96% over the planning horizon. Figure 4-5 shows the demand multipliers.

Figure 4-5
Long-Term Demand Multipliers



(Source: ABB Advisors)

Mid-term Gas Price

Gas price is a random-walking variable; that is, its variance grows linearly with time. Based on an examination of gas price behavior, the prices tend to mean-revert. That is, over some definable period of time, the price of the commodity tends to move back toward the mean value. For Stratified Monte Carlo sampling, monthly variability for mean-reverting, random-walking variables is expressed in terms of the normalized standard deviation of the error for the month. The variability is further defined by specifying the time period over which the price mean-reverts. This value is expressed in terms of months.

For price development, ABB uses the monthly normalized standard deviation of error terms and the mean reversion time detailed in Table 4-2. Additionally, the multipliers are limited on the low side to 0.7 thru 2021 and 0.6 from 2022-2036.

Table 4-2
Gas Random-Walking Parameters

	Gas Standard Deviation
Jan	0.094
Feb	0.093
Mar	0.087
Apr	0.092
May	0.083
Jun	0.087
Jul	0.088
Aug	0.103
Sep	0.09

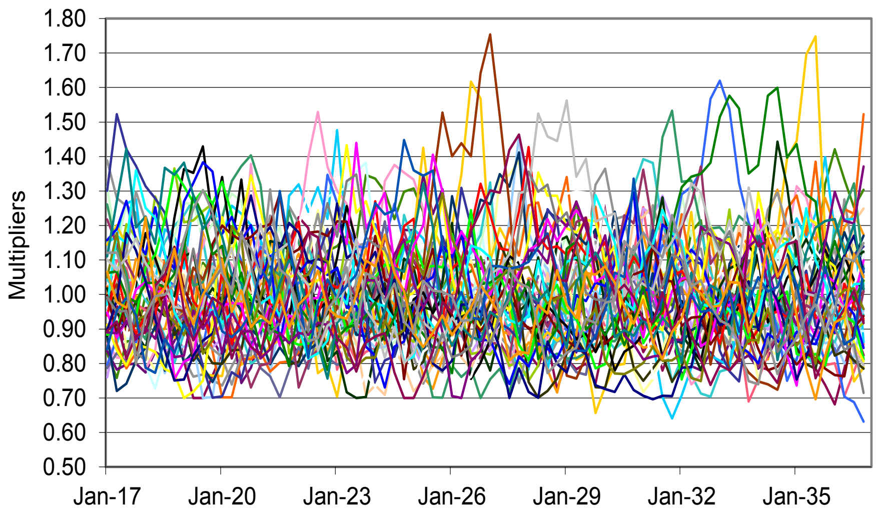
Oct	0.093
Nov	0.099
Dec	0.087
Reversion Time	4.682

(Source: ABB Advisors)

To develop monthly variability values for gas price, ABB began with a database of daily Henry Hub-delivered gas prices for the period 2001-2015. From the daily data, ABB calculated the average gas price by month and year. These averages are adjusted to remove outliers and underlying trends such as seasonal variation and growth rates. Using the resulting average monthly prices, ABB calculated the standard deviation of error terms.

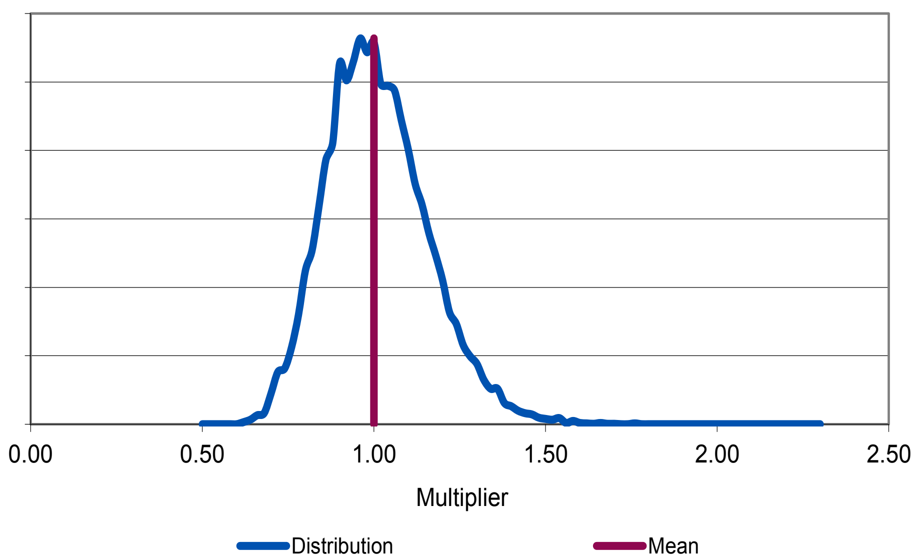
The multipliers resulting from the gas parameters in Table 4-2 are shown in Figure 4-6 and the probability distribution for gas is in Figure 4-7

Figure 4-6
Henry Hub Gas Price Multiplier



(Source: ABB Advisors)

Figure 4-7
Gas Price Distribution

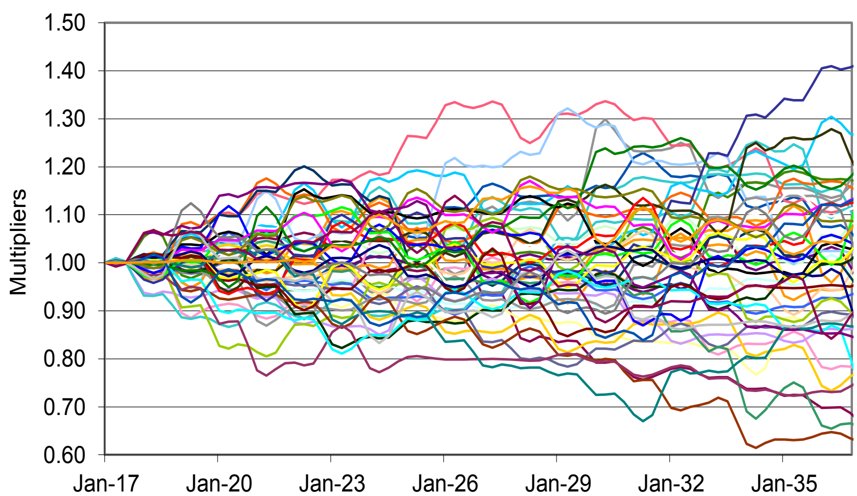


(Source: ABB Advisors)

Long-term Gas, Coal and Oil Price

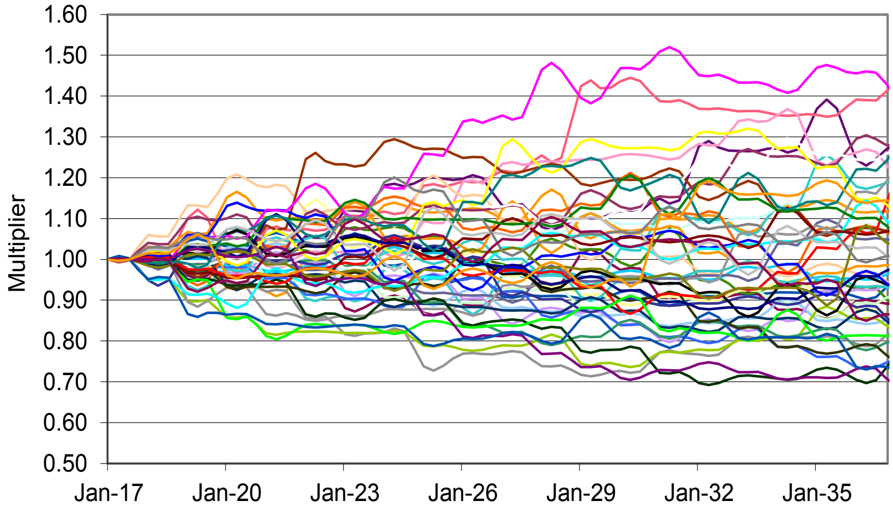
In order to consider the uncertainty in the long-term gas, coal and oil forecast, multipliers are created to modify the gas, coal and oil prices. The base assumption for the escalation of gas, coal and oil prices was 2.5%. Volatility parameters are adjusted to reflect a range of prices bounded by the minimum and maximum values of our fundamental forecast. Figure 4-8, Figure 4-9 and Figure 4-10 show the long-term gas, coal and oil multipliers, respectively.

Figure 4-8
Long-term Gas Multipliers



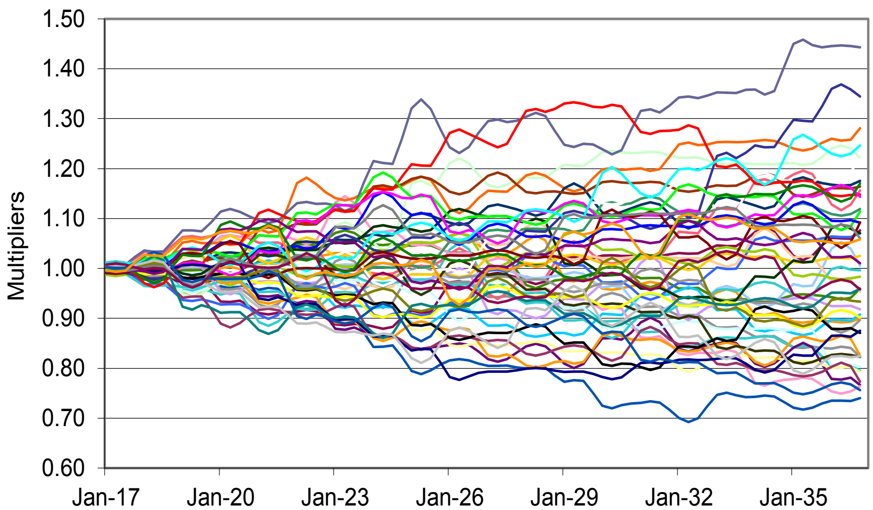
(Source: ABB Advisors)

Figure 4-9
Long-term Coal Multipliers



(Source: ABB Advisors)

Figure 4-10
Long-term Oil Multipliers



(Source: ABB Advisors)

Mid-term Coal Unit Availability by Region

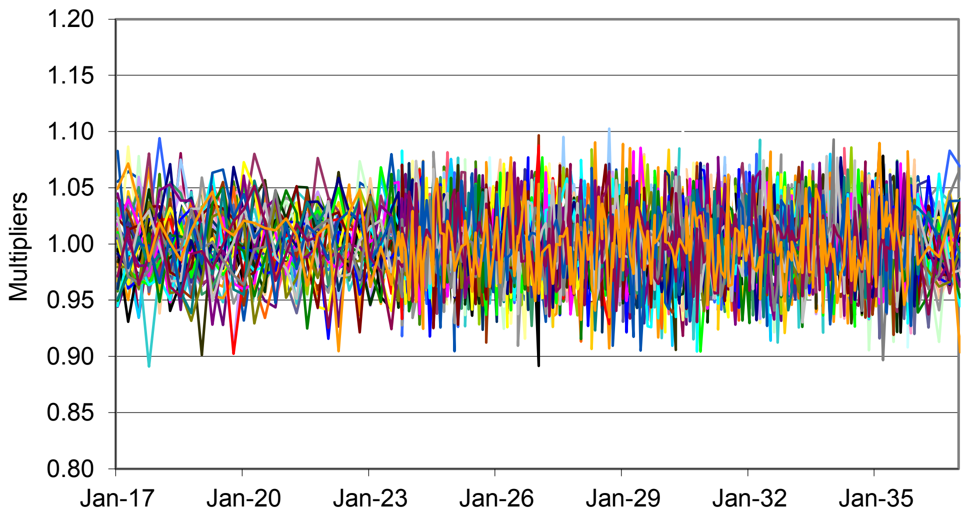
Given the stair-step behavior of the supply curve as it transitions from nuclear to coal to gas and oil, ABB has found that the availability of units within a zone by prime mover-fuel type can have a pronounced impact on market prices and congestion. Simply put, coal availability in a zone may have an impact on prices, flows, and congestion. To capture the stochastic uncertainty of unit availability, ABB makes draws to mimic the impact of availability.

Coal unit availability is a constant variance variable with a normal distribution. For coal availability, no monthly variation is defined. Draws are made using only the annual normalized standard deviation of the probability distribution (where the mean is assumed to be 1).

The coal availability multiplier varies the forced outage rate of coal units. It was assumed that there would be a 65% chance that 500 MW of capacity (out of 152,000 MW) would be unavailable for five days out of a month. Also, since the distribution of the coal availability is normal, there would be a 95% chance that 500 MW of capacity would be unavailable for ten days out of the month. These assumptions result in an annualized standard deviation of 0.03. Random draws using this standard deviation are made for each region for each endpoint.

Figure 4-11 shows the coal unit availability multiplier for a typical region for the 50 endpoints used to determine market prices.

Figure 4-11
Coal Unit Availability Multipliers



(Source: ABB Advisors)

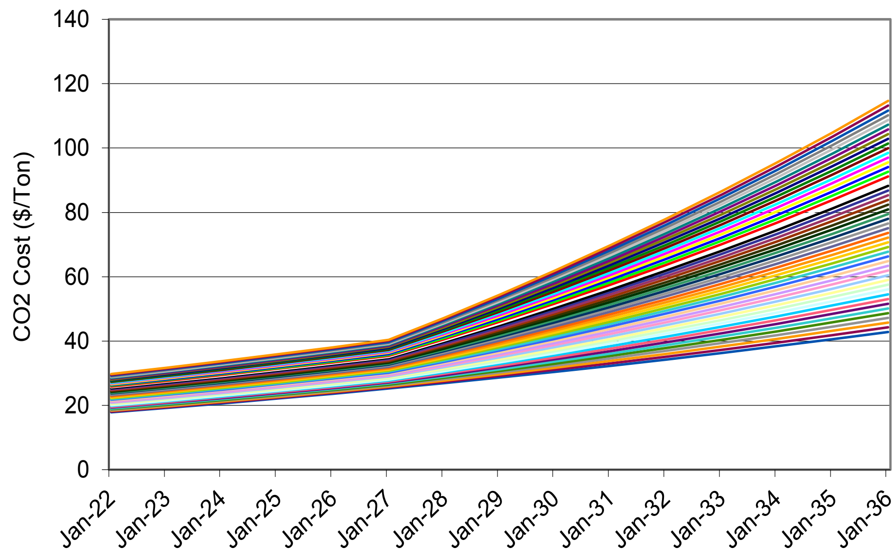
Long-Term Uncertainty CO_2 Price

Unlike the previous uncertainty variables, the lack of historical pricing for CO2 complicates its setup. For this reason, to create uncertainty for carbon pricing the Synapse Spring 2016 National Carbon Dioxide Price Forecast (Updated March 16, 2016) was used.

The Synapse CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility integrated resource planning (IRP) and other electricity resource planning analyses. The report includes updated information on federal regulations, state and regional climate policies, and utility CO_2 price forecasts, as well as Synapse's analysis of the final Clean Power Plan. Synapse's CO_2 price forecast reflects their expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term legislation passed by Congress to reach science-based emissions targets, will result in significant pressure to decarbonize the electric power sector. [4]

The following CO_2 prices in Figure 4-12 are bounded by the Synapse's high and low projections. The prices were not correlated to any of the other stochastic input variables, however the CO_2 prices were used in the stochastic market price development.

Figure 4-12
CO_2 Price Forecast Range

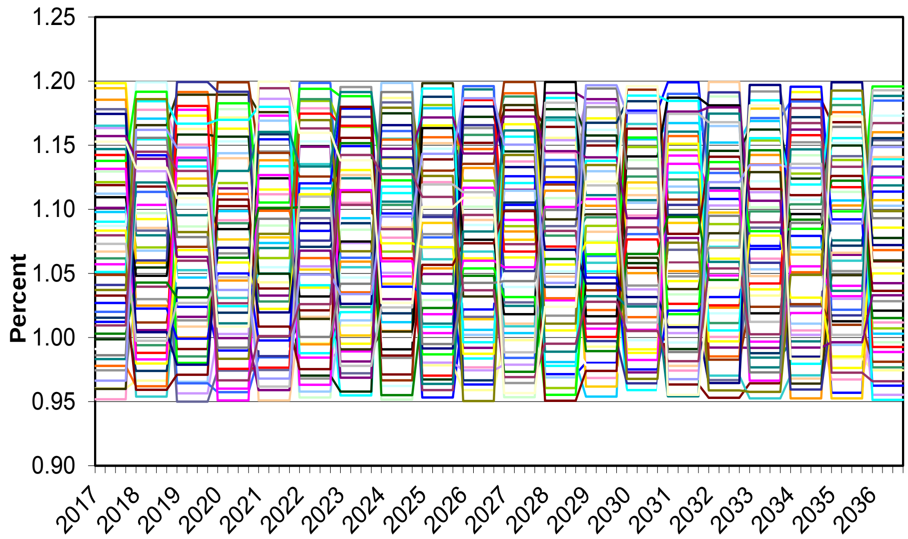


Long-Term Combined Cycle Plant Capital Cost

Combined Cycle (CC) plant capital cost is a constant variance variable with a uniform distribution. Due to site specific construction issues, capital costs are expected to be both higher and lower than the base estimate. It was assumed that the multipliers for capital cost will range from .95 to 1.20 with an expected value of 1.075. Figure 4-13 shows the multipliers used in the analysis.

Figure 4-13
Combined Cycle Plant Capital Cost Multiplier

[4] Spring 2016 National Carbon Dioxide Price Forecast, Synapse Energy Economics, Inc.

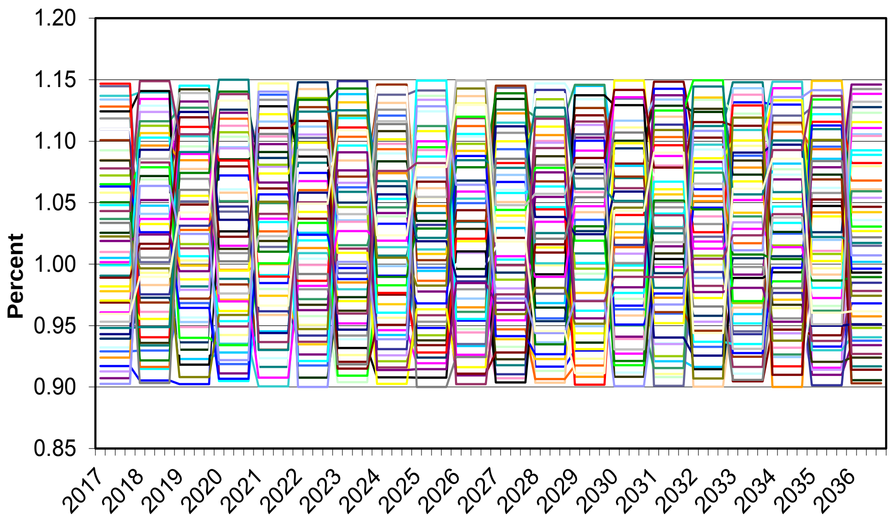


(Source: ABB Advisors)

Wind Capital Cost

Wind plant capital cost is a constant variance variable with a uniform distribution. Technology advances, tax breaks and subsidies have allowed the cost of production to vary in cycles; therefore, capital costs are expected to be higher and lower than the base estimate. It was assumed that the multipliers for capital cost will range from .90 to 1.15 with an expected value of 1.025. Figure 4-14 shows the multipliers used in the analysis.

Figure 4-14
Wind Plant Capital Cost Multiplier

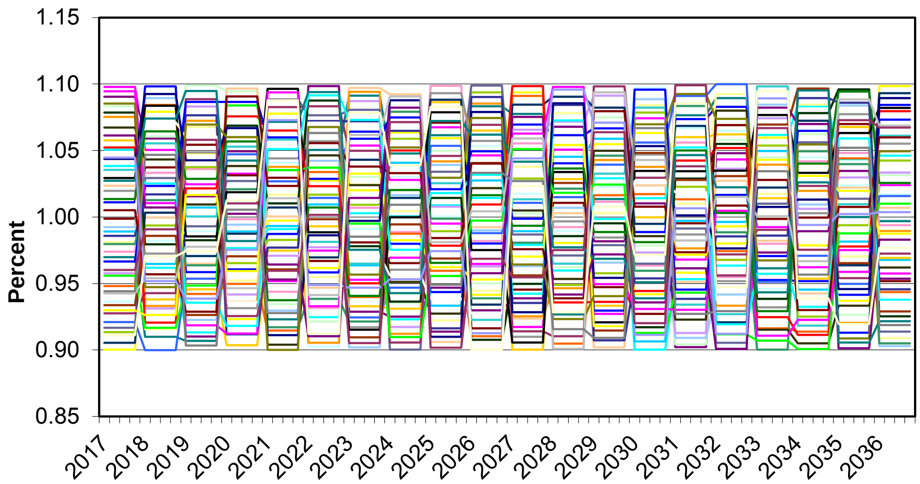


(Source: ABB Advisors)

Energy Storage (Battery) Capital Cost

Peaker Replacement Battery capital cost is a constant variance variable with a uniform distribution. Technology advances are projected to reduce capital costs over time. It was assumed that the multipliers for capital cost will range from .90 to 1.1 with an expected value of 1.0. Figure 4-15 shows the multipliers used in the analysis.

Figure 4-15
Energy Storage (Battery) Capital Cost Multiplier

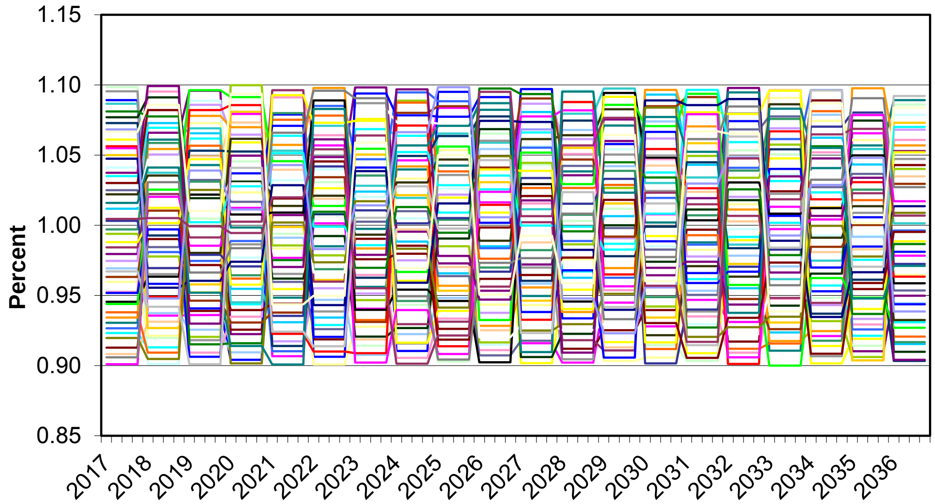


(Source: ABB Advisors)

Utility Solar Capital Cost (>5MW)

Utility Scale Solar plant capital cost is a constant variance variable with a uniform distribution. Like wind, technology advances, tax breaks and subsidies have allowed the cost of production to vary in cycles. In addition, these advances are projected to reduce capital costs over time. It was assumed that the multipliers for capital cost will range from 0.90 to 1.1 with an expected value of 1.0. Figure 4-16 shows the multipliers used in the analysis.

Figure 4-16
Utility Solar Plant Capital Cost Multiplier

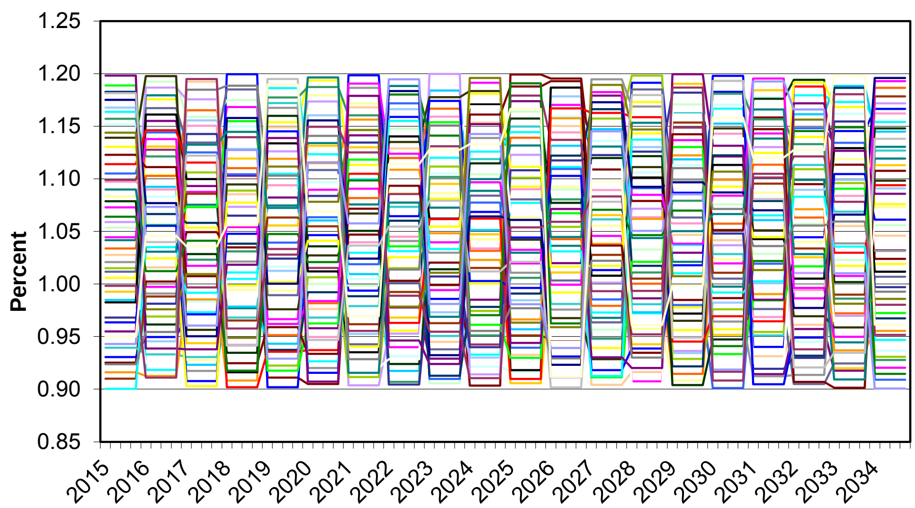


(Source: ABB Advisors)

Community Solar Capital Cost

Like Utility Scale Solar, Community Solar plant capital cost is a constant variance variable with a uniform distribution. Also like wind, technology advances, tax breaks and subsidies have allowed the cost of production to vary in cycles. In addition, these advances are projected to reduce capital costs over time. It was assumed that the multipliers for capital cost will range from .90 to 1.2 with an expected value of 1.05. Figure 4-17 shows the multipliers used in the analysis.

Figure 4-17
Community Solar Plant Capital Cost Multiplier (1MW)



(Source: ABB Advisors)

Summary for Uncertainty Variables

The following chart is a summary of the uncertainty variables and their range multipliers. IPL developed the multipliers for the capital cost uncertainties.

Table 4-3
Uncertainty Variable Range Multipliers

Uncertainty	Uncertainty Range Multiplier
Long-term Demand	.89 - 1.15
Long-term Oil	.69 - 1.46
Long-term Gas	.61 - 1.41
Long-term Coal	.69 - 1.52
Mid-term Peak	.6 - 1.39
Mid-term Energy	.67 - 1.33
Mid-term Gas	.60 - 1.75
Coal Unit Availability	.89 - 1.11
CO_2 Price	1.05 - 3.4
Combined Cycle Capital Costs	.95 - 1.2
Wind Capital Costs	.9 - 1.15
Solar Capital Costs	.9 - 1.1
Community Solar Capital Costs	.9- 1.2
Battery Capital Costs	.9- 1.1

5 MARKET PRICE RESULTS

Stochastic Market Price Formation

ABB used a fundamentals-based approach to calibrate unit performance, market prices, and power flows. Based on its proprietary Integrated Model, ABB simulated the operation of each generating unit in Eastern Interconnect. The Integrated Model is a sophisticated state-of-the-art, multi-area, chronological production/market simulation model. Each Integrated Model simulation includes pro forma financials, providing users with a complete enterprise-wide solution.

For each region, the Integrated Model considered:

- Individual generating unit characteristics including heat rates, variable O&M, fixed O&M, and other technical characteristics;
- Transmission line interconnections, ratings, and wheeling rates;
- Resource additions and retirements;
- Nuclear unit outages and refuelings;
- Hourly loads for each utility or load serving entity in the region; and
- The cost of fuels that supply the plants.

The Integrated Model simulated 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.

ABB's calibration methodology was to:

- Benchmark the model against observed prime mover output within the market zones;
- Benchmark the model against observed market prices; and
- Benchmark the model against observed power flows.

Bidding Behavior

To capture the unique bidding behavior of the energy market, the Integrated Model utilizes a dynamic bid adder algorithm that considers supply/demand conditions and technology type when submitting a bid. In replicating the actual bidding behavior, ABB captured three key elements:

- **Incremental Cost.** Includes fuel price, heat rate, and variable O&M. Under rational bidding, the incremental cost serves as a generator's minimum bid

- **Quasi-Rents Component.** Rent component added to the incremental cost to recover start-up costs, minimum-run costs, and a portion of fixed operating costs and financial expense.

- **Scarcity-Rents Component.** Rent component added to the incremental cost and quasi-rent. As demand increases, there are fewer alternative sources of generation, providing the higher cost generators an opportunity to bid above their variable cost.

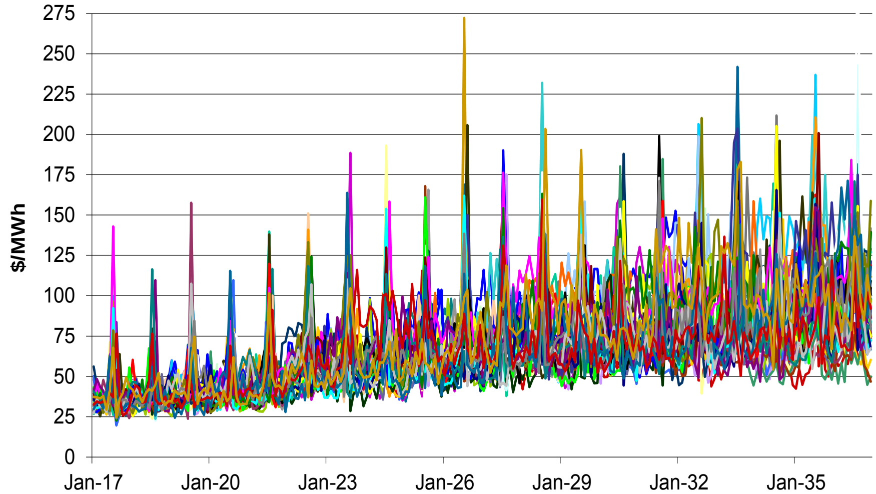
Stochastic Results

ABB's reference case database was combined with a set of 50 uncertainties that explicitly consider uncertainty in demand, fuel prices, supply, and emissions. These uncertainties were created with ABB's Smart Monte Carlo sampling program. The resulting fifty future scenarios were used by the Integrated Model to derive the multi-region, hourly market prices.

Monthly Results

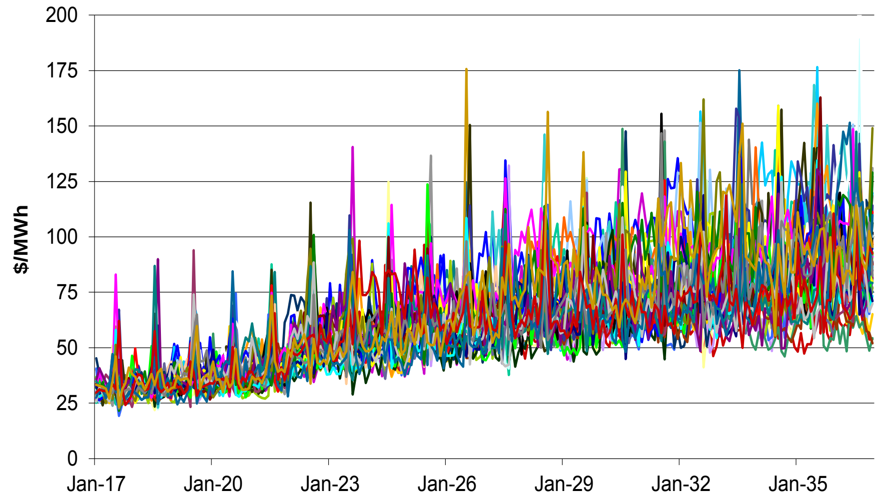
On-Peak and Average prices for the MISO-IN region are shown in Confidential Figure 5- and Confidential Figure 5-. These figures show the results for the 50 sets of stochastic draws.

Figure 5-4
MISO-IN On-Peak Stochastic Results



(Source: ABB Advisors)

Figure 5-5
MISO-IN Monthly Average Stochastic Results (7X24))



(Source: ABB Advisors)

6 SCENARIOS

The following resources were used in the Capacity Expansion Modeling. Unit characteristics were a combination of the Fall 2015 Reference Case and IPL sources. Capacities were modified for the combined cycle, nuclear unit and wind to represent partial unit ownership or a PPA option.

Table 6-1 - Confidential
Resources for Capacity Expansion Modeling (2015$)

To produce optimal resource plans, ABB and IPL identified six future scenarios which were built in the Capacity Expansion module to develop a portfolio for each scenario. The Initial Base Scenario had 2,500 MW of Wind without any constraints. IPL consulted its transmission planners to discuss potential issues with meeting voltage stability requirements to comply with NERC reliability standards. The planners recommended a minimum level of ~1200 MW natural gas fired generation on the IPL 138 kV transmission system to meet these requirements. The IRP team reviewed its minimum loading and developed a 1000 MW wind limit to align with min loads. In addition, the team suggested a limit of 250 MW per year based on procurement and construction constraints. The seven future scenarios screened by capacity expansion include the following:

1. Initial Base Scenario
   - Reference Case Gas, Market and Emission Prices for CO_2 Tax scenario
   - Base load forecast
   - Environmental Upgrade Pete 1-4 for NAAQS-SO_2 and CCR by 2018
   - Low cost of future environmental regulations for Pete 1-4
   - Retire HS GT 1&2 12/2023 and replace with small batteries to be used for blackstart
   - Retire HS 5&6 in 3/2031
   - Retire Pete 1 in 12/2032
   - Retire HS7 in 12/2033
   - Retire Pete 2 12/2034

2. Final Base Scenario
   - Same assumptions as Initial Base Scenario
   - Limit of 1000 MW of Wind for study period and 250 MW Year
   - Minimum ~1200 MW level of natural gas fired generation

3. Robust Economy Scenario
   - Reference Case High Gas Prices correlated with Market Prices and CO_2 Tax
   - High Load Forecast
   - Same retirements as in Initial Base Scenario

4. Recession Economy Scenario
   - Reference Case Low Gas Prices correlated with Market Prices and CO_2 Tax
   - Low Load Forecast
   -
   - Same retirements as in Initial Base Scenario

5. Strengthened Environmental Rules Scenario
   - Gas and Market Prices correlated with ICF Federal Legislation CO_2 Tax
   - Base Load Forecast
   -
   - High cost of future environmental regulations for Pete 1-4

6. High Customer Adoption of Distributed Generation Scenario

- Same assumptions as Initial Base Scenario
- Added 10 MW of Wind, 65 MW Community Solar and 75 MW CHP in each of the three years: 2022, 2025 & 2032

7. Quick Transition Scenario

- Reference Case Gas, Market and Emission Prices for CO_2 Tax scenario
- Base load forecast
- Upgrade Pete 1-4 in 2018
- Retire Pete 1 and Refuel Pete 2-4 in 2022
- Low cost of future environmental regulations for Pete 1-4
- Retire HS GT 1&2 12/2023
- Retire Pete 2-4, HS GT 4&5, HS 5&6, HS IC1, Pete IC 1-3 12/2029
- Adopt Maximum Achievable DSM

Table 6-2 below summarizes the optimal resource expansion plans developed by the Capacity Expansion module when simulated in Mixed Integer Linear Programming mode (MILP).

Table 6-2
Capacity Expansion Results

YEAR	Base Case	Robust Economy	Recession Economy	Strengthened Environmental Rules	High Customer Adoption of Distributed Generation	Quick Transition
2017	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW
2018	DSM - 17 MW	DSM - 22 MW	**Refuel Pete 1 - 4** DSM - 22 MW	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG** DSM - 22 MW	DSM - 17 MW	DSM - 28 MW
2019	DSM - 16 MW	DSM - 17 MW	DSM - 17 MW	DSM - 17 MW	DSM - 16 MW	DSM - 59 MW
2020	DSM - 12 MW	DSM - 12 MW	DSM - 12 MW	DSM - 12 MW Wind 500 MW PV 280 MW	DSM - 12 MW	DSM - 47 MW
2021	DSM - 15 MW	DSM - 10 MW	DSM - 10 MW	DSM - 10 MW	DSM - 15 MW	DSM - 52 MW
2022	DSM - 10 MW	DSM - 11 MW	DSM - 10 MW	DSM - 11 MW Wind 100 MW PV 50 MW	DSM - 10 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** DSM - 19 MW
2023	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 11 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 11 MW PV 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 18 MW
2024	DSM -11 MW	DSM -12 MW	DSM -11 MW	DSM -12 MW PV 10 MW	DSM -11 MW	DSM -16 MW
2025	DSM - 10 MW	DSM - 11 MW	DSM - 10 MW	DSM - 11 MW	DSM - 10 MW PV 65 MW Wind 10 MW CHP 75 MW	DSM - 18 MW
2026	DSM - 9 MW	DSM - 10 MW	DSM - 9 MW	DSM - 10 MW PV 10 MW	DSM - 9 MW	DSM - 18 MW

2027	DSM - 4 MW	DSM - 5 MW	DSM - 4 MW	DSM - 5 MW PV 10 MW	DSM - 4 MW	DSM - 13 MW
2028	DSM - 4 MW	DSM - 5 MW	DSM - 4 MW	DSM - 5 MW PV 10 MW	DSM - 4 MW	DSM - 13 MW
2029	DSM - 1 MW	DSM - 1 MW	DSM - 1 MW	DSM - 1 MW PV 10 MW	DSM - 1 MW	DSM - 10 MW
2030	**Retire HS 5&6 (-200MW) NG** DSM - 2 MW	**Retire HS 5&6 (-200MW) NG** DSM - 3 MW Wind 500 MW	**Retire HS 5&6 (-200MW) NG** DSM - 2 MW	**Retire HS 5&6 (-200MW) NG** DSM - 3 MW Wind 500 MW	**Retire HS 5&6 (-200MW) NG** DSM - 2 MW	**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** DSM - 12 MW Wind - 6000 MW Solar - 1146 MW Battery - 600 MW
2031	DSM - 3 MW	DSM - 3 MW Wind 500 MW Market 200 MW	DSM - 3 MW	DSM - 3 MW Wind 500 MW	DSM - 3 MW	DSM - 13 MW
2032	**Retire Pete 1 (-234 MW) Coal** DSM - 9 MW	**Retire Pete 1 (-234 MW) Coal** DSM - 10 MW Wind 500 MW PV 370 MW	**Retire Pete 1 (-234 MW) Coal** DSM - 9 MW	DSM - 10 MW Wind 500 MW	**Retire Pete 1 (-234 MW) Coal** DSM - 9 MW PV 65 MW Wind 510 MW CHP 75 MW	DSM - 18 MW
2033	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 250 MW Market 50 MW PV 90 MW Battery 100 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 500 MW PV 440 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 500 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 500 MW	**Retire HS7 (-428 MW) NG** DSM - 16 MW
2034	**Retire Pete 2 (-417 MW) Coal** DSM - 2 MW H-Class CC 450 MW Wind 250 MW	**Retire Pete 2 (-417 MW) Coal** DSM - 3 MW H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) NG** DSM - 2 MW H-Class CC 450 MW	**Retire Pete 2 (-417 MW) NG** DSM - 3 MW H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) Coal** DSM - 2 MW H-Class CC 450 MW Wind 500 MW	DSM - 9 MW H-Class CC 450 MW
2035	DSM - 2 MW Wind 250 MW Battery 250 MW Market 150 MW	DSM - 3 MW Wind 500 MW PV 190 MW Battery 250 MW Market 50 MW Comm Solar 1 MW	DSM - 2 MW H Class CC 200 MW	DSM - 3 MW Wind 500 MW PV 70 MW Market 50 MW	DSM - 2 MW Wind 500 MW Battery 50 MW Market 50 MW	DSM - 11 MW
2036	DSM - 2 MW Wind 250 MW Battery 150 MW PV 10 MW	DSM - 3 MW Wind 500 MW Battery 50 MW Comm Solar 5 MW	DSM - 2 MW	DSM - 3 MW Wind 500 MW PV 60 MW	DSM - 2 MW Wind 500 MW PV 60 MW Comm Solar 1 MW	DSM - 12 MW
	*DSM includes 58.1 MW of existing Demand Response					

(Source: ABB Advisors.)

The Final Base Plan and other scenarios were evaluated further using the production cost model
Strategic Planning.

7 DSM MODELING IN CAPACITY EXPANSION

Avoided Energy Costs

IPL's primary objective in performing its integrated resource plan is to find a mix of supply-side resources and demand-side management (DSM) programs that minimize the costs to customers presented in terms of the present value of revenue requirements (PVRR). The screening of DSM measures was performed by Applied Energy Group, Inc. (AEG) using avoided energy costs developed by ABB. The DSM measures that passed the AEG screening tests were input into the CEM as similar bundles of demand-side resources. CEM optimized both supply-side and demand-side resource completely enumerating all possible combinations and developing least cost integrated resource plans. This technique was used to develop the resource plans under the conditions described earlier in the Scenarios section of this report.

AEG used ABB's forward view of the demand and energy costs in the MISO-IN regional electricity market for screening. The following figure show the avoided energy costs for the CO_2 Tax Scenario. For more information on how the avoided costs were developed, please see section 2, Market Price Process.

Figure 7-1 - Confidential
Monthly On-Peak, Off-Peak and Average Avoided Energy Cost (Nominal $/MWh)

DSM Alternatives after Avoided Cost Screening

The DSM bundles that passed AEG's screening tests and were then passed on to ABB's CEM as a selectable resource are listed in Table 7-1. Some bundles were available for selection in the 2018-2020 time frame and some were available for selection in the 2021 and beyond time frame:

Table 7-1
DSM Bundles

Residential	Commercial	Direct Response
Res Other up to 30MWh 2018-2020	Bus Process up to 30MWh 2018-2020	DR Water Heating DLC
Res Other 30-60MWh 2018-2020	Bus Process 30-60MWh 2018-2020	DR Smart Thermostats
Res Lighting up to 30MWh 2018-2020	Bus Other up to 30MWh 2018-2020	DR Emerging Tech
Res HVAC up to 30MWh 2018-2020	Bus Other 60+ MWh 2018-2020	DR Curtail Agreements
Res HVAC 60+ MWh 2018-2020	Bus Other 30-60MWh 2018-2020	DR Battery Storage
Res HVAC 30-60MWh 2018-2020	Bus Lighting up to 30MWh 2018-2020	DR Air Conditioning Load Mgmt
Res Behavioral Program 2018-2020	Bus Lighting 60+ MWh 2018-2020	
Res Other up to 30MWh 2021+	Bus Lighting 30-60MWh 2018-2020	
Res Other 30-60MWh 2021+	Bus HVAC up to 30MWh 2018-2020	
Res Lighting up to 30MWh 2021+	Bus HVAC 60+ MWh 2018-2020	
Res HVAC up to 30MWh 2021+	Bus HVAC 30-60MWh 2018-20	
Res HVAC 60+ MWh 2021+	Bus Process up to 30MWh 2021+	
Res HVAC 30-60MWh 2021+	Bus Process 30-60MWh 2021+	
Res Behavioral Programs 2021+	Bus Other up to 30MWh 2021+	
	Bus Other 60+ MWh 2021+	
	Bus Other 30-60MWh 2021+	
	Bus Lighting up to 30MWh 2021+	
	Bus Lighting 60+ MWh 2021+	
	Bus Lighting 30-60MWh 2021+	
	Bus HVAC up to 30MWh 2021+	

	Bus HVAC 60+ MWh 2021+	
	Bus HVAC 30-60MWh 2021+	

The DSM bundles that were selected by the Capacity Expansion model and passed on to the portfolio evaluation for each scenario are in the following table. Note that the Quick Transition Scenario did not exclude any of the DSM bundles identified in Table 7-1 above.

Table 7-2
DSM Program by Scenario

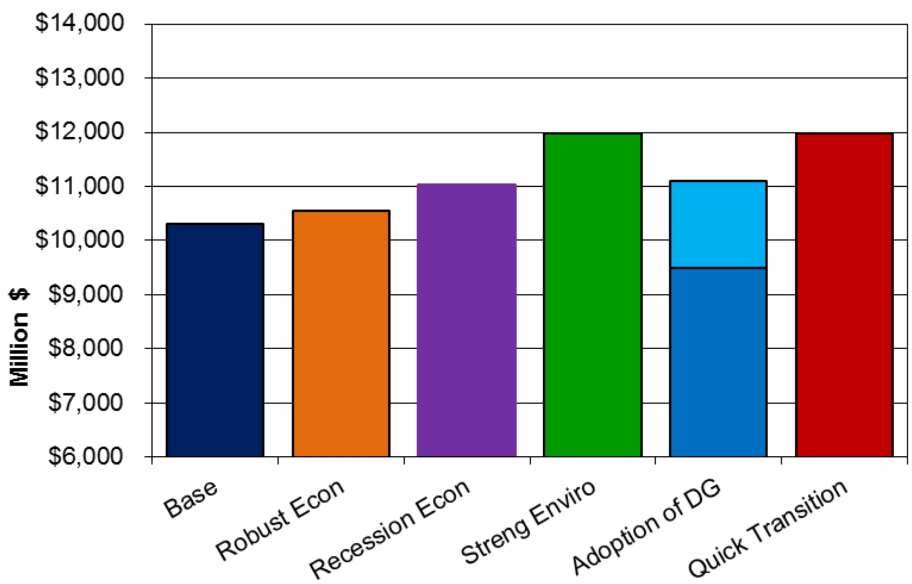
	Final Base	Robust Economy	Recession Economy	Strengthened Environmental Rules	Adoption of DG	Quick Transition
Res Other (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res Other ($30-60/MWh) - 2018-2020		✓		✓		✓
Res Lighting (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res HVAC (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res Behavioral Programs - 2018-2020		✓	✓	✓		✓
Bus Other (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Bus Lighting (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Bus HVAC (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res Other (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Res Lighting (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Res HVAC (up to $30/MWh) - 2021-2036		✓		✓		✓
Res Behavioral Programs - 2021-2036	✓	✓	✓	✓	✓	✓
Bus Process (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Bus Other (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Bus Lighting (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓

8 DETERMINISTIC PORTFOLIO RESULTS

The following series of graphs compares the deterministic results for the six scenario, which were modeled with the Production Cost Model. IPL used several metrics to compare the portfolios, including PVRR, rate impact, and planning reserve margins. Figure 8-1 shows the PVRR for each scenario under base case assumptions. These values are in millions $: Final Base Plan $10,309.02, Robust Economy $10,549.54, Recession Economy $11,042.06, Strengthened Environmental Rules $11,989.88, Adoption of DG $11,092.05, Quick Transition $11,988.14. The Adoption of DG scenario includes estimated DG costs for 450 MW. These costs are represented in the light blue block. Customer DG costs will vary.

Table 8-1 contains the incremental average annual revenue requirements in cents/kWh for the six scenarios. These prices are for resource plan comparative purposes and do not reflect the total revenue requirements of the IPL business. These prices include the costs of all fuel, variable O&M, and emission expenses, capacity and energy purchases for retail load (net of capacity and energy sales), property taxes, state and federal income taxes, and annual some generating unit fixed costs.

Figure 8-1
Scenario PVRR (2017-2036)



(Source: ABB Advisors.)

Table 8-1
Comparative Annual Costs by Scenario

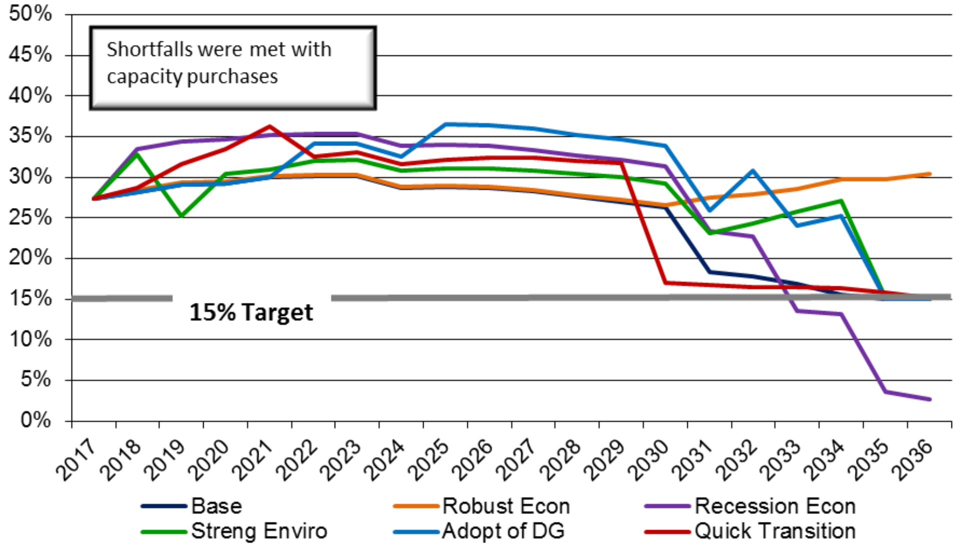
Incremental Average Annual Revenue Requirements (cents/kWh, in nominal $

Year	Final Base Plan	Robust Economy	Recession Economy	Strengthened Environmental Rules	Adoption of DG	Quick Transition
2017	0.032	0.032	0.032	0.032	0.032	0.032
2018	0.034	0.034	0.037	0.036	0.034	0.035
2019	0.036	0.036	0.040	0.045	0.036	0.038
2020	0.035	0.035	0.042	0.057	0.035	0.038
2021	0.036	0.036	0.044	0.055	0.036	0.040
2022	0.048	0.048	0.054	0.064	0.051	0.058
2023	0.051	0.051	0.057	0.066	0.055	0.060
2024	0.052	0.052	0.059	0.066	0.056	0.061
2025	0.060	0.060	0.065	0.071	0.066	0.066
2026	0.063	0.062	0.067	0.072	0.070	0.068
2027	0.064	0.064	0.069	0.073	0.070	0.070
2028	0.070	0.070	0.073	0.076	0.076	0.074
2029	0.072	0.072	0.076	0.078	0.078	0.077
2030	0.077	0.079	0.079	0.081	0.082	0.113
2031	0.081	0.086	0.083	0.089	0.086	0.122
2032	0.083	0.090	0.085	0.092	0.092	0.116
2033	0.088	0.096	0.089	0.095	0.100	0.112
2034	0.094	0.102	0.096	0.099	0.106	0.109
2035	0.102	0.107	0.104	0.106	0.113	0.108
2036	0.104	0.108	0.108	0.105	0.114	0.106

(Source: ABB Advisors.)

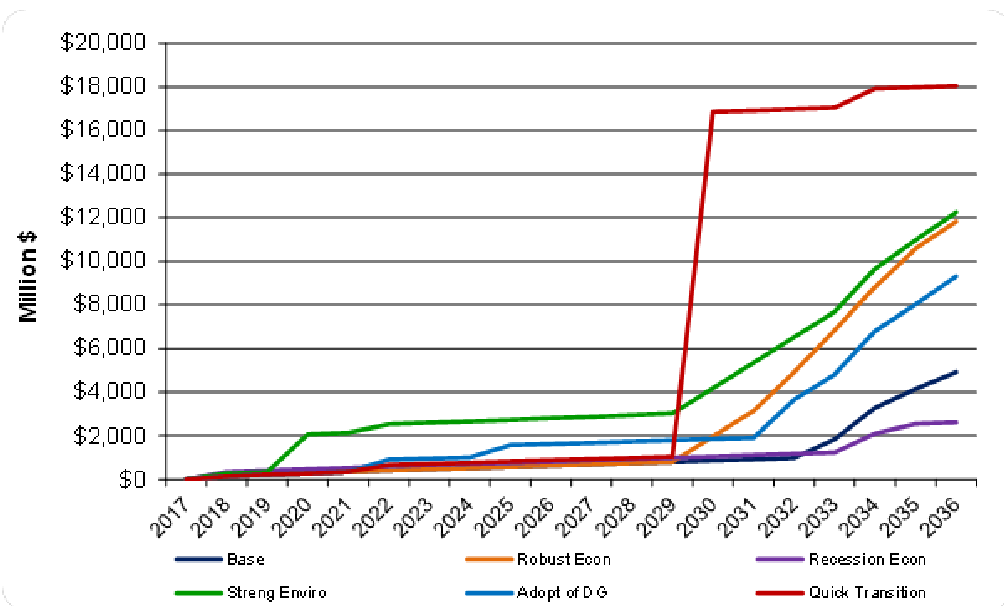
The following graphs compare the reserve margins and cumulative capital expenditures (plant in service) for all portfolios. For the reserve margin calculations, all portfolios utilize the base load assumption. Incremental plant in service includes annual capital expenditures and AFUDC closed to plant.

Figure 8-2
Reserve Margin (IPL Installed Planning Capacity)



(Source: ABB Advisors.)

Figure 8-3
Incremental Plant In-Service (in nominal $, includes DG costs, no depreciation



(Source: ABB Advisors.)

9 DETERMINISTIC PORTFOLIO RESULTS WITH END EFFECTS

End Effects

Strategic Planning (SP) is able to capture end effects. The process within SP to capture end effects consists of running the simulation beyond the study period. When conducting integrated resource planning and active evaluation of constructing base load generating facilities, it is critical to properly evaluate the cost effectiveness of resource additions by extending the planning horizon.

ABB developed a methodology that allows users to reflect an extension period where operational variables are constant and financial calculations continue.

Terms:

- <u>Study Period:</u> the time period over which all simulation features including resource expansion, changes in demand and retirements are measured.
- <u>Extension Period:</u> the time period directly after the study period over which resource expansion, changes to demand and other factors are held constant, while costs, revenues and financial treatments may change.
- <u>End Effects:</u> the impact on decisions made during the study period based upon the presence of costs, revenues and financial treatments occurring in the extension period.

For IPL, ABB utilized a study period of 2017-2036. To capture additional economic life of new resources added, SP simulations were for the period 2017-2046.

The end effects methodology may be explained by disaggregating the total study horizon into the study and extension period. In the study period, the model performs a full simulation of all key elements of the utility portfolio. Resource expansion (and retirement) decisions are made either explicitly or implicitly; demand may vary from year-to-year; the production system performs commitment and dispatch of resources is modeled against load, and so on.

In the extension period, SP continues with a “static” resource expansion scenario over the extension period. Costs are permitted to escalate either according to user-defined assumptions or according to “last year escalation changes” as defined below. Full commitment and dispatch of the model occurs, permitting dispatch that reflects long-run technology changes, as well as a full treatment of the financial assets. Thus, a capital project added in the last year of the simulation will receive a full treatment of capital, taxes and depreciation as well as the costs and revenues (and dispatch/commitment impact on the existing system).

The SP extension period methodology provides a strong representation of the year-to-year elements of the system to properly capture the relative benefits of resources added during the forecast horizon.

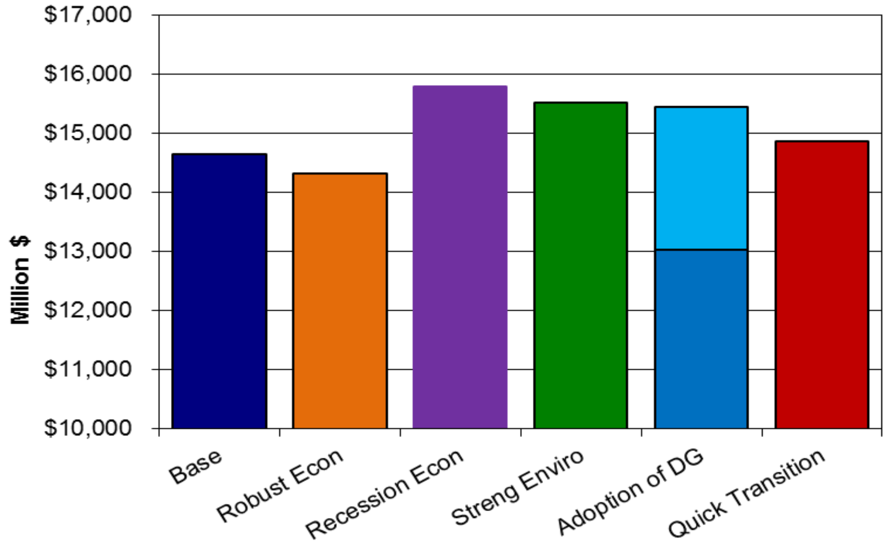
Table 9-1
Extension Period Treatment

	Study Period				Extension Period		
	Year 1	**Year 2**	**Year …**	**Year T**	**Year T+ 1**	**Year T + …**	**Year T + n**
Revenue	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Fuel Expense	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Variable O&M	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Emissions	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Total Expenses	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Capital Treatment	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Tax and Interest	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Commitment	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dispatch	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Resource Expansion	Yes	Yes	Yes	Yes	Static	Static	Static
Retirements	Yes	Yes	Yes	Yes	Static	Static	Static
Demand Growth	Yes	Yes	Yes	Yes	Static	Static	Static
Purchases & Sales	Yes	Yes	Yes	Yes	Yes	Yes	Yes

(Source: ABB Advisors.)

Figure 9-1 shows the PVRRs for the six scenarios with end effects. Again, the Adoption of DG scenario includes estimated DG costs for 450 MW. These costs are represented in the light blue block. Customer DG costs will vary.

Figure 9-1
Scenario PVRRs with End Effects (2017-2046)



(Source: ABB Advisors.)

10 RISK ANALYSIS

Introduction

ABB utilized the Strategic Planning Risk Module to develop cumulative probability distributions which are also known as Risk Profiles.

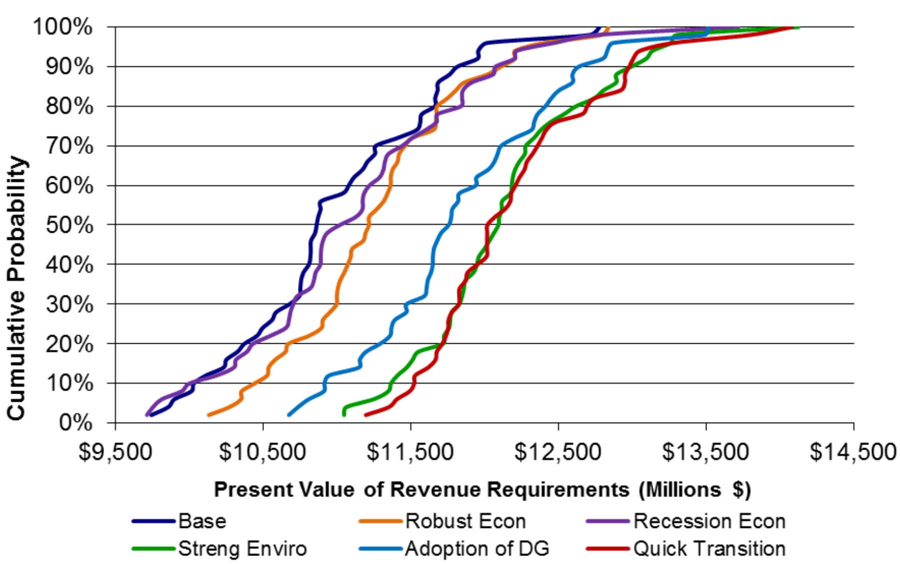
Risk Profiles

Risk Profiles provide the ability to visually assess the risks associated with a decision under uncertainty. The x-axis (Present Value of Revenue Requirements in millions $) shows the range of possible outcomes from the fifty stochastic draws. The y-axis is the cumulative probability of the occurrence of each outcome between 0% and 100%. For example, if the far left point is $9,745 mil and the far right point is $12,777 mil, then there is 100% confidence that the PVRR will be between those two points. The more narrow the range, the less the risk. For this study, ABB used its Integrated Model to develop a set of 50 stochastic prices using ABB's Smart Monte Carlo sampling program. These prices explicitly consider uncertainty in demand, fuel prices, supply, and emissions.

One can view the risk profile to determine the probability that the PVRR will be a particular value. Using the Final Base Plan as an example in the figure below, there is an 80% probability that PVRR could be as much as $11,682 million with an expected value of $11,005 million. From the prior deterministic simulation, the PVRR value was $10,309 million under "base case" conditions. The $696 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of the Preferred Plan with future uncertainty.

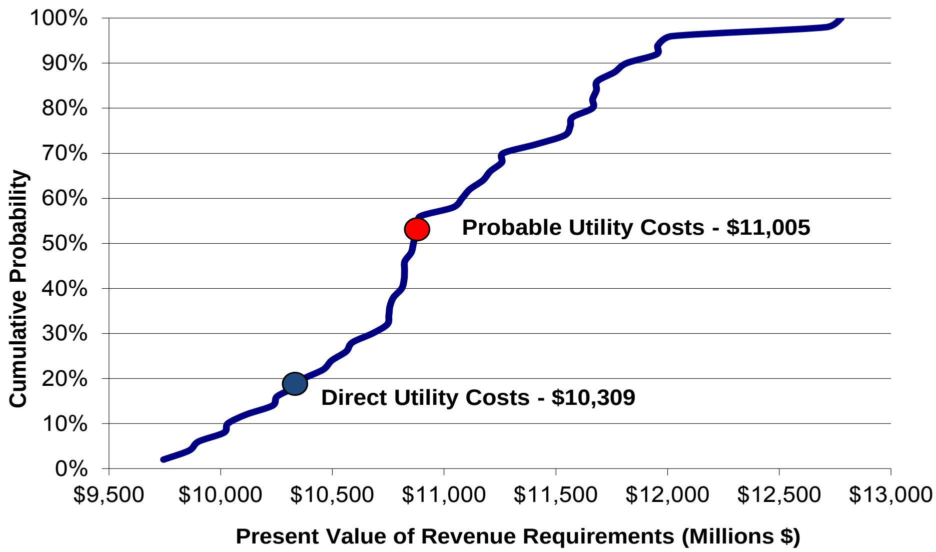
The risk profiles are labeled with two points. The "Direct Utility Cost" (Deterministic) point is the base case, and the "Probable Utility Cost" (Stochastic or Expected Value) point is the average of all 50 uncertain outcomes.

Figure 10-1
All Scenarios - Risk Profiles (2017-2036)



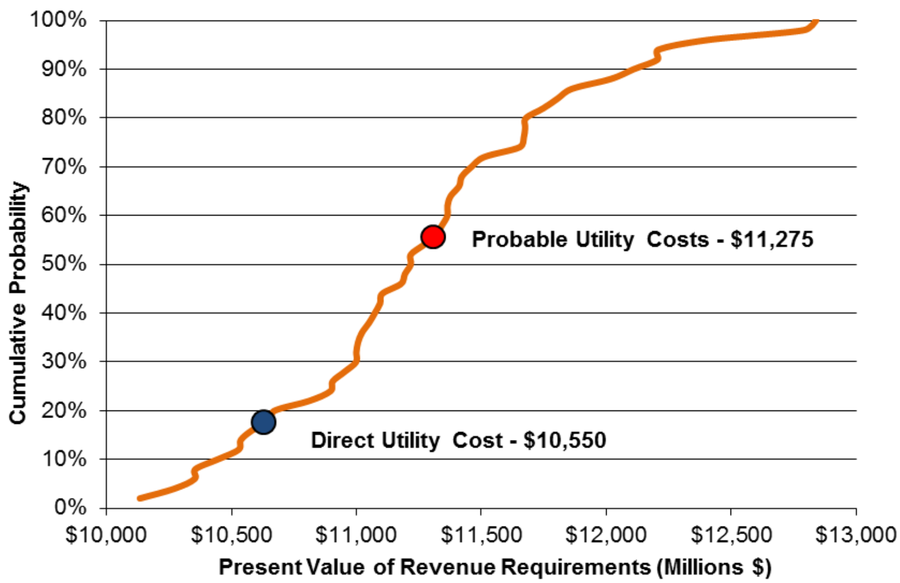
(Source: ABB Advisors.)

Figure 10-2
Base Plan - Risk Profile (2017-2036)



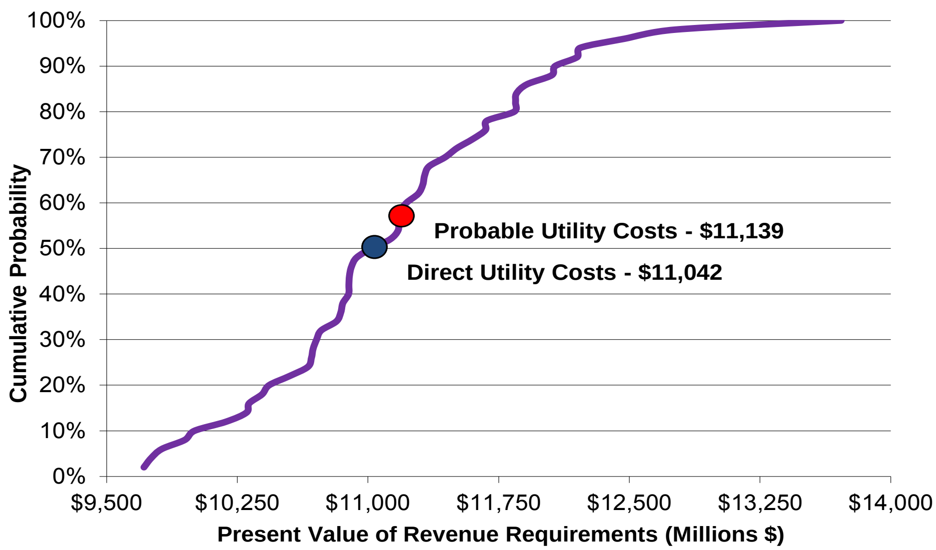
(Source: ABB Advisors.)

Figure 10-3
Robust Economy - Risk Profile (2017-2036)



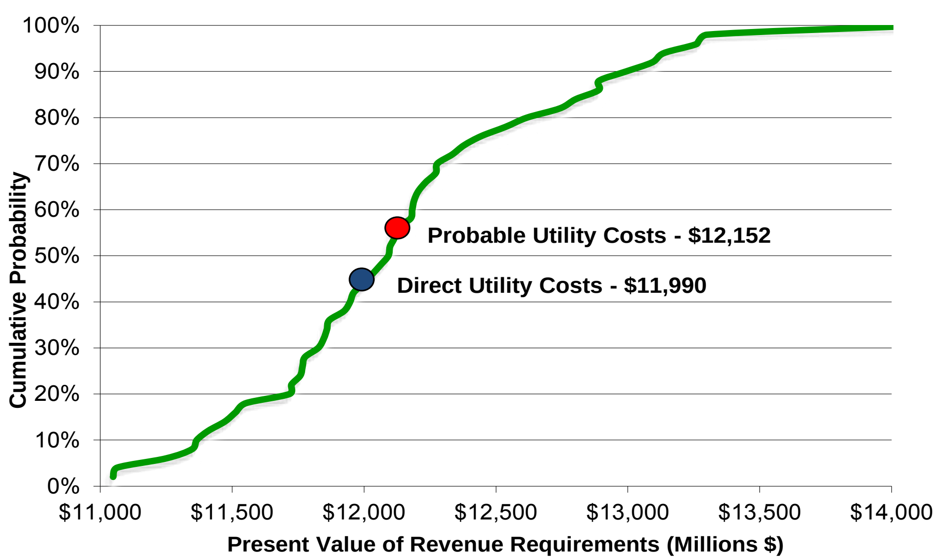
(Source: ABB Advisors.)

Figure 10-4
Recession Economy - Risk Profile (2017-2036)



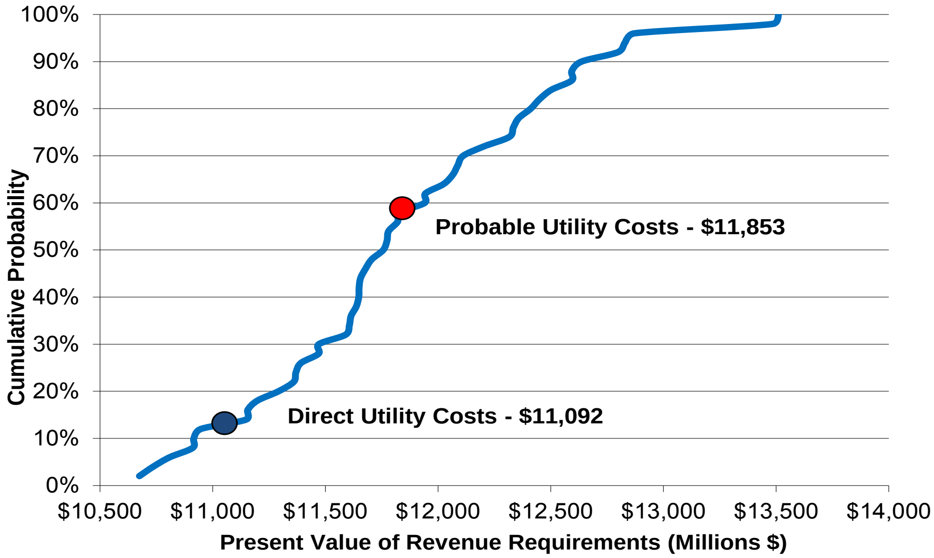
(Source: ABB Advisors.)

Figure 10-5
Strengthened Environmental - Risk Profile (2017-2036)



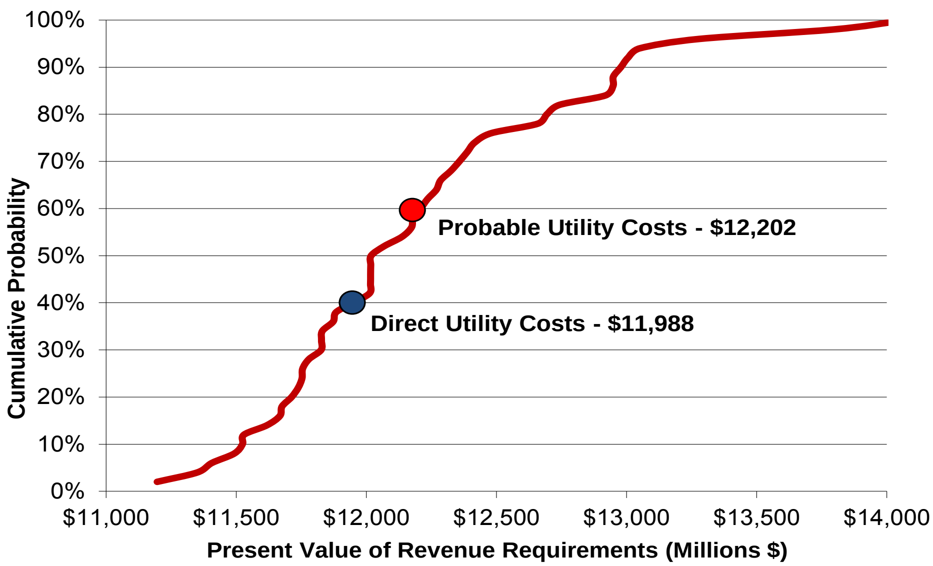
(Source: ABB Advisors.)

Figure 10-6
Adoption of DG - Risk Profile (2017-2036)



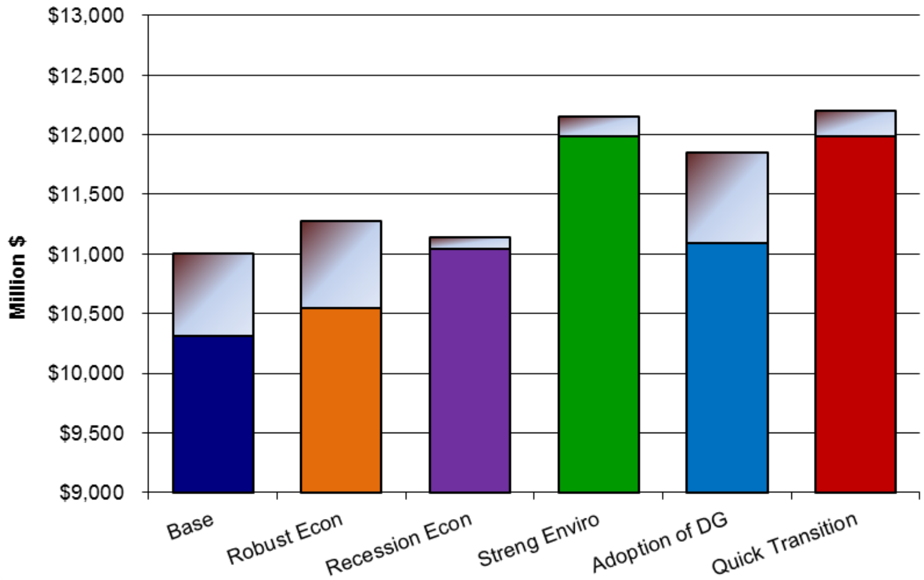
(Source: ABB Advisors.)

Figure 10-7
Quick Transition - Risk Profile (2017-2036)



(Source: ABB Advisors.)

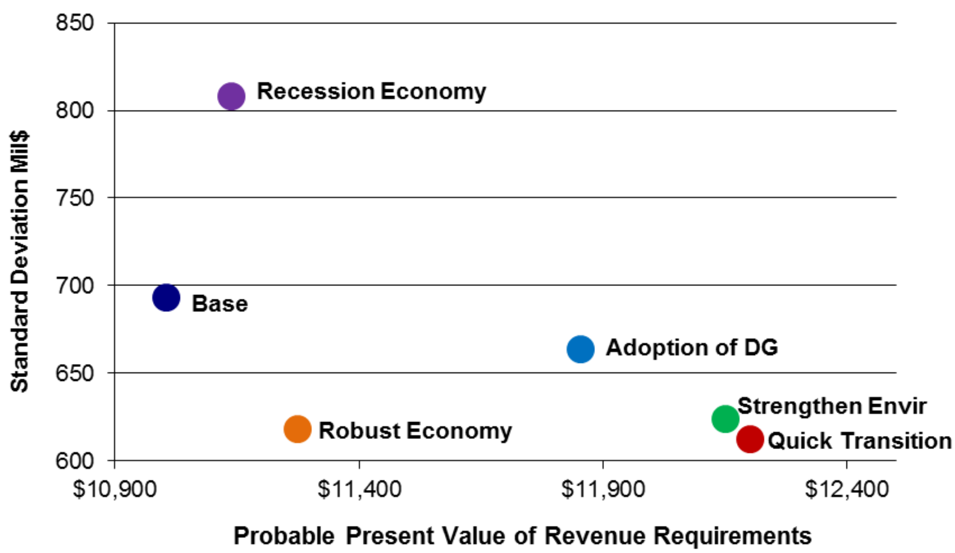
Figure 10-8
All Scenarios - PVRR with Risk Value (2017-2036)



(Source: ABB Advisors.)

The following trade-off diagram is another way to compare the six plans. The trade-off diagram plots the PVRRs on the x-axis and the standard deviation on the y-axis. The plan closest to the lower left quadrant would be the preferred plan because both PVRR and the standard deviation are both minimized.

Figure 10-9
All Scenarios - Trade-Off Diagram



(Source: ABB Advisors.)

11 BASE SENSITIVITY ANALYSIS

CO_2 Sensitivities

Two carbon sensitivities were modeled around the base case.

Case 1 – “Delayed CPP” - Timing of Clean Power Plan

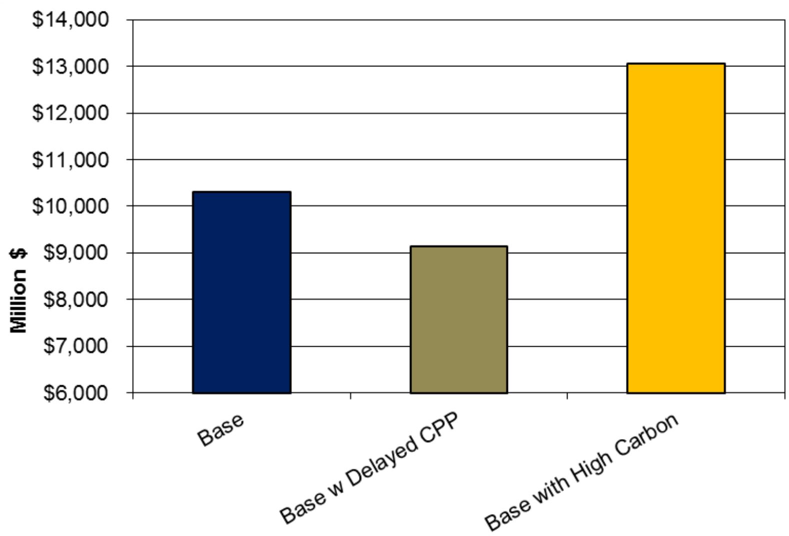
- Same modeling assumption as base plan with CPP starting in 2030 instead of 2022

Case 2 –“ICF Carbon” - More Stringent Clean Power Plan

- Same modeling assumption as base plan except used ICF’s Federal Legislation carbon price and market prices.

The following graph compares the results for the 2 cases against the Final Base Plan. Figure 11-1 shows the PVRR for each plan for the base scenario. These values are in millions $: Final Base Plan $10,309.02, Case 1 $9,129.93, Case 2 $13,054.86.

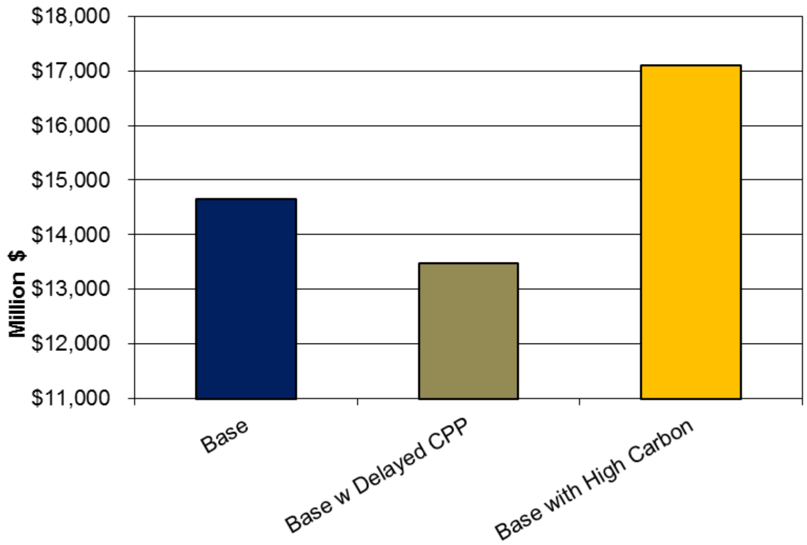
Figure 11-1
PVRR Case Ranking for the Base Case Scenario (2017-2036)



(Source: ABB Advisors.)

Figure 12-2 contains the PVRR for each plan for the base scenario with end effects. These values are in millions $: Final Base Plan $14,651.63, Case 1 $13,472.54, Case 2 $17,089.33.

Figure 11-2
PVRR Case Ranking for the Base Case Scenario (2017-2046)



(Source: ABB Advisors.)

12 SENSITIVITY

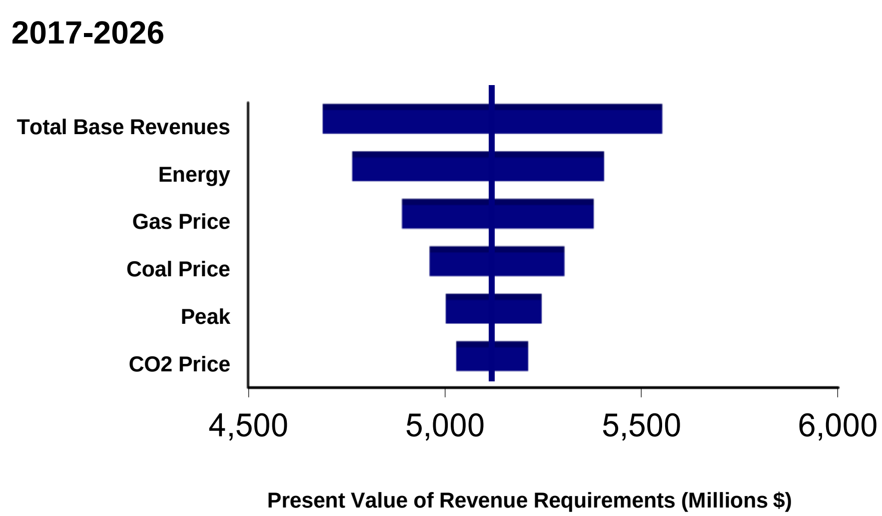
Tornado Charts

Tornado Charts provide information on the driving factors that influence PVRR and can also provide insight into where a risk aversion strategy could be focused to drive PVRR to lower levels or mitigate risk. The Total Base Revenue bar is the dependent variable and the remaining drivers are independent variables. The expected value is represented by the vertical line. When the independent bars are off-set to the left it means that the variable puts downward pressure on the PVRR (lower revenue requirements). If the independent bars are off-set to the right, then the variables put upward pressure on the PVRR (higher revenue requirements).

The tornado charts were developed in 10-year blocks for the stochastic results. There are not any substantial changes for the system in the first ten years. In the last ten years, the CO2 tax begins to have a larger impact on the unit dispatch and there are multiple unit additions and retirements.

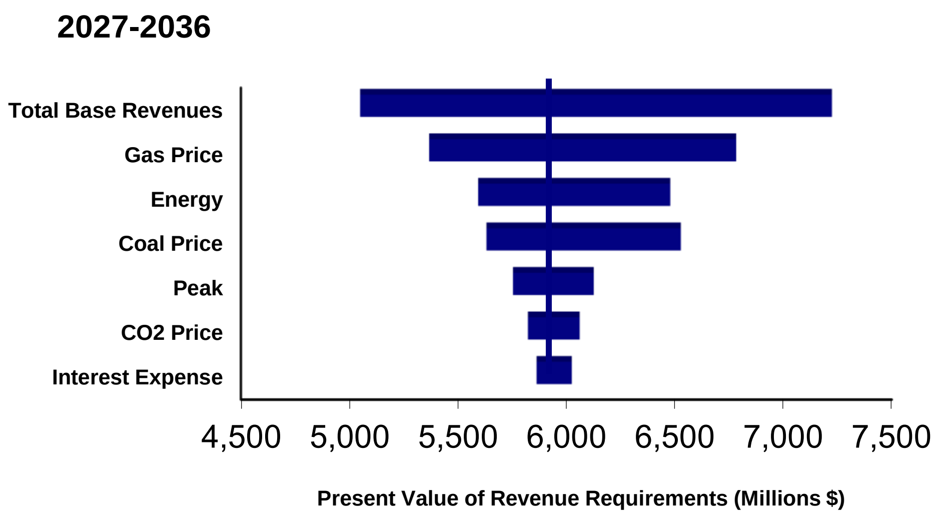
For all of the scenarios in the first ten years, their Tornado Charts indicate that the major driver of PVRR uncertainty is either gas price or energy. Again, for all the scenarios in the last ten years, their Tornado Charts indicate the major driver of PVRR uncertainty is either gas price or energy. The second major driver varies by scenario. For example, for the Quick Transition scenario, interest expense is the second major driver because of the very large capital expenditures in 2030.

Figure 12-1
Final Base Plan - Tornado Chart (2017-2026)



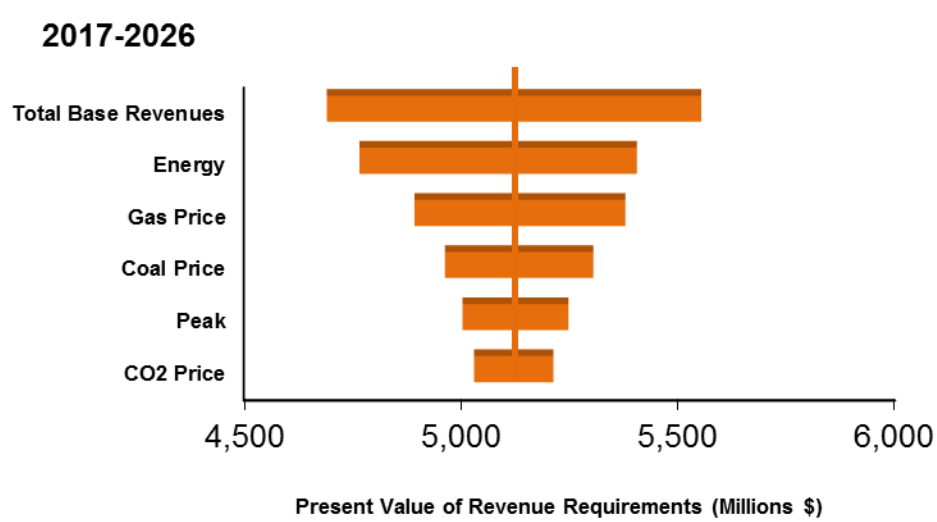
(Source: ABB Advisors.)

Figure 12-2
Final Base Plan - Tornado Chart (2027-2036)



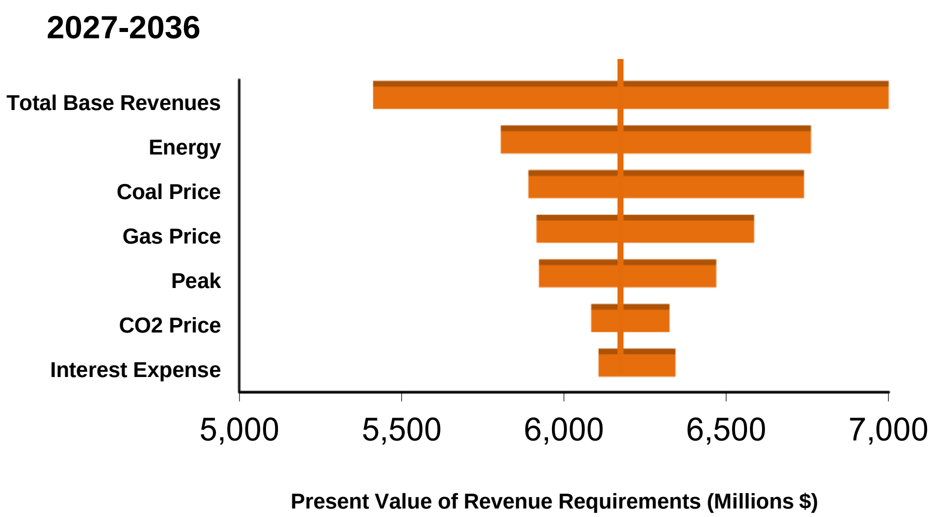
(Source: ABB Advisors.)

Figure 12-3
Robust Economy - Tornado Chart (2017-2026)



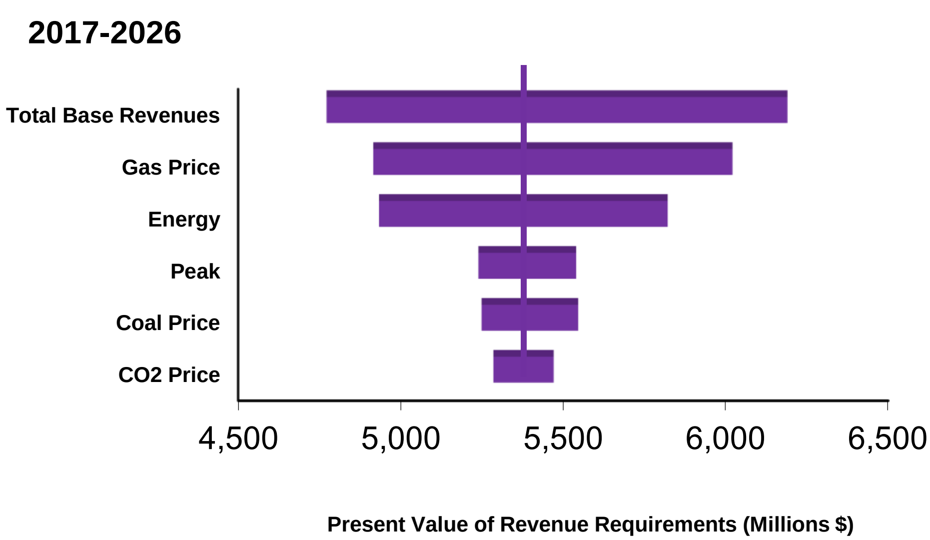
(Source: ABB Advisors.)

Figure 12-4
Robust Economy - Tornado Chart (2027-2036)



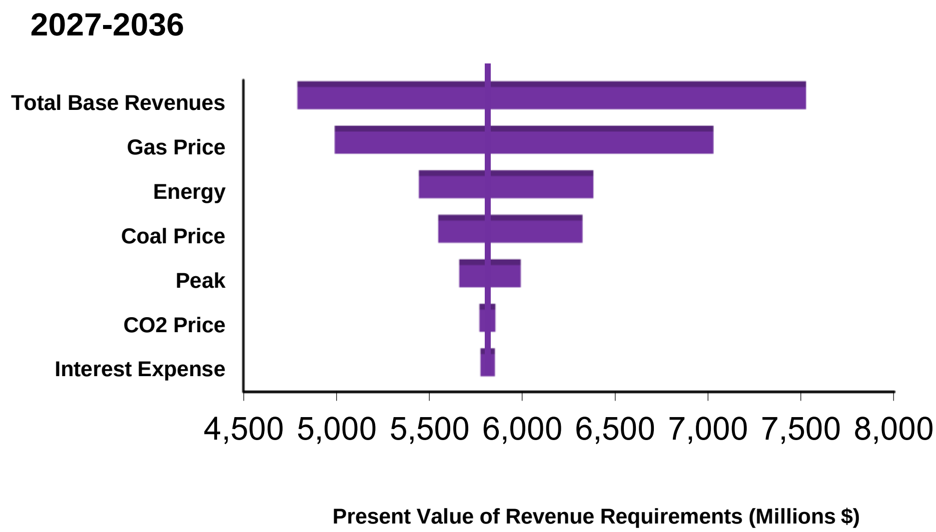
(Source: ABB Advisors.)

Figure 12-5
Recession Economy - Tornado Chart (2017-2026)



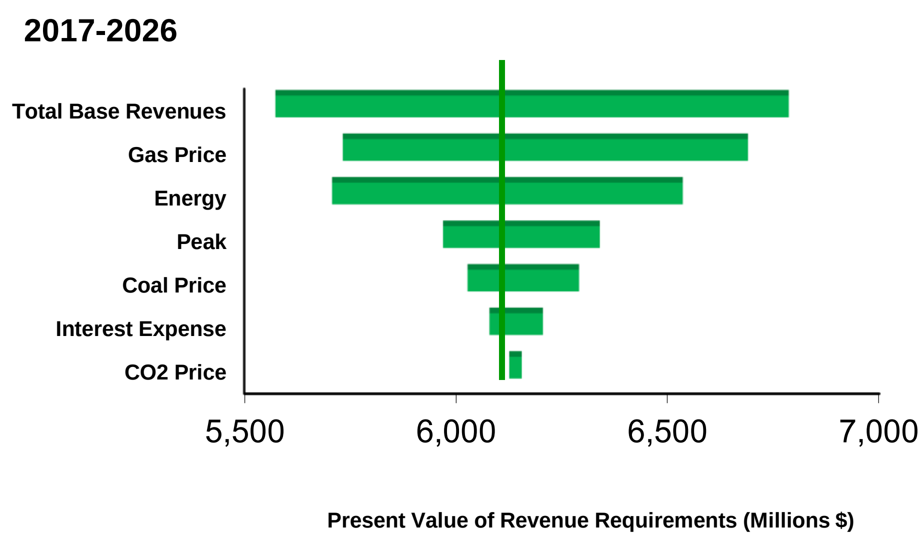
(Source: ABB Advisors.)

Figure 12-6
Recession Economy - Tornado Chart (2027-2036)



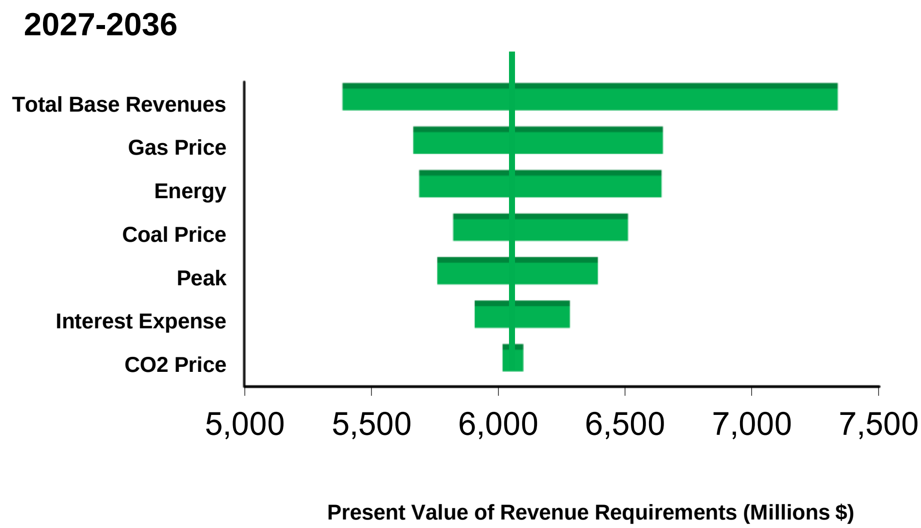
(Source: ABB Advisors.)

Figure 12-7
Strengthened Environmental - Tornado Chart (2017-2026)



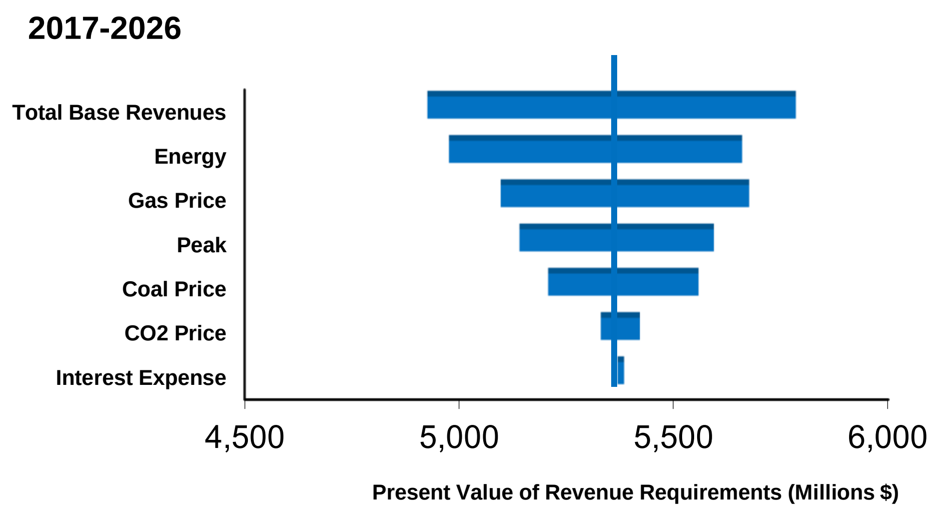
(Source: ABB Advisors.)

Figure 12-8
Strengthened Environmental - Tornado Chart (2027-2036)



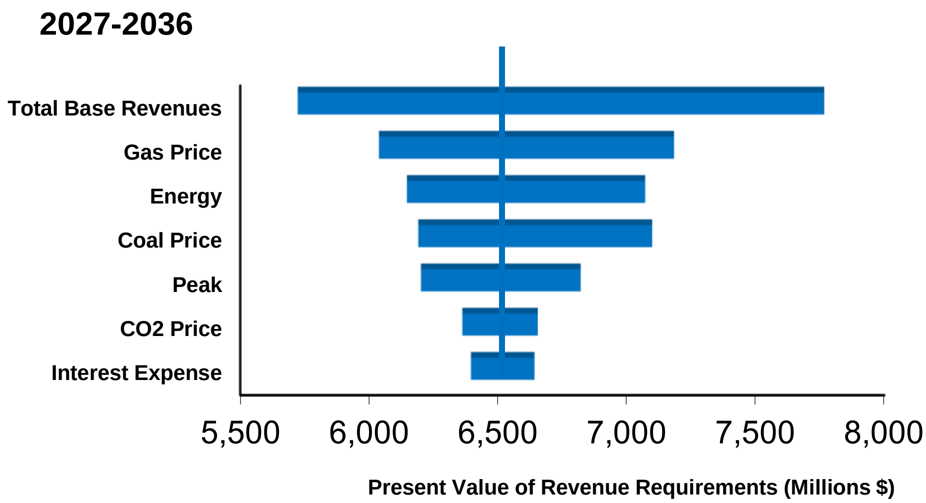
(Source: ABB Advisors.)

Figure 12-9
Adoption of DG - Tornado Chart (2017-2026)



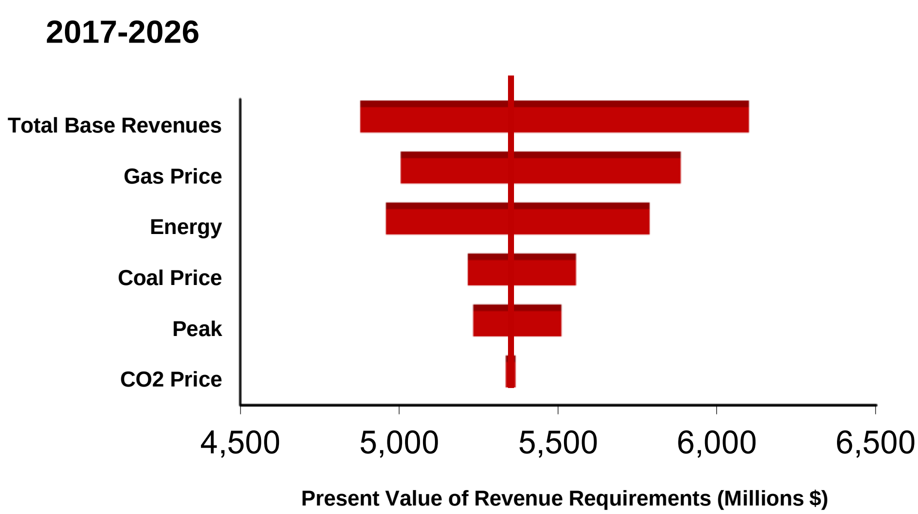
(Source: ABB Advisors.)

Figure 12-10
Adoption of DG - Tornado Chart (2027-2036)



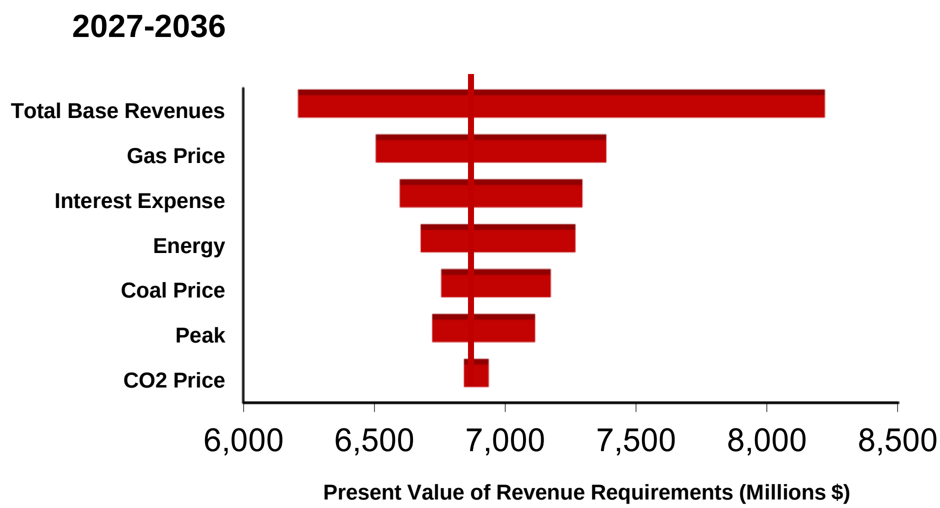
(Source: ABB Advisors.)

Figure 12-11
Quick Transition - Tornado Chart (2017-2026)



(Source: ABB Advisors.)

Figure 12-12
Quick Transition - Tornado Chart (2027-2036)



(Source: ABB Advisors.)

13 SOFTWARE USED FOR ABB REFERENCE CASE

Forecasting Methodology

The ABB Reference Case includes market-based forecasts of North American power, fuel, emission allowance, and renewable energy credit prices that are internally consistent with one another; that is:

- Natural gas and coal prices that are internally consistent with the associated power sector consumption of each fuel;
- Capacity additions, retirements, and retrofits that are internally consistent with the allowance and fuel prices;
- Electric energy and capacity prices that are internally consistent with the capacity additions, etc., and allowance and fuel prices; and
- Renewable energy credit prices that are internally consistent with state renewable portfolio standards and electric energy and capacity prices.

Module Descriptions

The following paragraphs describe the key aspects of each of the five modules of the Integrated Model comprising the forecasting process.

Power Module

The Power Module is a zonal model of the North American interconnected power system spanning 70 zones. The Module simulates separate hourly energy and annual capacity markets in all zones. The Module simulates the operations of individual generating units, i.e., not aggregations of units. The Power Module comprises two components, which simulate 1) operations; and 2) conventional power plant capacity additions.

Operations Component

For given assumptions such as generating unit characteristics described below, the Operations Component simulates a constrained least-cost dispatch of all of the power plants in the system, taking into account hourly loads, operating parameters and constraints of the units, and transmission constraints.

Investment Component

For a given set of the values of variables from the Operations Component, such as hourly electric energy prices, the Investment Component simulates the conventional power plant capacity additions likely to occur in the market:

- For capacity additions, the Investment Component identifies the additions that would be profitable in each zone based solely on first-year economics; i.e., without taking into account reserve margins and the associated capacity payments. The test for such additions is that energy market revenues are greater than the sum of 1) expenses for fuel, emission allowances, variable Operations and Maintenance (O&M), and fixed O&M; and 2) amortized capital costs. Once all such economic capacity additions have been made, the Investment Component identifies zones and groups of zones for which reserve margins are not satisfied. For each such deficiency, the Investment Component then identifies the set of capacity additions that 1) together satisfy the reserve margin requirement, and 2) require the lowest first-year capacity payment, as discussed below. Capacity additions can result in actual reserve margins above target reserve margins.

- The annual capacity price in each zone is calculated as the amount, measured in dollars per kW-year that the marginal unit in the zone required to satisfy the reserve margin would need over and above energy market revenues to break even financially, including the amortized capital cost of the unit.

Fuels Module

The Fuels Module comprises three sub-modules, one each for oil, natural gas, and coal.

Oil Sub-Module

U.S. crude oil prices are based on conditions in the world oil market. Based on extensive prior analysis, ABB Advisors believes that the feedback to the world oil market from the markets represented in the North American forecast, i.e., power, natural gas, coal, and emissions, is extremely weak. Moreover, the effects on the world oil market of the types of policies or exogenous events that might be modeled, such as a CO_2 cap-and-trade program, are also very weak. As a result, ABB Advisors believes it is appropriate to treat the world oil market—and more specifically U.S. crude oil prices—as an exogenous input, as opposed to modeling it explicitly. ABB Advisors currently use the forecast of West Texas Intermediate (WTI) price from the U.S. Energy Information Administration's (EIA) most recent Annual Energy Outlook. We generate forecasts of region-specific prices for refined oil products burned in power plants, e.g., diesel and residual, based on an analysis of historical relationships between these prices and the WTI price.

Natural Gas Sub-Module

The Natural Gas Sub-Module produces forecasts of monthly natural gas prices at individual pricing hubs. The Operations Component consists of a model of the aggregate U.S. natural gas sector. For each month and iteration, it executes in the following manner:

- The Operations Component includes an econometric model of Lower 48 demand in each of the sectors other than power, relating monthly consumption to the Henry Hub price.

- For each iteration of the Operations Module, natural gas demand by the power sector is taken from the prior iteration of the Power Module.

- LNG supply is forecast using proprietary global LNG model and Henry Hub prices from the previous iteration. This model utilizes forecasts of global LNG demand and supply.

- Domestic supply is represented in the Operations Components by exogenous Lower 48 production declines and exogenous assumptions about deliveries from Alaska; a pair of econometric equations relating Lower 48 productive capacity additions to Henry Hub prices in previous months and Lower 48 capacity utilization to the current Henry Hub/WTI price; and net storage withdrawals to balance supply and demand to the extent available storage capacity will permit.

- The Henry Hub price is simulated as the price that balances demand and supply, including net storage withdrawals.

Coal Sub-Module

The Coal Sub-Module utilizes a network LP that satisfies, at least possible cost, the demand for coal at individual power plants with supply from existing mines using the available modes of transportation. For each year and iteration, the Sub-Module executes in the following manner:

- For each iteration, demand by each power generating plant is taken from the prior iteration of the Power Module. The Sub-Module takes into account the potential to switch or blend coals at each plant, where and to the extent such potential exists.
- Supply is represented by mine-level short- and long-run marginal cost curves, maximum output, and developable reserves.
- Transportation is represented as the minimum cost rate for each mine-plant pairing, taking into account the modes of transportation that are possible, e.g., rail, truck, barge.
- The network LP generates forecasts of annual FOB prices by mine, delivered prices by plant, and the characteristics of the coal delivered to each plant, e.g., sulfur and heat content.
- Known contracts between specific mines and power plants are represented. These contracts influence the forecast of spot coal produced at each mine.

Renewables Module

The Renewables Module simulates the market reaction to the imposition of state renewable portfolio standards (RPS). The Module simulates annual additions of renewable capacity that will be made in each zone, by technology type, given 1) the total potential capacity for each technology for each area, and 2) the relevant RPS. The Module also simulates the annual renewable energy certificate (REC) prices for each jurisdiction that imposes an RPS.

The Module considers zone-specific supply curves for renewable additions. Each supply curve is expressed in terms of the amount of capacity that would be constructed, measured in MWh of renewable energy generated, at various REC prices. These supply curves are adjusted to take into account zonal energy and capacity prices. The Module then identifies the renewable capacity additions that 1) together satisfy the RPS, and 2) require the lowest first-year REC price. In such instances, the REC price is set as the additional payment, measured in dollars per MWh, that the marginal capacity addition requires to break even financially, taking into account the energy market revenues, variable and fixed O&M expenses, and amortized capital costs.

14 SOFTWARE USED FOR IRP ANALYSIS

Reference Case Power Price Formation Process

Market prices were used from the Fall 2015 Midwest Reference Case. ABB uses a fundamentals-based methodology to forecast power prices in each region of North America. Based on its proprietary PROMOD IV® software—a proven data management and production simulation model—ABB simulates the operation of each region of North America. PROMOD IV is recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations.

For each region, PROMOD IV considers:

- Individual power plant characteristics including heat rates, start-up costs, ramp rates, and other technical characteristics of plants;
- Transmission line interconnections, ratings, losses, and wheeling rates;
- Forecasts of resource additions and fuel costs over time;
- Forecasts of loads for each utility or load serving entity in the region; and
- The cost and availability of fuels that supply the plants.

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PROMOD IV performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, and transmission flows.

The heart of PROMOD IV is an hourly chronological dispatch algorithm that minimizes costs (or bids) while simultaneously adhering to a wide variety of operating constraints, including generating unit characteristics, transmission limits, and customer demand.

Strategic Planning Software

Strategic Planning *powered by MIDAS Gold* was utilized to measure and analyze the consumer value of competition.

Strategic Planning (SP) includes multiple modules for an enterprise-wide strategic solution. The modules used for this IRP were:

- Portfolio
- Capacity Expansion
- Financial/Risk

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision making tools necessary to value customers, portfolios and business unit profitability.

Portfolio Module

Once the price trajectories have been completed, the portfolio module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against presolved market prices from the markets module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve. SP operates generation fleet based on unit commitment logic, which allows for plant specific parameters of:

- Ramp rates;
- Minimum/maximum run times; and
- Startup costs.

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on Monte Carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints.

Portfolio module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

Capacity Expansion Module

Capacity Expansion automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions. With Capacity Expansion, the optimal resource expansion strategy is determined based on an objective function subject to a set of constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR) subject to meeting load plus reserves, and various resource planning constraints.

Decisions to build generating units or expand transmission capacity, purchase or sell contracts, or retire generating units are made based on the expected market value (revenue) less costs including both variable and fixed cost components. The model is a mixed integer linear program (MILP) in which the objective is minimization of the sum of the discounted costs of supplying customer loads in each area with load obligations. The model can be used to also represent areas that provide energy and capacity from power stations or contracts, but have no load obligations. The model includes all existing and proposed plants and transmission lines in a utility system.

Financial Module

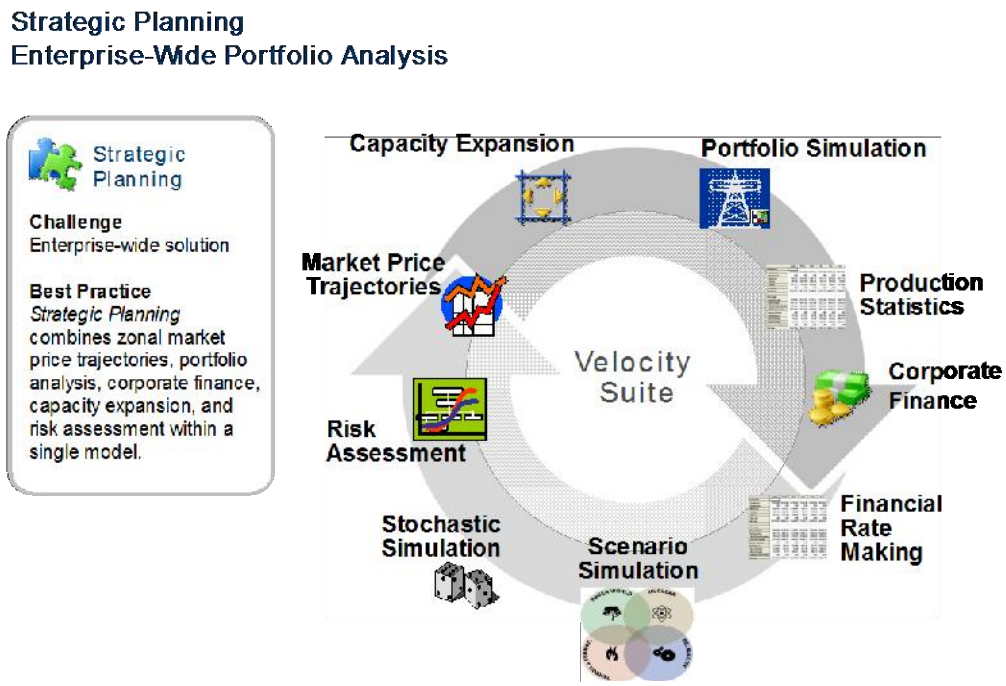
The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Risk Module

Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) 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) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

Figure 14-1
Overview of Process



(Source: ABB Advisors.)

IPL 2016 IRP

Confidential Attachment 2.2 (ABB Modeling Summary – Confidential Version) is only available in the Confidential IRP.

Short Term Action Plan Transmission Expansion Projects

	Project	Description	Construction Period
1	Guion to Westlane Line - 132-40	Upgrade of the IPL Guion to Westlane 138 kV line to at least 298 MVA. The upgrade is needed to increase the line during contingency loading conditions and meet NERC reliability standards.	2017
2	Stout 345-138 kV Auto Transformer	The replacement is needed to due to transformer health.	2017
3	Rockville Substation	The upgrade of the Rockville substation include two new 345 kV breakers and one 138 kV breaker. The project increases imports capability into the IPL 138 kV transmission system, improves reliability, and allows for better operational flexibility.	2018
4	Stout CT to Southwest Line - 132-02	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 to meet NERC reliability standards.	2018
5	Stout CT to Stout North Line - 138-98	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.	2018
6	Georgetown to Westlane Line - 132-41	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 and meet NERC reliability standards.	2018
7	Guion Substation	The upgrade of the Guion Substation include two new 345 kV breakers. The project increase imports capability into the IPL 138 kV transmission system, improves reliability, and allows for better operational flexibility.	2018
8	Parker Substation	The Parker Substation project includes replacement of three 138 kV breakers. The replacement is needed to increase interrupting capability and meet NERC reliability standards.	2018
9	River Road Substation	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	2018
10	Center Substation	The Center Substation project includes new 138 kV breakers, disconnects, and relay equipment.	2018
		Estimated Total Cost of all Projects:	**$26.2M**

Note: This does not include any costs for projects completed by other MISO members that will be allocated to IPL.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF ALTERNATIVE REGULATION PLAN FOR EXTENSION OF DISTRIBUTION AND SERVICE LINES, INSTALLATION OF FACILITIES AND ACCOUNTING AND RATEMAKING OF COSTS THEREOF FOR PURPOSES OF THE CITY OF INDIANAPOLIS' AND BLUEINDY'S ELECTRIC VEHICLE SHARING PROGRAM PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.*	))))))))))	**CAUSE NO. 44478**

SUBMISSION OF COMPLIANCE FILING

Petitioner, Indianapolis Power & Light (IPL), in accordance with the Commission's February 11, 2015 Order in this Cause, files the attached annual report. It recently came to IPL's attention that the annual report was inadvertently not filed by December 31, 2015. IPL acknowledges that this report is late-filed and respectfully requests the Commission accept the late filing. The annual report provides a general update on the BlueIndy project including (1) any profit share received and (2) data gathered at each charging site for purposes of observing, on a generic basis, consumer behavior and the grid in terms of operational effects and costs. In accordance with the Order in this Cause, IPL will file a report by September 2, 2016 (which is within one year of the public opening) on its efforts with respect to a vehicle-to-grid pilot. IPL will file its next annual report on or before December 31, 2016.

Respectfully submitted,

By: ______________________________

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 30th day of June 2016, via electronic mail, on the following:

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THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM ANNUAL REPORT

JUNE 30, 2016

GENERAL UPDATE

As of June 30, 2016, BlueIndy has deployed 74 electric car sharing charging stations, which includes approximately 369 electric vehicle chargers and 234 vehicles. BlueIndy has over 2,000 registered members and has logged over 20,000 rides. There are currently 18 sites under construction which are focused at local universities, grocery stores, neighborhoods, healthcare, retail, and the outer ring of the IPL service territory.

The line extension costs incurred as of the most recent reporting cycle (June 1, 2016) approximates $919,000.

PROFIT SHARE RECEIVED

Indianapolis Power & Light Company ("IPL") has not received profit share at the time of this filing.

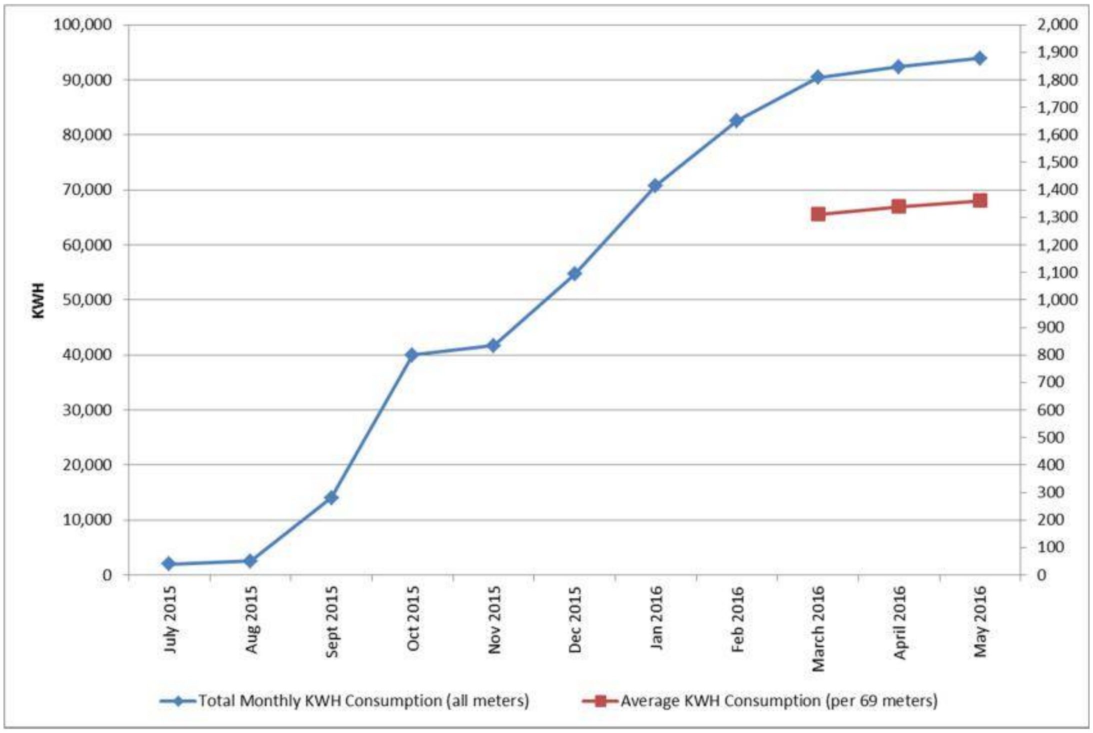
DATA GATHERED AT EACH CHARGING SITE

BlueIndy launched an initial Demo Station downtown at 2 E. Washington in early 2015 to demonstrate the service months ahead of the public opening. BlueIndy's service formally launched to the public on September 9, 2015 with an initial network of 25 Stations and 50 Bluecars in the fleet.

Generally, each BlueIndy Station consists of five (5) parking spots (each spot with a Charging Point Station Kiosk for powering Bluecars or members' personal EVs), a Reservation Kiosk and a Meter Pedestal. Approximately, every 10th Station also has a covered Enrollment Kiosk. BlueIndy memberships can be secured online, in person with a BlueIndy Ambassador's iPad, via smartphones or via an Enrollment Kiosk.. BlueIndy steadily added Bluecars and Stations to the service since September 9, 2015 and they are planning to meet the original goal of 500 Bluecars and up to 200 Stations in 2017.

Continuous strategic load balancing is performed by BlueIndy Ambassadors to try to make sure no Station has no more than four (4) and no fewer than one (1) Bluecar charging at any point in time to provide maximum Bluecar and parking availability, which is especially important before the two (2) daily weekday rush hours. BlueIndy Accounting reports that as of May 31, 2016, there has been a total of 597,923 kWh used by 69 of the 74 Stations since the demo site was launched. (BlueIndy will include energy consumption data for the recently launched 5 private Stations including the 4 Stations at the Indianapolis Airport and the 1 Station at the Marriott East in future reports.) There were a total of 544 total months of service across these 69 Stations, which translated to an overall average use of ~1100 kWh per month, per BlueIndy's calculations. In addition, BlueIndy has 80 "EV Charging Members" who use the Stations to charge their personal EVs. BlueIndy will be able to provide segregated personal EV energy consumption data in future reports.

IPL's data analysis as of May 9, 2016 depicted that the 69 meters in service during the most recent 3 month period revealed an average meter consumption of ~1,300 KWhrs/month. This monthly level of consumption is only slightly above a typical residential average energy consumption of 1,100 kWhrs. Please see the graphical representation of aggregate BlueIndy energy consumption below.



The impacts to the IPL system have been minimal and represent a modest load growth comparable to the addition of less than 100 residential homes.

Photos of BlueIndy Local Use

BlueIndy Station downtown Indianapolis showing Bluecars and Personal EV charging, Charging Points, Reservation Kiosk and Meter Pedestal.

BlueIndy at the Indianapolis Airport 5th Floor Parking Garage (4 Stations).

STATE OF INDIANA

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VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF ALTERNATIVE REGULATION PLAN FOR EXTENSION OF DISTRIBUTION AND SERVICE LINES, INSTALLATION OF FACILITIES AND ACCOUNTING AND RATEMAKING OF COSTS THEREOF FOR PURPOSES OF THE CITY OF INDIANAPOLIS' AND BLUEINDY'S ELECTRIC VEHICLE SHARING PROGRAM PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.*	))))))))))	**CAUSE NO. 44478**

SUBMISSION OF COMPLIANCE FILING

Petitioner, Indianapolis Power & Light Company ("IPL"), in accordance with the Commission's February 11, 2015 Order in this Cause, files the attached report on its efforts with respect to a vehicle-to-grid ("V2G") pilot.

Respectfully submitted,

By: ______________________

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 31st day of August 2016, via electronic mail, on the following:

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Vehicle to Grid Report – Cause No. 44478

City of Indianapolis and Indianapolis Power & Light Company

Background

In Cause No. 44478, IPL received approvals to install and defer the costs related to the line extensions necessary to provide electric service to the Blue Indy charging stations. This Order included a provision of a settlement agreement, wherein IPL and the City of Indianapolis (City) agreed to collaborate with BlueIndy to determine the potential feasibility of using the BlueIndy electric vehicles ("EVs") as providers of energy back to the IPL grid as a demand response resource and whether a Vehicle to Grid ("V2G") pilot would be viable. 44478 Settlement Agreement, at 4 (Paragraph 2k).

In accordance with the Settlement Agreement, in the February 11, 2015 Order in Cause No. 44478 (at 21), the Commission directed IPL to provide a report on the V2G pilot efforts within one year of the public opening of the BlueIndy project, which is September 2, 2016.

As stated in the BlueIndy status report filed in this Cause on June 30, 2016, BlueIndy has deployed approximately 74 of 200 planned electric car sharing charging stations. They continue to deploy sites with their original goal still intact.

V2G is a broad term which describes a system in which plug-in electric vehicles communicate with the power grid to provide demand response services (sometimes referred to as a Distributed Energy Resources ("DERs")) by either returning electricity to the grid, charging during off-peak periods or by reducing their charging rate. Some industry experts have introduced the term Vehicle to Grid Integration "(VGI") as a more inclusive description for V2G.

The possibilities for EVs to serve as a DER are intriguing. For example, an EV with an average sized 30 kWh battery has approximately the amount of energy storage as the typical IPL residential customer uses in day.

Report Approach

This report summarizes discussions with BlueIndy, IPL's V2G efforts, lists potential V2G benefits, challenges identified and conclusions.

Discussions with BlueIndy

The fact that BlueIndy has selected Indianapolis as one of the initial communities to deploy an EV ridesharing service makes the City of Indianapolis and IPL uniquely situated to explore and evaluate the possibility of using fleet vehicles in a V2G study/pilot. In particular, the fact that Indianapolis is home to a fleet of identically prepared EVs that have a significant amount of distributed energy storage capacity makes the possibility of grid provided services interesting. Having BlueIndy as a willing partner in this study provides expertise and data not available in other V2G research. The last year has been focused on the rollout of the BlueIndy infrastructure. The cooperation between IPL and BlueIndy during this time has been very collaborative and continues to be so. While BlueIndy is open to future coordinated V2G efforts, their preference is to focus on the initial deployment of project infrastructure in the short-term. Furthermore, many details would need to be worked out before a pilot could begin.

IPL Efforts

IPL has conducted research related to V2G efforts around the United States. The current pilots seem to concentrate on using second life batteries as stationary sources to provide grid services as a predecessor to actual mobile batteries in EVs. While multiple pilots are in progress, commercialization is not yet viable. Please see Appendices 1 and 2 for more detail.

Load Modifying Resource Demonstration Project

As a complement to the evaluation of V2G, IPL contracted with a local electrical contractor to complete a Distributed Energy Storage ("DES") demonstration pilot showcasing home energy storage system technology in a laboratory setting. This demonstration project employs battery energy storage packs from two vendors (Tesla Powerwall and LG Chem) that will provide back-up power and demand response in the form of a Load Modifying Resource ("LMR"). For capacity planning purposes, IPL may eventually aggregate multiple customer systems into a resource that can supply at least 100 kW in order for home energy storage units to qualify as a MISO LMR.

IPL invited BlueIndy and Landis+Gyr (IPL's Advanced Metering Infrastructure (AMI) provider), to a demonstration of the DES pilot. Initial favorable results indicate the DES has the ability to monitor and control individual home circuit breaker loads and call upon the battery to discharge to reduce grid demand. Essentially, the batteries used in the lab replicate vehicle battery technology on a smaller scale.

The control system software under development for the LMR may be used to demonstrate V2G grid capability in a lab setting. Essentially, the batteries used in the lab (approximately 7 kWh battery packs) can replicate some of the functionality of the vehicle battery technology as a grid resource. This work can be considered as an incremental step to prove the technical feasibility of controlling a battery source.

Potential benefits of V2G/VGI

- Demand Response ("DR") resource which results in peak load reduction on the electric grid.
- Provider of ancillary services (frequency response).
- Integration with renewables for reliability, economic and sustainability benefits.
- Support sustainability through repurposing of used of EV batteries.
- Collaboration with local stakeholders including Energy Systems Networks, IUPUI Renewable Energy Center , the City of Indianapolis and others.

Challenges/Opportunities to Consider

The adoption of electric vehicles as a grid resource comes with many challenges:

- Lack of standard protocols for proprietary battery management system.
- Uncertainty about utility communication protocols with battery management systems.
- Battery Original Equipment Manufacturers ("OEMS") unwillingness to warranty batteries used for V2G purposes.
- Warranty concerns among vehicle owners.
- Uncertainty about more frequent charging/discharging cycling on battery life.
- The battery packs in each vehicle will have a unique set of characteristics based on their age and prior charging histories.
- Range and vehicle availability anxiety that results from electric vehicles being used for something other than their primary purpose.
- The need to develop a value proposition for all stakeholders: vehicle owners, manufacturers, dealerships, utilities, system operators.
- Economies of scale: The market for small scale battery energy storage itself will also dictate how soon V2G makes sense to pursue. Due to economic considerations, the market today favors large battery energy storage resource (i.e. one (1) plus MWh size per site). Since a car battery may provide about 20 kWh of capacity, it would be necessary to combine 50 to 100 vehicle battery pacts to get a similar amount of energy as a larger scale stationary system.

Conclusion

At this time, the parties do not believe a full V2G pilot is appropriate given the current status of the BlueIndy build system build out and the challenges cited above.

IPL will continue to stay abreast of V2G utility pilot developments nationally and gain insights related to its LMR pilot. In addition, IPL and BlueIndy will monitor pertinent battery management system standards and communication protocol developments. Following full deployment of its local infrastructure, BlueIndy expects to understand charging data to further explore the magnitude and variability of controllable EV charging over a wide range of factors, including location, vehicle type, charging time of day, charging location, and distances driven.

The parties expect to continue to discuss V2G options and will inform the Commission if a V2G pilot is undertaken.

Appendix 1 – IPL Research related to V2G and VGI

IPL reviewed industry reports[1] and met with vehicle Original Equipment Manufacturers (OEMS) to derive the following observations:

The current research and pilots seem to concentrate on using second life batteries (stationary sources) as a device for the provision of grid services rather than using electric vehicles that are in still in active service.

However, a Demand Response project being run by BMW and Pacific Gas & Electric does combine active EVs with a stationary source. High level details of the current BMW effort and earlier efforts are as follows:

- BMW iChargeForward program
    - 18-month pilot, July 2015 through end of this year.
    - 100 BMW i3 vehicle customers enrolled, get up to $1,540 for participating http://www.bmwusa.com/bmw/bmwi.
    - How it works:
        - PG&E sends DR signal to BMW server for 100 kW reduction.
        - BMW decides how to respond to signal from pool of 100 i3 drivers and/or stationary storage at its Mountain View office.
        - Stationary storage available is a 240 kWh system using eight battery packs pulled from BMW's MINI E project.
        - Project has been successful; PG&E has called many DR events at different times to test the capability; learning a lot about value of EVs as a grid resource.
    - Early BMW EV deployment pilots
            - Mini E program (2009)
                - Converted Mini Cooper.
                - 450 vehicles in the U.S. (CA, NY, NJ).
                - 35 kWh battery pack.
            - ActiveE program (2012)
                - Converted 1 Series Coupe.
                - Deployed 700 in the U.S.; 2 year lease for $499 per month.
                - 32 kWh battery pack.
                - 150 put into service in BMW's DriveNow car sharing. program, which has since become the ReachNow program.
        - UC San Diego demonstrations
            - Testing second-life battery applications by integrating into solar, using batteries from the Mini E program.

[1] These reports are referenced in Appendix 2.

- Florida Power & Light project announced on June 16 will repurpose 200 second life batteries from more than 200 electric vehicles test "peak shaving" for better grid management during periods of high demand via a storage system to be installed in a densely populated residential area in southwestern Miami.

- This project is one of the private sector commitments made during the June 16 White House announcement on Scaling Renewable Energy and Storage with Smart Markets

- In 2015, NextEra, signed a contract for the delivery of 20 MWh of Battery 2nd Life automotive batteries. These batteries were sourced from the BMW ActiveE test fleet in the US and from early BMW i3 vehicles. NextEra will operate them in various industrial sized stationary electricity storage systems.

- BMW Home energy storage with 2nd life batteries
    - Announced on June 21. 2016 http://www.autoblog.com/2016/06/21/bmw-i3-battery-home-energy-storage
        - Initially uses 2nd life batteries from the i3.
    - “The battery storage system electrified by BMW i, enables customers to more fully realize their commitment to sustainability – and to take the next step towards energy independence. With this system, which integrates seamlessly with charging stations and solar panels, customers can offset peak energy costs and also enjoy the added security of an available backup energy supply during power outages.”
    - For commercial and home.
    - Can accommodate new and used batteries.
    - 22 kWh or 33 kWh capacity, “ideally suited to operate a variety of appliances and entertainment devices for up to 24 hours on its own”.
    - “Because the electric draw is much less at home when compared to automotive usage, this storage system is an ideal application for a retired BMW i3 battery and ensures that the repurposed battery will offer many additional years of service”.
    - “The battery storage system also includes a voltage converter and power electronics to manage the energy flow between renewable energy sources, the house interface, and the Li-Ion high-voltage battery from the BMW i3.”

        - “The battery storage system electrified by BMW i is ideally sized so it can be conveniently placed in the basement or the garage of a detached house, where the stored energy can either be used for electrically-operated devices in the home or for charging the battery of an electric car.”
        - For reference, BMW i3 has a 22 kWh pack; BMW has delivered 20,000 in the U.S. since sales began in May 2014; that is 440,000 kWh or 440 MWh of energy storage in the field; some of the early ones will be coming off of lease soon.
- Mercedes-Benz
    - Daimler subsidiary ACCUmotive.
    - Commercial and residential applications.
    - Modules come in 2.5 kWh (residential), which can be scaled up to 20 kWh; or 5.9 kWh (commercial), which can be scaled up to whatever size is needed.
    - 500 kW deployed in Germany; went on market in Germany in April 2016.
- Volkswagen
    - Renewed “interest” in electrification following emissions scandal settlement.
    - Intent is to “rectify shortcomings and establish a corporate culture that is open, value-driven and rooted in integrity."
    - 30 new electric models on the road by 2025.
    - Possible gigafactory of its own.
- Tesla
    - Powerwall consumer product.
    - Green Mountain Power (GMP) deployment of Powerwall.
        - “GMP has worked closely with customers to help make the Powerwall an affordable option. Customers can lease one for about $37.50 a month or about $1.25 a day, with no upfront cost. Customers can also choose to partner with GMP to purchase the Powerwall, and with shared access will receive a monthly bill credit of $31.76. Both options represent the value of leveraging the battery to help lower peak energy costs.”
- Some of the above projects and additional initiatives are outlined and included in a White House Press Release from June 21, 2016. https://www.whitehouse.gov/the-press-office/2016/06/16/fact-sheet-obama-administration-announces-federal-and-private-sector.

Appendix 2 Literature Review

A summary of research and other utility initiatives. The recent June 2016 publication by Rocky Mountain Institute is particularly comprehensive and useful:

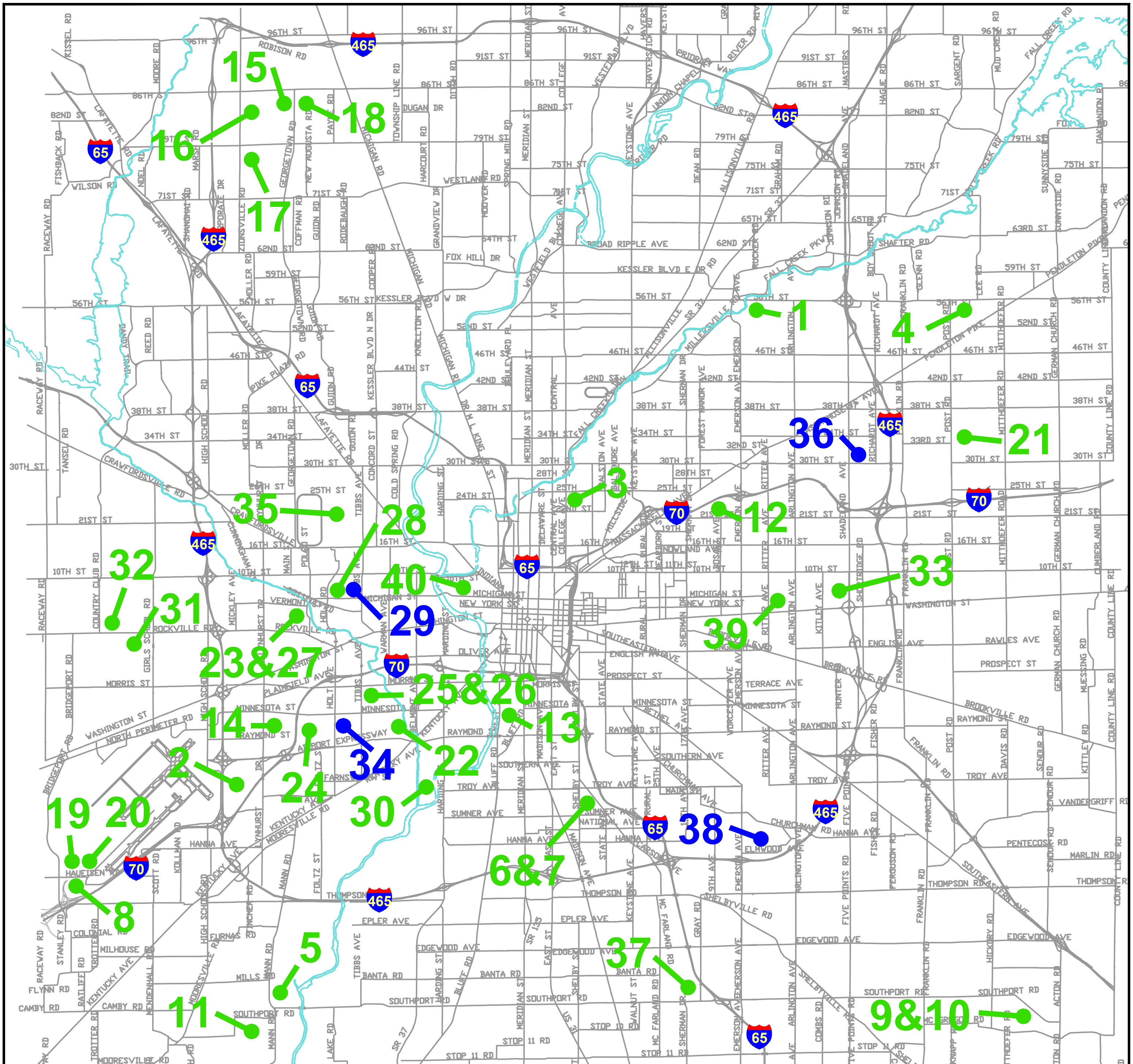
- National Renewable Energy Laboratory: Multi-Lab EV Smart Grid Integration Requirements Study http://www.nrel.gov/docs/fy15osti/63963.pdf
- Electricity Innovation Lab: Electric Vehicles as Distributed Energy Resources http://www.rmi.org/Content/Files/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf
- AC Propulsion, Inc.: Electric Drive Vehicles: A Huge New Distributed Energy Resource http://www1.udel.edu/V2G/resources/A-Brooks-ETI-conf.pdf
- Impact of Electric Vehicles as Distributed Energy Storage in Isolated Systems: the Case of Tenerife http://www.mdpi.com/2071-1050/7/11/15152
- Distributed energy resources management using plug-in hybrid electric vehicles as a fuel shifting demand response resource. http://www.sciencedirect.com/science/article/pii/S0196890415002289
- Rocky Mountain Institute "Electric Vehicles as DERs V2 Final, June 2016 http://www.rmi.org/Content/Files/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf
- Rocky Mountain Institute _ Blog _ EVs "Time to Plan on EVs on the Grid" http://blog.rmi.org/blog_2016_06_15_its_time_to_plan_for_evs_on_the_grid

FINAL RATE REP PARTICIPANTS

Count	Customer	Address	Nameplate Capacity (kW, AC)		Ground / Roof
1	Cathedral High School	5525 E. 56th St.	50		R
2	ES by JMS	5925 Stockberger Place	90		R
3	Indiana Veneers	1121 E. 24th Street	85		R
4	GSA Bean Finance Center	8899 E. 56th Street	1,800		R
5	Melloh Enterprises	6627 Mann Road	39		G
6	L&R #1 (Laurelwood Apts.)	Building #6, 3340 Teakwood Dr	30		R
7	L&R #2 (Laurelwood Apts.)	Building #16, 3340 Teakwood Dr	28		R
8	Airport I	7800 Col. H. Weir Cook Memorial Drive	9,800		G
9	Indy Solar I	10321 East Southport Road	10,000		G
10	Indy Solar II	10321 East Southport Road	10,000		G
11	Indy Solar III	5800 West Southport Road	8,640		G
12	Indy DPW	3915 E 21st Street	95		R
13	Indy DPW	1737 S. West St	95		R
14	Schaefer Technologies	4901 W. Raymond St, 46241	500		G
15	Citizens Energy (LNG North)	4650 W. 86th	1,500		G
16	Duke Realty #98	8258 Zionsville Rd, 46278	2,720	*	R
17	Duke Realty #87	5355 W. 76th St., Indpls., 46268	2,720	*	R
18	Duke Realty #129	4925 W. 86th St. Indianapolis, IN 46268	3,400	*	R
19	Airport Phase IIB	Intersection of Brushwood Rd & Hoffman I	2,500		G
20	Airport Phase IIA	4250 W Perimeter Rd	7,500		G
21	Celadon Trucking Services	9503 E. 33rd Street, 46235	82		R
22	Vertellus	1500 S. Tibbs Ave, 46241	8,000	*	G
23	Merrell Brothers	4251 W. Vermont ST	96		R
24	Grocers' Supply Co.	4310 Stout Field Dr. North	1,000		R
25	A-Pallet Co.	1225 S. Bedford St.	48		G
26	A-Pallet Co.	1305 S. Bedford St.	96		R
27	Town of Speedway, IN	4251 W. Vermont ST	750		G
28	GenNx Properties VI, LLC (Maple Creek Apts)	3800 W. Michigan Street (Bldg 17)	20		R
29	GenNx Properties VI, LLC (Maple Creek Apts)	3800 W. Michigan Street (Bldg 1)	20		R
30	CWA Authority	2700 S. Belmont (WWTF)	3,830		G
31	Rexnord Industries	7601 Rockville Road	2,800		G
32	Equity Industrial A-Rockville LLC	7900 Rockville Road	2,725		R
33	Lifeline Data Centers	401 N. Shadeland Ave	4,000		Carports
34	Omnisource	2205 S. Holt	1,000		G
35	Indianapolis Motor Speedway	3702 W 21st Street	9,000	*	G
36	DEEM	6900 E. 30th Street	500		R
37	Indy Southside Sports Academy	4150 Kildeer Dr	200		R
38	Marine Center of Indiana	5701 Elmwood Ave	500		R
39	5855 LP	5855 E. Washington St.	78		R
40	IUPUI	801 W. Michigan Rd	48		R
		Total	96,384		

0	10/1/2016	Under Construction	0
36		Operating	94,392
4		In Development	1,993

* Reduced from approved capacity



1. CATHEDRAL HIGH SCHOOL
2. ES by JMS
3. INDIANA VENEERS
4. GSA BEAN FINANCE CENTER
5. MELLOH ENTERPRISES
6. L&R #1 (LAURELWOOD APTS.)
7. L&R #2 (LAURELWOOD APTS.)
8. AIRPORT I
9. INDY SOLAR I
10. INDY SOLAR II
11. INDY SOLAR III
12. INDY DPW
13. INDY DPW
14. SCHAEFER TECHNOLOGIES
15. CITIZENS ENERGY (LNG NORTH)
16. DUKE REALTY #98
17. DUKE REALTY #87
18. DUKE REALTY #129
19. AIRPORT PHASE IIA
20. AIRPORT PHASE IIB
21. CELADON TRUCKING SERVICES
22. VERTELLUS
23. MERRELL BROTHERS
24. GROCERS' SUPPLY CO.
25. A-PALLET CO.
26. A-PALLET CO.
27. TOWN OF SPEEDWAY, IN
28. GenNx PROPERTIES VI, LLC. (MAPLE CREEK APTS.)
29. GenNx PROPERTIES VI, LLC. (MAPLE CREEK APTS.)
30. CITIZENS ENERGY/CWA AUTHORITY
31. REXNORD INDUSTRIES
32. EQUITY INDUSTRIAL A-ROCKVILLE LLC.
33. LIFELINE DATA CENTERS
34. OMNISOURCE
35. INDIANAPOLIS MOTOR SPEEDWAY
36. DEEM
37. INDY SOUTHSIDE SPORTS ACADEMY
38. MARINE CENTER OF INDIANA
39. 5855 LP
40. IUPUI

LEGEND

\# - OPERATING
\# - UNDER CONSTRUCTION
\# - IN DEVELOPMENT

INDIANAPOLIS POWER & LIGHT CO.

SOLAR FACILITIES

ipl an AES company

DRAWN BY: RLW
5-18-15
solar-REP-GIS-map
REV. 11-12-15 WJK

Load Research *[170 IAC 4-7-4 Sec 4 (2) A-E]*

Load shape data is maintained by IPL at the rate class/customer class level. The sample for the Small Commercial Class Rate SS is stratified using NAICS codes in to manufacturing low and high use and non-manufacturing low and high use strata. All load research is developed by IPL.

IPL currently maintains a load research sample of 562 load profile meters. The distribution of these meters by rate and class are shown in the following table.

Load Research Meters by Rate and Class			
Rate RS	126	Rate SS	95
Rate RC	102	Rate SH	68
Rate RH	151		
Residential	379	Sm C & I	163

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

Table 1 shows the load research sample design which is designed based upon a 90% confidence interval plus or minus 10% error. The stratification criteria are shown for the following rates:

RS – Residential Basic Service
RC – Residential Basic Service with electric water heating
RH – Residential Basic Service with electric heat
SS – Small Commercial & Industrial Secondary Service (Small)
SH – Small Commercial & Industrial Secondary Service (Electric Space Conditioning

Table 1

STRATIFICATION CRITERIA BY RATE

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

Hourly 8760 data is retained in EXCEL spreadsheets.

Historical Billing Data

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

IPL 2016 IRP

Attachment 4.2 (2015 Hourly Loads by Rate and Class) is provided electronically.

Knowledge to Shape Your Future

Electric | Gas | Water
information collection, analysis and application

2016 Long-Term Electric Energy and Demand Forecast Report

Indianapolis Power & Light

Submitted to:

Indianapolis Power & Light
Indianapolis, Indiana

Submitted by:

Itron, Inc.
20 Park Plaza
Suite 428
Boston, Massachusetts 02116
(617) 423-7660

July 19, 2016

Contents

1 Overview

Indianapolis Power & Light Company (IPL) serves over 480,000 customers in the city of Indianapolis and surrounding area (primarily Marion County). The service area includes a large non-residential base that accounts for nearly two thirds of IPL's sales. In 2015, residential sales represented 37% of sales, Small Commercial & Industrial 13%, Large Commercial & Industrial 13, and Street Lighting 1% of sales. Figure 1 shows 2015 class-level sales distribution.

Figure 1: 2015 Class Sales (kWh) Distribution

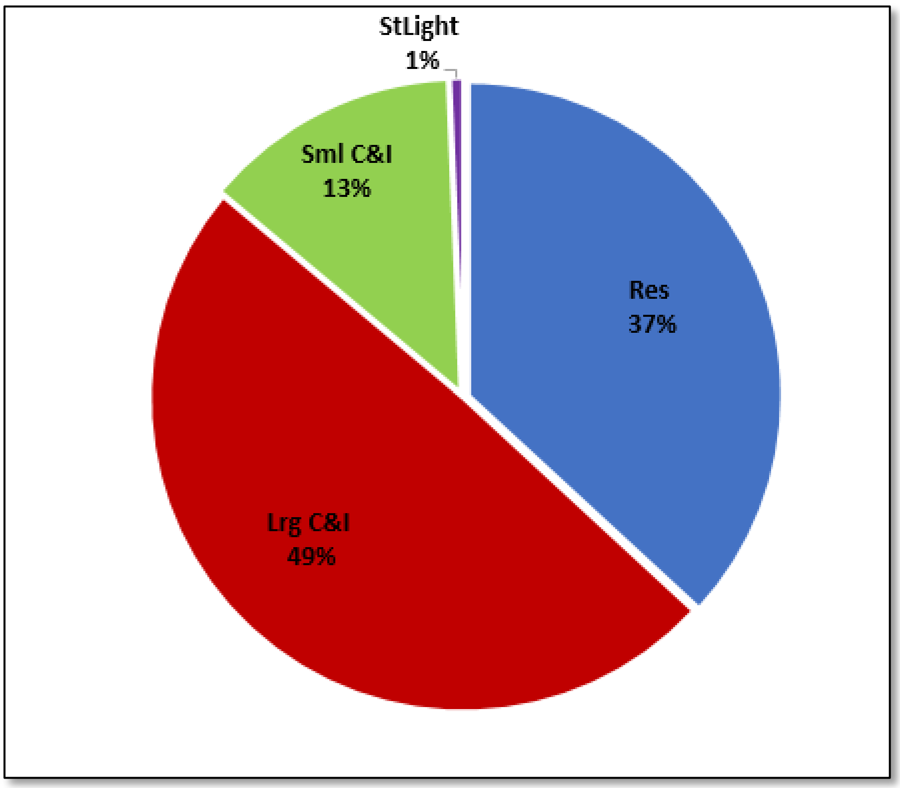
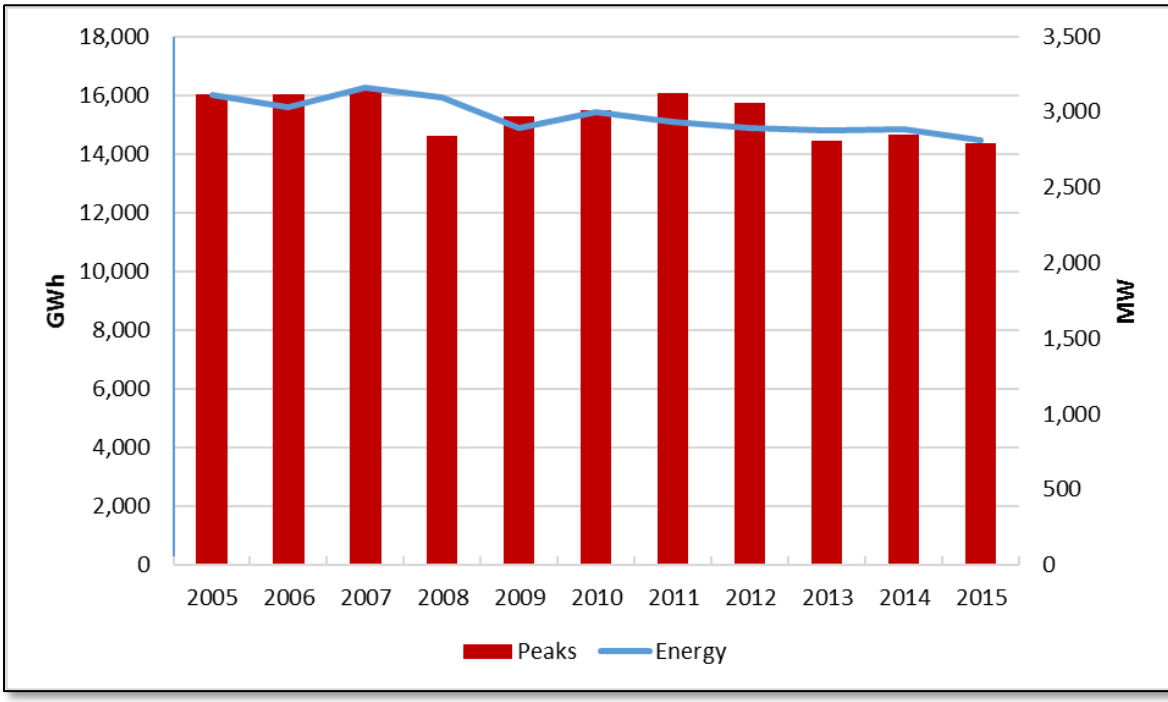


Figure 2 shows total system energy requirements and actual annual peak demand from 2005 to 2015.

Figure 2: IPL System Energy Requirements



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.

Part of the decline can be contributed to the 2008 recession and the slow recovery. Between 2007 and 2011 customer growth actually declined 0.1% per year. Since 2011, customer growth has 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. 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 Demand Side Management (DSM) program activity.

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 programs[1]. Table 1-1 shows annual energy and demand forecast before DSM program savings.

Table 1-1: Energy and Demand Forecast (Excluding Future DSM Program Savings)

Year	Energy (GWh)		Peaks (MW)	
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%

[1] Future DSM programs refers to the amount of DSM that the IPL 2016 Integrated Resource Plan (IRP) selects. The forecasts presented in this report have not been adjusted for this DSM since Itron's scope only included providing pre-adjusted forecasts to be used as IRP inputs. DSM adjustments have been made by IPL based on the amount of DSM selected through the IRP process. These adjustments are provided in the IRP report.

2 Forecast Approach

The forecast approach is similar to method used by other state electric utilities. The process begins by developing customer sales forecast and using forecast results to drive future energy requirements and peak demand.

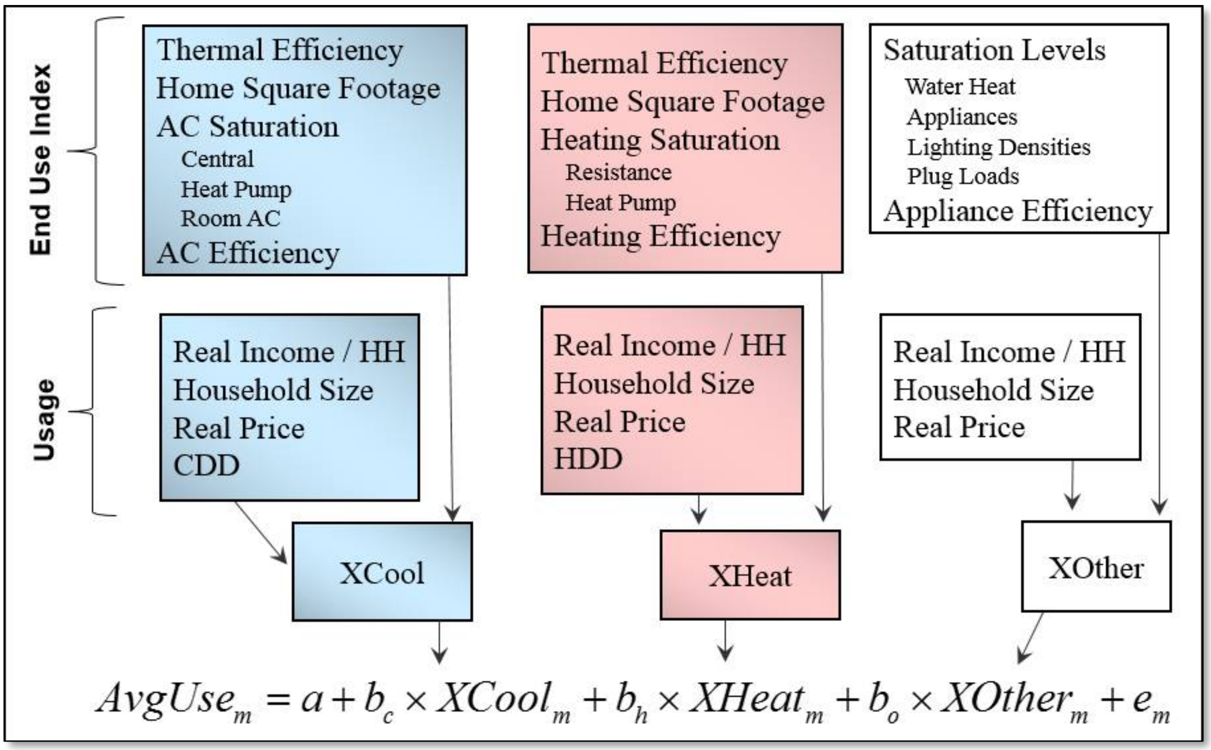
Rather than develop sales forecast for the generalized rate classes (i.e., Residential, Commercial, Industrial, and Street Lighting), IPL forecasts sales at the rate-schedule level and aggregates rate-schedule sales forecast to rate-classes. The reason is that IPL uses a single monthly forecast for near-term budget and financial planning and long-term resource planning. IPL revenue forecast requires sales forecast at the rate-class and even billing determinant level. Table 2-1 shows the specific rate-schedules forecasted and associated customers, sales, and average use.

Table 2-1: 2015 Customers and Sales

Sector	Rate Schedule	Definition	Customers	MWh	Avg kWh
RES	RS	General Service	246,481	2,342,108	9,502
RES	RH	Electric Heat	150,498	2,323,908	15,441
RES	RC	Electric Water Heat	32,022	406,586	12,697
Sml C&I	SS	General Service	46,153	1,228,878	26,626
Sml C&I	SH	GS All Electric	4,035	562,864	139,495
Sml C&I	SE	GS Electric Heat	3,357	19,383	5,774
Sml C&I	CB	GS Water Heat (Controlled)	95	432	4,549
Sml C&I	UW	GS Water Heat (Uncontrolled)	84	1,506	17,923
Sml C&I	APL	GS Security Lighting	364	31,620	86,868
Lrg C&I	SL	Secondary Service	4,539	3,504,652	772,120
Lrg C&I	PL	Primary Service	142	1,260,060	8,873,663
Lrg C&I	HL1	High Load Factor 1	28	1,373,248	49,044,572
Lrg C&I	HL2	High Load Factor 2	5	225,376	45,075,200
Lrg C&I	HL3	High Load Factor 3	3	345,920	115,306,667
Lrg C&I	APL	IND Security Light	364	5,725	15,728
Other	ST	Street Lighting		53,280	
Total			488,170	13,685,546	28,034

Usage measured in kWh per customer has been steadily declining over the last ten years largely driven by end-use efficiency improvements and DSM program activity. As new standards will continue to drive usage downwards it's critical to capture these efficiency improvements in the sales forecast models. The approach is to use an end-use modeling framework where the constructed model variables incorporate structural changes (thermal shell and end-use energy intensity trends) as well as economic activity, electric prices, and weather conditions (heating and cooling degree-days). Figure 3 provides an overview of this framework for the residential rate class; the same framework is used for the commercial rate class.

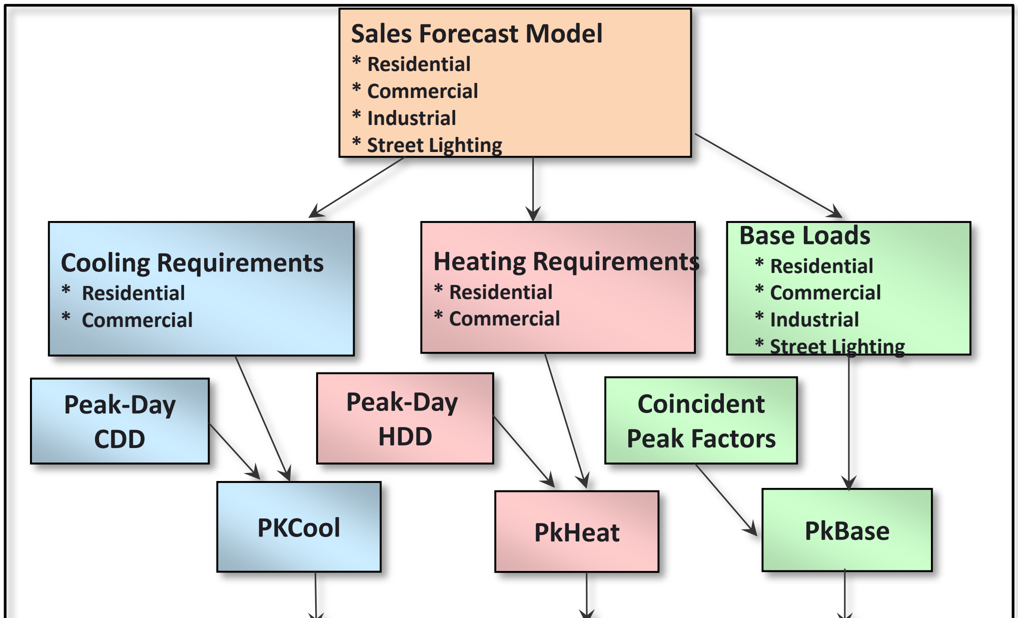
Figure 3: Residential Forecast Model Framework



Average customer use or sales is defined as a function of cooling requirements (XCool), heating requirements (XHeat), and other use (XOther). The model variables incorporate both structural factors such as the average air conditioning saturation and efficiency, and factors that impact utilization of the stock of equipment including the weather conditions, electric prices, number of people per household, and average household income. The model is estimated using linear regression that relates actual monthly sales or average use to the constructed end-use variables. The resulting model coefficients (b_c, b_h, and b_o) are used to generate average use and sales forecasts based on projected economic activity, normal weather, and end-use intensity trends. This is known as a Statistically Adjusted End-Use (SAE) model. A detail description of the model is included in Appendix B.

Energy and Peak. From a supply planning perspective, the most critical planning inputs are total system energy requirements and system peak demand. The energy forecast is derived by aggregating monthly sales forecast and adjusting the total sales forecast for line losses. The peak forecast is based on monthly peak-demand regression model that relates monthly maximum peak demand to cooling and heating requirements, peak-day CDD and HDD, and base energy requirements at time of peak. Heating, cooling, and base use requirements are derived from the rate schedule forecast models. Figure 4 shows the peak model framework.

Figure 4: Peak Model Framework



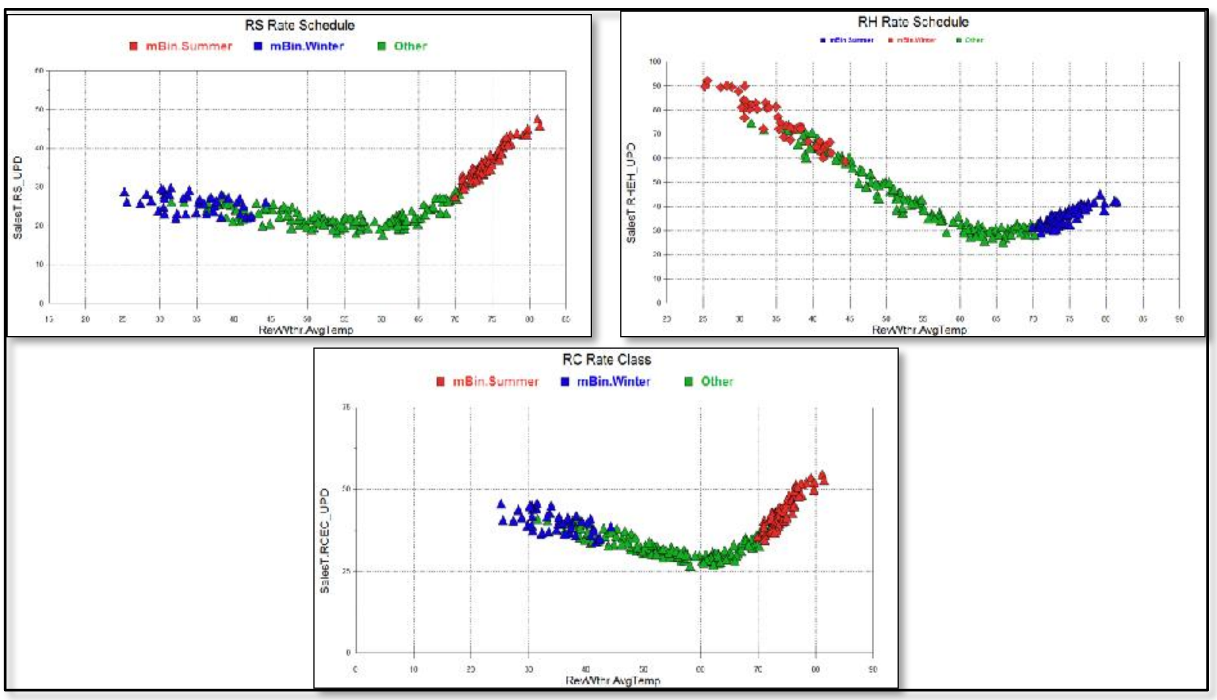
$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_b \times PkBase_m + e_m$$

Historical and forecasted cooling requirements are interacted with peak-day CDD (PkCool) and heating requirements are interacted with peak-day HDD (PkHDD); the underlying theory is that the impact of peak-day weather conditions will increase with increase in total cooling and heating requirements. System peak base-use (PkBase) is derived by combining base-use energy requirements with end-use coincident peak factors; end-use coincident peak factors are derived from Itron's end-use shape library. The coefficients (b_c, b_h, b_b) are estimated using a linear regression model. The advantage of this approach when compared with a more traditional load factor model is that we can capture factors that may contribute to differences between energy and demand growth. For example, cooling requirements may be increasing faster than heating requirements and as a result the summer peak could potentially increase faster than overall sales and winter peak demand. While lighting sales are declining as a result of the new lighting standards, we can capture the fact that this will impact winter peaks more than summer peaks. As shown in the model section, the model explains historical sales variation well with a high adjusted R-Squared and highly statistically significant model coefficients.

2.1 Residential Models

Average Use. Residential average use is modeled for three rate schedules. Non-electric heat customers (RS), electric heat customers (RH) and electric water heat customers (RC). Each rate schedule has a very different load curves and sensitivity to heating and cooling conditions as result of differences in end-use mix. Figure 5 shows the sales/weather relationship for these classes.

Figure 5: Residential Weather Response Curves



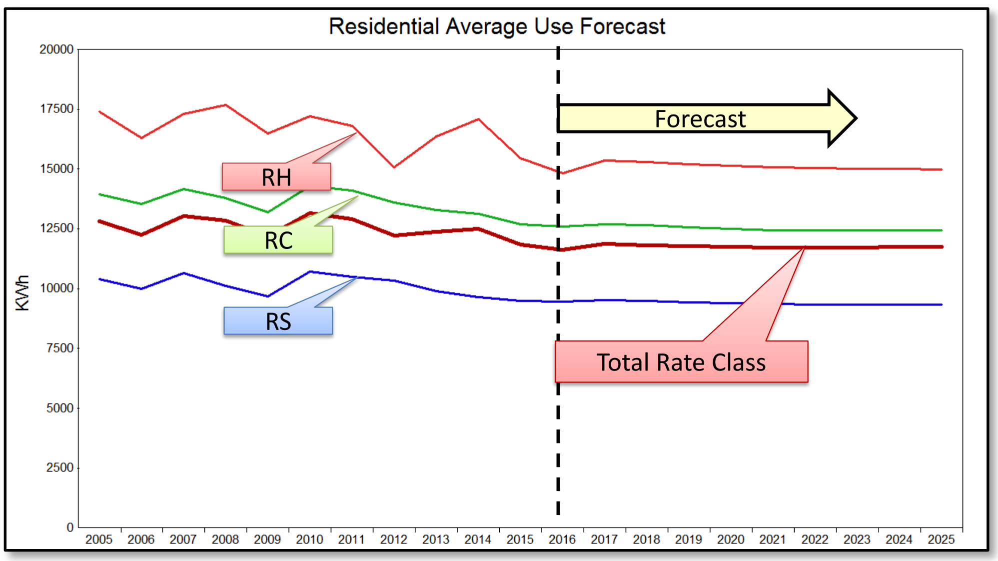
Each slide shows the relationship between average monthly temperature on the X axis and average class monthly use on a per billing-day basis. The curves are quite distinct with the RH rate schedule having a significantly steeper heating-side slope than either the RS or RC rate schedules. The RH and RC rate classes have greater cooling use for given temperature as these customers tend to be larger/single family homes. The base use for RC customers is higher reflecting the high electric water heating saturation.

As discussed earlier, the residential average use model relates customer average monthly use to a customer's heating requirements (XHeat), cooling requirements (XCool), and other use (XOther):

- $ResAvgUse_m = (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$

The model coefficients (B_1, B_2, and B_3) are estimated using a linear regression model. Monthly average use data is derived from historical monthly billed sales and customer data from January 2005 to March 2016. Model statistics are included in Appendix A. Figure 6 shows historical and forecasted average use.

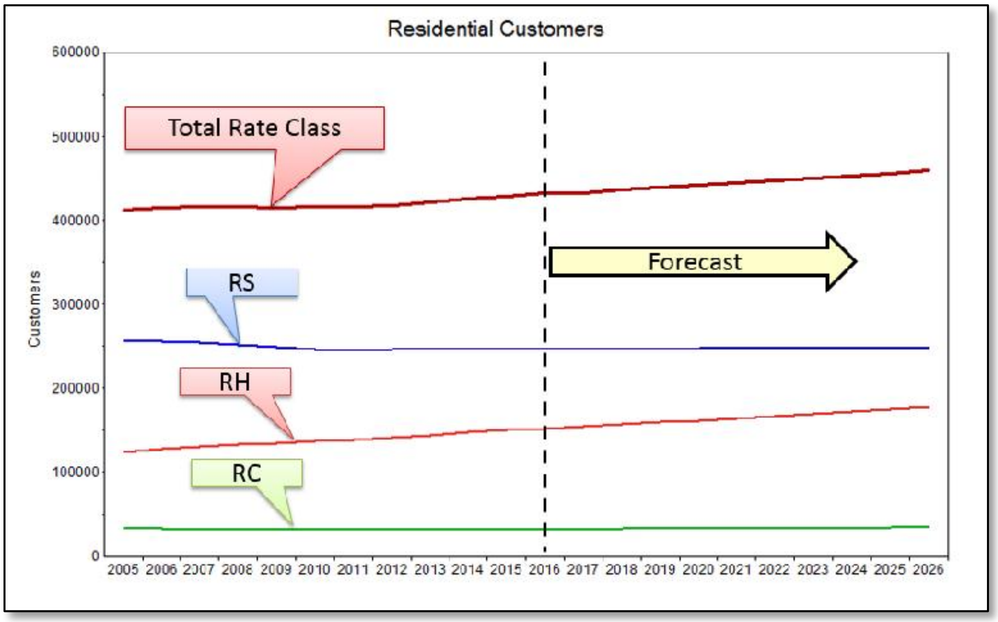
Figure 6: Residential Average Use (Excluding DSM Program Savings)



As depicted in Figure 6, average use has been declining since 2005. We expect average use to flatten out over the forecast period as increase in economic growth counters improving end-use efficiency and customer growth shifts to multifamily apartments. Total rate class average use actually increases somewhat as of increasing share of customers with electric heat.

Customer Forecast. The customer forecast is based on population forecast for Marion County. The correlation between Marion County population and number of IPL residential customers is close to ninety percent. The customer growth across rate schedules is quite different with nearly all the growth falling in RH (electric heat). Figure 7 shows the residential customer forecast.

Figure 7: Residential Customers



The residential sales forecast is generated as the product of the average use and customer forecasts. Total residential sales are calculated by adding across the rate schedule forecasts. Table shows the forecasted residential customer, sales, and average use before DSM adjustments.

Table 2-2: Residential Forecast (Excluding Future DSM Savings)

Year	Sales (MWh)		Customers		Avg. Use (kWh)	
2016	5,044,959		431,927		11,680	
2017	5,143,168	1.9%	433,312	0.3%	11,869	1.6%
2018	5,158,436	0.3%	436,053	0.6%	11,830	-0.3%
2019	5,172,841	0.3%	438,998	0.7%	11,783	-0.4%
2020	5,200,609	0.5%	441,877	0.7%	11,769	-0.1%
2021	5,210,360	0.2%	444,712	0.6%	11,716	-0.5%
2022	5,237,255	0.5%	447,074	0.5%	11,715	0.0%
2023	5,272,924	0.7%	449,772	0.6%	11,724	0.1%
2024	5,325,273	1.0%	452,719	0.7%	11,763	0.3%
2025	5,358,336	0.6%	455,803	0.7%	11,756	-0.1%
2026	5,399,202	0.8%	458,957	0.7%	11,764	0.1%
2027	5,445,053	0.8%	461,977	0.7%	11,786	0.2%
2028	5,503,149	1.1%	464,906	0.6%	11,837	0.4%
2029	5,548,440	0.8%	468,010	0.7%	11,855	0.2%
2030	5,596,246	0.9%	471,305	0.7%	11,874	0.2%
2031	5,647,282	0.9%	474,723	0.7%	11,896	0.2%
2032	5,709,122	1.1%	478,071	0.7%	11,942	0.4%
2033	5,754,021	0.8%	481,341	0.7%	11,954	0.1%
2034	5,811,200	1.0%	484,556	0.7%	11,993	0.3%
2035	5,870,805	1.0%	487,634	0.6%	12,039	0.4%
2036	5,937,316	1.1%	490,584	0.6%	12,103	0.5%
2037	5,981,896	0.8%	493,391	0.6%	12,124	0.2%
16-37		0.8%		0.6%		0.2%

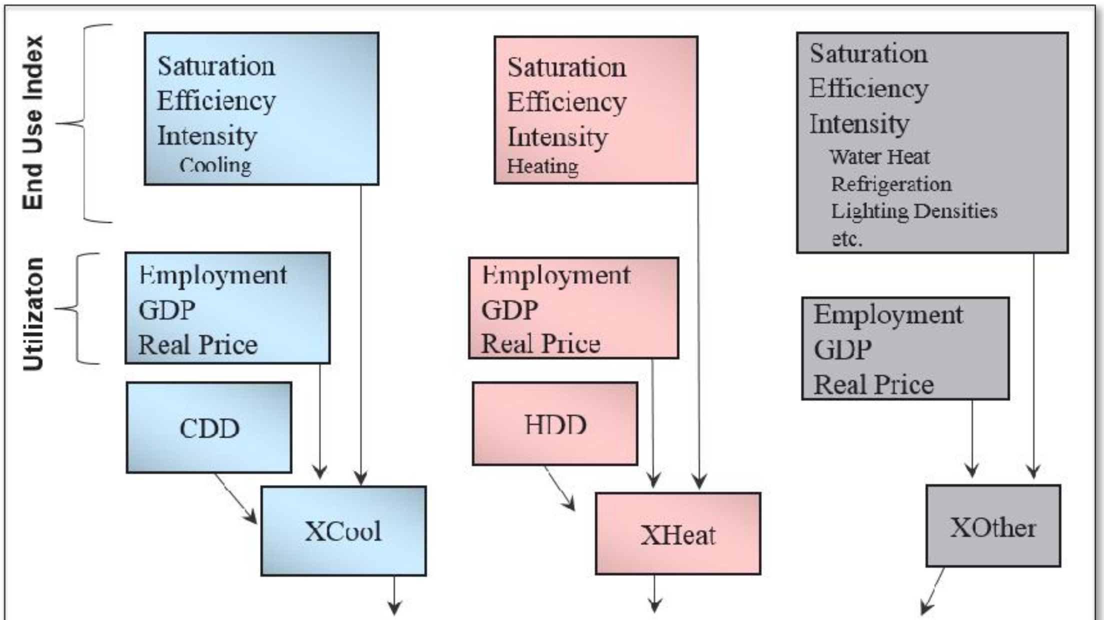
2.2 Nonresidential ~~Commercial and Industrial~~ Models

Commercial ~~The commercial~~ sales are~~model is~~ also estimated using an SAE model structure. The difference is that in the commercial sector sales forecast is based on a total sales model rather than an average use and customer model. Commercial sales are expressed as a function of heating requirements, cooling requirements, and other commercial use:

- $ComSales_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$

The constructed model variables include HDD, CDD, billing days, commercial economic activity variable, price, and end-use intensity trends (measured on a kWh per sqft basis). All but miscellaneous end-use intensities are trending down as end-use efficiency improvements outweigh increase in commercial end-use saturation growth. Figure 8 shows the commercial SAE model framework

Figure 8: Commercial Model Framework



$$Sales_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + e_m$$

A detailed description of the Commercial SAE model is included in Appendix B.

Separate monthly regression models are estimated for each non-residential rate schedule. While the rate schedules are defined by customer size (Small C&I and Large C&I), all but the high load factor rate schedules (H1, H2, and H3) are modeled using the commercial SAE model specification; the commercial model specification explained sales variation well based on model fit statistics. The high load factor rates are assumed to be primarily industrial loads and include some of IPL's largest customers.

Commercial sales like residential have been trending down. Since 2007 annual commercial sales have declined on average 0.9%. The primary factors driving commercial sales are expected economic activity, declining end-use intensities, and increasing electric prices. Over the next twenty years, economic driver (combination of employment and output) averages 1.2% annual growth, total end-use intensity declines 0.2% per-year, and real prices increase 1.5% annually. The combination of these factors results in 0.5% annual commercial sales growth through 2037 before DSM savings adjustments.

Economic Driver. The economic variable is weighted between non-manufacturing employment and non-manufacturing output for the Indianapolis MSA. The variable is more heavily weighted on employment than output as the stronger weighting on employment yields better in-sample and out-of-sample model fit statistics. The two concepts account for different but overlapping aspects of business activity; employment growth captures commercial customer growth and expansion at existing customers' sites and output growth reflects productivity growth and increase in product and service demand. The constructed economic variable for the Large Secondary Service (SL) rate schedule is defined as:

- $SLEconVar_m = (NonManOutput_m^{0.2}) \times (NonManEmployment_m^{0.8})$

The weighting is the same for the small commercial rate schedules – secondary service (SS) and secondary service electric heat (SH). The large primary service (PL) rate class is modeled using total employment and total output rather than non-manufacturing employment and output as model results are slightly better using measures of total economic activity.

Overall, the constructed model variables explain historical variation well as measured by model Adjusted R-Squared and MAPE. Adjusted R-Squared varies from 0.90 to 0.98 with MAPEs that vary from 6.15% to 1.00%. Model statistics and forecast plots are included in Appendix A.

Industrial Models. The high load factor rate schedules (H1, H2, and H3) include primarily industrial customers. Monthly billed sales are modeled as a function of CDD (in the H1 model), manufacturing employment, and industrial output. The constructed model variables do not include end-use intensity estimates given lack of data for developing industrial intensity estimates. Like commercial models, the economic variables are weighted between manufacturing employment and industrial output with a stronger weight on employment:

- $H1EconVar_m = (ManOutput_m^{0.2}) \times (ManEmployment_m^{0.8})$
- $H2EconVar_m = (ManOutput_m^{0.1}) \times (ManEmployment_m^{0.9})$

The H3 rate-schedule is relatively small consisting of two customers. Sales dropped in the beginning of 2016 and are expected to hold at current levels.

The economic weighting is derived by evaluating the model in-sample and out-sample statistics. Model statistics and forecast plots are included in Appendix A.

Table 2-3 shows the small C&I, large C&I, and total non-residential sales forecast; sales forecast excludes the impact of future DSM program activity.

Table 2-3: Non-Residential Sales Forecast (Excluding Future DSM Savings)

Year	Small C&I (MWh)		Large C&I (MWh)		Total C&I (MWh)	
2016	1,867,062		6,819,677		8,686,739	
2017	1,897,316	1.6%	6,843,124	0.3%	8,740,440	0.6%
2018	1,896,822	0.0%	6,833,942	-0.1%	8,730,765	-0.1%
2019	1,895,903	0.0%	6,823,963	-0.1%	8,719,866	-0.1%
2020	1,901,780	0.3%	6,832,396	0.1%	8,734,176	0.2%
2021	1,902,404	0.0%	6,812,428	-0.3%	8,714,832	-0.2%
2022	1,909,343	0.4%	6,822,236	0.1%	8,731,579	0.2%
2023	1,919,440	0.5%	6,844,915	0.3%	8,764,355	0.4%
2024	1,930,778	0.6%	6,872,892	0.4%	8,803,670	0.4%
2025	1,934,469	0.2%	6,871,699	0.0%	8,806,169	0.0%
2026	1,942,211	0.4%	6,888,650	0.2%	8,830,860	0.3%
2027	1,950,298	0.4%	6,908,352	0.3%	8,858,650	0.3%
2028	1,963,051	0.7%	6,947,166	0.6%	8,910,216	0.6%
2029	1,968,699	0.3%	6,956,565	0.1%	8,925,264	0.2%
2030	1,978,955	0.5%	6,984,495	0.4%	8,963,450	0.4%
2031	1,989,545	0.5%	7,013,945	0.4%	9,003,490	0.4%
2032	2,004,625	0.8%	7,061,589	0.7%	9,066,214	0.7%
2033	2,013,616	0.4%	7,083,003	0.3%	9,096,619	0.3%
2034	2,028,173	0.7%	7,125,681	0.6%	9,153,854	0.6%
2035	2,043,386	0.8%	7,170,399	0.6%	9,213,785	0.7%
2036	2,062,677	0.9%	7,231,561	0.9%	9,294,238	0.9%
2037	2,073,523	0.5%	7,259,323	0.4%	9,332,846	0.4%
16-37		0.5%		0.3%		0.3%

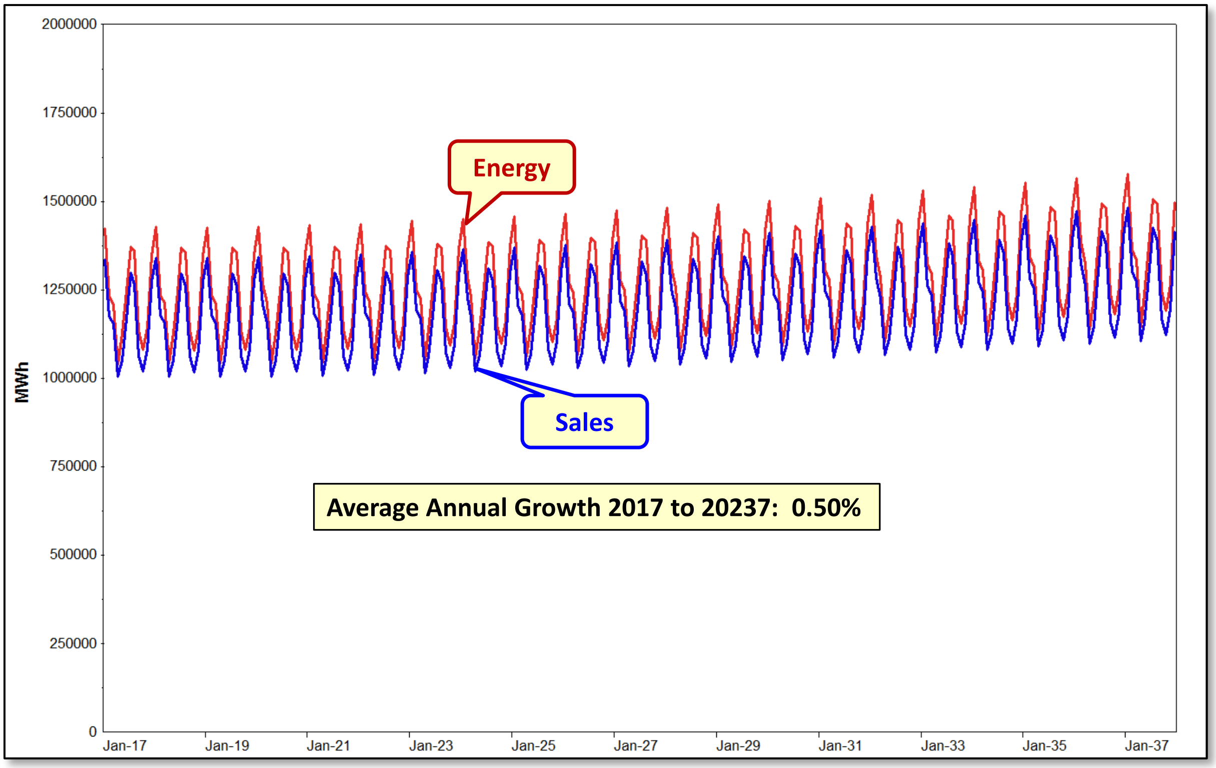
2.3 Street and Security Lighting Models

Street lighting and security lighting are estimated using simple trend and monthly binary models. Street lighting sales have been declining and are expected to continue to decline through the forecast period as increasing lamp efficiency outpaces installation of new street lights. The monthly binary variables capture the variation in monthly lighting sales across the year with the highest level of lighting in January and lowest level of lighting in July. Lighting models are included in Appendix A.

2.4 Energy and Peak Forecast Models

Energy Forecast. System energy forecast 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. The adjustment factors are calculated for each month. The annual forecast adjustment factor is 1.059. Figure 9 compares monthly energy and sales forecast.

Figure 9: Energy and Sales Forecast (Excluding DSM Program Savings)



Peak Forecast. The peak forecast is driven by heating, cooling, and base-use energy requirements derived from the sales forecast models. Cooling and heating requirements are interacted with peak-day CDD and HDD:

- $PkCool_m = CoolLoad_m \times PkCDD_m$
- $PkHeat_m = HeatLoad_m \times PkHDD_m$

As cooling requirements ($CoolLoad_m$) increase so will the impact of peak-day CDD ($PkCDD_m$). The impact of peak-day HDD ($PkHDD_m$) on the winter peak-day depends on electric heating requirements ($HeatLoad_m$). The base-load variable ($PkBase_m$) captures non-weather sensitive load at the time of the monthly peak. Annual base-load energy requirements are derived by subtracting weather-normalized heating and cooling requirements from total sales. Monthly base-load estimates are calculated by allocating base-use energy requirements to end-use estimates at the time of peak; end-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 10 to Figure 12 shows the calculated model variables.

Figure 10: Peak Heating Variable

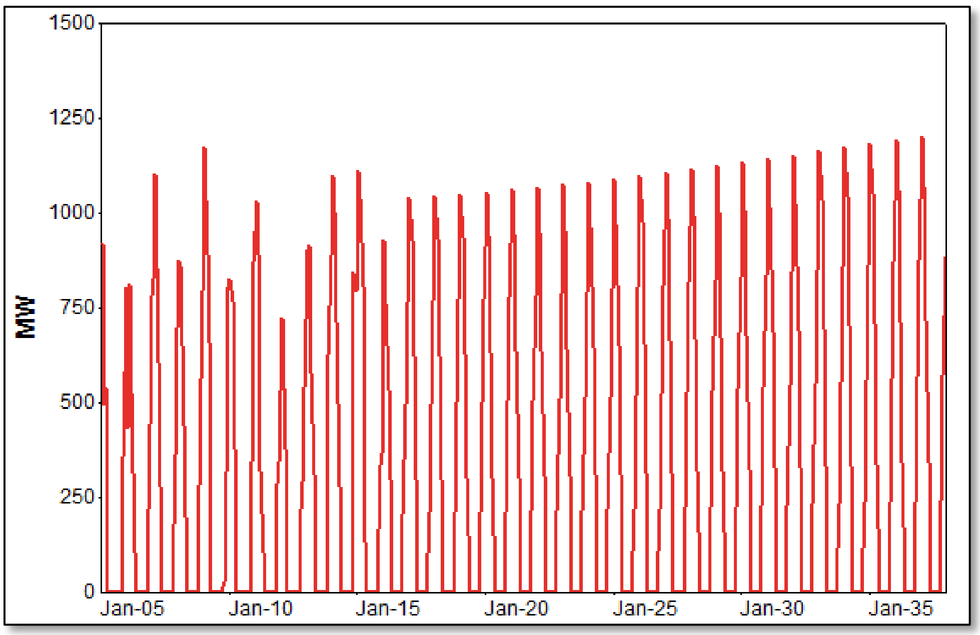


Figure 11: Peak Cooling Variable

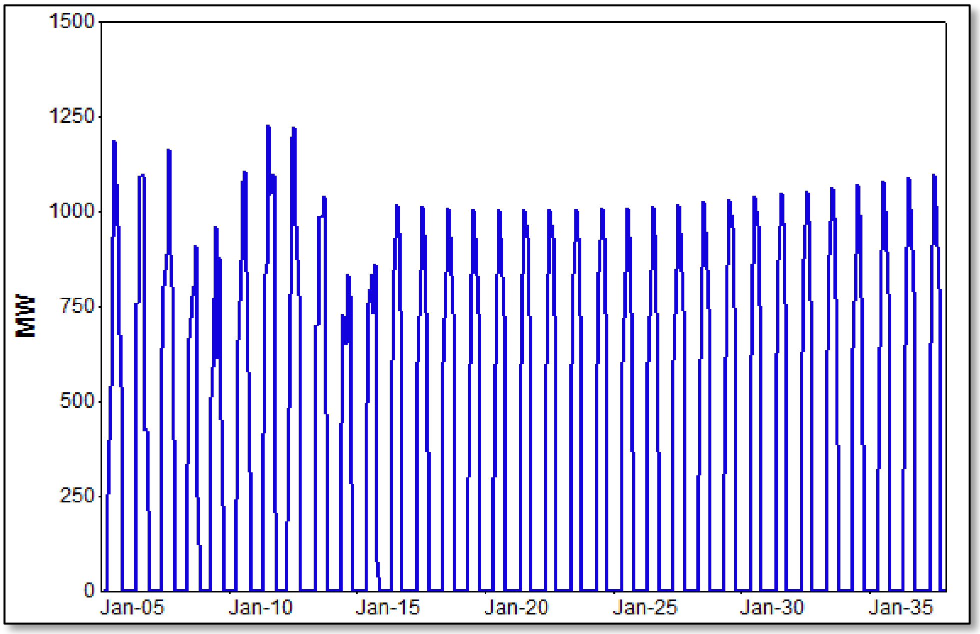
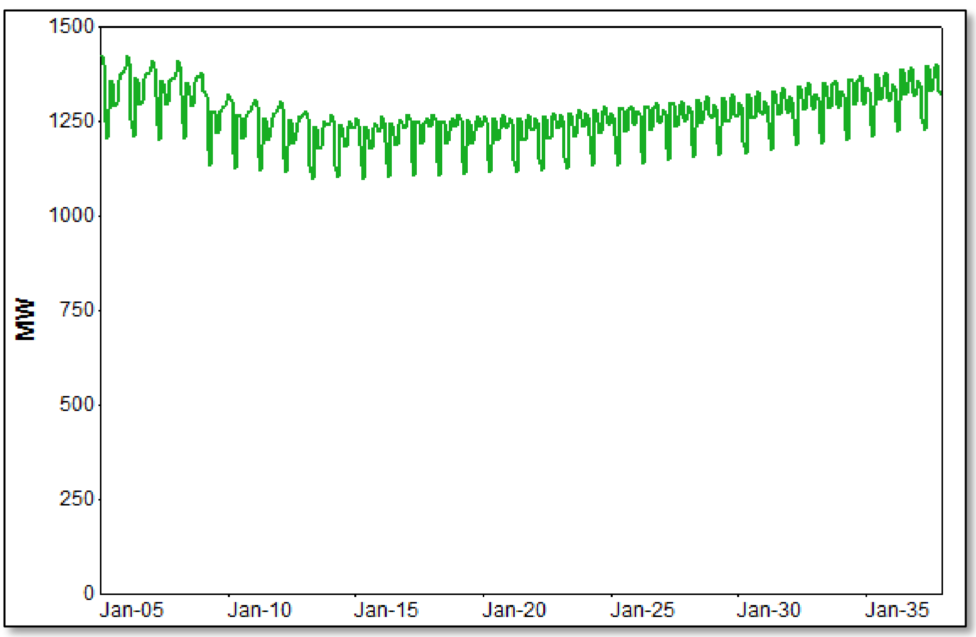
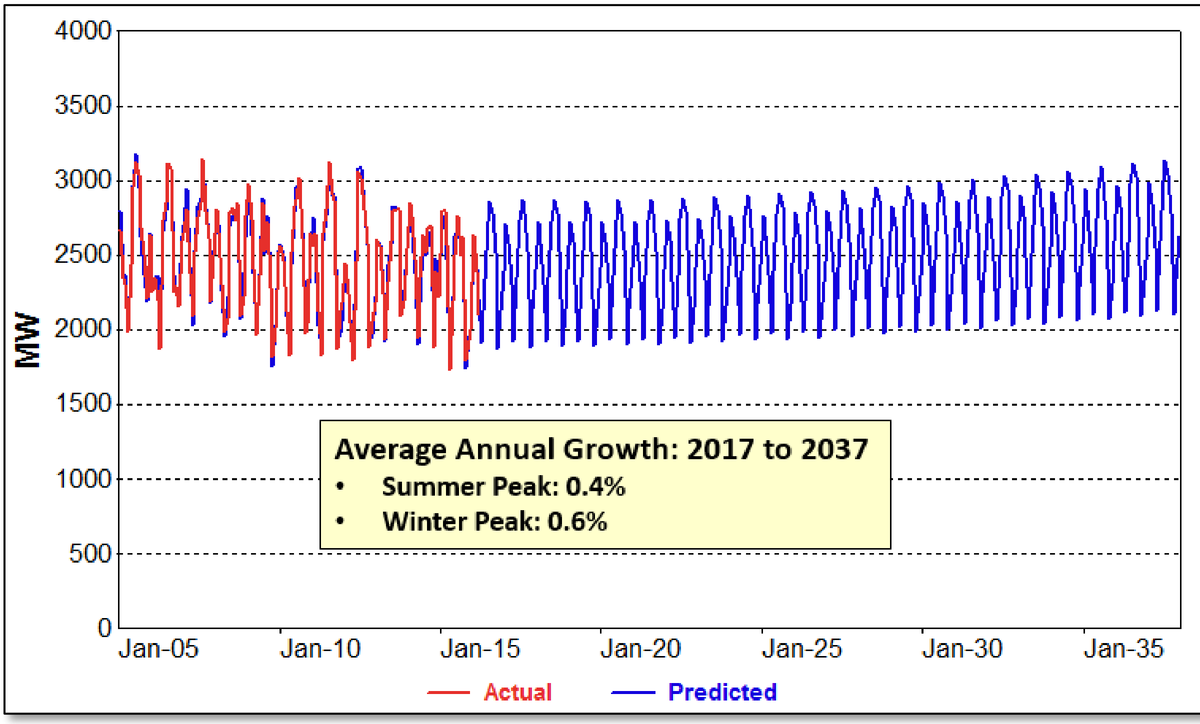


Figure 12: Peak Base Variable



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. The model is estimated over the period January 2005 to March 2016. The model explains monthly peak variation well with an adjusted R^2 of 0.96 and an in-sample MAPE of 2.1%. The model variables – *PkHeat*, *PKCool*, and *PkBase* are all highly significant. Figure 13 shows actual and predicted model results.

Figure 13: System Peak Model



Forecasted system peak growth is just slightly lower than system energy (0.4% vs 0.5%). shows actual and predicted results. Model statistics and parameters are included in Appendix A.

3 Forecast Assumptions

3.1 Weather Data

Actual and normal monthly HDD and CDD are key inputs in the monthly sales forecast models. Historical and normal monthly HDD and 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 from 1986 to 2015 by averaging the historical monthly HDD and CDD for each month. Figure 14 and Figure 15 show historical and forecasted monthly HDD and CDD.

Figure 14: Heating Degree Days

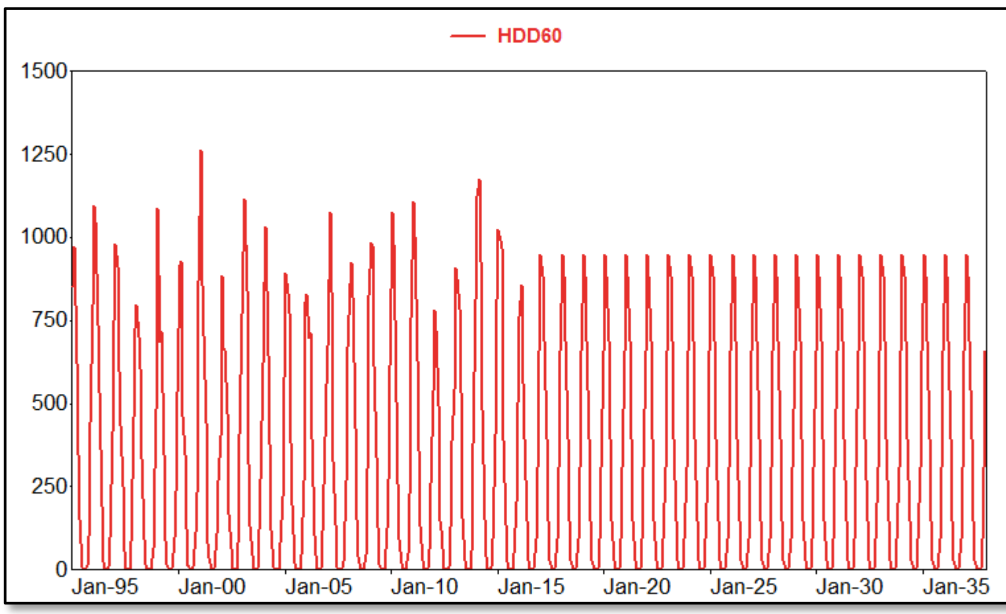
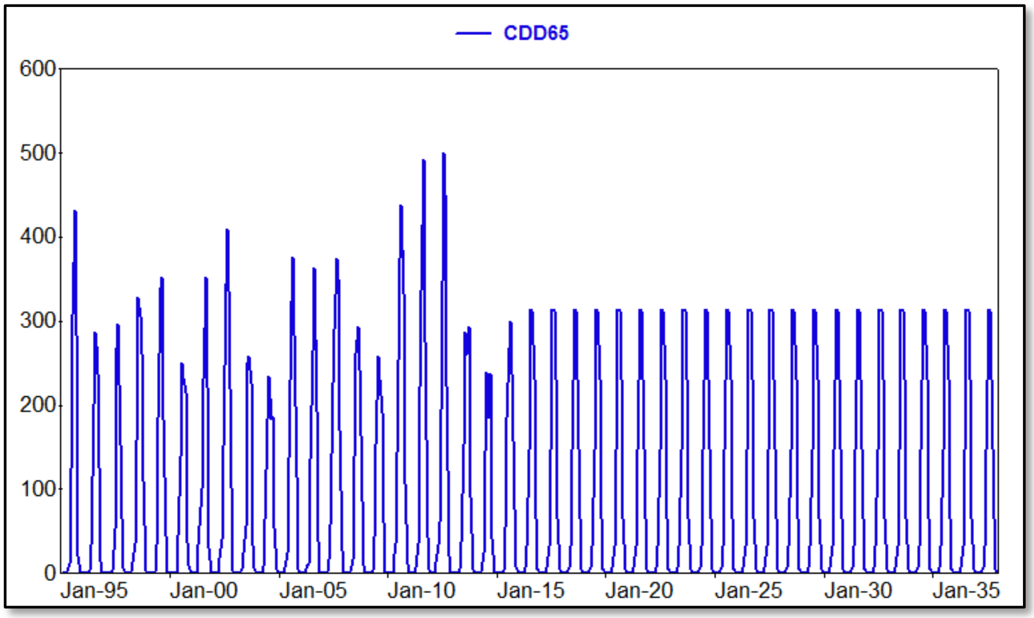


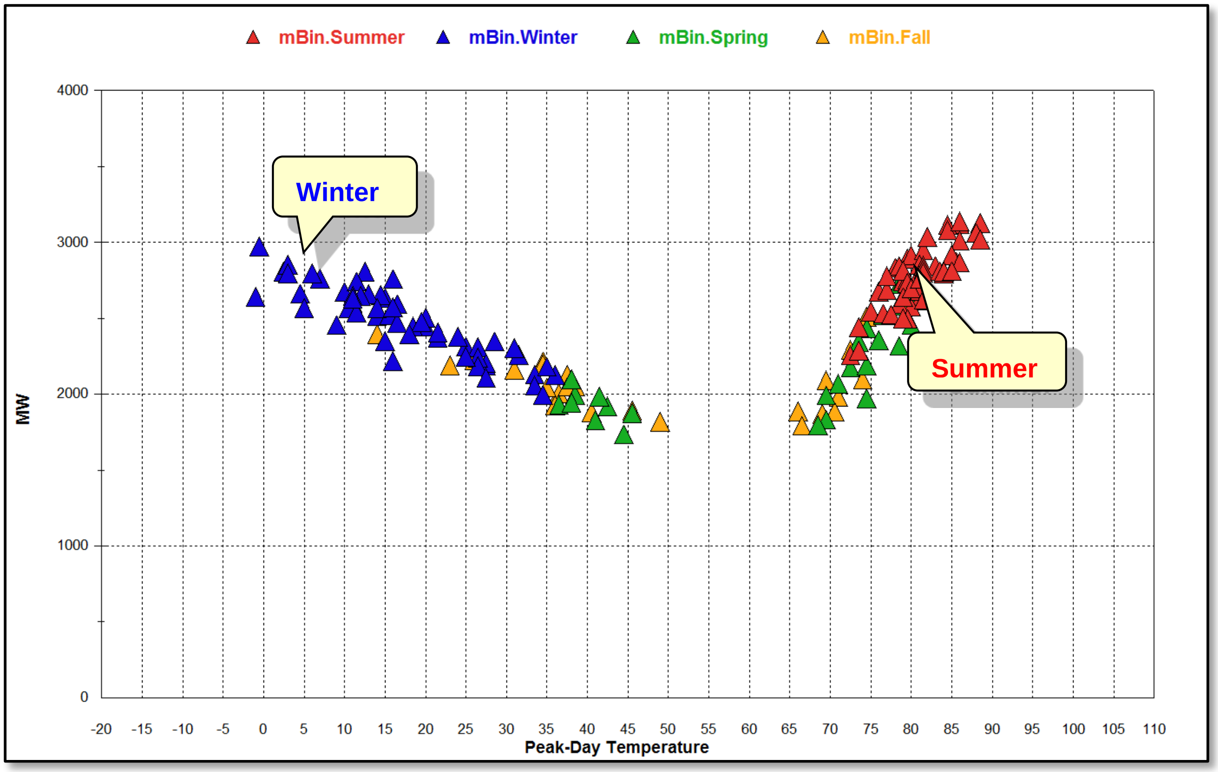
Figure 15: Cooling Degree Days



Peak-Day Weather Variables

Peak-day CDD and HDD are used in forecasting system peal demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature as shown in Figure 16.

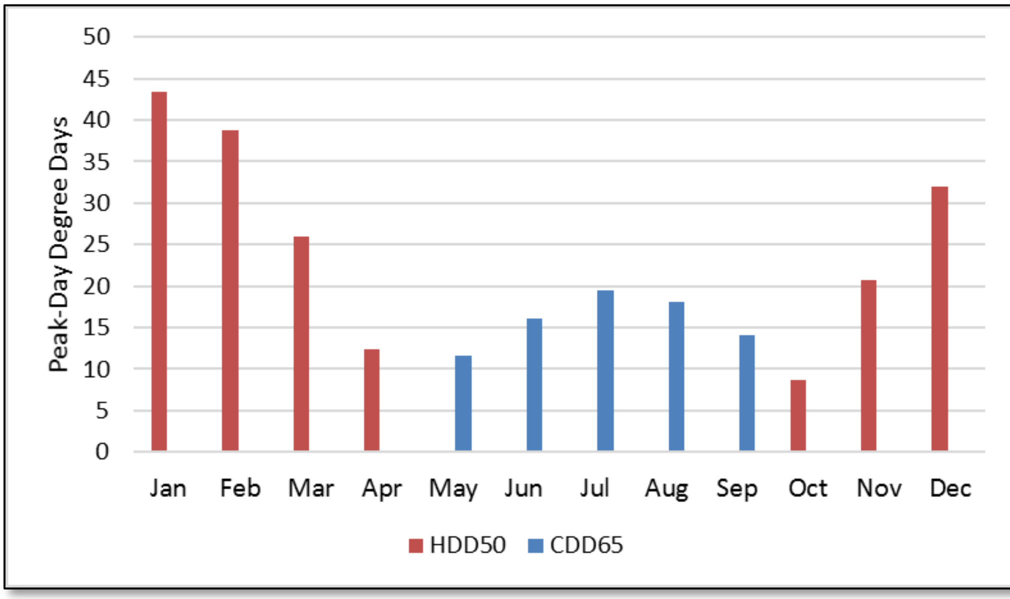
Figure 16: Monthly Peak Demand /Temperature Relationship



Peak-day cooling occurs when temperatures are above 65 degrees and peak-day heating occurs when temperatures are below 50 degrees.

Normal peak-day HDD and CDD are calculated using 15 years of historical weather data (2001 to 2015). Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. Figure 17 shows normal peak-day HDD (base 50 degrees) and peak-day CDD (base 65 degrees).

Figure 17: Normal Peak-Day HDD & CDD



3.2 Economic Data

Economic projections are key driver of the forecast. The class sales forecasts are based on economic forecast for Marion County and the greater Indianapolis Metropolitan Statistical Area (MSA). The primary economic drivers in the residential model are Marion County population projections and real income projections. Commercial sales are driven by Indianapolis MSA non-manufacturing employment and non-manufacturing output and industrial sales by manufacturing employment and manufacturing output.

The forecast incorporates economic projections from two economic forecasting firms – Moody Analytics and Woods & Poole. IPL has traditionally used Moody Analytics economic forecast. This year, however, the near-term forecast seemed unreasonably high; Moody's December 2015 forecast showed Indianapolis 2017 real GDP growth over 5.0%; actual GDP growth has been averaging a little over 2.0%. Woods & Poole is projecting more reasonable near-term economic growth with GDP growth of a little over 2.0%. Moody's economic forecast through 2020 is an adjusted down to reflect Woods & Poole's more reasonable near-term forecast. Table 3-1 through Table 3-3 shows the economic forecasts applicable to each class.

Table 3-1: Residential Economic Drivers

Year	Households (Thou.)		Household Income ($)	
2005	355		42,854	
2006	357	0.5%	44,344	3.5%
2007	359	0.5%	43,472	-2.0%
2008	361	0.6%	42,834	-1.5%
2009	364	0.9%	41,215	-3.8%
2010	366	0.6%	41,304	0.2%
2011	369	0.7%	41,681	0.9%
2012	373	1.1%	42,454	1.9%
2013	377	1.1%	41,541	-2.1%
2014	380	0.9%	42,076	1.3%
2015	383	0.8%	43,387	3.1%
2016	386	0.7%	44,432	2.4%
2017	388	0.6%	45,383	2.1%
2018	392	0.9%	46,342	2.1%
2019	395	0.9%	47,156	1.8%
2020	399	0.9%	47,810	1.4%
2021	402	0.9%	48,542	1.5%
2022	405	0.7%	49,280	1.5%
2023	408	0.8%	49,945	1.3%
2024	412	0.8%	50,625	1.4%
2025	415	0.9%	51,387	1.5%
2026	419	0.9%	52,188	1.6%
2027	422	0.8%	53,057	1.7%
2028	426	0.8%	54,002	1.8%
2029	429	0.8%	54,975	1.8%
2030	433	0.8%	55,964	1.8%
2031	437	0.9%	56,964	1.8%
2032	440	0.8%	57,988	1.8%
2033	444	0.8%	59,031	1.8%
2034	447	0.8%	60,115	1.8%
2035	451	0.7%	61,246	1.9%
2036	454	0.7%	62,399	1.9%
2037	457	0.7%	63,611	1.9%
16-37		0.8%		1.7%

Table 3-2: Commercial Economic Drivers

Year	Indianapolis Non-Manufacturing Employment (Thou)	Chg	Indianapolis Non-Manufacturing Output (Mil)	Chg
2005	833.9		73,130.0	
2006	849.4	1.9%	74,374.4	1.7%
2007	852.9	0.4%	73,913.8	-0.6%
2008	869.7	2.0%	73,906.3	0.0%
2009	874.0	0.5%	72,925.7	-1.3%
2010	862.0	-1.4%	74,059.6	1.6%
2011	871.1	1.1%	75,190.0	1.5%
2012	876.4	0.6%	77,626.5	3.2%
2013	890.6	1.6%	78,792.2	1.5%
2014	904.5	1.6%	79,757.2	1.2%
2015	915.7	1.2%	82,905.2	3.9%
2016	926.8	1.2%	86,045.3	3.8%
2017	933.2	0.7%	88,083.0	2.4%
2018	937.9	0.5%	90,152.6	2.3%
2019	943.5	0.6%	92,236.2	2.3%
2020	951.3	0.8%	94,364.3	2.3%
2021	960.4	1.0%	96,463.1	2.2%
2022	968.8	0.9%	98,692.9	2.3%
2023	977.3	0.9%	100,993.3	2.3%
2024	985.9	0.9%	103,216.0	2.2%
2025	994.5	0.9%	105,523.2	2.2%
2026	1,002.6	0.8%	107,938.8	2.3%
2027	1,010.7	0.8%	110,570.0	2.4%
2028	1,019.2	0.8%	113,339.4	2.5%
2029	1,027.8	0.8%	116,228.7	2.5%
2030	1,036.7	0.9%	119,219.8	2.6%
2031	1,045.9	0.9%	122,254.6	2.5%
2032	1,055.5	0.9%	125,368.1	2.5%
2033	1,066.5	1.0%	128,649.7	2.6%
2034	1,078.4	1.1%	132,120.9	2.7%
2035	1,090.6	1.1%	135,714.4	2.7%
2036	1,102.6	1.1%	139,336.1	2.7%
2037	1,114.7	1.1%	143,022.9	2.6%
16-37		0.9%		2.4%

Table 3-3: Industrial Economic Drivers

Year	Indianapolis Manufacturing Employment (Thou)	Chg	Indianapolis Manufacturing Output (Mil)	Chg
2005	107.5		18,330.3	
2006	106.3	-1.1%	18,691.2	2.0%
2007	101.8	-4.2%	21,706.3	16.1%
2008	99.3	-2.5%	23,450.5	8.0%
2009	88.0	-11.4%	21,738.9	-7.3%
2010	85.6	-2.7%	23,136.6	6.4%
2011	84.6	-1.2%	21,209.5	-8.3%
2012	86.8	2.5%	19,643.9	-7.4%
2013	87.7	1.1%	21,117.0	7.5%
2014	89.3	1.8%	21,490.7	1.8%
2015	91.8	2.8%	22,220.4	3.4%
2016	92.1	0.3%	23,038.0	3.7%
2017	92.6	0.6%	23,513.9	2.1%
2018	92.9	0.3%	23,943.9	1.8%
2019	92.9	0.0%	24,365.0	1.8%
2020	92.2	-0.7%	24,757.5	1.6%
2021	91.2	-1.1%	25,160.4	1.6%
2022	90.3	-1.0%	25,635.4	1.9%
2023	89.4	-0.9%	26,130.8	1.9%
2024	88.7	-0.8%	26,629.3	1.9%
2025	88.0	-0.7%	27,136.9	1.9%
2026	87.4	-0.7%	27,692.4	2.0%
2027	86.9	-0.6%	28,316.9	2.3%
2028	86.4	-0.5%	28,993.1	2.4%
2029	86.1	-0.4%	29,689.1	2.4%
2030	85.7	-0.4%	30,387.8	2.4%
2031	85.5	-0.3%	31,081.2	2.3%
2032	85.2	-0.3%	31,782.7	2.3%
2033	85.0	-0.3%	32,520.1	2.3%
2034	84.8	-0.2%	33,304.6	2.4%
2035	84.6	-0.2%	34,135.7	2.5%
2036	84.4	-0.2%	34,965.0	2.4%
2037	84.3	-0.2%	35,768.5	2.3%
16-37		-0.4%		2.1%

3.3 Prices

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. Prices impact residential and commercial sales through imposed short-term price elasticities. Short-term price elasticities are small; residential elasticities are set at -0.05 and commercial and industrial price elasticities are set at -0.10. Figure 18 shows price forecasts for the residential RH and RS schedules, the Small C&I SS schedule, and the Large C&I SL and PL schedules.

Figure 18: Historical and projected real electricity prices (cents per kWh)

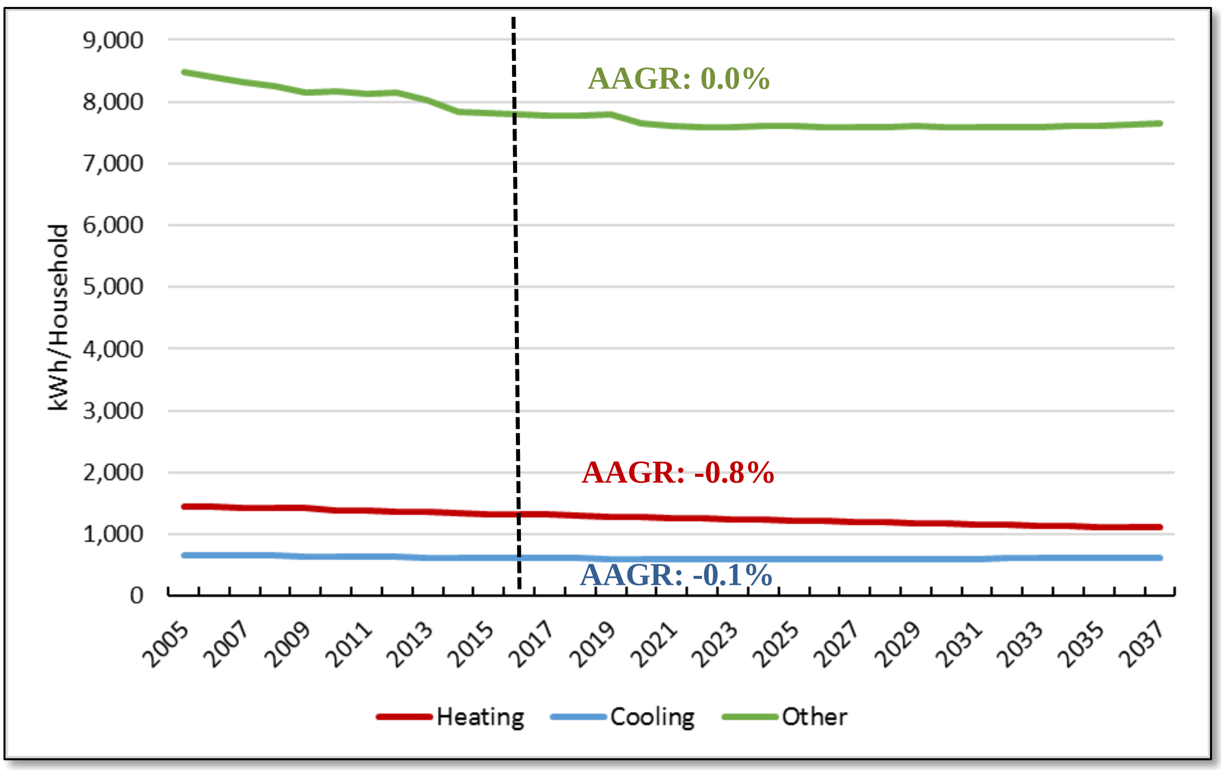
Electric prices are expected to average 3.1% growth over the next five years, before leveling out at a long-term growth rate of 1.2%; the long-term electric price projections are consistent with Energy Information Administration (EIA) projections.

3.4 Appliance Saturation and Efficiency Trends

Over the long-term, changes in end-use saturation and stock efficiency impact class sales, system energy, and peak demand. End-use energy intensities, expressed in kWh per household for the residential sector and kWh per square foot for the commercial sectors, are incorporated into the constructed forecast model variables. Energy intensities reflect both change in ownership (saturation) and average stock efficiency. In general efficiency is improving faster than growth in end-use saturation as a result end-use energy intensities are declining. Energy intensities are derived from Energy Information Administration's (EIA) 2015 Annual Energy Outlook for the East North Central Census Division. 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.

Residential end-use intensities are used in constructing residential XHeat, XCool, and XOther in the residential average use model. Figure 19 shows the resulting aggregated end-use intensity projections.

Figure 19: Residential End-Use Energy Intensities

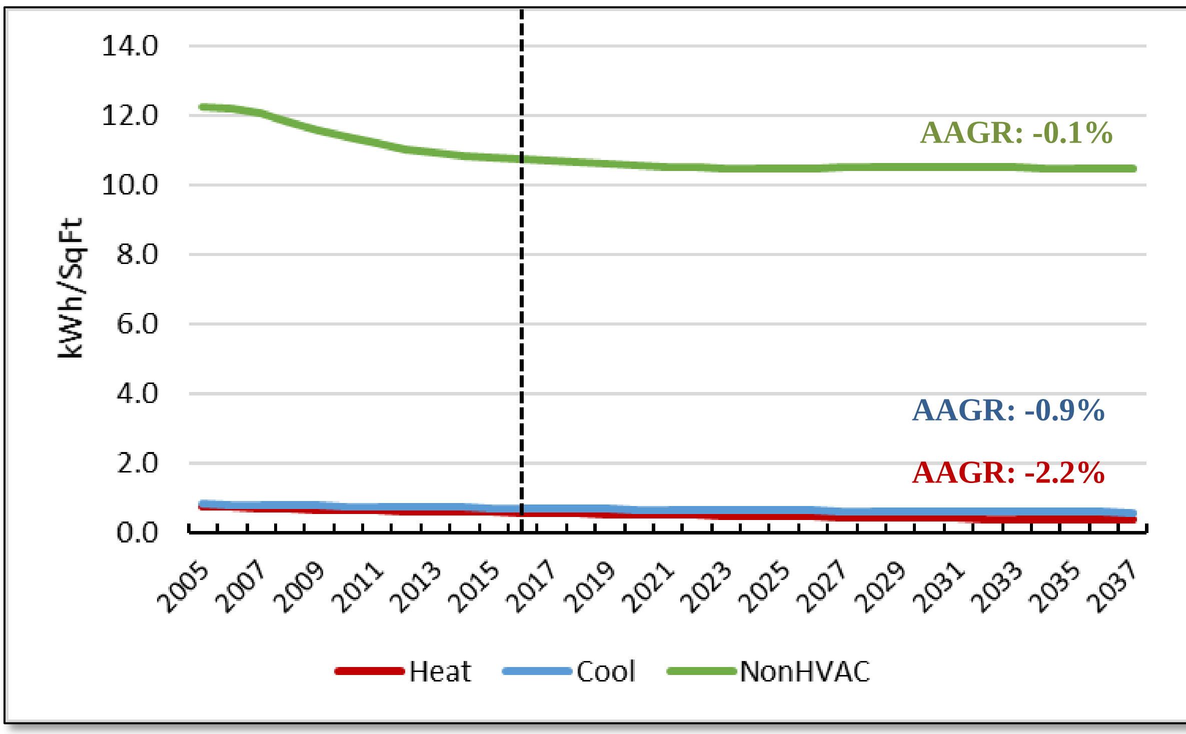


*AAGR=Average Annual Growth Rate

While overall, heating use per household is declining, total IPL heating load is increasing as a result of strong growth in electric heat customers. Cooling intensity declines 0.1% annually through the forecast period as overall air conditioning efficiency improvements and change from less efficient room air conditioning to central air conditioning slightly outweighs overall increase in air conditioning saturation. Again, while cooling intensity is declining overall cooling load is increasing as the number of new customers is increasing faster than cooling use per customer is declining. Total non-weather sensitive end-use intensity (Other) is flat over the forecast period. The majority of non-weather sensitive end-uses are declining driven by end-use efficiency improvements. Decline in intensities are offset by miscellaneous end-use sales growth.

Commercial end-use intensities are expressed in kWh per sqft. As in the residential sector, there have been significant improvements in end-use efficiency as a result of new codes and standards. Figure 20 shows commercial end-use energy intensity forecasts for the aggregated end-use categories.

Figure 20: Commercial End-Use Energy Intensity



Commercial usage is dominated by non-weather sensitive end-uses, which over the forecast period are projected to decline 0.1% annually. Cooling intensity declines 0.7% annually through the forecast period, driven by improvements in air conditioning efficiency. Heating intensity declines an even stronger 2.2% annual rate though commercial electric heating is relatively small.

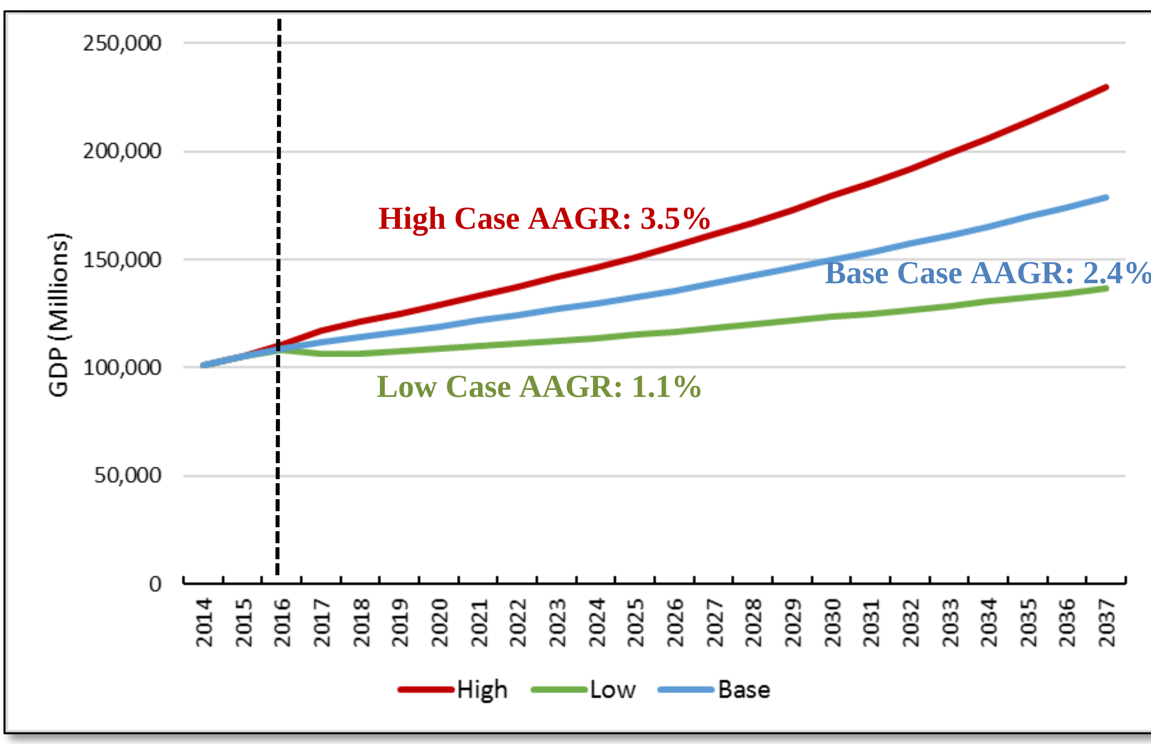
4 Forecast Sensitivities

A high and low case sales, energy, and demand forecasts were developed for respective economic growth scenarios.

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 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. Figure 21 shows the output forecasts from the base, high, and low cases.

Figure 21: Economic Scenarios



The estimated residential and commercial forecast models are used to generate high and low sales forecasts for the high and low economic scenarios. High and low energy projections then drive system peak forecast. Table 4-1 and Table 4-2 summarize base, high, and low case energy and peak forecasts.

Table 4-1: Scenario Forecasts: Energy (Excluding DSM Impacts)

Year	Base (GWh)		Low (GWh)		High (GWh)	
2016	14,487		14,432		14,574	
2017	14,707	1.5%	14,411	-0.1%	15,032	3.1%
2018	14,713	0.0%	14,268	-1.0%	15,182	1.0%
2019	14,717	0.0%	14,195	-0.5%	15,315	0.9%
2020	14,761	0.3%	14,162	-0.2%	15,451	0.9%
2021	14,751	-0.1%	14,068	-0.7%	15,523	0.5%
2022	14,797	0.3%	14,044	-0.2%	15,665	0.9%
2023	14,870	0.5%	14,043	0.0%	15,828	1.0%
2024	14,967	0.7%	14,056	0.1%	16,014	1.2%
2025	15,005	0.3%	14,014	-0.3%	16,133	0.7%
2026	15,074	0.5%	14,006	-0.1%	16,289	1.0%
2027	15,152	0.5%	14,012	0.0%	16,464	1.1%
2028	15,268	0.8%	14,056	0.3%	16,687	1.4%
2029	15,332	0.4%	14,051	0.0%	16,854	1.0%
2030	15,423	0.6%	14,064	0.1%	17,049	1.2%
2031	15,520	0.6%	14,077	0.1%	17,247	1.2%
2032	15,651	0.8%	14,120	0.3%	17,485	1.4%
2033	15,731	0.5%	14,113	0.0%	17,663	1.0%
2034	15,853	0.8%	14,142	0.2%	17,891	1.3%
2035	15,979	0.8%	14,176	0.2%	18,130	1.3%
2036	16,135	1.0%	14,237	0.4%	18,405	1.5%
2037	16,223	0.5%	14,239	0.0%	18,606	1.1%
16-37		0.5%		-0.1%		1.2%

Table 4-2: Scenario Forecasts: Demand (Excluding DSM Impacts)

Year	Base (MW)		Low (MW)		High (MW)	
2016	2,863		2,854		2,878	
2017	2,866	0.1%	2,814	-1.4%	2,922	1.5%
2018	2,864	-0.1%	2,787	-1.0%	2,944	0.7%
2019	2,862	-0.1%	2,773	-0.5%	2,964	0.7%
2020	2,870	0.3%	2,768	-0.2%	2,988	0.8%
2021	2,868	-0.1%	2,752	-0.6%	3,001	0.4%
2022	2,875	0.2%	2,746	-0.2%	3,023	0.7%
2023	2,885	0.4%	2,744	-0.1%	3,050	0.9%
2024	2,900	0.5%	2,745	0.0%	3,079	1.0%
2025	2,907	0.3%	2,738	-0.2%	3,101	0.7%
2026	2,920	0.4%	2,737	0.0%	3,128	0.9%
2027	2,933	0.5%	2,738	0.0%	3,158	1.0%
2028	2,952	0.7%	2,745	0.2%	3,195	1.2%
2029	2,965	0.4%	2,746	0.0%	3,225	1.0%
2030	2,983	0.6%	2,750	0.2%	3,261	1.1%
2031	3,002	0.6%	2,755	0.2%	3,298	1.1%
2032	3,026	0.8%	2,763	0.3%	3,340	1.3%
2033	3,042	0.5%	2,764	0.0%	3,373	1.0%
2034	3,065	0.7%	2,770	0.2%	3,414	1.2%
2035	3,088	0.8%	2,777	0.3%	3,456	1.2%
2036	3,116	0.9%	2,788	0.4%	3,504	1.4%
2037	3,134	0.6%	2,791	0.1%	3,542	1.1%
16-37		0.4%		-0.1%		1.0%

5 Appendix A: Model Statistics

RH Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
RH_Vars.XOther	1.06	0.02	58.08	0.00%
RH_Vars.XHeat	1.08	0.01	83.27	0.00%
RH_Vars.XCool	0.96	0.03	36.31	0.00%
mBin.Jan	83.51	14.31	5.84	0.00%
mBin.Feb	66.41	12.83	5.18	0.00%
mBin.Nov	-49.07	9.69	-5.06	0.00%
mBin.Jan06	-77.47	31.48	-2.46	1.52%
mBin.Jan07	-135.85	31.82	-4.27	0.00%
mBin.Yr2012Plus	-44.80	9.70	-4.62	0.00%
MA(1)	0.56	0.08	7.38	0.00%

Model Statistics	
Iterations	18
Adjusted Observations	135
Deg. of Freedom for Error	125
R-Squared	0.996
Adjusted R-Squared	0.996
Model Sum of Squares	39,103,854.28
Sum of Squared Errors	163,032.57
Mean Squared Error	1,304.26
Std. Error of Regression	36.11
Mean Abs. Dev. (MAD)	27.87
Mean Abs. % Err. (MAPE)	2.10%
Durbin-Watson Statistic	1.878

RH Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-119,334.34	23,141.40	-5.16	0.00%
Econ.MarionHH	703.08	60.22	11.68	0.00%
mBin.Jan	216.13	42.88	5.04	0.00%
mBin.Feb	329.63	48.27	6.83	0.00%
mBin.Mar	193.79	41.46	4.67	0.00%
mBin.May	-297.41	44.62	-6.67	0.00%
mBin.Jun	-511.60	58.42	-8.76	0.00%
mBin.Jul	-494.07	65.32	-7.56	0.00%
mBin.Aug	-493.47	67.45	-7.32	0.00%
mBin.Sep	-503.12	65.31	-7.70	0.00%
mBin.Oct	-532.18	58.41	-9.11	0.00%
mBin.Nov	-347.44	44.61	-7.79	0.00%
AR(1)	0.97	0.01	85.83	0.00%

Model Statistics	
Iterations	25
Adjusted Observations	131
Deg. of Freedom for Error	118
R-Squared	1
Adjusted R-Squared	1
Model Sum of Squares	8,177,887,395.05
Sum of Squared Errors	2,888,799.89
Mean Squared Error	24,481.36
Std. Error of Regression	156.47
Mean Abs. Dev. (MAD)	118.02
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.607

RS Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
RS_Vars.XOther	0.84	0.01	79.99	0.00%
RS_Vars.XCool	1.04	0.02	71.26	0.00%
RS_Vars.XHeat	1.04	0.04	23.68	0.00%
mBin.Jan	40.68	7.08	5.74	0.00%
mBin.Apr	-21.92	7.16	-3.06	0.27%
mBin.May	-15.39	7.38	-2.09	3.90%
mBin.Dec	23.03	7.09	3.25	0.15%
mBin.Mar05	-44.78	18.34	-2.44	1.60%
mBin.May15	-24.86	18.85	-1.32	18.97%
mBin.Yr2012Plus	14.12	5.42	2.61	1.03%
MA(1)	0.51	0.08	6.34	0.00%

Model Statistics	
Iterations	15
Adjusted Observations	135
Deg. of Freedom for Error	124
R-Squared	0.99
Adjusted R-Squared	0.989
Model Sum of Squares	5,178,615.13
Sum of Squared Errors	53,501.13
Mean Squared Error	431.46
Std. Error of Regression	20.77
Mean Abs. Dev. (MAD)	15.68
Mean Abs. % Err. (MAPE)	1.85%
Durbin-Watson Statistic	1.853

RS Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ.MarionHH	438.47	152.21	2.88	0.47%
mBin.Feb	313.72	71.48	4.39	0.00%
mBin.Mar	292.90	71.48	4.10	0.01%
mBin.May	-533.33	81.91	-6.51	0.00%
mBin.Jun	-905.76	107.27	-8.44	0.00%
mBin.Jul	-887.36	119.96	-7.40	0.00%
mBin.Aug	-958.60	123.88	-7.74	0.00%
mBin.Sep	-1036.74	119.94	-8.64	0.00%
mBin.Oct	-1037.95	107.26	-9.68	0.00%
mBin.Nov	-699.20	81.90	-8.54	0.00%
AR(1)	1.00	0.00	622.35	0.00%

Model Statistics	
Iterations	26
Adjusted Observations	131
Deg. of Freedom for Error	120
R-Squared	0.995
Adjusted R-Squared	0.995
Model Sum of Squares	2,001,189,786.14
Sum of Squared Errors	10,177,005.65
Mean Squared Error	84,808.38
Std. Error of Regression	291.22
Mean Abs. Dev. (MAD)	215.26
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.877

RC Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
RC_Vars.XHeat	1.03	0.03	31.49	0.00%
RC_Vars.XCool	0.96	0.03	37.18	0.00%
RC_Vars.XOther	1.18	0.02	71.62	0.00%
mBin.Jan	34.38	5.95	5.77	0.00%
mBin.Apr	-14.28	8.33	-1.71	8.91%
mBin.May	-27.29	9.09	-3.00	0.32%
mBin.Jul	44.70	9.49	4.71	0.00%
mBin.Aug	49.54	9.56	5.18	0.00%
mBin.Oct	-29.67	9.75	-3.04	0.29%
mBin.Nov	-28.73	8.75	-3.28	0.13%
MA(1)	0.75	0.09	8.53	0.00%
MA(2)	0.28	0.09	3.18	0.19%

Model Statistics	
Iterations	14
Adjusted Observations	135
Deg. of Freedom for Error	123
R-Squared	0.986
Adjusted R-Squared	0.984
Model Sum of Squares	5,229,520.52
Sum of Squared Errors	76,314.49
Mean Squared Error	620.44
Std. Error of Regression	24.91
Mean Abs. Dev. (MAD)	17.72
Mean Abs. % Err. (MAPE)	1.56%
Durbin-Watson Statistic	1.794

RC Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ.MarionHH	79.71	2.41	33.08	0.00%
mBin.Jan	39.68	11.66	3.40	0.09%
mBin.Feb	44.06	13.15	3.35	0.11%
mBin.Mar	42.40	11.29	3.76	0.03%
mBin.May	-58.85	12.15	-4.84	0.00%
mBin.Jun	-95.11	15.91	-5.98	0.00%
mBin.Jul	-85.70	17.79	-4.82	0.00%
mBin.Aug	-88.19	18.37	-4.80	0.00%
mBin.Sep	-101.60	17.79	-5.71	0.00%
mBin.Oct	-110.31	15.91	-6.93	0.00%
mBin.Nov	-77.06	12.15	-6.34	0.00%
AR(1)	0.99	0.00	332.89	0.00%

Model Statistics	
Iterations	12
Adjusted Observations	131
Deg. of Freedom for Error	119
R-Squared	0.994
Adjusted R-Squared	0.994
Model Sum of Squares	37,536,587.45
Sum of Squared Errors	220,603.50
Mean Squared Error	1,853.81
Std. Error of Regression	43.06
Mean Abs. Dev. (MAD)	29.54
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.77

CR Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CR_Custs.Filled	216.19	8.22	26.31	0.00%
mBin.Jan	2,336.64	300.13	7.79	0.00%
mBin.Feb	1,323.81	301.98	4.38	0.00%
mBin.Mar	992.52	248.35	4.00	0.01%
mBin.Jun	769.88	239.98	3.21	0.17%
mBin.Jul	1,035.36	275.77	3.75	0.03%
mBin.Aug	726.30	239.77	3.03	0.30%
mBin.Dec	1,258.26	246.81	5.10	0.00%
mBin.Oct	-799.06	197.83	-4.04	0.01%
AR(1)	0.82	0.05	15.27	0.00%

Model Statistics	
Iterations	12
Adjusted Observations	132
Deg. of Freedom for Error	122
R-Squared	0.856
Adjusted R-Squared	0.846
Model Sum of Squares	525,114,815.11
Sum of Squared Errors	88,130,728.36
Mean Squared Error	722,383.02
Std. Error of Regression	849.93
Mean Abs. Dev. (MAD)	600.01
Mean Abs. % Err. (MAPE)	6.12%
Durbin-Watson Statistic	2.243

Residential APL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	1,665,551.19	75,862.18	21.96	0.00%
mBin.Feb	1,523,025.24	74,781.18	20.37	0.00%
mBin.Mar	1,480,205.00	74,411.85	19.89	0.00%
mBin.Apr	1,344,275.11	74,371.20	18.08	0.00%
mBin.May	1,267,516.89	74,489.14	17.02	0.00%
mBin.Jun	1,194,379.75	74,685.17	15.99	0.00%
mBin.Jul	1,212,201.25	74,920.02	16.18	0.00%
mBin.Aug	1,280,387.69	75,174.24	17.03	0.00%
mBin.Sep	1,346,817.70	75,438.18	17.85	0.00%
mBin.Oct	1,494,785.35	75,707.00	19.74	0.00%
mBin.Nov	1,575,628.97	75,978.29	20.74	0.00%
mBin.Dec	1,649,460.62	76,250.85	21.63	0.00%
mBin.TrendVar	-23,869.21	3,374.49	-7.07	0.00%
AR(1)	0.49	0.09	5.50	0.00%

Model Statistics	
Iterations	7
Adjusted Observations	107
Deg. of Freedom for Error	92
R-Squared	0.941
Adjusted R-Squared	0.932
Model Sum of Squares	3,104,314,046,358.64
Sum of Squared Errors	194,263,914,829.61
Mean Squared Error	2,111,564,291.63
Std. Error of Regression	45951.76
Mean Abs. Dev. (MAD)	30744.65
Mean Abs. % Err. (MAPE)	3.37%
Durbin-Watson Statistic	2.278

SS Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
SS_Vars.XOther	0.92	0.01	66.26	0.00%
SS_Vars.XHeat	23.45	1.87	12.51	0.00%
SS_Vars.XCool	11.00	0.58	18.94	0.00%
mBin.Dec07	-5,164.21	1,329.03	-3.89	0.02%
mBin.Jan	1,478.69	640.35	2.31	2.26%
mBin.Feb	4,527.54	829.51	5.46	0.00%
mBin.Mar	5,588.51	769.67	7.26	0.00%
mBin.Apr	4,758.15	927.74	5.13	0.00%
mBin.May	6,430.75	1,156.57	5.56	0.00%
mBin.Jun	7,668.22	1,588.01	4.83	0.00%
mBin.Jul	9,731.86	2,016.91	4.83	0.00%
mBin.Aug	11,536.27	2,089.54	5.52	0.00%
mBin.Sep	8,455.50	1,826.37	4.63	0.00%
mBin.Oct	5,687.84	1,185.28	4.80	0.00%
mBin.Nov	1,991.25	738.07	2.70	0.80%
AR(1)	0.84	0.05	16.77	0.00%

Model Statistics	
Iterations	9
Adjusted Observations	135
Deg. of Freedom for Error	119
R-Squared	0.982
Adjusted R-Squared	0.98
Model Sum of Squares	18,079,367,990.45
Sum of Squared Errors	326,318,447.58
Mean Squared Error	2,742,171.83
Std. Error of Regression	1655.95
Mean Abs. Dev. (MAD)	1213.82
Mean Abs. % Err. (MAPE)	1.14%
Durbin-Watson Statistic	1.852

SH Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
SH_Vars.XOther	0.60	0.03	19.12	0.00%
SH_Vars.XHeat	107.22	5.53	19.37	0.00%
SH_Vars.XCool	13.80	1.65	8.39	0.00%
mBin.Jan	5,409.23	876.45	6.17	0.00%
mBin.Feb	8,392.10	1,066.13	7.87	0.00%
mBin.Mar	8,456.17	908.09	9.31	0.00%
mBin.Apr	6,414.15	1,088.37	5.89	0.00%
mBin.May	5,410.94	1,384.04	3.91	0.02%
mBin.Jun	4,363.37	1,959.03	2.23	2.78%
mBin.Jul	4,885.18	2,537.23	1.93	5.65%
mBin.Aug	6,654.30	2,648.75	2.51	1.33%
mBin.Sep	5,413.26	2,327.12	2.33	2.17%
mBin.Oct	4,694.27	1,536.30	3.06	0.28%
mBin.Nov	1,117.66	1,011.04	1.11	27.12%
AR(1)	0.41	0.08	4.98	0.00%

Model Statistics	
Iterations	18
Adjusted Observations	135
Deg. of Freedom for Error	120
R-Squared	0.976
Adjusted R-Squared	0.973
Model Sum of Squares	20,632,717,895.24
Sum of Squared Errors	510,208,753.64
Mean Squared Error	4,251,739.61
Std. Error of Regression	2061.97
Mean Abs. Dev. (MAD)	1491.4
Mean Abs. % Err. (MAPE)	2.88%
Durbin-Watson Statistic	2.163

SE Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1,909.34	54.53	35.02	0.00%
mRevWthr.CDD65	1.05	0.22	4.79	0.00%
mRevWthr.HDD55	1.35	0.08	16.35	0.00%
mBin.Apr	-129.70	44.34	-2.93	0.41%
mBin.Jun	-137.89	54.09	-2.55	1.20%
mBin.Jul	-380.64	68.52	-5.56	0.00%
mBin.Aug	-282.64	61.77	-4.58	0.00%
mBin.Nov	-189.86	46.51	-4.08	0.01%
mBin.Yr10Plus_Trend	-20.47	2.50	-8.19	0.00%
mBin.Yr11Plus_Winter	-258.98	61.90	-4.18	0.01%
AR(1)	0.51	0.08	6.46	0.00%

Model Statistics	
Iterations	14
Adjusted Observations	132
Deg. of Freedom for Error	121
R-Squared	0.903
Adjusted R-Squared	0.895
Model Sum of Squares	29,126,421.76
Sum of Squared Errors	3,142,542.19
Mean Squared Error	25,971.42
Std. Error of Regression	161.16
Mean Abs. Dev. (MAD)	121.74
Mean Abs. % Err. (MAPE)	6.15%
Durbin-Watson Statistic	2.087

CB Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	50.39	1.89	26.62	0.00%
mRevWthr.HDD60	0.02	0.00	9.20	0.00%
mBin.Mar	5.57	1.65	3.37	0.10%
mBin.Apr	9.11	1.99	4.57	0.00%
mBin.May	10.32	2.19	4.72	0.00%
mBin.Jun	11.66	2.32	5.03	0.00%
mBin.Jul	7.52	2.35	3.20	0.18%
mBin.Aug	4.79	2.35	2.04	4.40%
mBin.Sep	3.19	1.84	1.73	8.62%
mBin.Yr08Plus	-20.49	1.44	-14.19	0.00%
MA(1)	0.53	0.08	6.69	0.00%

Model Statistics	
Iterations	19
Adjusted Observations	133
Deg. of Freedom for Error	122
R-Squared	0.872
Adjusted R-Squared	0.861
Model Sum of Squares	20,428.43
Sum of Squared Errors	3,008.09
Mean Squared Error	24.66
Std. Error of Regression	4.97
Mean Abs. Dev. (MAD)	3.65
Mean Abs. % Err. (MAPE)	7.83%
Durbin-Watson Statistic	1.48

Small C&I APL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	16.66	6.99	2.38	1.90%
mBin.Jan	2,916.79	148.76	19.61	0.00%
mBin.Feb	2,581.95	149.00	17.33	0.00%
mBin.Mar	2,389.10	149.53	15.98	0.00%
mBin.Apr	2,115.80	150.07	14.10	0.00%
mBin.May	1,791.33	150.61	11.89	0.00%
mBin.Jun	1,588.55	151.15	10.51	0.00%
mBin.Jul	1,588.00	151.69	10.47	0.00%
mBin.Aug	1,753.13	152.23	11.52	0.00%
mBin.Sep	1,947.73	152.77	12.75	0.00%
mBin.Oct	2,334.44	153.31	15.23	0.00%
mBin.Nov	2,600.23	153.85	16.90	0.00%
mBin.Dec	2,792.36	153.66	18.17	0.00%
MA(1)	0.26	0.09	2.80	0.60%

Model Statistics	
Iterations	8
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.884
Adjusted R-Squared	0.87
Model Sum of Squares	24,757,847.37
Sum of Squared Errors	3,253,116.45
Mean Squared Error	30,689.78
Std. Error of Regression	175.18
Mean Abs. Dev. (MAD)	126.58
Mean Abs. % Err. (MAPE)	5.01%
Durbin-Watson Statistic	1.761

SL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
SLVars.XOther	1.09	0.01	156.71	0.00%
SLVars.XHeat	0.90	0.24	3.79	0.02%
SLVars.XCool	0.98	0.03	29.69	0.00%
mBin.Yr2010Plus	8,091.00	1,540.44	5.25	0.00%
mBin.Feb	9,890.71	1,205.43	8.21	0.00%
mBin.Mar	6,169.19	1,184.18	5.21	0.00%
mBin.May	2,839.14	1,079.53	2.63	0.96%
mBin.Aug	9,914.71	1,310.65	7.57	0.00%
mBin.Sep	8,896.82	1,514.22	5.88	0.00%
mBin.Oct	7,671.07	1,551.85	4.94	0.00%
mBin.Nov	3,154.23	1,359.28	2.32	2.20%
AR(1)	0.60	0.07	8.23	0.00%

Model Statistics	
Iterations	11
Adjusted Observations	135
Deg. of Freedom for Error	123
R-Squared	0.98
Adjusted R-Squared	0.978
Model Sum of Squares	86,927,294,407.87
Sum of Squared Errors	1,795,362,886.66
Mean Squared Error	14,596,446.23
Std. Error of Regression	3820.53
Mean Abs. Dev. (MAD)	2901.19
Mean Abs. % Err. (MAPE)	0.98%
Durbin-Watson Statistic	2.25

PL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
PLVars.XOther	0.98	0.01	93.77	0.00%
PLVars.XCool	1.01	0.05	20.28	0.00%
mBin.BfrSept08	-11,081.26	1,660.50	-6.67	0.00%
mBin.Yr2013Plus	-5,315.43	1,779.17	-2.99	0.34%
mBin.Yr2015Plus	-5,965.74	2,238.22	-2.67	0.87%
mBin.Jan07	-6,959.76	3,138.76	-2.22	2.84%
mBin.Feb07	12,837.79	3,247.21	3.95	0.01%
mBin.Sep09	8,241.14	2,815.21	2.93	0.41%
mBin.Aug12	-9,057.08	2,819.48	-3.21	0.17%
mBin.Jul14	-8,564.60	2,819.32	-3.04	0.29%
mBin.Feb	2,132.48	853.70	2.50	1.38%
AR(1)	0.61	0.07	8.22	0.00%

Model Statistics	
Iterations	13
Adjusted Observations	135
Deg. of Freedom for Error	123
R-Squared	0.932
Adjusted R-Squared	0.926
Model Sum of Squares	18,305,245,125.31
Sum of Squared Errors	1,332,690,411.75
Mean Squared Error	10,834,881.40
Std. Error of Regression	3291.64
Mean Abs. Dev. (MAD)	2543.98
Mean Abs. % Err. (MAPE)	2.22%
Durbin-Watson Statistic	2.26

H1 Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	5,728.50	7,277.00	0.79	43.27%
HLVars.XOther	1.10	0.07	17.01	0.00%
HLVars.XCool	1.00	0.09	11.16	0.00%
mBin.Yr12	-2,974.95	2,543.64	-1.17	24.45%
mBin.Yr2013Plus	-8,311.14	1,711.42	-4.86	0.00%
mBin.Feb06	-20,676.82	7,712.57	-2.68	0.84%
mBin.Dec12	-21,318.62	7,756.49	-2.75	0.69%
mBin.Jan15	26,417.03	7,519.02	3.51	0.06%
mBin.Sep07	-30,235.47	7,531.52	-4.02	0.01%
mBin.Feb	4,716.61	2,537.63	1.86	6.55%
mBin.Mar	9,402.22	2,406.31	3.91	0.02%
mBin.Apr	5,343.18	2,456.31	2.18	3.15%
mBin.May	7,990.39	2,406.23	3.32	0.12%
mBin.Jun	8,201.87	2,390.61	3.43	0.08%
MA(1)	-0.04	0.09	-0.43	66.69%

Model Statistics	
Iterations	20
Adjusted Observations	136
Deg. of Freedom for Error	121
R-Squared	0.879
Adjusted R-Squared	0.865
Model Sum of Squares	47,088,895,244.82
Sum of Squared Errors	6,473,321,422.13
Mean Squared Error	53,498,524.15
Std. Error of Regression	7314.27
Mean Abs. Dev. (MAD)	4386.02
Mean Abs. % Err. (MAPE)	3.28%
Durbin-Watson Statistic	1.958

H2 Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-12,598.85	2,917.09	-4.32	0.00%
mCalWthr.CDD60	9.64	0.94	10.23	0.00%
mEcon.HL2_EconVar	35,191.07	3,281.13	10.73	0.00%
mBin.Feb11	-9,568.60	1,644.98	-5.82	0.00%
mBin.Mar11	11,081.88	1,644.70	6.74	0.00%
mBin.Sep07	-2,841.29	1,576.10	-1.80	7.38%
mBin.Aug15	-13,755.45	1,645.28	-8.36	0.00%
mBin.Sep15	15,106.26	1,644.56	9.19	0.00%
AR(1)	0.34	0.08	4.03	0.01%

Model Statistics	
Iterations	7
Adjusted Observations	135
Deg. of Freedom for Error	126
R-Squared	0.843
Adjusted R-Squared	0.833
Model Sum of Squares	1,838,730,006.65
Sum of Squared Errors	342,148,095.42
Mean Squared Error	2,715,461.07
Std. Error of Regression	1647.87
Mean Abs. Dev. (MAD)	1249.68
Mean Abs. % Err. (MAPE)	6.21%
Durbin-Watson Statistic	2.305

H3 Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	32,609.33	404.19	80.68	0.00%
mCalWthr.CDD60	8.07	1.12	7.18	0.00%
mBin.Yr2009Plus	-10,665.16	600.08	-17.77	0.00%
mBin.May11Plus	6,052.91	592.92	10.21	0.00%
mBin.Oct15Plus	-2,312.64	1,512.95	-1.53	12.88%
mBin.YrPlus16	-2,140.21	2,067.45	-1.04	30.25%

Model Statistics	
Iterations	1
Adjusted Observations	136
Deg. of Freedom for Error	130
R-Squared	0.755
Adjusted R-Squared	0.746
Model Sum of Squares	2,567,749,516.75
Sum of Squared Errors	833,400,383.62
Mean Squared Error	6,410,772.18
Std. Error of Regression	2531.95
Mean Abs. Dev. (MAD)	1920.35
Mean Abs. % Err. (MAPE)	6.60%
Durbin-Watson Statistic	1.89

Large C&I APL Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	761.07	40.77	18.67	0.00%
mBin.Feb	698.26	40.48	17.25	0.00%
mBin.Mar	649.42	40.23	16.14	0.00%
mBin.Apr	592.32	40.25	14.71	0.00%
mBin.May	515.17	40.28	12.79	0.00%
mBin.Jun	459.81	40.17	11.45	0.00%
mBin.Jul	446.08	40.09	11.13	0.00%
mBin.Aug	501.17	39.99	12.53	0.00%
mBin.Sep	545.59	39.89	13.68	0.00%
mBin.Oct	628.87	39.78	15.81	0.00%
mBin.Nov	690.21	39.67	17.40	0.00%
mBin.Dec	731.75	39.56	18.50	0.00%
mBin.May06	-128.98	37.58	-3.43	0.08%
mBin.Yr2013Plus	-81.81	44.38	-1.84	6.77%
AR(1)	0.88	0.05	19.69	0.00%

Model Statistics	
Iterations	10
Adjusted Observations	135
Deg. of Freedom for Error	120
R-Squared	0.916
Adjusted R-Squared	0.906
Model Sum of Squares	2,942,551.29
Sum of Squared Errors	271,042.47
Mean Squared Error	2,258.69
Std. Error of Regression	47.53
Mean Abs. Dev. (MAD)	35.63
Mean Abs. % Err. (MAPE)	6.03%
Durbin-Watson Statistic	2.431

Street Lighting Sales

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	6,798.55	177.48	38.31	0.00%
mBin.Feb	5,947.67	177.65	33.48	0.00%
mBin.Mar	5,894.28	177.24	33.26	0.00%
mBin.Apr	5,059.77	174.31	29.03	0.00%
mBin.May	4,761.83	173.47	27.45	0.00%
mBin.Jun	4,425.01	173.50	25.51	0.00%
mBin.Jul	4,637.25	173.89	26.67	0.00%
mBin.Aug	5,020.05	174.43	28.78	0.00%
mBin.Sep	5,419.90	175.02	30.97	0.00%
mBin.Oct	6,216.07	175.63	35.39	0.00%
mBin.Nov	6,523.93	176.25	37.02	0.00%
mBin.Dec	6,925.89	176.87	39.16	0.00%
mBin.TrendVar	-45.66	7.45	-6.13	0.00%
AR(1)	0.48	0.10	4.67	0.00%

Model Statistics	
Iterations	9
Adjusted Observations	74
Deg. of Freedom for Error	60
R-Squared	0.996
Adjusted R-Squared	0.996
Model Sum of Squares	49,797,472.88
Sum of Squared Errors	183,582.22
Mean Squared Error	3,059.70
Std. Error of Regression	55.31
Mean Abs. Dev. (MAD)	32.76
Mean Abs. % Err. (MAPE)	0.67%
Durbin-Watson Statistic	2.204

6 Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

6.2 Residential Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_{m} = a + b_1 \times \mathrm{XHeat}_{m} + b_2 \times \mathrm{XCool}_{m} + b_3 \times \mathrm{XOther}_{m} + \varepsilon_{m} \tag{2}$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

6.2.1 Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 6-1.

Table 6-1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}}\right)^{0.15} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{-0.1} \qquad (7)$$

Where:

- *HDD* is the number of heating degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

6.2.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \qquad (8)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{9}$$

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 6-2.

Table 6-2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}} \right) \times \left(\frac{HHSize_y}{HHSize_{05,7}} \right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}} \right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{05,7}} \right)^{-0.1} \tag{10}$$

Where:

- *CDD* is the number of cooling degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first term, which involves cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

6.2.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{05}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{12}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_y}{HHSize_{05,7}} \right)^{0.26} \times \left(\frac{Income_y}{Income_{05,7}} \right)^{0.15} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}} \right)^{-0.1} \tag{13}$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{14}$$

7 Appendix C: Commercial SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

7.2 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_m = a + b_1 \times \mathrm{XHeat}_m + b_2 \times \mathrm{XCool}_m + b_3 \times \mathrm{XOther}_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

7.2.1 Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\mathrm{XHeat}_{y,m} = \mathrm{HeatIndex}_y \times \mathrm{HeatUse}_{y,m} \quad (3)$$

Where:

- *$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),*
- *$HeatInde_{xy}$ is the annual index of heating equipment, and*
- *$HeatUse_{y,m}$ is the monthly usage multiplier.*

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y / Eff_y \right)}{\left(HeatShare_{04} / Eff_{04} \right)} \qquad (4)$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft} \right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \qquad (5)$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}} \right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}} \right) \times \left(\frac{Price_{y,m}}{Price_{05,7}} \right)^{-0.10} \qquad (6)$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

7.2.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Commercial output, employment, population and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \tag{7}$$

Where:

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{\left(CoolShare_{y} \big/ Eff_{y} \right)}{\left(CoolShare_{04} \big/ Eff_{04} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e}\right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y,m}}{Price_{05,7}}\right)^{-0.15} \tag{10}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first term, which involves cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

7.2.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,

- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{04}^{Type} / Eff_{04}^{Type}} \right) \tag{12}$$

Where:

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}} \right) \times \left(\frac{\Pr ice_{y.m}}{\Pr ice_{05,7}} \right)^{-0.15} \tag{14}$$

IPL 2016 IRP

Confidential Attachment 4.4 (EIA End Use Data) is only available in the Confidential IRP.

Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \quad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_m = a + b_1 \times \mathrm{XHeat}_m + b_2 \times \mathrm{XCool}_m + b_3 \times \mathrm{XOther}_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \qquad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	505
Electric Space Heating Heat Pump	190

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \middle/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma} \quad (8)$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20}$$
$$\times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05,7}}\right)^{\kappa} \qquad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left({Sat_y^{Type}}\big/{Eff_y^{Type}} \right)}{\left({Sat_{05}^{Type}}\big/{Eff_{05}^{Type}} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,661
Space Cooling Heat Pump	369
Room Air Conditioning	315

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectric\,Price_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\,Price_{y,m}\right)^{\gamma} \tag{13}$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{05}}\right)^{\kappa} \quad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(\frac{Sat_{y}^{Type}}{\frac{1}{UEC_{y}^{Type}}} \right)}{\left(\frac{Sat_{05}^{Type}}{\frac{1}{UEC_{05}^{Type}}} \right)} \times MoMult_{m}^{Type} \times (TenYearMovingAverageElectric\,Price)^{\lambda} \times (TenYearMovingAverageGas\,Price)^{\kappa} \tag{16}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.46} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.10} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05}}\right)^{\phi} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05}}\right)^{\lambda} \tag{17}$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{18}$$

Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.2 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\text{USE}_m = a + b_1 \times \text{XHeat}_m + b_2 \times \text{XCool}_m + b_3 \times \text{XOther}_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\text{XHeat}_{y,m} = \text{HeatIndex}_y \times \text{HeatUse}_{y,m} \quad (3)$$

where, $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),
$HeatIndex_y$ is the annual index of heating equipment, and
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y / Eff_y \right)}{\left(HeatShare_{04} / Eff_{04} \right)} \quad (4)$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_{e} {kWh}/{Sqft}_{e}}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \tag{6}$$

where, *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days

WgtHDD is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.

HDD is the annual heating degree days for 2004,

Output is a real commercial output driver in year (y),

Price is the average real price of electricity in month (m) and year (y),

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{\mathrm{y,m}} = \mathrm{CoolIndex}_{\mathrm{y}} \times \mathrm{CoolUse}_{\mathrm{y,m}} \qquad (7)$$

where, $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
$CoolIndex_y$ is an index of cooling equipment, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left({CoolShare_y}/{Eff_y} \right)}{\left({CoolShare_{04}}/{Eff_{04}} \right)} \qquad (8)$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e}\right) \qquad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \qquad (10)$$

where, *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.

CDD is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} \big/ Eff_y^{Type}}{Share_{04}^{Type} \big/ Eff_{04}^{Type}} \right) \tag{12}$$

where, *Weight* is the weight for each equipment type,

Share represents the fraction of floor stock with an equipment type, and

Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh \big/ Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}} \right)^{-0.18} \tag{14}$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

IPL 2016 IRP

Attachment 4.6 (10 Yr. Energy and Peak Forecast) is provided electronically.

IPL 2016 IRP

Attachment 4.7 (20 Yr. High, Base and Low Forecast) is provided electronically.

IPL 2016 IRP

Confidential Attachment 4.8 (Energy-Forecast Drivers) is only available in the Confidential IRP.

IPL 2016 IRP

Attachment 4.9 (Energy Input Data - Residential) is provided electronically.

IPL 2016 IRP

Attachment 4.10 (Energy Input Data – Small C&I) is provided electronically.

IPL 2016 IRP

Attachment 4.11 (Energy – Large C&I) is provided electronically.

IPL 2016 IRP

Attachment 4.12 (Peak – Forecast Drivers and Input Data) is provided electronically.

IPL 2016 IRP

Attachment 4.13 (Forecast Error Analysis) is provided electronically.

PUBLIC VERSION

ABB

Midwest Fall 2015 Reference Case

Generic Unit Cost and Operating Characterisitcs

	Abbreviations	GT	CC - F class	CC - H class	NU	PV	CS	WT	CH	ES - PR	ES - AS
Unit Characteristics	**Units**	**Combustion Gas Turbine**	**Combined Cycle**	**Combined Cycle**	**Nuclear**	**Utility-scale PV (10 MW system)**	**Community solar (1 MW system)**	**Wind Turbine**	**CHP (Steam Turbine)**	**Battery - Peaker Replacement**	**Battery - Ancillary Services**
Earliest Feasible Year of Installation		2021	2022	2022	2027	2020	2019	2020	2020	2018	2018
Lead Time		4	5	5	10	3	2	3	3	1	1
Summer Capacity	MW	160	450	400	1000	10	1	100	8.54	50	20
Winter Capacity	MW	180	490	425	1000	10	1	100	10.02	50	20
Modeling Planning Capacity	%	100%	100%	100%	100%	48%	48%	10%	100%	100%	25%
Ownership	MW	160	200	200	200	10	1	50	10	50	20
Full Load Heat Rate	HHV, Btu/kWh	10,500	6,800	6,400	10,400	0	0	0	11,402	0	0
SO2 Emission Rate	(lb/MMBtu)	0	0	0	0	0	0	0	0.00	0	0
NOX Emission Rate	(lb/MMBtu)	0.03	0.01	0.01	0	0	0	0	0.064	0	0
CO2 Emission Rate	(lb/MMBtu)	120	120	120	0	0	0	0	117	0	0
Fixed O&M	2015 $/kW-yr	[redacted]									
Variable O&M	2015 $/MWh										
Forced Outage Rate	%	3.60%	5.50%	5.00%	3.80%	0.00%	0.00%	0.00%	1.90%	1.00%	1.00%
Maintenance Outage Rate (MOR)	%	4.10%	9.70%	9.50%	6.10%	0.00%	0.00%	0.00%	2.10%	2.00%	2.00%
Overnight Construction Cost	2015 $/kW	[redacted]									
Upper Stochastic Multiplier for Construction Cost		1.10	1.10	1.20	2.00	1.10	1.20	1.15	1.20	1.10	1.10
Lower Stochastic Multiplier for Construction Cost		0.95	0.95	0.95	1.00	0.90	0.90	0.90	0.90	0.90	0.90
Maximum Annual Units		4	4	4	4	60	5	5	1	5	15
Maximum Cumulative Units		40	40	40	40	100	50	100	10	100	200
Book Life	Years	20	30	30	40	25	25	20	30	20	20
Tax Life	Years	15	20	20	20	5	5	5	15	7	7
Carrying Charge--ABB to calculate with latest Capital Structure											

PUBLIC VERSION

Attachment 5.2 (Modeling Parameters-Generic CHP, May 20 2016)

CHP Technology Type:	combustion turbine generator (CTG) with single pressure heat recovery steam generator (HRSG)		
Combustion Turbine Generators	Solar Taurus 70	Solar Mars 100	Siemens SGT-400
Nominal published rating (kW)	7,965	11,350	14,400
Nominal expected rating (kW)	7,045	10,039	12,737
Summer System rated Electric Capacity (kW)	5,990	8,536	10,829
Winter System rated Electric Capacity (kW)	8,268	10,018	12,710
Annual Hours of Operation (hrs)	8,410	8,410	8,410
Capacity Factor %	96%	96%	96%
Forced Outage Rate (%)	[redacted]		
Maintenance Planned Outage Rate (%)			
Annual Power Generation (MWhrs/year)	59,248	84,427	107,115
Economic (Useful) Life, with LTSA (yrs)	30	30	30
Tax Life (yrs)	15	15	15
Electric Heat Rate, nominal gross, LHV (Btu/kWh)	[redacted]		
Electric Heat Rate, expected gross, LHV (Btu/kWh)			
Fuel Usage Rate, LHV (MMBtu/hr)			
Annual Fuel, LHV (MMBtu/year)			
Overall CHP System Thermal Efficiency	80%	80%	80%
SO2 Emission Rate (lb/MMBtu)	Based on fuel composition. For natural gas SO2 is minimal to none. There are no industry controls for SO2 in combustion turbine based CHP systems.		
NOx Emission Rate (lb/MMBtu) with dry low NOx combustion, lower with SCR	0.064	0.064	0.064
CO2 Emission Rate (lb/MMBtu)	117	117	117
Thermal Energy Output (MMBtu/hr)	33.97	51.81	58.17
Overnight Construction Cost ($/kW) (all cost applied to power production, none to heat production)	[redacted]		
Fixed O&M ($/kWh) (based on LTSA covering minor, major, parts, but not fluids)			
Variable O&M ($/MWh) (based on fuel at $4.00/MMBtu HHV)			

IPL 2016 IRP

Confidential Attachment 5.3 (AES Proprietary Battery Cost Information) is only available in the Confidential IRP.

Local Green Power Advisory Committee (LGP AC)
Participant List

Participant Name	**Organization**
Peyton Berg	Rolls Royce
Honorable Dan Forestal (Invited)	Indiana Legislature
Joe Hanson	Indianapolis Neighborhood Housing Partnership (INHP)
Jesse Kharbanda (Invited)	Hoosier Environmental Council (HEC)
Rev. Larry Kleiman	Hoosier Interfaith Power & Light (HIPL)
Kerwin Olson	Citizens Action Coalition (CAC)
Jodi Perras	Sierra Club
Chrystal Ratcliffe	National Association for the Advancement of Colored People (NAACP)
Dr. Peter Schubert	IUPUI Lugar Center for Renewable Energy
Barbara Smith & Cindy Armstrong	Office of Utility Consumer Counselor (OUCC)
Tristan Vance	Indiana Office of Energy Development (OED)
Facilitator	
Dr. Bill Beranek	Beranek Analysis, LLC
IPL Representatives	
Jake Allen	IPL
Brandi Davis-Handy	IPL
Ken Flora	IPL
Bill Henley	IPL
Joan Soller	IPL
Shelby Houston	IPL
Chad Rogers	IPL

IPL Local Green Power Advisory Committee

Meeting #1

January 8, 2016

1 INDIANAPOLIS POWER & LIGHT COMPANY

Welcome & Introductions

2 INDIANAPOLIS POWER & LIGHT COMPANY

What we will cover today

- Advisory Committee objectives
- IPL renewables experience
- Initial Local Green Power (LGP) program ideas
- Describe solar as a Local Green Power option
- Local and national trends in shared solar programs
- Other Indiana initiatives
- Program design factors
- Roundtable discussion
- Next steps

Advisory Committee (AC) Objectives

- Purpose of the Advisory Committee
- Focus of each meeting

Date	IPL	Advisory Committee
Jan 8, 2016	Provide background	Share perspectives
	Present program options	
Feb 4, 2016	Share initial program design	Share perspectives
Mar 16, 2016	Present revised program design	Provide feedback

IPL's renewables experience

- Existing Green Power program
- Wind Power Purchase Agreements (PPAs)
- Former Renewable Energy Incentive program
- Net metering
- Renewable Energy Production (Rate REP)
- Resulting in IPL's changing generation mix

Existing Green Power Program

- Standard Contract Rider No. 21 – Green Power Initiative
- Voluntary option for customers to purchase Renewable Energy Credits (RECs)
- Modest premium to retail rates ($0.0015/kWh)
- Program dates to March 1998
- Currently about 4,400 customers
- Sales to Customers: 165 GWh annually (or slightly more than 1% of IPL Retail sales)

Wind Energy - Power Purchase Agreements (PPAs)

- IPL has two agreements in place to purchase a significant amount of wind
- Hoosier Wind Park - Benton County, Indiana – 100 MW since 2009
- Lakefield Wind Park – Minnesota - 200 MW since 2011
- Together these wind projects provide about 5 percent of IPL's generation

7 INDIANAPOLIS POWER & LIGHT COMPANY

Renewable Energy Incentive Program

- Demand-Side Management (DSM) offering (from 2004 to 2014)
- Initially provided grants to purchase demonstration projects
- Evolved from grants to $1 per watt credit in 2010
- IPL provided incentive payments for 57 customer owned systems from 2010 thru 2014

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State Fair Demonstration Project

- Under Construction – Circa 2009

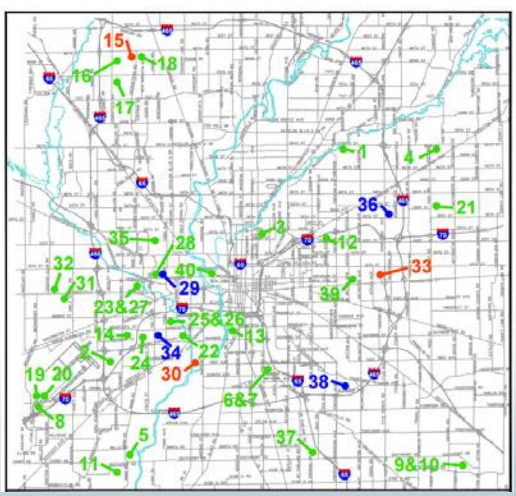
Net Metering

- Available to all IPL customers that self produce wind, hydro or solar energy – up to 1 MW in size.
- Customer bills are credited the full retail rate for all kWh displaced
- IPL currently has 79 net metered customers
  - 78 solar and one wind
  - Installed solar capacity approximately 1.45 MW
  - 21 new systems added in 2015

Renewable Energy Production (Rate REP)

- Fully subscribed in 2013
- 36 operating solar farms with 95 MW of solar capacity
- Indianapolis is ranked second in the amount of solar PV on a per capita basis

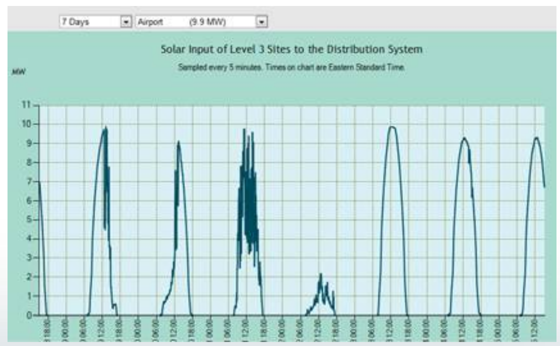
Rate Renewable Energy Production (REP)



Legend
Green = Operating
Red = Under Construction
Blue = In Development

Rate REP - Solar Lessons Learned

- Overall performance of ~18% of all hours vs. estimated 15%
- IPL communicates closely with operators 24/7
- Intermittency causes voltage fluctuations
- System protection settings are site specific
- Feeder maintenance causes facilities to be taken off line



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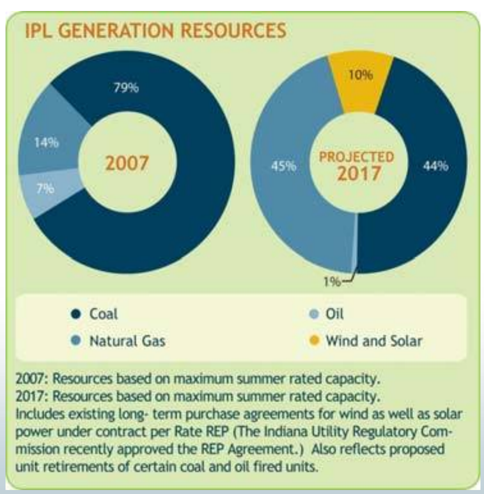
IPL's Changing Generation Mix



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Why is IPL considering a LGP offering?

- Listened to public feedback during the 2014 Integrated Resource Plan process
- Provide customers with tangible ways to participate in energy choices
- Continue to diversify our portfolio
- Foster continued leadership in industry

IPL's initial Local Green Power ideas

- Local renewable resource
- Voluntary offering for all customers
- Self-sustaining subscription-based
- IPL owned and operated – competitively sourced
- 1 MW blocks (7 to 10 acres per MW)
- Customer transaction based on energy produced
- May include "anchor" corporate subscribers

Potential local renewable resource options

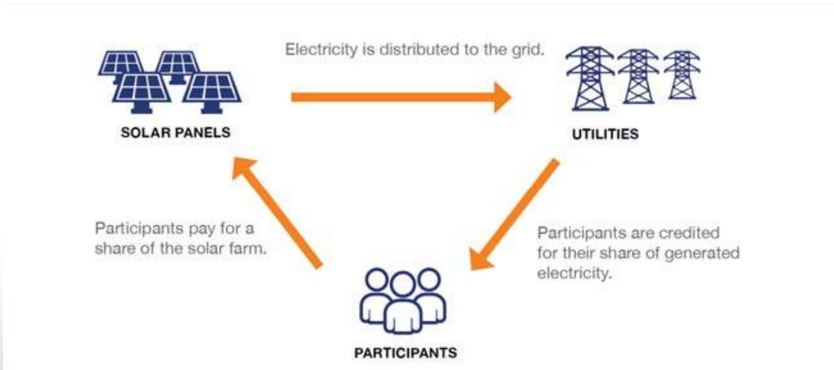
Resource	$/kW to build	Benefits	Limitations
Solar[1]	$3,000	Visually appealing	Land requirement
Wind[2]	$2,213	Low cost per kWh	Limited local resource
Biomass[3]	$4,114	Consumption of waste fuel	Limited fuel availability

[1]Source: IPL generated from IRP
[2]Source: State Utility Forecasting Group, 2014 Indiana Renewable Energy Resources Study, does not include transmission costs
[3]Source: State Utility Forecasting Group, 2014 Indiana Renewable Energy Resources Study

Why is solar a good option for Local Green Power?

- Solar is modular and flexible
- Solar is most suitable renewable resource for Indianapolis
- Solar is most easily sited in an urban area
- Solar provides high visibility improving marketability

Shared solar simply stated



Source: Solar Electric Power Association (SEPA), Community Solar Program Design Models

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Solar LGP provides significant benefits

Customer Benefits

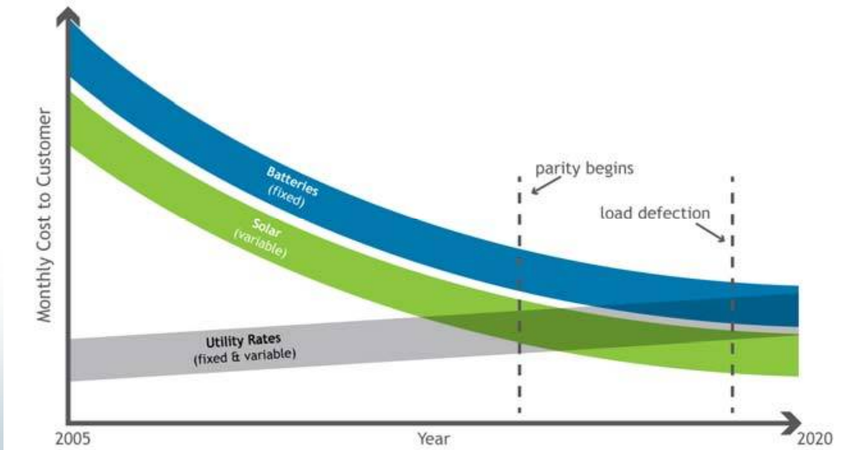
- Additional customer choice
- Overcomes barrier that many homes are not conducive for rooftop PV
- All customers, not just homeowners, may participate
- Lower capital cost than dispersed small scale renewables (i.e. rooftop)
- Solar production is optimized

Utility Benefits

- Proactive approach to market disruptions
- Positive customer and community engagement
- Control power quality
- Potential to mitigate impact of future CO_2 regulations
- Eases grid integration

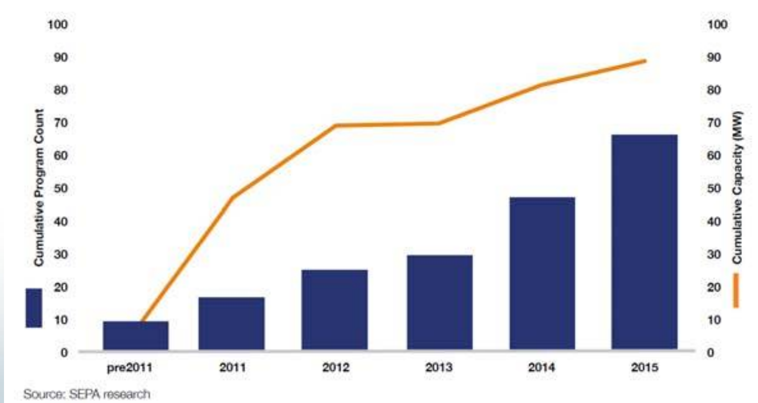
20 INDIANAPOLIS POWER & LIGHT COMPANY

Alternative energy solutions are causing market disruptions



Source: Global Trends in Renewable Energy Investments 2015, BNEF
Distributed Generation defined as < 1MW

Nationally, there is a steady increase in shared solar programs



Other Initiatives in Indiana – Public Utilities

- Indiana Municipal Power Agency (IMPA)
  - Six solar projects totaling 10 MW
  - Plans to build a solar project in all 60 communities IMPA serves
- Hoosier Energy
  - Hoosier has a variety of renewable resource
  - Ten 1 MW solar projects are planned by the end of 2016
- Tipmont REMC
  - Installment plan charging $3 per Watt (purchase model)

Other Initiatives in Indiana – Investor Owned Utilities

Duke

- Utilizing their existing GoGreen Program to purchase RECs from the 4 PPAs (25MW total, 5MW each) on behalf of the program

I&M – Clean Energy Solar Pilot Project (CESPP)

- Solar Power Rider (SPR) to recover program costs
- SRECs: customer retires them, I&M also reserves the right to comply with future mandates
- Building at substations

NIPSCO – Feed-In Tariff Program

- Phase I - Ended in March 2015
- Phase II – Currently Enrolling

Program design factors

- Facility ownership & operation
- Customer Offer
  - Upfront payments ($/watt)
  - Ongoing payment ($/kWh)
- Subscription Transfer
- Participation limit (capacity & usage)
- Siting and Scale
- Program Length
- Minimum Term

See SEPA report: *Community Solar: Program Design Models*

Roundtable Discussion

Next Steps

- IPL prepare strawman and initial design(s) for the next meeting
- IPL will continue to develop market research framework to determine customer interest
- Other ideas?

Next Meeting February 4, 2016

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Appendix

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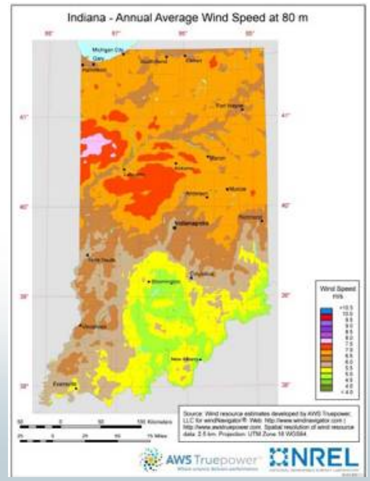
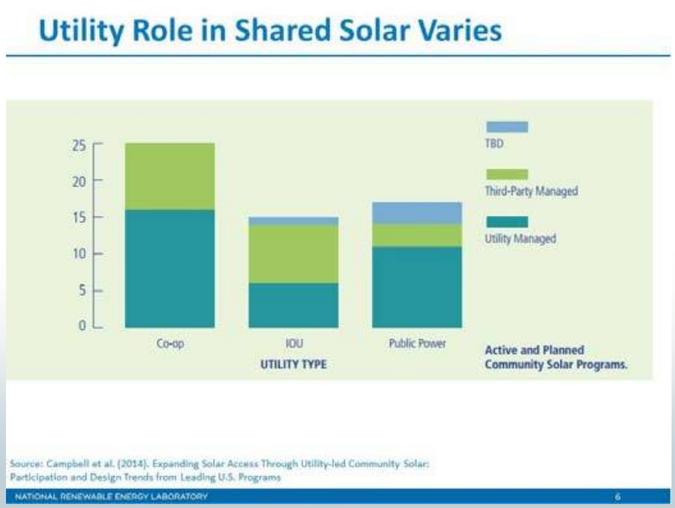
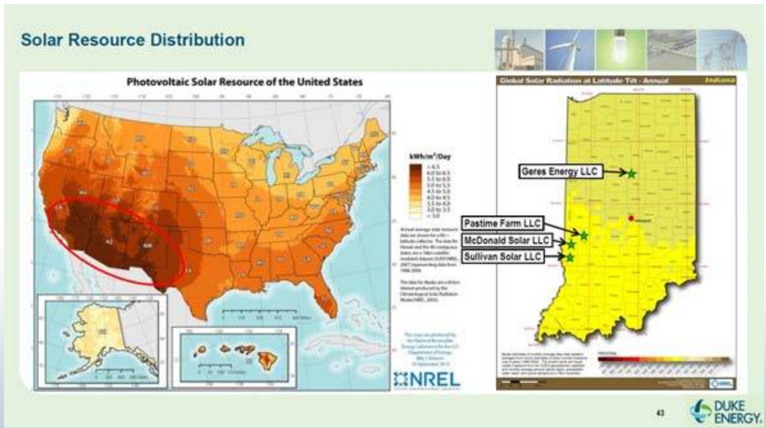
Solar and wind resources vary in IN



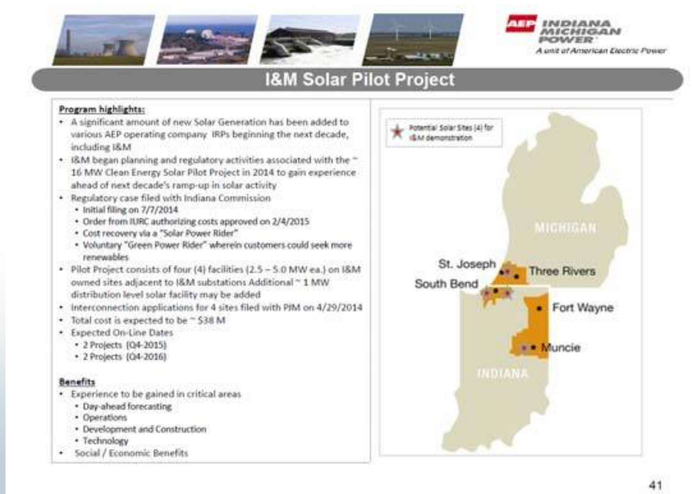
Community solar programs ownership differs based on the utility type



Duke IRP Solar Slide (from June 2015)



I&M IRP Solar Update Slide (from May 2015)



Local Green Power Advisory Committee (LGP AC) Meeting #2 Agenda
February 5, 2016

8:30 – 8:35am	*Welcome & Safety Message*
8:35 – 9:00am	Introduction of Attendees, Recap of 1st Meeting
9:00 – 9:15 am	Discussion of SEPA Report, “Community Solar: Program Design Models”
9:15 – 9:45am	Key Success Factors (Jodi’s KPIs)
9:45 – 10:00am	*Break*
10:00 – 10:45am	Discussion of Survey Results and IPL Strawman
10:45 – 11:00am	Site Selection, Draft Criteria
11:00 – 11:15am	Opportunities, Economic Analysis Framework
11:15am – 11:30am	Expectations for Next Meeting & Closing Comments

IPL Local Green Power Advisory Committee

Meeting #2

February 5, 2016

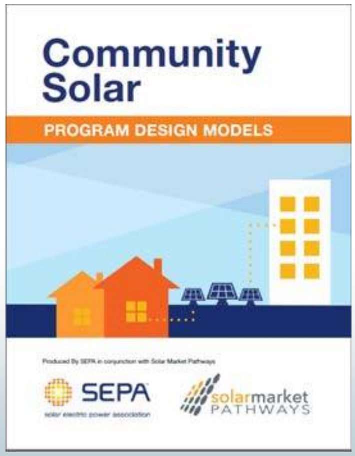
Welcome & Safety Message

What we will cover today

- Recap of 1st meeting
- SEPA Community Solar: Program Design Models Report Discussion
- Key Success Factors
- Break
- Design Factor Survey Results
- IPL Strawman Proposal
- Site Selection Draft Criteria
- Potential Grant Opportunities
- Economic Analysis Framework
- Expectations for Next Meeting
- Closing Comments

Recap of 1st Meeting

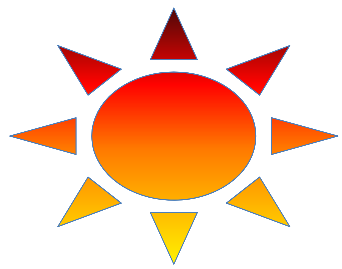
SEPA Community Solar: Program Design Models Report Discussion



Key Success Factors

- Size of projects
- Electricity generated
- Number of local projects
- Subscribers
- Indy's national solar ranking
- Reduction in pollutants
- Customer Satisfaction
- Environmental and economic justice
- Displacement of coal
- CPP
- Financial
- Jobs
- Where projects are located

BREAK



Design Factors, IPL Strawman & Survey Results

Design Factors	IPL Strawman
Facility Ownership & Operation	IPL owned and operated
Customer Offer	Fixed kWh block or customer choice
Subscription Transfers	IPL managed, prorated for the rest of the minimum term, unless waitlist can pick it up
Participation Limits	100% of average usage, to allow for more broad participation for the first offering, if not fully subscribed then future offering could allow for future blocks for customers
Siting & Scale	RFP Criteria
Program Length	Based on the asset life, for example: 25 years
Minimum Term	24 months

- Discussion of survey results (see handout)

Site Selection Draft Criteria

- Cost to Construct with grid interconnection
- Feasible to interconnect (not on circuit with large Rate REP facility already)
- Brownfield reuse benefits
- Community Visibility
- Anchor sponsorship
  - e.g. non-profit, corporation, public funding
- Levelized cost per kWh

Potential for Grant Opportunities

- Solar Electric Power Association (SEPA)
  - Grants for technical assistance to 8 Utilities for Program Design
  - Research request made to SEPA staff to identify other potential opportunities
- Other Grant Opportunities?

Economic Analysis Framework

Factors to calculate net costs & benefits include the following:

- RFP results for project costs
- 25 year asset life
- Financial metrics
- Credit for avoided generation expense based on 2014 IRP forecast
- Value of renewable attributes such as Solar Renewable Energy Credits (SRECs) or carbon
- Forecasted utility solar costs to determine likely break-even/grid parity
- Compare to rooftop solar forecasted costs

Expectations for Next Meeting

- Discussion

Next Meeting: Wednesday, March 16

Local Green Power Advisory Committee (LGP AC) Meeting #3 Agenda
March 18, 2016

9:00 – 9:05am	*Welcome & Safety Message*
9:05 – 9:15am	Recap of 2nd Meeting
9:15 – 10:00am	IPL Local Green Power Illustrative Solar Economic Analysis
10:00 – 10:15am	Findings
10:15 – 10:30am	*Break*
10:30 – 11:00am	Discussion
11:00 – 11:15am	Next Steps
11:15 – 11:30am	*Closing Remarks*

IPL Local Green Power Advisory Committee

Meeting #3

March 18, 2016

INDIANAPOLIS POWER & LIGHT COMPANY

1

Welcome & Safety Message

INDIANAPOLIS POWER & LIGHT COMPANY

2

What we will cover today

- Recap of 2nd meeting
- IPL Local Green Power Project Illustrative Solar Economic Analysis
- Findings
- Break
- Discussion
- Next Steps
- Closing Remarks

Recap of 2nd Meeting

Grocers Supply Roof, 1MW rooftop system.

IPL Local Green Power Project Illustrative Solar Economic Analysis

*This analysis represents a snapshot in time and is for discussion purposes ONLY and is not intended for a regulatory filing.

Assumptions and Data Sources

Item		Unit	Source
Size of Solar PV System	1 MW		IPL Assumption
Capacity Factor	18%		IPL's Rate REP experience
Capital Cost of Solar	$2.93	$/W - AC	2015 SunShot-National Renewable Energy Laboratory (NREL) Solar Report, Photovoltaic System Pricing Trends, normalized and converted from DC to AC
Useful Life (Depreciation)	25 years		http://www.nrel.gov/analysis/tech_footprint.html
Development Capital Costs	15%		NREL report, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial and Utility-Scale Systems, p. 39
Federal Tax Credit	30%		Reflected as a credit to the intial project cost; research and analysis continue on IPL's ability to take advantage of the ITC. 30% through 2019 http://energy.gov/savings/residential-renewable-energy-tax-credit
IPL WACC & PV Discount Rate	6.91%		From IPL Rate Case Cause 44576 using a 10.93% Requested ROE
Annual O&M	$ 0.02	per watt	http://www.nrel.gov/analysis/tech_cost_om_dg.html
O&M Escalation	2.46%		Averaged 20YR and 30YR Daily Treasury Yield Curve Rates
			https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
Degradation	0.50%	per year	NREL report, Photovoltaic Degradation Rates - An Analytical Review, listed in abstract
Avoided Energy Cost (Fuel)	$ 0.032	$/kWh	Fuel cost based on Cost of Service Study (COSS) from IPL Rate Case Cause 44576
Avoided Energy Cost (Non-Fuel)	$ 0.002	$/kWh	Non fuel, variable O&M cost based on Cost of Service Study (COSS) from IPL Rate Case Cause 44576
Avoided Capacity Cost (Reserve Margin)	7%		Avoided Planning Reserve Margin Requirement (PRMR)
Avoided Capacity Cost	Ranging from ~$0.50 in 2016 to ~$113 in 2021	$/kW-yr	Curve is based on IPL's bilateral transactions in the short term plus Capacity Prices from ABB Fall 2015 Reference Case
Avoided Capacity Credit (Peak Reduction)	47%		% reduction at forecasted peak based on Rate REP Solar experience
Avoided Long-Term Distribution Capital Costs	$ 0.001	$/kWh	Reflects % of IPL circuits that may require upgrades based on the avoided cost of a new distribution circuit and % of peak reduction
Avoided T&D Losses	1.8%		Estimated from recent line loss study
Solar RECs Credit	$21 in 2016	$/MWh	Forward Price Forecast from ACES Power Marketing group

Illustrative Local Green Power Model - Inputs

		Capacity Factor	
Annual Hours of Solar	1,577	18%	
Base Cost of Solar PV System	$ 2.93	$/watt AC	
Development Cost of Solar PV System	$ 0.29	15%	
Total Cost of Solar PV System	$ 3.22	$/watt AC	
Size of Solar PV System	1,000	kw	
Total Cost of Solar PV System	$ 3,223,000		
Federal Tax Credit	$ (966,900)	30%	
Net Cost of Solar PV System	$ 2,256,100		
IPL WACC (Weighted Average Cost of Capital)	6.91%		
Revenue Coversion Factor (Return on)	1.43067		
Revenue Coversion Factor (Recovery of)	1.02043		
Annual Depreciation	$ 90,244	25	years
Annual O&M	$ 20,000	$ 0.02	per watt
O&M Escalation	2.5%		
Solar Production Degradation	0.5%		
Avoided Line Losses	1.8%		

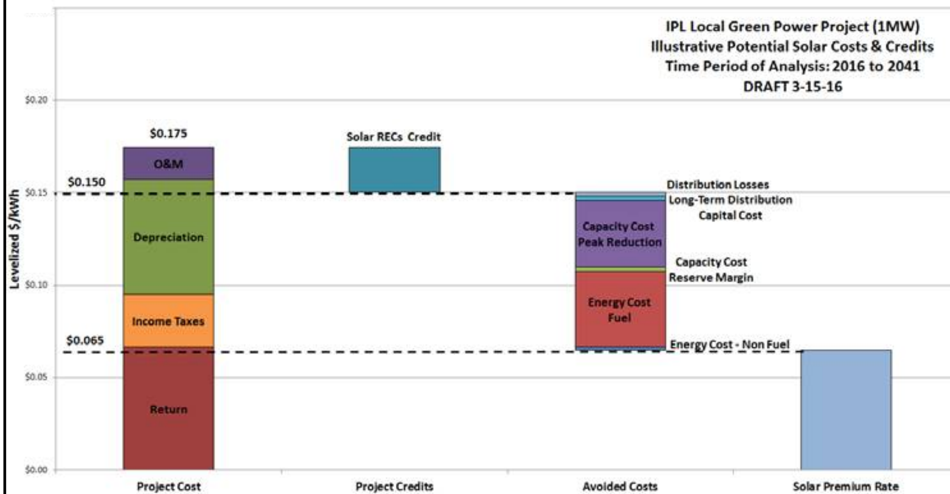
	2016	2017	2018	...	2039	2040	2041
Solar Production (kWh)	1,576,800	1,568,916	1,561,071		1,405,101	1,398,075	1,391,085
Investment Balance	$ 2,256,100	$ 2,165,856	$ 2,075,612		$ 180,488	$ 90,244	$ 0

Illustrative Local Green Power Model - Results

	2016	2017	2018	...	2039	2040	2041
Solar Production (kWh)	1,576,800	1,568,916	1,561,071		1,405,101	1,398,075	1,391,085
Investment Balance	$ 2,256,100	$ 2,165,856	$ 2,075,612		$ 180,488	$ 90,244	$ 0
Project Cost							
Return	$ 223,036	$ 214,115	$ 205,194		$ 17,843	$ 8,921	$ 0
Recovery Depreciation	$ 92,088	$ 92,088	$ 92,088		$ 92,088	$ 92,088	$ 92,088
Recovery O&M	$ 20,409	$ 20,911	$ 21,425		$ 35,691	$ 36,569	$ 37,469
Total Project Cost	$ 335,533	$ 327,113	$ 318,706		$ 145,622	$ 137,579	$ 129,557
Levelized Rate ($/kWh)	$0.175						
Project Credits							
Solar RECs Credit ($/kWh)	$ 0.021	$ 0.021	$ 0.021		$ 0.031	$ 0.032	$ 0.032
Solar RECs Credit	$ (33,113)	$ (33,214)	$ (33,469)		$ (43,839)	$ (44,431)	$ (45,029)
Levelized Rate ($/kWh)	($0.025)						
Total Project Cost less Project Credits	$ 302,420	$ 293,899	$ 285,237		$ 101,783	$ 93,148	$ 84,527
Levelized Rate ($/kWh)	$0.150						
Avoided Costs							
Avoided Energy Cost - Fuel ($/kWh)	$ 0.0315	$ 0.032	$ 0.033		$ 0.051	$ 0.051	$ 0.052
Avoided Energy Cost - Fuel	$ (49,669)	$ (50,380)	$ (51,724)		$ (71,877)	$ (71,945)	$ (72,013)
Avoided Energy Cost - Non-Fuel ($/kWh)	$ 0.0015	$ 0.002	$ 0.002		$ 0.002	$ 0.002	$ 0.002
Avoided Energy Cost - Non-Fuel	$ (2,365)	$ (2,399)	$ (2,463)		$ (3,423)	$ (3,426)	$ (3,429)
Avoided Long-Term Dist Capital Costs ($/kWh)	$ 0.002	$ 0.002	$ 0.002		$ 0.004	$ 0.004	$ 0.004
Avoided Long-Term Dist Capital Costs	$ (3,429)	$ (3,496)	$ (3,564)		$ (5,344)	$ (5,448)	$ (5,554)
Avoided Cap Cost - Reserve Margin ($/kWh)	[redacted]						
Avoided Cap Cost - Reserve Margin							
Avoided Cap Cost - Peak Reduction ($/kWh)							
Avoided Cap Cost - Peak Reduction							
Avoided T&D Losses ($/kWh)	$ 0.001	$ 0.001	$ 0.001		$ 0.002	$ 0.002	$ 0.002
Avoided T&D Losses	$ (1,134)	$ (1,294)	$ (1,681)		$ (3,046)	$ (3,104)	$ (3,149)
Total Avoided Cost to Solar Customers	$ (64,141)	$ (73,199)	$ (95,098)		$ (172,254)	$ (175,526)	$ (178,073)
Levelized Rate ($/kWh)	($0.085)						
Net Charge to Customer	$ 238,279	$ 220,700	$ 190,139		$ (70,471)	$ (82,378)	$ (93,546)
Levelized Premium Solar Rate ($/kWh)	$0.065						

Dist=Distribution
Cap=Capacity
Cap cost is proprietary, and therefore is redacted.

Components of the Costs and Credits



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Solar Economic Analysis - Levelized Cost of Production

Solar System Size	Capital cost ($/watt - AC)	Levelized Cost – Before Credits ($/kWh)
1 MW	$2.93	$0.175
5 MW	$2.27	$0.139
4 kW – Customer Build 4% Cost of Capital	$3.50	$0.157
4 kW – Customer Build 10% Cost of Capital	$3.50	$0.238

Source:
2015 SunShot-National Renewable Energy Laboratory (NREL) Solar Report, Photovoltaic System Pricing Trends

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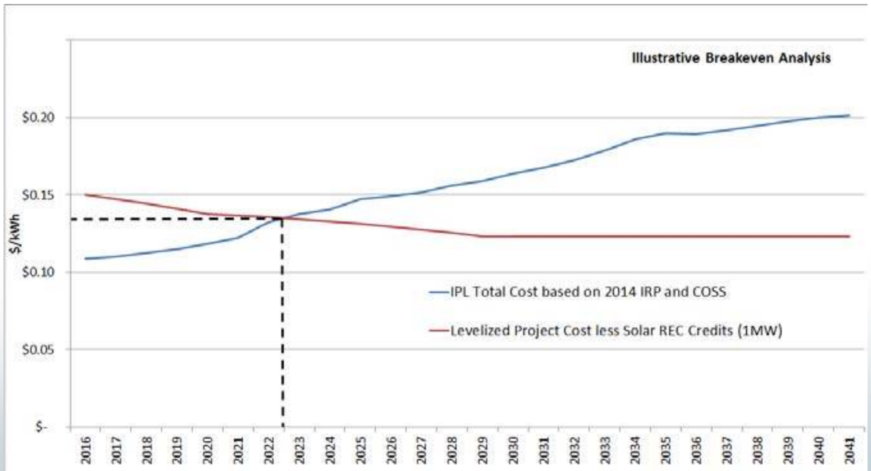
A decrease in solar capital costs would improve the value to the customer



Findings

- Solar resources remain more expensive than current IPL retail rates
- A larger site produces economies of scale, however, subscription risk is greater
- As capital costs for solar decrease, the economic case for solar improves
- Cost of carbon will impact future levelized costs

Break

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Discussion

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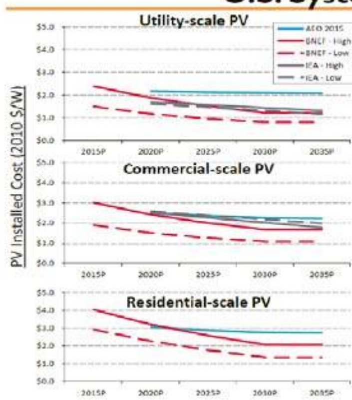
Next Steps

- Consider the following questions:
  - Does it make sense to do this now?
  - If not, when will it make sense?
  - How large of an economic gap will altruism cover?
  - How do we address the gap between the asset life (25 years) and the customer subscription commitment (1 year)?
  - Besides economics what are other drivers for customers to choose solar?
- Incorporate economic analysis into 2016 IRP

Closing Remarks

Appendix A – Cost of Solar

Range of Analyst Expectations of Long-term U.S. System Price



- BNEF and IEA expect pricing in all PV markets to continue to decrease and to get very close to the SunShot targets between 2020-2030
- AEO has a much more conservative outlook with respect to PV system pricing, with system pricing projected to remain relatively flat through 2035
- Analyst expectations of future pricing are currently far lower than projections made even just a few years ago, reflecting very rapid change in the U.S. market.

Sources: International Energy Agency, "World Energy Outlook 2014," November 2014 (New Policy & 450 Scenarios for utility-scale & commercial-scale); Bloomberg New Energy Finance, "H1 2015 North American PV Outlook" (01/16/15); U.S. Energy Information Administration, Annual Energy Outlook 2015 (June 2015). In years where projection was not made, most recent projection used.

SunShot 31

energy.gov/sunshot

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Appendix B – Minnesota Ex.

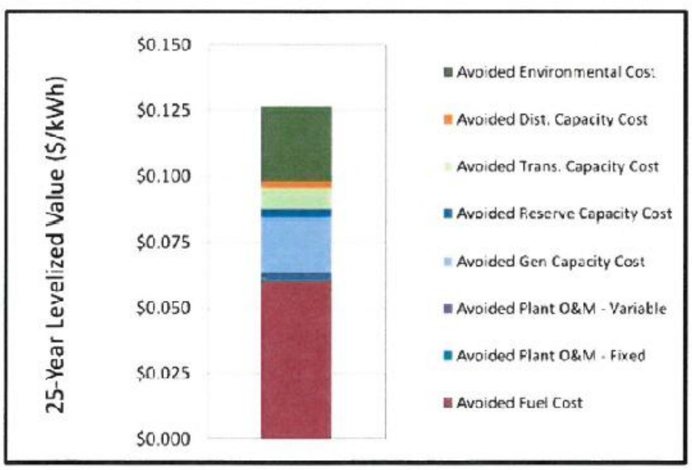

Figure 2. Minnesota VOS – sample calculations

Source: MN DOC (2014)

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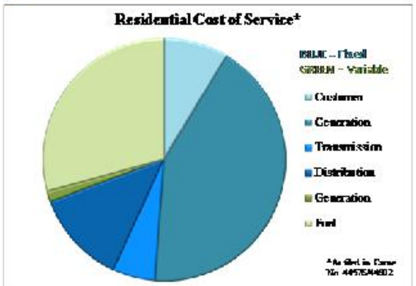
Appendix C – IPL Rates 101

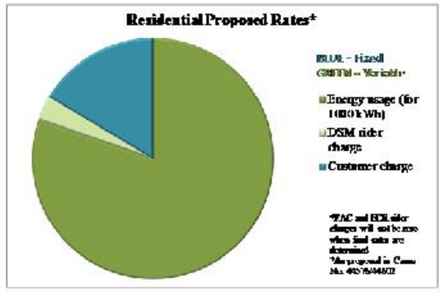
IPL Rates 101 DRAFT

Local Green Power Project - Supplementary Material

	Residential Cost of Service % of Total
Customer	9%
Generation	45%
Transmission	6%
Distribution	12%
Generation	1%
Fuel	29%
Total	100%

	Residential Proposed Rate
Energy use (first 500 kWh)	$0.0958
Energy use (next 500 kWh)	[illegible]
Energy usage (for 1000 kWh)	[illegible]
DSM rider charge	[illegible]
Customer charge	$17.00
Total	$105.61





This illustrates how IPL's costs are largely fixed costs, while customers' bills are based mostly on their variable usage.

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INDIANAPOLIS POWER & LIGHT COMPANY

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY FOR APPROVAL OF A ONE-YEAR EXTENSION OF THE IMPLEMENTATION ITS DEMAND-SIDE MANAGEMENT PROGRAMS FOR 2017 AND FOR APPROVAL OF ASSOCIATED RATEMAKING TREATMENT, INCLUDING EXTENSION OF THE CURRENT RATEMAKING TREATMENT OF SUCH PROGRAMS, *I.E.*, TIMELY RECOVERY OF PROGRAM COSTS, LOST REVENUES, AND A SHARED SAVINGS INCENTIVE VIA STANDARD CONTRACT RIDER NO. 22	)))))))))))))	**CAUSE NO. 44792**

PETITIONER'S SUBMITTAL OF PROPOSED FORM OF FINAL ORDER

Petitioner Indianapolis Power & Light Company, by counsel, respectfully submits to the Indiana Utility Regulatory Commission its Proposed Form of Final Order in this Cause No. 44792.

Dated this 23rd day of September, 2016.

Respectfully submitted,

By: Mark Alson

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CERTIFICATE OF SERVICE

The undersigned, one of the attorneys for Petitioner, hereby certifies that the foregoing was served via Electronic Mail this 23rd day of September, 2016, to the following:

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INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY FOR APPROVAL OF A ONE-YEAR EXTENSION OF THE IMPLEMENTATION ITS DEMAND-SIDE MANAGEMENT PROGRAMS FOR 2017 AND FOR APPROVAL OF ASSOCIATED RATEMAKING TREATMENT, INCLUDING EXTENSION OF THE CURRENT RATEMAKING TREATMENT OF SUCH PROGRAMS, *I.E.,* TIMELY RECOVERY OF PROGRAM COSTS, LOST REVENUES, AND A SHARED SAVINGS INCENTIVE VIA STANDARD CONTRACT RIDER NO. 22	)))))))))))))	**CAUSE NO. 44792**

***PROPOSED* ORDER OF THE COMMISSION**

Presiding Officers:
James F. Huston, Commissioner
Aaron A. Schmoll, Administrative Law Judge

On May 27, 2016, Petitioner Indianapolis Power & Light Company ("IPL" or "Petitioner") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Petition for approval of 2017 electric demand side management programs ("DSM Portfolio" or "DSM Plan") and associated ratemaking treatment. On May 27, 2016, IPL filed direct testimony constituting its case-in-chief. On July 12, 2016, IPL, the Indiana Office of Utility Consumer Counselor ("OUCC"), and Citizens Action Coalition of Indiana ("CAC") filed an Agreed Upon Procedural Schedule. On August 17, 2016, the Commission issued a docket entry accepting the proposed procedural schedule. On May 31, 2016, CAC filed a Petition to Intervene, which was granted on _____________, 2016.

On August 11, 2016, the OUCC submitted a notice of its intent not to file testimony. On August 11, 2016, CAC filed direct testimony. On August 24, 2016, IPL filed rebuttal testimony.

Pursuant to notice duly published as required by law, a public evidentiary hearing was held in this Cause on September 8, 2016 at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Proofs of publication of the notice of the evidentiary hearing were incorporated into the record and placed into the official files of the Commission. IPL, the OUCC, and CAC attended the evidentiary hearing represented by counsel, at which the prefiled testimony of IPL and CAC were admitted into the record without objection, along with several exhibits consisting of IPL's and CAC's non-confidential responses to discovery requests. CAC's motion for administrative notice of two documents was also granted without objection. All of the parties waived cross-examination of witnesses. No members of the public testified at the hearing.

The Commission, having considered the evidence of record and applicable law, finds as follows:

1. Commission Jurisdiction and Notice. Proper notice in this Cause was given as required by law. IPL is a "public utility" as that term is defined in Ind. Code § 8-1-2-1 and an "electricity supplier" as that term is defined in Ind. Code §§ 8-1-2.3-2(b) and 8-1-8.5-9. In accordance with Ind. Code ch. 8-1-8.5, § 8-1-2-42(a), and 170 IAC 4-8-1 *et seq.*, the Commission has jurisdiction over IPL's DSM programs and associated ratemaking treatment. Therefore, the Commission has jurisdiction over IPL and the subject matter of this Cause.

2. IPL's Organization and Business. IPL is an operating public utility, incorporated under the laws of the State of Indiana, with its principal office and place of business at One Monument Circle, Indianapolis, Indiana. IPL renders retail electric utility service to approximately 480,000 retail customers located principally in and near the City of Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam and Shelby. IPL owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power.

3. **Legal Background.** On March 27, 2014, Senate Enrolled Act 340 ("SEA 340") became law. Among other things, SEA 340 (codified at Ind. Code § 8-1-8.5-9) provides as follows:

> After December 31, 2014, an electricity supplier may offer a cost effective portfolio of energy efficiency programs to customers. An electricity supplier may submit a proposed energy efficiency program to the commission for review. If an electricity supplier submits a proposed energy efficiency program for review and the commission determines that the portfolio included in the proposed energy efficiency program is reasonable and cost effective, the electricity supplier may recover energy efficiency program costs[1] in the same manner as energy efficiency program costs were recoverable under the DSM order issued by the commission on December 9, 2009. The commission may not: (1) require an energy efficiency program to be implemented by a third party administrator; or (2) in making its determination, consider whether a third party administrator implements the energy efficiency program.

SEA 340 also allows large industrial customers to "opt out" of participating in and paying for utility-sponsored DSM programs.

On May 6, 2015, Senate Enrolled Act 412 ("SEA 412") became law. Among other things, SEA 412 (codified at Ind. Code § 8-1-8.5-10) continued the large industrial customer opt out, and required that, by calendar year 2017, an electricity supplier shall petition the Commission for approval of an energy efficiency plan. If such plan is found to be reasonable and to meet certain statutory criteria, the utility shall be authorized to recover direct and indirect

[1] "Energy efficiency program costs" are defined in SEA 340 to include program costs, lost revenues, and incentives approved by the Commission.

program costs, evaluation, measurement and verification ("EM&V") costs, lost revenues, and a financial incentive.

Prior to the enactment of SEA 340 and SEA 412, for many years the Commission has authorized recovery of DSM costs, lost revenues, and performance incentives, on a timely basis pursuant to Ind. Code § 8-1-2-42(a) and 170 IAC 4-8-1- *et seq*. Ind. Code § 8-1-2-42(a) authorizes the Commission to allow recovery of approved costs via tracking mechanisms. 170 IAC 4-8-1 *et seq.* allow electric utilities to recover DSM program costs, lost revenues, and financial incentives.

IPL's current DSM programs, and associated ratemaking treatment, were approved by the Commission on December 17, 2014, in Cause No. 44497. In our Order, we approved IPL's current programs for 2015 and 2016, based upon IPL's three-year (2015-2017) Action Plan, finding that the portfolio of programs was cost-effective and reasonable. We rejected CAC's recommendation that IPL include in its IQW program funding for remediation of health and safety measures, and we declined to require IPL to include CAC as a voting member on its OSB. We approved timely recovery of program costs via IPL's Standard Contract Rider No. 22. We also approved timely recovery through Rider 22 of lost revenues (upon the effective date of IPL's 2016 rate case order), and rejected CAC's recommendation to limit lost revenue recovery to two years, noting that "[l]ost revenues continue to accrue over the useful life of the measure. . . ." Finally, we approved a shared savings incentive based on actual net benefits, as determined by independent EM&V, with the utility retaining 15% of net Utility Cost Test benefits and customers realizing and retaining 85% of Utility Cost Test net benefits. In so doing, we noted that "Indiana recognizes that the offering of incentives is an acceptable and appropriate means of encouraging cost-effective DSM and offsetting the financial bias for supply-side resources" and that “incentives have become more important to support the aggressive pursuit and implementation of cost-effective DSM programs [without mandated energy savings goals].”

4. **<u>Relief Requested</u>.** IPL requests that the Commission approve a one-year extension of its current DSM programs and current ratemaking treatment. More specifically, IPL requests the following relief in this proceeding, pursuant to Ind. Code § 8-1-8.5-9 (“Section 9”). First, IPL requests approval of its proposed 2017 DSM Portfolio. Second, IPL requests authority to recover direct and indirect program costs, including EM&V costs, associated with its 2017 DSM Plan through its Standard Contract Rider No. 22. Additionally, IPL requests certain spending and program flexibility with regard to its 2017 DSM Plan. IPL also requests authority to recover lost revenues and a shared savings incentive associated with its 2017 DSM Plan, via Standard Contract Rider No. 22. IPL further requests approval to continue to utilize its existing IPL Oversight Board (“OSB”) to administer the 2017 DSM Plan. Finally, IPL requests approval of necessary changes to its Standard Contract Rider No. 22 tariff to effectuate approval of the 2017 DSM Portfolio and the other relief requested herein. IPL requests the above authority beginning January 1, 2017, and continuing until the later of December 31, 2017, or the effective date of a Commission order approving IPL’s post-2017 DSM programs.

5. **<u>IPL’s Case-in-Chief</u>.** IPL presented the testimony of four witnesses in support of its petition: Lester H. “Jake” Allen, DSM Program Development Manager; Zac Elliot, Manager of Energy Efficiency Programs; Erik Miller, Senior Research Analyst; and Kimberly Aliff, Senior Regulatory Analyst.

a. **Lester Allen**. Mr. Allen’s testimony described the planning process IPL undertook for DSM program delivery in 2017, summarized the current status of IPL’s DSM programs, explained the evolving Indiana DSM policy landscape, summarized IPL’s request for approval of a one-year extension of the current portfolio of its DSM programs, summarized IPL's requested ratemaking treatment, described the continuing role of the OSB, and explained why the relief requested by IPL is reasonable and consistent with sound regulatory policy, is consistent with IPL's most recent integrated resource plan ("IRP"), serves the public interest, and should be approved.

Mr. Allen explained that IPL was taking a two-phased approach to developing its plans for delivery of post-2016 DSM programs. First, in this case, IPL is requesting approval of a one-year extension of its current DSM programs, supported by an update of its 2015-2016 DSM Action Plan, along with a continuation of the current ratemaking treatment associated with such programs. Second, in a case to be filed in 2017, IPL will propose a 2018-2020 DSM Plan, based on a new market potential study that will be more closely integrated with a new IRP.

Mr. Allen provided a detailed history of IPL's DSM efforts, noting that IPL has offered DSM programs to its customers since 1993, and has been successful in implementing a broad range of programs for its customers. He noted that through April 2016, IPL had realized approximately 67% of the savings targeted by the 2015-2016 DSM Portfolio.

With regard to the Indiana DSM policy landscape, Mr. Allen provided an overview of SEA 412 (Ind. Code § 8-1-8.5-10 or "Section 10"). He noted, however, that IPL was seeking approval of its 2017 DSM Portfolio under Section 9, not Section 10, despite IPL's belief that its proposed 2017 DSM Portfolio meets the Section 10 criteria. With regard to SEA 340, specifically the opt out provisions of that legislation, Mr. Allen testified that as of January 1, 2016, a total of 106 customers representing 22% of IPL's annual sales had opted out of DSM program participation.

Mr. Allen explained that the proposed 2017 DSM Portfolio is comprised of the following programs:

- Residential Lighting
- Residential Income Qualified Weatherization ("IQW")
- Residential Air Conditioning Load Management ("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

He testified that these programs in total are expected to result in first year gross energy savings of approximately 129,000 MWh, as well as approximately 58 MW of gross demand reduction in 2017. This represents an approximately 0.94% reduction in energy sales and, when sales are adjusted to take into account customers that have opted out, the savings represent about a 1.21% reduction in sales. Mr. Allen testified that the total estimated cost of the proposed 2017 DSM Portfolio, prior to recovery of incentives or lost revenues, is $24.8 million – comparable to the annual budgets approved for 2015 and 2016.

Mr. Allen also discussed the flexibility requested in the 2017 DSM Portfolio implementation. He stated that IPL's request includes spending flexibility of 10% of direct program costs (included in the $24.8 million budget), as well as a request to carryover funds that are not utilized in 2015/2016 into 2017. Additionally, IPL proposes that the 2017 DSM Portfolio budget include indirect program costs and costs associated with emerging technologies, which will provide additional resources to develop, add, and/or modify programs in 2017 as needed. Mr. Allen further explained that IPL also requests that the OSB be authorized to either increase the scale of programs or identify and add new cost-effective programs to produce energy efficiency savings, if appropriate, without coming back to the Commission for pre-approval, but subject to the total authorized 2017 DSM Portfolio budget. IPL is also seeking authority to continue to pay the program delivery costs related to energy services provided through the end of 2016, but not known until 2017.

Mr. Allen next summarized the ratemaking relief being sought by IPL: timely recovery through IPL Standard Contract Rider 22 of all costs incurred, including direct and indirect program development and implementation costs, lost revenues, and a shared savings incentive – the same ratemaking treatment currently in effect. Mr. Allen explained that IPL is proposing to recover its 2017 DSM costs in the same manner as in previous years, via a DSM rate adjustment mechanism (IPL's Standard Contract Rider No. 22), using allocations on a class basis.

With regard to the OSB, Mr. Allen testified that IPL requests approval to continue to utilize the existing IPL OSB to administer the 2017 DSM Portfolio. As proposed, the OSB will be able to shift dollars within a program budget as needed as well as shift dollars among existing or new programs as long as the programs are cost-effective and the overall approved DSM Portfolio budget is not exceeded. In addition, IPL proposes that the OSB have the same authority to increase funding in the aggregate, without shifting dollars from other programs, by up to 10% of direct program costs, and to modify programs based on a review of initial program results as reported by an independent third party evaluator.

Mr. Allen testified that, in order to avoid interruption of program delivery, IPL seeks these approvals through the later of December 31, 2017, or the effective date of an order approving IPL's post-2017 DSM programs and ratemaking treatment.

Mr. Allen testified that IPL's proposed 2017 DSM Portfolio and associated ratemaking treatment is consistent with regulatory policy and the public interest. He noted that the proposal is consistent with the Commission's DSM rules and past Commission practice, as well as SEA 340 and SEA 412. Mr. Allen emphasized that it is important for the Commission to provide timely cost recovery of DSM-related costs, including recovery of lost revenues and a shared savings incentive, to maintain robust and cost-effective DSM programs in Indiana. He noted the importance of allowing rate recovery of all three cost categories – program cost, lost revenues, and shared savings incentives – which has been recognized by numerous policymakers as well as state and federal governments. He stated that a lack of timely cost recovery in any of these three areas creates a financial disincentive for a utility to aggressively pursue DSM.

Mr. Allen testified as to why it is important for IPL to be allowed timely recovery of DSM-related costs, including lost revenues and financial incentives. He explained that program cost recovery and lost revenue recovery are necessary to eliminate disincentives for a utility to pursue energy efficiency. Without these, he stated, a utility will effectively be financially penalized for pursuing energy efficiency. But these two ingredients alone, while necessary, are not sufficient. Mr. Allen explained that capital is a scarce commodity, and a rational utility will seek to employ its capital in activities where it has the potential to earn a reasonable return. Accordingly, while program cost recovery and full recovery of lost revenues obviates a financial penalty, the opportunity for a financial incentive is another necessary ingredient to truly place energy efficiency on a level playing field with other investments, such as supply-side resource investments. Mr. Allen stressed that this "three-legged stool" – full program cost and lost revenue recovery, plus an opportunity for a financial incentive – is important to produce robust utility-sponsored energy efficiency programs. He testified that lack of recovery in any of these areas creates a financial disincentive to aggressively pursue DSM or serves as a financial penalty for a utility that does aggressively pursue DSM. He noted that the level of DSM proposed in the

2017 DSM Portfolio remains at a level that is significantly greater than most of IPL's preceding DSM plans prior to 2012, and he stated that IPL should not be penalized for its commitment to DSM.

With regard to the shared savings incentive, Mr. Allen also testified that 2017 is the third year of a three-year plan, and as such, it would be reasonable for costs previously approved (such as the shared savings incentive) to remain recoverable. Additionally, he noted the infeasibility of IPL preparing a Section 10 plan just for one year (2017). Finally, he emphasized IPL's long-term and consistent commitment to DSM for the benefit of its customers. With regard to lost revenues, Mr. Allen added that it is important to recognize that lost revenues are a real and calculable cost that extends for the life of the applicable energy efficiency measure (or until a new base rate case, whichever occurs first). He concluded that IPL should be authorized to continue to recover program costs, lost revenues over the life of the measure (or until a new base rate case order), and a shared savings incentive.

b. Zac Elliot. Mr. Elliot's testimony presented and described IPL's 2017 DSM Action Plan Update, described IPL's planning approach which led to the development of the proposed 2017 DSM Portfolio, and provided an overview of the proposed 2017 DSM Portfolio (including program descriptions, forecast participation, estimated savings, and budgets).

Mr. Elliot testified that the 2017 DSM Action Plan Update was updated in advance of this proceeding, and builds upon the 2015-2017 DSM Action Plan prepared and presented as evidence to support IPL's two-year 2015-2016 DSM portfolio (approved in Cause No. 44497). The 2017 DSM Action Plan Update reflects the same portfolio of programs approved by the Commission in Cause No. 44497, and simply represents a request for extension of IPL's current DSM offerings with contemporary updates to planning assumptions for program year 2017.

According to Mr. Elliot, the key changes in this proceeding to the 2015-2017 DSM Action Plan include:

- Updates to projections of avoided costs, retail rates, discount rates, line losses, and other inputs integral to economic modeling.
- Updates to measure-level attributes driven by the completion of, and IPL's adoption of, the Indiana Technical Resource Manual version 2.2 ("IN TRM ver. 2.2").
- Updated cost and performance attributes of Light Emitting Diode ("LED") technologies consistent with the rapidly evolving market and IPL's recent experience.
- The level of large customer opt-outs IPL has actually experienced, and the associated impact on reasonable market potential.

Mr. Elliot explained that the savings projections for the 2017 DSM Action Plan were developed utilizing a bottom-up approach. IPL relied on its outside consultant's industry expertise in addition to IPL's historical measure participation to forecast participation rates for each eligible measure included in the portfolio. Where appropriate, deemed energy and demand savings were applied utilizing EM&V of previously delivered IPL DSM programs or the IN TRM ver. 2.2. For those measures neither included in the scope of previous IPL specific EM&V nor contemplated in the IN TRM ver. 2.2, IPL's consultant projected savings values representative of the characteristics of IPL's service territory.

Mr. Elliot testified that its consultant also utilized a bottom-up approach to forecast direct program costs, which are comprised of five distinct cost categories: (1) IPL labor; (2) education & outreach; (3) implementation; (4) EM&V; and (5) customer incentives. In addition to these five direct program cost categories, Mr. Elliot testified that successful administration of the 2017 DSM Action Plan will require indirect program costs including: (1) umbrella outreach & education; (2) consulting; (3) memberships; (4) staff development; and (5) indirect IPL labor, as follows:

Indirect Program Costs	2017
Umbrella Outreach & Education	$ 750,000
Consulting	$ 175,000
Memberships	$ 50,000
Staff Development	$ 25,000
Indirect IPL Labor	$ 500,000
Total	$ 1,500,000

Mr. Elliot testified that IPL projects the following annual costs will be necessary to successfully administer and implement programs outlined in the 2017 DSM Action Plan Update:

Cost Categories (000)	2017
Direct Program Costs	$20,930,000
Indirect Program Costs	$1,500,000
Shared Savings	$4,265,612
Lost Revenues	$1,836,765
Sub total	$28,532,377
Emerging Technology	$250,000
Spending Flexibility (10% of Direct Program Costs)	$2,093,000
Sub total	$2,343,000
Total	**$30,875,377**

Mr. Elliot testified that the 2017 DSM Portfolio is cost-effective under several cost-benefit perspectives. He explained that IPL analyzed the program economics of the 2017 DSM Portfolio utilizing multiple benefit-to-cost ratio tests. IPL considered all stakeholder perspectives when analyzing the cost-effectiveness of the 2017 DSM Portfolio, including those of participating customers and non-participating customers.

Additionally, Mr. Elliot testified that IPL sought stakeholder input to the extent allowed by the timeframe to develop and submit a plan. IPL provided a summary of the updated 2017 DSM Action Plan to the OUCC and CAC, and solicited feedback prior to submission of this proceeding's filing.

Mr. Elliot explained that IPL intends to act as administrator of the 2017 DSM Portfolio, and will largely rely on third parties to manage the implementation and fulfillment of programs. Ultimately, IPL and its energy service providers will work with a number of trade allies and other small businesses to support outreach and delivery of the programs as proposed in the 2017 DSM Plan.

c. Erik Miller. Mr. Miller testified concerning the cost-effectiveness of the 2017 DSM Portfolio and programs, as well as the methods and assumptions used to conduct the cost-effectiveness analysis, and IPL's plan for conducting ongoing EM&V.

Regarding cost-effectiveness, Mr. Miller testified that IPL's analysis includes the Participant Cost Test ("PCT"), Utility Cost Test ("UCT"), Rate Impact Measure ("RIM") Test, and Total Resource Cost ("TRC") Test. The analysis was performed for 2017 as an extension of IPL's 2015–2016 program offerings. Programs were evaluated using the DSMore model – a nationally recognized economic analysis tool that is specifically designed to evaluate the cost effectiveness of implementing energy efficiency and demand response programs. Mr. Miller explained that, unlike many other DSM evaluation tools, the DSMore model spreads the savings impacts over distributions of hourly energy prices to provide a robust estimate of the value of DSM. Additionally, the model factors in variances due to weather through the use of historical weather data. DSMore model inputs include program costs (internal administration, vendor implementation, customer incentives, EM&V costs, and any incremental customer costs), measure savings, measure useful lives, net-to-gross ratios, and participation rates.

Mr. Miller testified that program costs were determined by reference to 2016 program delivery costs, based on prior contracts and performance in the field, resulting in very accurate estimates. When additional information was needed, IPL consulted with the program vendors that will deliver the 2017 DSM Plan.

Mr. Miller stated that energy and demand savings were determined by using the IN TRM ver. 2.2 or recent EM&V results. For measures that were not addressed in the IN TRM ver. 2.2 or EM&V, IPL used Technical Resource Manual resources from nearby states.

Mr. Miller testified that model inputs include avoided costs specific to IPL, customer rates, discount rates, and escalation rates. Both avoided capacity and operating costs were updated. Avoided costs were calculated by an outside vendor as part of a Fall 2015 Power Reference Case, which will also be used in IPL's 2016 IRP modeling.

Mr. Miller testified that the cost-effectiveness of the proposed 2017 DSM Portfolio and programs, and the results for all four conventional cost-effectiveness tests, are as follows:

IPL's 2017 DSM Plan Cost Effectiveness Results

	UCT	TRC	RIM	PCT
RES	**1.56**	**1.37**		
Air Conditioner Load Management	1.03	1.03	0.92	N/A
Appliance Recycling	1.35	1.35	0.50	N/A
Home Energy Assessment	1.79	1.79	0.55	N/A
Income Qualified Weatherization	1.21	1.21	0.51	N/A
Residential Lighting	2.64	1.39	0.68	2.60
Multifamily Direct Install	3.21	3.21	0.63	N/A
Online Kit	2.73	2.73	0.62	N/A
Peer Comparison	1.01	1.01	0.37	N/A
School Education	2.76	2.76	0.67	N/A
C&I	**2.24**	**1.34**		
Air Conditioner Load Management	0.40	0.40	0.40	N/A
Custom Rebates	3.10	1.59	0.80	2.46
Prescriptive Rebates	3.98	1.74	0.79	2.52
Small Business Direct Install	1.25	1.25	0.55	N/A

Mr. Miller explained IPL's process for determining programs based on the cost-effectiveness results, noting that the results of all tests were reviewed. PL considers the results from the PCT as an indicator of whether customers will adopt the measures offered in a program. A PCT below one indicates that a customer will spend more money than they save from program participation. Thus, these programs are screened out of the portfolio. IPL also looks for programs that pass the RIM test. This test provides an indicator of both efficiency and fairness among customers. Any program passing this test benefits non-participating customers as well as participating customers in the form of lower rates in the long run and should be considered acceptable. Mr. Miller noted that most energy efficiency programs do not pass the RIM test due to the loss in energy sales from savings. Additionally, IPL looks for programs that pass both the TRC and UCT tests. The TRC test compares the total costs and benefits of a program for the whole population of customers. The costs include the total costs to the utility and incremental participating cost to customers, and the benefits include tax incentives plus the avoided costs of energy supply. Program participants benefit through lower bills, whereas non-participants may be burdened by the costs of the program for which they are assessed through higher rates. A TRC test above one indicates that, on average, the customer population as a whole benefits. The UCT assesses the benefits and costs from the utility's perspective by comparing the utility benefits versus the utility costs (e.g., benefits of avoided fuel and operating capacity costs compared to rebates, incentives and administrative costs) – similar to a Present Value Revenue Requirements Integrated Resource Plan analysis. Mr. Miller testified that projected shared savings incentives are included in IPL's cost-effectiveness analyses at the portfolio level.

Mr. Miller noted that certain proposed programs do not pass the traditional benefit-cost tests. However, these programs have other societal benefits or the benefits are difficult to quantify and have been generally accepted subject to budget restrictions. Specifically, low-income weatherization programs typically do not pass these cost-effectiveness tests; but Mr.

Miller emphasized that IPL believes it is important to provide low-income customers DSM program offerings in order to give such customers the opportunity to participate in programs that will help them control their energy usage and their energy bills. Additionally, IPL proposes to continue offering the C&I ACLM program despite not being cost effective. Mr. Miller explained that IPL has offered the ACLM program to residential customers since 2003, expanding to the C&I sector in 2012 to provide equity across customer sectors. IPL proposes to continue to offer the C&I ACLM program in order to maintain this equity among sectors. Additionally, Mr. Miller noted that this program is still relatively small with the burden of high fixed costs. Over time as new participants are added, IPL anticipates increased cost effectiveness as the high fixed costs are spread over more savings.

Mr. Miller next testified concerning IPL's EM&V protocols and procedures. He explained that an independent third party has been contracted to perform EM&V of IPL's 2015–2016 programs approved by the Commission in Cause No. 44497. IPL intends to extend the contract for EM&V of the 2017 programs because these programs are an extension of IPL's 2015-2016 programs. IPL plans to work with its OSB to gain approval of this request.

Mr. Miller testified that the EM&V plans will meet or exceed the requirements of the Commission's rules. IPL will use the *IPL EM&V Framework*, which was approved by the IPL OSB in June 2015, as a guiding document for the scope of work with IPL's third party EM&V contractor. Where applicable, the scope of work will include:

- Process evaluations so that program delivery can be improved to maximize cost-effectiveness and customer satisfaction;
- Impact evaluations to measure the gross and net impacts of measures and programs;
- Verification that measures have been installed and identify discrepancies in the reported quantities; and
- Calculation of the cost-effectiveness parameters.

Mr. Miller explained that a considerable amount of valuable work was accomplished through the Indiana Demand Side Management Coordination Committee ("DSMCC") EM&V Subcommittee over the past several years. Work products that include the Indiana Technical Reference Manual and the Indiana Evaluation Framework are efforts worthy of continuing. IPL proposes to continue working with other utilities and interested parties to that end.

d. Kimberly Aliff. Ms. Aliff testified about (1) the impact of the 2017 DSM Portfolio on the approved cost recovery mechanism utilized in the Company's semi-annual filings (Cause No. 43623-DSM-X), including the allocation of cost recovery among the customer classes; (2) IPL's proposal to continue earning performance incentives using a shared savings methodology and how the performance incentives should be accounted for in the fuel adjustment clause ("FAC") earnings test; (3) the calculation of lost revenues and how the proposed lost revenues recovery should be accounted for in the FAC earnings test; and (4) the bill impacts associated with implementation of the 2017 DSM Portfolio.

Ms. Aliff explained that IPL is seeking a cost recovery mechanism similar to what has been previously authorized by the Commission most recently in Cause No. 44497. IPL proposes to continue to prepare semi-annual filings under Standard Contract Rider No. 22 ("Rider 22") to recover the forecasted costs (including shared savings incentives and lost revenues) of the IPL 2017 DSM Plan over six-month periods that match the billing periods of the tracker. The semi-annual periods of January to June and July to December will continue to be used. The 2017 DSM Plan expenditures will continue to be forecasted semi-annually and reconciled to actual expenditures in a subsequent semi-annual filing.

Ms. Aliff sponsored the cost allocation basis to the customer classes for each component of the 2017 DSM Portfolio. As reflected in IPL's recent base rate case in Cause No. 44576, she noted that lighting customers are now included in IPL's rate adjustment mechanisms. Accordingly, a portion of DSM costs will be allocated to rate codes APL and MU-1 for both residential and C&I programs. Ms. Aliff explained that the residential allocation factors are based on each class' share of the twelve monthly average system peaks used to allocate production plant, operating expenses and depreciation expenses, from the Company's cost of service study prepared for IPL's most recent base rate case in Cause No. 44576. She further testified that commercial and industrial customer allocation factors are based on each class' share of the twelve monthly average system peaks from the Cause No. 44576 cost of service study, excluding those customers who have chosen to opt-out of participation in IPL's DSM programs.

Ms. Aliff next testified about IPL's shared savings incentive. As a component of its 2017 DSM Plan, IPL is proposing to continue the performance based incentive mechanism approved in Cause No. 44497. The proposed shared savings incentive is calculated as 15% of the net present value of UCT's net benefits. The net benefits of the UCT equate to the difference between the costs avoided by DSM programs and the costs incurred by the utility to deliver the program. She testified that shared savings incentives are contemplated by the IURC's DSM rules; for example, 170 IAC 4-8-7(a) specifically refers to an incentive mechanism based on "a percentage share of the net benefit attributable to a demand-side management program." She noted that shared savings can be used as an incentive for the implementation of cost effective DSM programs by sharing the measurable net benefits of DSM programs between customers and the utility. In addition, Ms. Aliff pointed out that the Order in Cause No. 44497 states:

> [W]e note that our DSM rules specifically allow for shared savings incentives. 170 IAC 4-8-7(a)(1) refers to "[g]rant[ing] a utility a percentage share of the net benefit attributable to a demand-side management program" - the very definition of a shared savings mechanism. Further, 170 IAC 4-8-7(f) specifically requires that "[a] shareholder incentive mechanism must reflect the value to the utility's customers of the supply-side resource cost avoided or

deferred by the utility's DSM program minus incurred utility DSM program cost." This requirement is directly met by a shared savings mechanism.

Consistent with the existing shared savings incentive calculation, IPL is proposing to continue to earn performance incentives on all cost-effective programs with a UCT greater than 1.0, except for the IQW program. As described by Mr. Miller, all programs proposed in the 2017 DSM Plan, other than the C&I ACLM program, are cost-effective. Ms. Aliff further noted that the performance incentive will be based on actual (ex-post) net savings and will be trued-up after EM&V for 2017 is completed. Also consistent with treatment of performance incentives approved in the Commission's 43623, 43960, 44328, and 44497 Orders, IPL proposes the shared savings incentives billed, including any reconciled amount of over/under recovery, will continue to be included in the FAC earnings test.

Ms. Aliff next testified about the calculation and recovery of lost revenues. She explained that estimates of the kWh consumption and kW demand reductions per participant and the number of participants for each program were determined from the analysis prepared by IPL Witnesses Elliot and Miller. For programs where historical participation was reported by rate code, estimated participants were allocated between the individual rate codes based upon the historical participation. For other programs, estimated participants were allocated based upon the ratio of the annual historical kWh consumption within their rate class. Allocated participants by rate were then multiplied by the estimated kWh consumption and kW demand reductions by participant to determine the total kWh consumption and kW demand amounts by rate within each program and then totaled by rate. For the 2017 DSM Portfolio estimates, these amounts for each individual rate were then multiplied by the lost revenue margin rates per kWh and kW as presented in the Cause No. 44576 Compliance Filing (dated March 23, 2016). This methodology was also used most recently in IPL's Rider No. 22 proceeding in Cause No. 43623 DSM-13.

The estimates of kWh consumption and kW demand reductions tie directly to the Net Incremental Energy Savings and Net Incremental Demand Savings in the 2017 DSM Action Plan Update (Petitioner's Attachment ZE-1), which have been adjusted to reflect the net to gross ratio for each program to account for free ridership. However, to the customer's benefit, IPL does not start calculating lost revenue until the month following installation of the measures.

Ms. Aliff emphasized that the participation in DSM programs by customers reduces kWh consumption and kW demand which results in reduced revenue collections for utilities (such as IPL) which are only partially offset by a reduction in base fuel and variable operations and maintenance ("O&M") costs. To calculate lost revenues, the lost revenue margin rates begin with IPL's approved rate block for each rate schedule at which customers' marginal energy consumption or demand occurs (determining the impact to IPL's revenues) and are adjusted to remove the base cost of fuel, variable O&M expenses, and applicable Indiana Utility Receipts Tax (determining the expenses IPL avoids by not generating the electricity that would have otherwise been consumed). The result is the decrease to operating margin (a financial penalty) that IPL experiences as a result of implementing energy efficiency programs. This impact to operating margin continues until the earlier of the end of the energy efficiency measure life, or the effective date of a new base rate case order. Ms. Aliff testified that the DSM lost revenues billed, including any reconciled amount of over/under recovery, will continue to be included in the FAC earnings test.

According to Ms. Aliff, the overall average monthly impact of IPL's 2017 DSM proposal, relative to basic rates and charges, is shown as follows:

Estimated Bill Impact			
		DSM 2017 excluding persisting lost revenue	DSM 2017 with persisting lost revenue
Base Rates	$97.42		
DSM-13 factor (pending)	$3.72	$2.91	$3.32
Bill including factor	$101.14	$100.33	$100.74
Change relative to Base Rates	3.82%	2.99%	3.41%
Change relative to DSM-13		-0.80%	-0.39%

6. **CAC's Case-in-Chief.** Shawn M. Kelly, an independent consultant, testified on behalf of the CAC. The purpose of his testimony was to provide his opinion as to whether or not IPL's 2017 DSM Portfolio is reasonable and cost effective under Indiana Code § 8-1-8.5-9. Mr. Kelly recommended that the Commission approve IPL's 2017 DSM Portfolio, but also requested that the Commission require IPL to implement several recommendations included in his testimony, as follows: (1) increase the amount of savings to a reasonable and cost-effective level that would provide a comparable level of energy services; (2) place a 4-year or life of the measure cap, whichever is shorter, on lost revenues attributed to IPL's 2017 DSM Plan; (3) add health and safety funding to IPL's IQW program for an average of $500 per customer; (4) make CAC a voting member on the IPL OSB; (5) deny IPL's request for a performance incentive consistent with recent commission orders, but if a performance incentive is approved, it should be based on multiple performance metrics, be subject to a financial cap, and be contingent upon lost revenue recovery being limited to the shorter of 48 months or the life of the measure; (6) initiate an investigation into lost revenues and DSM cost recovery filings for the five investor-owned electric utilities in Indiana; and (7) order the IPL OSB to begin discussions on expanding low-income programs before its next DSM plan filing.

With regard to the level of savings included in IPL's 2017 DSM Plan, Mr. Kelly opined that the Plan was not reasonable because IPL is leaving a great deal of cost-effective savings on the table. In support of this opinion, Mr. Kelly referenced that DSM in IPL's 2014 IRP was represented as a reduction in the load and not as a selectable resource in the capacity expansion model. He noted that the Commission's Electricity Division Director's Final Report on the 2014-2015 IRPs submitted by IPL and other utilities found that the utilities may be using a hardwired fixed amount of DSM in their IRP scenarios. In this report, the Director noted his concern that if the bundling of various DSM programs is not done with care and sufficient detail, an unintentional bias may result which would cause the capacity expansion planning model to not pick DSM even though a more careful packaging of DSM might have resulted in its inclusion. In Mr. Kelly's view, even though IPL is going through the process of developing its 2016 IRP, IPL's customers are losing out on cost-effective savings because of the flaws in IPL's 2014 IRP.

Mr. Kelly also testified that IPL's proposed savings for 2017 is significantly below its former 2017 savings goal from its 2012 market potential study. He conceded that some of this reduction is due to large industrial customers no longer participating in the programs, but contended that even after taking that into consideration, IPL's 2017 goal is only 1.2 percent of eligible sales. This compares with the former 2017 target of 1.7 percent for 2017, based on IPL's 2012 market potential study. Mr. Kelly also testified that IPL's 2017 savings goal is significantly lower than its goals for 2014 through 2016. He again conceded some of this is caused by the opt-out of industrial customers, but he stated that it also appears IPL has ramped down many of its programs.

Mr. Kelly testified that there are additional opportunities for energy efficiency beyond what IPL is proposing in its 2017 DSM Plan. He stated that IPL should, at a minimum, pursue all reasonably achievable savings by increasing the goals for those programs unaffected by opt-out customers to levels consistent with its 2012 market potential study. Additionally, Mr. Kelly testified that IPL should work with the OSB to explore additional programs, such as new construction programs and a residential prescriptive program.

Mr. Kelly next addressed the issue of lost revenues. He noted that CAC has consistently argued that the utilities are over-collecting revenues from customers that are not truly lost revenues, and that the accumulation of lost revenues from multiple program years and long periods between rate cases creates a harmful "pancake effect" that was never intended. Mr. Kelly stated that a shorter of four years or the life of a measure cap is a reasonable limit to place on lost revenue recovery – although CAC disagrees with the Commission's determination in other cases that this cap should only apply to program years at issue in current DSM approval proceedings and not to past program years ("legacy lost revenues").

Mr. Kelly next argued that EM&V results do not truly represent lost revenues. He stated that the utility industry is exceedingly reliant on studies from third-party vendors. Further, he believes the EM&V vendors should report directly to the Commission rather than the utility. Mr. Kelly opined the true measure of lost revenues is to evaluate actual customer usage. He claimed that EM&V does not take into consideration other impacts that may have driven usage up as a result of more efficient usage of energy – the so-called "rebound effect." He pointed out that, according to IPL, IPL does not measure the rebound effect in its EM&V reports.

Mr. Kelly claimed that there is a potential with the current lost revenue calculation methodology that utilities are double-collecting revenues from customers because of the lack of billing analysis. He claimed that a customer that implements energy efficiency measures but has some usage increases leads to the utility over-collecting lost revenues, regardless of the reason why the customer's usage increased in some respects. As support for his argument, Mr. Kelly cited the fact that IPL customers' weather-normalized usage in aggregate has not decreased as much as the energy efficiency measures EM&V results indicate. He further supported this argument by pointing out that the lost revenue adjustment mechanism gives the utility an incentive to increase energy usage on their system, which acts in conflict with goals to reduce usage.

Mr. Kelly opined that EM&V is valuable information to help improve program design and implementation, but it should not be utilized as the sole resource in determining the amount of lost revenue collection. He offered his opinion that EM&V vendors are not truly independent, despite the fact that the IPL OSB has input into vendor selection and gets an opportunity to review all EM&V reports, because the vendor is ultimately accountable to the utility who pays the vendor's fees. In his view, a better approach to ensure true independence would be to have the Commission select and manage the relationship with the EM&V vendors.

Mr. Kelly suggested that the Commission open an investigation into the investor-owned utilities electric DSM rider filings to create consistency in the format and methodologies of each filing and to simplify these schedules wherever possible. CAC recommends this investigation also include a review of lost revenues to give the Commission and stakeholders comfort that customers are not paying for lost revenues that are not truly lost.

Regarding IPL's IQW program, Mr. Kelly testified that IPL should include in this program funding of $500 in health and safety measures per household. As support for this recommendation, he noted that the average number of IPL customers that were turned down due to health and safety concerns is approximately 306 per year – 20 percent of total IQW jobs. He also noted that three other electric utilities do fund health and safety measures in their IQW program budgets, and such funding has been approved by the Commission. Mr. Kelly opined that increasing the overall budget to include health and safety measures would not have a significant impact on rates.

Mr. Kelly testified that IPL should broaden its low-income program in other ways, as well. He stated that the current program mainly focuses on single-family homeowners. He believes a large portion of the low-income community in IPL's service territory is being missed; a stronger effort is needed to target renters of single-family homes and multi-family units. He also testified that increasing more specific outreach and education to the low-income community would help greatly. He pointed to a strong model from Ameren Missouri, which focuses on a combination of weatherization efforts for low-income, multi-family complexes and energy efficiency education that engages customers to learn how to reduce their energy bills. Mr. Kelly recommended for 2017 that the Commission approve the current IQW program with an increased budget of $250,000 to include health and safety funding for an average of $500 per IQW participant. For the other enhancements, he suggested the OSB begin collaborating on an expanded low-income program to culminate in a new filing before the Commission.

Regarding the IPL OSB, Mr. Kelly testified and recommended that CAC be granted voting member status. He noted that this was the current structure for the OSBs for Indiana Michigan Power Company, Northern Indiana Public Service Company, and Vectren. In support of his recommendation, Mr. Kelly testified that stakeholders should have a strong influence on savings levels, program designs, and other outcomes. He stated that CAC will continue to raise program issues with every utility in its capacity as an OSB member, but without a vote, CAC remains an undervalued OSB member. He concluded by opining that granting CAC OSB voting member status will make collaboration on IPL's 2018-2020 DSM filing more effective.

Finally, Mr. Kelly addressed the issue of performance incentives. He stated that CAC believes IPL's request for a shared savings incentive should be denied in this proceeding and then re-evaluated in its Section 10 filing for program years 2018-2020. He noted that denial of performance incentives would be consistent with recent Commission orders in other cases decided under Section 9.

7. IPL Rebuttal Testimony. IPL witnesses Allen and Elliot testified in rebuttal.

a. Lester Allen. Mr. Allen responded to issues raised by CAC witness Kelly relating to lost revenues, financial incentives, the development of IPL's 2017 DSM Portfolio, the administration of EM&V vendors, and the composition of IPL's OSB.

Mr. Allen offered his opinion that some of Mr. Kelly's testimony positions were disappointing and at odds with IPL's longtime and consistent commitment to providing DSM opportunities for its customers. He noted that IPL has been a dependable and good actor in DSM programs and has a track record of program success, starting in the early 1990s. He further noted that IPL has been a leader in the state in terms of scale and scope of DSM program delivery and IPL's current proposal to extend its DSM programs for 2017 continues its good faith efforts to provide energy savings options for customers and stakeholders.

Mr. Allen stated that IPL believes performance incentives, such as its shared savings incentive, are necessary and appropriate. Incentives are necessary to put DSM on the level playing field with supply-side resources from the utility perspective, and incentives are appropriate in this particular case as IPL's 2017 DSM Plan is simply the third year of a three-year plan that includes a shared savings incentive. He emphasized that nothing has changed in the last two years that somehow makes IPL's shared savings incentive unnecessary or inappropriate.

Mr. Allen further testified that a shared savings incentive is reasonable because it aligns IPL's interests with the interests of its customers, is based on cost-effective DSM results, and is earned when savings are realized. Mr. Allen emphasized that program costs recovery and lost revenue recovery are necessary to incentivize a utility to pursue DSM, but they are not sufficient to truly put energy efficiency on a level playing field with supply-side resources. Financial incentives, such as IPL's shared savings incentive, are the third leg of the stool necessary to encourage utilities to pursue energy efficiency, by providing a "return" on prudent energy efficiency investments, analogous to the return available for prudent supply-side investments. Mr. Allen reiterated that IPL is proposing exactly the same shared savings incentive as was approved by the Commission in Cause No. 44497 for program years 2015 and 2016.

Mr. Allen noted that Mr. Kelly provided no evidence to support his contention that continuation of a shared savings incentive for IPL is unreasonable. Rather, Mr. Kelly simply cited a few recent Commission orders whereby other Indiana utilities were denied the ability to recover a financial incentive for plans submitted under Section 9. Mr. Allen testified that IPL's situation is distinguishable and IPL should be authorized to continue its shared savings incentive for a number of reasons. First, this is the third year of a 3-year plan filed in 2014 for which a shared savings incentive was approved for 2015 and 2016. Second, it is consistent and appropriate to authorize the same incentives for the third year of the 3-year plan, particularly as nothing material has changed with respect to IPL's offering of DSM programs in 2017, as compared to 2015 and 2016. Third, the Commission's DSM rules are still in effect and allow for performance incentives. Fourth, it would have been highly inefficient and costly for IPL to have developed a separate interim IRP analysis outside of the normal IRP cycle for the sole purpose of modeling DSM as a selectable resource in order to be in a position to present a Section 10 plan in this proceeding – especially when there was a 3-year action plan filed in 2014 which included 2017. Fifth, the amount of DSM requested in 2017 is consistent with and in the range of the amount of DSM preliminarily selected as a resource in IPL's draft 2016 IRP for 2018 through 2020. Sixth, the approach used to identify the target level of DSM for 2017 in this proceeding is reasonable; it has been the standard approach to determining the appropriate amount of DSM for more than two decades. The new approach of making DSM a selectable resource corroborates IPL's requested level of DSM for 2017. Seventh, IPL has been a consistent, long-time advocate and practitioner of DSM.

In sum, Mr. Allen emphasized that IPL has not proposed any changes to the current incentive approach in this request for a one-year extension of its current programs. IPL is only seeking to apply the same construct previously approved by the Commission that encourages IPL to maximize the benefits in the delivery of cost-effective DSM programs.

With regard to lost revenues, Mr. Allen stated that lost revenue recovery calculated using independent EM&V results is reasonable and consistent with long-standing industry and Commission practice. He characterized CAC's criticism of the EM&V approach in favor of an alternative billing analysis approach as another attempt to deprive utilities of lost revenue recovery in cases where sales volumes may have increased for reasons entirely unrelated to DSM. Mr. Allen noted that the approach used by IPL's independent EM&V evaluator is consistent with framework adopted several years ago by the DSMCC and is consistent with industry practice. He further noted that CAC had opportunities to propose alternative methodologies during IPL OSB meetings but chose not to do so. He pointed out that the Commission has relied on EM&V to calculate lost revenues since the early 1990s, and that Commission's DSM rules contemplate the use of EM&V to calculate lost revenues. He noted that the EM&V performed by IPL's independent third-party evaluator fully complies with the Commission's DSM rules.

Mr. Allen also pointed to the fact that discussions held in the Indiana General Assembly during the passage of SEA 412 indicate that EM&V should be used to calculate lost revenues. For example, the House Sponsor of Senate Bill 412 stated that "lost revenues were a feature of the old plan and under this bill are subject to very stringent EM&V requirements." Further, Mr. Allen testified that the EM&V methodology used by IPL's independent third-party evaluator is similar to the approach used by other utilities in Indiana and across the country. In contrast, he noted that Mr. Kelly's position is inconsistent with the well-established and accepted practices of an entire industry with years of experience and expertise.

Mr. Allen also provided examples of several downsides associated with trying to calculate lost revenues using the billing analyses as suggested by Mr. Kelly. For example, it would be necessary to randomly select control groups for each program. This would not only be impractical, but also would render a large portion of IPL's customer base ineligible to participate in energy efficiency programs. Additionally, Mr. Kelly's proposal fails to account for changes in the load (for example, load growth in the absence of DSM programs). Also, Mr. Kelly's methodology does not account for the temporal nature of energy efficiency installations and corresponding lost revenue. His testimony shows savings amounts that are annualized, while IPL's methodology begins to calculate lost revenues only after a measure is installed and implemented.

Regarding Mr. Kelly's suggestion that the Commission should hire and manage EM&V vendors, Mr. Allen testified there is no indication or evidence that such a change is necessary. He opined that IPL's EM&V evaluator is professional, expert, independent, transparent, and open to working with stakeholders. He noted that the evaluator is not simply selected by IPL, but more accurately is selected by the IPL OSB, and CAC has input into that selection process. Additionally, CAC's suggestion would add administrative burdens to the Commission's already significant workload – and would not noticeably decrease the utility's workload. Finally, Mr. Allen noted that CAC has not pointed to any deficiencies in the EM&V vendor or the EM&V study themselves. Mr. Allen emphasized that IPL's independent EM&V vendor takes a rigorous approach to evaluating the performance of IPL's programs. He also noted that IPL's 2015 program evaluation met a 90 percent confidence and 10 percent precision level in all critical estimates.

Mr. Allen also took issue with Mr. Kelly's position that lost revenue recovery should be artificially capped at four years. Mr. Allen stated that full lost revenue recovery for the life of the measure is necessary to avoid penalizing the utility for implementing DSM. Moreover, he testified that if lost revenue recovery is artificially capped at something less than the applicable measure life, the cost-effectiveness and IRP analyses should also reflect such shorter artificial caps. Mr. Allen emphasized that lost revenues are a real cost of engaging in utility energy efficiency programs, and sales are lost throughout the useful life of the measures unless or until base rates are reset in a rate case.

Regarding CAC's suggestion that the Commission initiate an investigation into utility lost revenues, Mr. Allen testified that such an investigation is not warranted. Again, lost revenues are a real and calculable cost to utilities resulting from implantation of DSM programs. This reality is recognized by many experts, regulators, and legislators. There is simply nothing to investigate.

Contrary to Mr. Kelly's assertions, Mr. Allen argued that IPL's development of its 2017 DSM Portfolio was reasonable. He noted that it is the third year of the previously filed three-year plan, developed using a methodology that has been in use in Indiana for years. He further explained that IPL is addressing the DSM methodology concerns cited in the 2014 IRP Director's Report in its current 2016 IRP process. Mr. Allen pointed out it would not make sense for IPL to develop a separate, interim IRP analysis just for this 2017 DSM case.

Finally, Mr. Allen testified that IPL continues to believe that its OSB should remain as currently constituted. He testified that the OSB functions well and the appropriate voting members are the utility that is accountable for its DSM programs (IPL), and the statutory representative of all utility customers in the state (OUCC). He stated that CAC has ample opportunity as a nonvoting member to provide input, review proposals, etc., but including CAC as a voting member would be duplicative of the OUCC's role and would leave IPL, the party ultimately responsible for its DSM programs, as a potentially minority member.

b. Zac Elliot. Mr. Elliot responded to Mr. Kelly's arguments about the projected level of 2017 savings and IPL's program designs. Regarding the reasonableness of IPL's 2017 savings, Mr. Elliot emphasized there is no evidence that IPL's 2017 Portfolio leaves significant cost-effective savings on the table. In fact, he testified, IPL's anticipated 2017 savings level is consistent with the range of achievable savings for 2017 from IPL's 2012 Market Potential Study. Mr. Elliot noted that Mr. Kelly relied on IPL's 2012 Action Plan, which he mistakenly referred to as the 2012 Market Potential Study, to support his argument that IPL's 2017 proposed savings level is unreasonable. In fact, Mr. Elliot testified that the projected net energy impacts from this 2017 proposal are 106,327 MWh, whereas the 2012 Market Potential Study showed a range of savings for 2017 between 89,000 and 158,000 MWh. Further, Mr. Kelly's advocated savings level would be at the uppermost extremity of achievability, as shown in the 2012 Market Potential Study. This upper level of achievability would require ideal markets, implementation, and customer preference conditions and represents a maximum target that an administrator can "hope to achieve." It also involves incentives that represent a substantial portion of the incremental costs, combined with high administrative and marketing costs. In other words, to even hope to achieve the levels Mr. Kelly advocates would require budgets and expenditures at the most aggressive end of the spectrum. Plus, factors over which IPL has little or no influence, such as customer preferences and adoption behavior, would have to optimally align with those factors under IPL's control.

Mr. Elliot explained that the Action Plan cited by Mr. Kelly (as opposed to the Market Potential Study), represented a good faith attempt by IPL to define a plan that would achieve compliance with the targets previously prescribed by the Commission. He also noted that in an attempt to meet those prior DSM targets, IPL would have been required to pursue significantly more non-cost-effective measures and programs.

Further, Mr. Elliot explained that the reduction in expected 2017 savings, compared to years 2015 and 2016, is explained in part by the number of large customers that have opted out of IPL's programs. The other significant contributor to this reduction is the residential lighting program, due to the proposed removal of compact fluorescent lamps ("CFLs") in the 2017 plan. In 2015 and 2016, CFLs represented approximately 80 percent of the residential lighting program impact, but are not modeled as an eligible measure in 2017. IPL's residential lighting program will rely solely on LED impacts in 2017, and IPL does not project LED sales sufficient in 2017 to replace the significant savings historically contributed by CFL sales. However, IPL anticipates that LED sales will continue to gain market share in coming years, thus increasing gross energy savings potential.

In sum, Mr. Elliot emphasized that the current 2017 savings goal is reasonable and is within the range of savings identified by IPL's 2012 Market Potential Study, while Mr. Kelly's proposal is beyond the maximum achievable level identified in that study. The relatively small extent to which IPL's proposed energy savings goal for 2017 is lower than that of 2015 and 2016 results from the ability of large customers to opt out and from IPL's proposed discontinuance of CFL lighting in its programs.

Mr. Elliot also addressed CAC's assertions that IPL should make programmatic changes. First, with regard to Mr. Kelly's contention that IPL should consider a new construction program and prescriptive rebates for non-lighting measures, Mr. Elliot testified that IPL has offered prescriptive rebates for residential HVAC equipment and new construction in prior years. However, IPL experienced low volumes of participation for both programs and both programs had poor program cost-effectiveness. In IPL's 2014 DSM plan case (Cause No. 44328), Mr. Elliot testified that IPL was proposing to discontinue the residential HVAC program due to lack of cost-effectiveness, and the Commission's Order in that case states that "no party took issue with IPL's decision to discontinue the PerfectCents Residential HVAC program," including CAC, a party to that proceeding.

Regarding the new construction program, Mr. Elliot noted that program was particularly challenging given the fact that IPL's rebates targeted all-electric homes. He noted that the program was met with reluctance from the building community to install all-electric space and water-heating equipment given the low cost of natural gas, and building envelope measures had minimal electricity savings impact in natural gas heated homes. Mr. Elliot noted that the IPL OSB, including CAC, agreed to discontinue the program in July 2014.

With regard to CAC's recommendation that IPL budget funds to remediate health and safety issues in its IQW program, Mr. Elliot noted that neither IPL nor its customers have historically borne the costs for remediating health and safety related issues in the IQW program. He noted that in Cause No. 44497, the Commission concluded it would not require IPL to fund health and safety measures in connection with its IQW program because "we have not been presented with sufficient evidence justifying a requirement that ratepayers subsidize these improvements for other ratepayers." Mr. Elliot discussed what IPL has done to address the high participant deferral rate due to health and safety issues. First, he testified, IPL has maintained a gas leak procedure similar to the process developed by the DSMCC during Energizing Indiana. This procedure involves decreasing audit deferrals by having auditors wear personal metering devices that measure both carbon monoxide and ambient methane levels. If a gas leak is detected but the ambient meter does not alarm, the auditor can continue with the audit. Second, Mr. Elliot testified that IPL has begun to track IQW deferral reasons in greater detail in an effort to better understand the underpinnings of annual deferral rates. He noted that in 2015, IPL had an overall completion rate of 38% for the IQW program, meaning that the program experienced an overall deferral rate of 62%. He noted that in 2015, 12% of audits scheduled were deferred due to health and safety reasons, and 50% were deferred due to customers canceling or rescheduling the appointment. He noted that under IPL's vendor agreement, customers are contacted in advance of the audit to mitigate deferrals and three reschedule attempts are made if the audit is canceled. Further, Mr. Elliot stated that because that the cancelation rates were significantly higher than health and safety deferral rates in 2015, IPL is working to increase completion rates by offering $25 promotional incentives to customers who complete the audit -- in addition to the measures offered through the program. Additionally, Mr. Elliot testified that during the site visit IPL has been able to convert many of the IQW health and safety deferrals to Home Energy Assessments, providing energy saving benefits to the customer. Home Energy Assessments do not provide air sealing and insulation measures, thereby mitigating the health and safety risks associated with sealing at the home. Lastly, Mr. Elliot testified that IPL continues to provide reports to Citizens Energy when natural gas safety related items are encountered in the field. While health and safety deferral reasons vary, he noted that over 50% of the health and safety related deferrals are natural gas related.

Consistent with the Commission's recommendation to explore alternative sources of funding of health and safety, Mr. Elliot testified that IPL has met and continues to meet with a number of local community development corporations, neighborhood groups, and community based organizations, in an effort to find health and safety dollars. He noted, however, that these organizations may have home repair dollars available for only a few homes a year and as a result, there is minimal potential to meaningfully impact deferral rates through this funding. He stated that IPL will continue its efforts to seek alternative sources of funding for health and safety remediation.

Mr. Elliot also testified that IPL has continued to look for ways to improve its IQW program and has successfully launched several initiatives in the last couple of years. For example, IPL has developed a partnership with local food pantries to distribute energy efficient LED lamps to recipients of food pantry services. During food pantry distribution dates, customers can also schedule an IQW audit, in addition to receiving LEDs. Mr. Elliot testified that IPL has also partnered with several neighborhood groups and community development corporations to sponsor and participate in community-focused events. During these events, IPL has been able to target specific areas with IQW audits and LED giveaways to provide direct energy saving benefits in local communities. Lastly, Mr. Elliot testified that IPL is proposing to offer ENERGY STAR® refrigerator replacements and is considering the addition of smart thermostats to IQW participants beginning in 2017, which should provide significant additional benefits for eligible customers.

Mr. Elliot next addressed Mr. Kelly's argument that IPL should also consider expanding its low-income program to include non-owner-occupied single-family residences and multi-family units. Mr. Elliot noted that IPL does offer IQW to both owner-occupied and non-owner-occupied single-family residences. In fact, 18% of those who enrolled in IPL's IQW program in 2015 were non-owner occupiers of the residence. Additionally, many multi-family properties qualify for the program, because IPL defines an eligible single-family residence to include no more than four adjacent units. Further, for any residence that does not meet the definition for single-family, those residences would qualify for IPL's Multifamily Direct Install program. The Multifamily Direct Install program resembles IPL's IQW program in terms of measures installed, with the exception of building envelope measures.

Finally, Mr. Elliot responded to Mr. Kelly's position that IPL should expand its energy efficiency outreach and education to its low-income customers. Mr. Elliot agreed, and stated that IPL has been expanding outreach and education activities in 2015 and 2016. As mentioned above, IPL has expanded and continues to expand its outreach efforts through partnerships with community organizations. These activities include direct interaction with customers at food pantries, as well as community outreach and education partnerships with community based organizations. Mr. Elliot emphasized that IPL is always willing to discuss additional outreach channels with its OSB.

8. Commission Discussion and Findings. IPL requests approval for a one-year extension of its current DSM programs and the current ratemaking treatment authorized for such programs. IPL's current DSM programs for which it seeks authority to continue to implement in 2017 are as follows:

- Residential Lighting
- Residential Income Qualified Weatherization ("IQW")
- Residential Air Conditioning Load Management ("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

IPL requests that we continue to approve its OSB as currently constituted and that we grant its OSB oversight over certain budget or spending flexibility and certain program flexibility (10% spending flexibility, approval to carryover unused funds from 2015/2016, and programmatic flexibility for the OSB to modify or add cost-effective programs and emerging technologies). IPL also requests that we approve the overall DSM program budget (direct and indirect program costs, emerging technologies and spending flexibility), and that we approve continuation of lost revenue recovery and the shared saving incentive approved in Cause No. 44497. IPL requests that our approvals in this Cause commence January 1, 2017 and continue until the later of December 31, 2017 or the date of our order in IPL's next DSM plan approval proceeding. Finally, IPL requests that we authorize it to make changes to its Standard Contract Rider No. 22 consistent with these requested approvals.

IPL presented evidence that its 2017 programs in total are expected to result in first year gross energy savings of approximately 129,000 MWh and approximately 58 MW of gross demand reduction in 2017. This represents an approximately 0.94% reduction in energy sales and, when sales are adjusted to take into account customers that have opted out, the savings represent about a 1.21% reduction in sales.

IPL estimated the total cost of its proposal for 2017 as follows.

Cost Categories (000)	2017
Direct Program Costs	$20,930,000
Indirect Program Costs	$1,500,000
Shared Savings	$4,265,612
Lost Revenues	$1,836,765
Sub total	$28,532,377
Emerging Technology	$250,000
Spending Flexibility (10% of Direct Program Costs)	$2,093,000
Sub total	$2,343,000
Total	**$30,875,377**

IPL noted that the total estimated cost of the proposed 2017 DSM programs, prior to recovery of incentives or lost revenues, is $24.8 million – comparable to IPL's annual budgets approved for 2015 and 2016.

IPL's proposal is supported by an updated DSM Action Plan which accounts for (1) updates to avoided costs, rates, discount rates, line losses, etc.; (2) updates to measure-level attributes, driven by the IN TRM ver. 2.2; (3) updated cost and performance attributes of LED lighting technologies; and (4) the level of large customer opt-outs IPL has actually experienced. IPL's proposal is also supported by cost-benefit analyses, which demonstrate that the entire portfolio of proposed programs is cost effective under both the UCT and TRC perspectives, and the individual programs – with the exception of the Business ACLM program – are also cost-effective under both the UCT and TRC perspectives.

a. IPL's Projected Savings and Planning Process. CAC takes issue with IPL's projected 2017 savings level, arguing that it is unreasonably low. We are not persuaded that the level of projected 2017 savings is unreasonable. IPL has demonstrated that its projected 2017 savings are in the range expected by its 2012 Market Potential Study and subsequent Action Plan updates, even with lower savings due to customer opt outs and the transition from CFL to LED lighting. CAC has mistakenly confused the 2012 Market Potential Study with the 2012 Action Plan, and Mr. Elliot has explained that the Action Plan targeted an aggressive high level of savings in order to try and reach previous Commission energy efficiency targets. Further, Mr. Elliot explained that to reach those targets, IPL would have to spend more on marketing, advertising, and customer incentives. Additionally, issues outside of IPL's control, such as customer preferences and adoption rates – would have to be realized, as well. We conclude that the Market Potential Study is a more realistic and achievable measure of expected savings, and that IPL's 2017 DSM proposal is in line with the 2012 Market Potential Study.

We are also not persuaded by CAC's contention that IPL's IRP process was flawed and therefore its DSM portfolio is unreasonable. We agree with Mr. Allen that utilities', including IPL's, IRP processes are evolving toward modeling DSM as a selectable resource, as opposed to modeling DSM largely outside of the IRP process. While we believe this evolution is positive, it does not negate the reasonableness of past IRP processes and results, nor does it indicate that IPL's proposed 2017 DSM portfolio is unreasonable. In fact, Mr. Allen's testimony indicates that its preliminary 2016 IRP, which is modeling DSM as a selectable resource, is producing similar DSM results. Moreover, the preferred forum for this issue is the utility's IRP stakeholder process. While we continue to believe that utilities should strive to evaluate energy efficiency and supply-side resources in a consistent and comparable manner, we also recognize that there are differences between energy efficiency and supply-side resources that may require utilities to model energy efficiency and supply-side resources in slightly different ways for IRP purposes. Notably, IPL's proposed 2017 DSM Portfolio is premised upon a market potential study and is a continuation of its existing portfolio of programs, which we have previously approved. Additionally, the proposed 2017 DSM Portfolio is a very short-term issue (one year only), while CAC's argument goes to a long-term IRP planning issue. For all of these reasons, we reject CAC's recommendation that we order any changes to the proposed 2017 program portfolio as a result of its IRP concerns. In sum, we find that IPL's projected level of 2017 savings is reasonable.

b. IPL's Program Portfolio and Budgets. By virtue of its decision not to file testimony in this proceeding, we infer that the OUCC is generally supportive of IPL's proposed 2017 DSM programs. CAC also appears supportive of most of the programs that make up IPL's proposal, but contends that (1) IPL should include in its IQW program budget $500 per home to allow for remediation of health and safety issues, and (2) IPL should expand its programs for residential and low-income customers in other ways.

With regard to CAC's recommendation concerning funding health and safety remediation efforts through IPL's IQW program, we note that IPL's research and statistics on the issue of IQW "deferrals" indicate that the majority of such deferrals stem from customer cancellations, not health and safety issues, and that IPL is attempting to reduce cancellations through a variety of creative and proactive means. The evidence also indicates that gas leak issues account for a number of health and safety deferrals, and that IPL continues to employ protocols that allow auditors to continue to work in certain gas leak situations where ambient meters indicate that methane and carbon dioxide levels are acceptable. Further, IPL continues to report such issues to

Citizens Energy. Finally, we note that IPL continues to seek outside funding for remediating health and safety issues, although that funding is limited. For all of these reasons, we decline to adopt CAC's recommendation that we require IPL to modify its IQW program to include funding for health and safety measures. We continue to believe that IPL's IQW program strikes a reasonable balance between cost-effectiveness and assistance for low-income customers. Adopting CAC's recommendations would increase the cost of the program and would require funding for health and safety remediation measures to be provided by other customers. However, we encourage IPL and its OSB to continue to search for alternative sources of funding to address these issues (while recognizing that such alternative sources of funding may be limited).

We next address CAC's argument that IPL should broaden its low-income program in other ways, such as by targeting renters of single-family homes and multi-family units, and by increasing more specific outreach and education to the low-income community. Mr. Elliot's testimony demonstrates that both single-family home renters and multi-family unit renters are already eligible to participate in IPL's programs. Further, Mr. Elliot's testimony shows that IPL has increased outreach and education to the low-income community. Accordingly, while we continue to encourage such outreach and education, we will not direct IPL to make any program changes.

With regard to CAC's contention that IPL's program portfolio should include new construction programs and a residential prescriptive program, we are persuaded by the evidence that IPL has implemented such programs in the past, and reasonably discontinued them for valid reasons related to participation levels, competing natural gas prices, and cost-effectiveness concerns. We find that IPL's program portfolio is reasonable and we will not direct IPL to add new construction or residential prescriptive programs.

No party took issue with IPL's proposed program budgets, direct or indirect costs, 10% spending flexibility, emerging technology budget, carryover and use of unused 2015/2016 funds, or requested OSB authority to transfer funds between programs or modify, add, or terminate programs consistent with cost-effectiveness. We find these aspects of IPL's proposal to be reasonable and consistent with past practice. Accordingly, we approve IPL's proposed program budgets (including the budget for emerging technology), grant it 10% direct cost spending flexibility, approve the carryover and use in 2017 of any unused 2015/2016 program funds, and authorize the IPL OSB to transfer funds between programs, add, or modify, or terminate programs, as it deems necessary and reasonable, consistent with principles of cost-effectiveness. Further, based on the evidence presented, the Commission finds that IPL's proposed 2017 DSM Portfolio is cost-effective, reasonable and should be approved.

c. **Term of Approval.** IPL has requested a one-year extension of its DSM Portfolio and associated ratemaking treatment, from January 1, 2017 to the later of December 31, 2017, or the effective date of our order in IPL's next DSM plan approval proceeding, so as to avoid disruption in program implementation should such order not be issued by December 31, 2017. No party expressed any objection to the proposed term of our approval. Based on the evidence, the Commission finds that our approvals herein should extend from January 1, 2017 to the later of December 31, 2017 or the effective date of our order in IPL's next DSM plan approval proceeding. However, in order to facilitate an order in IPL's next DSM plan approval proceeding by approximately year-end 2017, we direct IPL to petition the Commission and seek approval of its post-2017 DSM plan no later than May 31, 2017.

d. Governance Oversight Board. IPL requests approval to continue to utilize its existing OSB to assist in the administration of the 2017 DSM Plan. The Commission has previously approved OSBs to oversee and monitor energy efficiency programs for utilities. *See, e.g., Indiana Michigan Power Co.,* Cause No. 43959, 2011 Ind. PUC LEXIS, (IURC Apr. 27, 2011); *Southern Indiana Gas and Elec. Co.,* Cause No. 43427, 2009) Ind. PUC LEXIS 495, (IURC Dec. 16, 2009). No party to this proceeding opposed the continuation of IPL's currently approved OSB to administer IPL's 2017 DSM Plan. However, CAC requested that the Commission require that IPL include CAC as a voting member in IPL's OSB (in addition to IPL and the OUCC). IPL expressed concern, noting that the OUCC already represents all customer interests and CAC representation would therefore be duplicative. IPL indicated that CAC attends the OSB meetings and provides input as a non-voting member. IPL also indicated that it should not be a potential minority vote on its own OSB given its ultimate accountability and responsibility for the successful delivery of its DSM programs. Further, IPL presented evidence from Cause No. 44497 indicating both the OUCC's and CAC's views that IPL's OSB worked well as currently constituted.

The Commission will not require CAC to be included on the OSB as a voting member. We agree that these DSM programs are IPL's ultimate responsibility, and for this reason, IPL should not be placed in a potentially minority position with respect to program decisions. We also agree that the OUCC is statutorily charged with representing all customers, and that CAC's participation as a voting member could potentially be duplicative. The evidence shows that the other OSB members welcome CAC's input, and we encourage the OSB to continue to seek input from CAC and other interested parties.

e. **EM&V.** IPL presented its proposed EM&V plans, consistent with the provisions of 170 IAC 4-8-1 *et seq*. and consistent with EM&V approved by the Commission's Order in Cause No. 44497. IPL witnesses testified that IPL, with agreement of the OSB, will engage an independent EM&V vendor, and that the EM&V protocols for its 2017 DSM Portfolio will meet or exceed the requirements of 170 IAC 4-8-1 *et seq*. No party to this proceeding opposed the continuation of IPL's currently approved EM&V program for its 2017 DSM Portfolio or took issue with IPL's current EM&V processes, although CAC did take issue with the use of EM&V to calculate lost revenues, as is discussed below. CAC also recommended that the Commission retain and manage utilities' EM&V vendors. IPL opposed this recommendation, noting that this would increase the Commission's workload with no discernible benefits. We agree. The Commission accordingly finds that IPL's proposed EM&V processes for 2017 are reasonable.

f. **Ratemaking Treatment.** Cost recovery is an essential component of meaningful utility investments in energy efficiency. The generally accepted cost recovery framework is typically referred to as the "three-legged stool," consisting of: (a) program cost recovery, (b) lost revenue recovery, and (c) financial incentives.[2] This policy is widely recognized, in Indiana and elsewhere. For example, our DSM rules represent "a regulatory framework that allows a utility an incentive to meet long term resource needs with both supply-side and demand-side resource options in a least-cost manner and ensures that the financial incentive offered to a DSM program participant is fair and economically justified." *See* 170 IAC 4-8-3(a). This regulatory framework "attempts to eliminate or offset regulatory or financial bias against DSM, or in favor of a supply-side resource, a utility might encounter in procuring least-cost resources." *Id*. We will, where

[2] ACEEE, The Old Model Isn't Working: Creating the Energy Utility for the 21st Century, http://aceee.org/files/pdf/white- paper/The_Old_Model_Isnt_Working.pdf.

appropriate, "review and evaluate, as a package, the proposed DSM programs, DSM cost recovery, lost revenue, and shareholder DSM incentive mechanisms." *See* 170 IAC 4-8-3(c).

The Indiana General Assembly, in SEA 340, has recognized the legitimacy of this "three-legged stool." SEA 340 explicitly recognizes that program costs, lost revenues, and investment incentives are legitimate costs of energy efficiency. *See* Ind. Code § 8-1-8.5-9(d). Similarly, with SEA 412, the Indiana General Assembly confirmed that reasonable program costs, lost revenues, and investment incentives should all be reflected in a utility's rates. *See* Ind. Code § 8-1-8.5-10(h), (k).

These three components of energy efficiency cost recovery are widely recognized by other states, the federal government, and energy efficiency experts. For example, ACEEE has noted that, "in order to prioritize investments in energy efficiency over new power generation, utility regulators need to adopt a new business model. The model encourages utilities to save energy through a 'three-legged stool' approach that supports the financial interests of utilities and provides their customers with cheaper, cleaner energy through improvements in energy efficiency."[3] Consistent with this approach, federal law states that "[t]he rates allowed to be charged by any electric utility shall (i) align utility incentives with the delivery of cost-effective energy efficiency; and (ii) promote energy efficiency investments."[4] Many states have adopted such an approach; for example, the Mississippi PSC unanimously decided to use the "three-

[3] *Id. See also* Section 10 of 111(d) of the Clean Air Act, which contemplates the use of "economic incentives" for promoting DSM and EE. *See also* Kate Konschnick and Ari Peskoe, who note that twenty- six states had EERS by 2013, and by mid-2012, twenty-three states offered incentives to utilities. ("Efficiency Rules," Harvard Law School Policy Initiative (2014) at p. 12.)

[4] Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)), as amended by section 532 of the Energy Independence and Security Act of 2007.

legged stool" approach.[5] Numerous states allow program recovery costs, as well as performance incentives and lost revenues, including, among others, Kentucky, Ohio and Connecticut.[6]

We examine IPL's proposal to continue its current cost recovery mechanisms, in light of these policy considerations.

(1) Cost Recovery. With respect to its 2017 DSM Portfolio, IPL proposes to recover its budgeted DSM costs on a projected/reconciled basis, via its Standard Contract Rider No. 22. . Should actual costs deviate from IPL's projections, IPL will utilize its semi-annual DSM rider mechanism to reconcile any differences. No party took issue with IPL's proposal for recovering its DSM program development, implementation, and EM&V costs. Having reviewed the evidence of record, the Commission finds that the proposed cost recovery methodology is reasonable, is consistent with the requirements of 170 IAC 4-8-5, and should be approved. Accordingly, IPL is authorized to recover program costs and other approved budget items (e.g., indirect costs, EM&V costs) related to[7] the period of January 1, 2017 through the later of December 31, 2017, or the effective date of our order in IPL's post-2017 DSM plan approval proceeding, on a timely basis via its Standard Contract Rider No. 22.

(2) Lost Revenue Recovery. IPL proposes continuation of its existing lost revenue recovery via its Standard Contract Rider No. 22, as approved in Cause Nos. 44497 and 44576. CAC opposed IPL's recovery of lost revenues, arguing that EM&V protocols are not sufficient

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[5] Presentation of Mississippi Development Authority (n.d.) Retrieved on September 21, 2016 from: http://annualmeeting2013.naseo.org/Data/Sites/2/presentations/Zweig.pdf.

[6] National Action Plan for Energy Efficiency (2007). *Aligning Utility Incentives with Investment in Energy Efficiency*. Prepared by Val R. Jensen, ICF International. Retrieved on September 21, 2016, from https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf. *See also* Kate Konschnick and Ari Peskoe, who noted that by mid-2012, twenty-three states offered incentives to utilities. ("Efficiency Rules," Harvard Law School Policy Initiative (2014) at p. 12.) *See also,* The Edison Institute for Energy Efficiency, *State Electric Efficiency Regulatory Frameworks (December 2014),* which indicates that by December 2014, 32 states allowed some form of fixed cost (lost revenue) recovery, and 29 states allowed performance incentives. Retrieved on September 21, 2016, from http://www.edisonfoundation.net/iei/Documents/IEI_stateEEpolicyupdate_1214.pdf.

[7] Including costs related to 2017 DSM programs but actually paid post-2017.

to justify lost revenue recovery and therefore IPL had not justified its proposal for lost revenue recovery. In support of its position, CAC presented evidence that on a weather-normalized basis, IPL's overall sales had increased rather than decreased. Alternatively, CAC argued that IPL's lost revenue recovery should be capped at four years. CAC also requested that the Commission initiate a generic investigation into lost revenue recovery for Indiana utilities (among other things).

The Commission's DSM rules state that "the Commission may allow the utility to recover the utility's lost revenue from the implementation of a demand-side management program sponsored or instituted by the utility." *See* 170 IAC 4-8-6. Similarly, lost revenues are explicitly defined as a legitimate and recoverable cost of energy efficiency in Section 9 (*see* Ind. Code § 8-1-8.5-9(d)). Both the statute and our rules recognize that recovery of lost revenues is an important ingredient in a successful DSM program and represents sound regulatory policy. The evidence in this case shows that IPL has voluntarily proposed significant DSM investments that, absent the Commission granting lost revenues, will financially harm IPL's shareholders.

CAC proffers a somewhat creative argument, positing that EM&V processes are not sufficient to be used to calculate lost revenues, and that lost revenue recovery should be denied. Instead, CAC argues that weather-normalized billing analyses should be used – asserting, in essence, that if a utility's weather-normalized sales have increased, it should not be allowed to recover lost revenues. This argument is simply old wine in a new bottle; CAC continues to argue that a utility should not be allowed to recover lost revenues if its year-over-year sales increase for any reason (apparently other than weather). And as with past CAC arguments, this argument against lost revenue recovery misses the point. The Commission addressed and decided this very issue in *In re the Verified Petition of Southern Indiana Gas and Electric Company*, IURC Cause

No. 44495, (Oct. 15, 2014) (the "*Vectren Order*.") In the *Vectren Order,* the Commission noted, regardless of whether sales are higher now than at the time of the last rate case, that does not change the fact that utilities are entitled to recovery of lost revenues. Specifically, the Commission stated:

> While we agree with the CAC that a utility's ability to recover lost revenues is not automatic and may be periodically reviewed, we have also previously explained that the recovery of lost revenues is a tool to assist in removing the disincentive a utility may have in promoting DSM in its service territory. *See* 170 lAC 4-8-6(c); *Southern Ind. Gas & Elec. Co.,* Cause No. 43938 at 40-41 (IURC August 31, 2012). We also explained that because the purpose of lost revenue recovery is to return the utility to the position it would have been in absent implementation of DSM, simply eliminating lost revenue recovery when sales are higher than the levels used to develop a utility's current base rates would be contrary to this purpose. *Id.*

(Vectren Order, at p. 10)

The Commission's findings in the *Vectren Order* recognize that the purpose of lost revenue recovery is to put the utility in the position it would have been in absent implementation of DSM, and that is precisely what IPL has requested in this case. CAC attempts to makes the argument that the reduction in overall IPL annual sales should correspond to the annual savings from DSM, and because of this, further investigation should be conducted into the EM&V methodology used to calculate the annual savings. However, CAC presents an over-simplified analysis that does not consider the fact that many customers may have increased load over the same time period. The EM&V methodology used by IPL is standard across the industry and has been used in Indiana since the inception of Energizing Indiana. Based on results of the current EM&V practice, the savings that occur absent freeriders would not have occurred had the programs not been implemented and are thus eligible for lost revenue recovery. CAC has presented no evidence that EM&V protocols are conceptually insufficient to calculate lost revenues, nor has CAC presented any evidence that IPL's EM&V protocols are insufficient or flawed. CAC has failed to provide evidence that implementation of IPL's 2017 portfolio of DSM programs would not result in lost revenues.

CAC next argues that lost revenue recovery, for 2017 programs and for previously-approved programs ("legacy lost revenues") should be capped at four years or the measure life, whichever is shorter. With regard to "legacy lost revenues," we note that what is at issue in this proceeding is ratemaking treatment for IPL's 2017 DSM programs, not ratemaking treatment for IPL's pre-2017 DSM programs. The ratemaking treatment for such pre-2017 programs has been authorized in previous cases, for example, Cause No. 44497. Accordingly, we reject CAC's recommendation that lost revenues for IPL's pre-2017 DSM programs be limited.

Concerning the lost revenues that are at issue in this proceeding – lost revenues that will result from implementation of IPL's 2017 programs -- although we have recently accepted such a cap in other cases, we decline to do so in this case, for several reasons. First and foremost, we believe that such a cap ignores the fact that savings, as well as lost revenues, accrue for the life of the measure. In other words, a measure with a 10-year life will continue to provide energy savings for 10 years, not for an arbitrary four-year period. As the Indiana General Assembly has made clear – in both SEA 340 and SEA 412 – lost revenues are real and calculable costs to a utility as a result of implementing DSM programs. It would be inequitable to arbitrarily cut off lost revenue recovery while the benefits of the measures, in the form of energy efficiency savings, continue to accrue to customers. Moreover, in this particular case, IPL has recently completed a base rate case, which mitigates our concern expressed in other cases about the "pancake effect" of lost revenues. Further, Indiana would be an outlier in capping lost revenue recovery in the absence of a utility settlement agreement or a utility proposal to do so. At least sixteen states allow lost revenue recovery through adjustment mechanisms, and in the absence of such a utility proposal or settlement, none of those states limit the time period over which lost revenue recovery may take place (other than tying lost revenue recovery to the life of the measure).[8] Another fourteen states address lost revenue recovery through decoupling

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[8] *See, e.g.*, *Consideration of Sections 532 & 1307 of the Energy Indep. & Sec. Act of 2007,* No. 31045, 2010 WL 5144859 (Ala. Pub. Serv. Comm'n Oct. 28, 2010) (discussing a Rate Stabilization and Equalization mechanism in effect for Alabama Gas Company and Alabama Power Company); *In Re Alabama Gas Corp.*, No. 18046, 2013 WL 8210834 (Ala. Pub. Serv. Comm'n Dec. 20, 2013) (modifying Alabama Gas Company's Rate Stabilization and Equalization mechanism); *In the Matter of the Application of Arizona Pub. Serv. Co. for A Hearing to Determine the Fair Value of the Util. Prop. of the Co. for Ratemaking Purposes, to Fix A Just & Reasonable Rate of Return Thereon, & to Approve Rate Schedules Designed to Develop Such Return.*, No. 73183, 2012 WL 1996807 (Ariz. O.L.C. May 24, 2012) (approving a non-precedential settlement agreement which included a lost revenue adjustment mechanism for the Arizona Public Service Company). *See also In the Matter of the Application of UNS Gas, Inc.'s Request for Approval of Rider R-6 Lost Fixed Cost Recovery Tariff Adjustment*, No. 75173, 2015 WL 4390053, at *1 (Ariz. O.L.C. July 15, 2015) (adopting Lost Fixed Cost-Revenue mechanism adjustment); *In Re Innovative Approaches to Ratebase Rate of Return Ratemaking*, 285 P.U.R.4th 513 (Ark. Dec. 10, 2010), *aff'd on reh'g* (approving investor owned utilities recovery of "lost contributions to fixed costs"); *See, e.g.*, *In the Matter of the Application of Pub. Serv. Co. of Colorado for Approval of A No. of Strategic Issues Relating to Its Demand Side Mgmt. Plan.*, No. 13A-0686EG, 2014 WL 3368570 (Colo. Pub. Utilities Comm'n July 1, 2014) (approving Public Service Company of Colorado's DSM plan, providing for ability to recover a "disincentive offset" or "bonus"); *In Re Westar Energy, Inc.*, No. 10-WSEE-775-TAR, 2011 WL 1227146 (Kan. Comm'n Jan. 31, 2011) (authorizing Westar Energy, Inc. and Kansas Gas and Electric Company to recover lost margins from implementation of an energy efficiency program through completion of its next rate case); Ky. Rev. Stat. Ann. § 278.285 (permitting utilities to "recover the full costs of commission-approved demand-side management programs and revenues lost by implementing these programs"). *See also In the Matter of: Application of Kentucky Power Co. for (1) Auth. to Modify Certain Existing Demand-Side Mgmt. Programs; (2) Auth. to Implement New Programs; (3) Auth. to Discontinue Certain Existing Demand-Side Mgmt. Programs; (4) Auth. to Recover Costs & Net Lost Revenues, & to Receive Incentives Associated with the Implementation of the Programs; & (5) All Other Required Approvals & Relief*, No. 2015-00271, 2016 WL 1029315 (Ky. Pub. Serv. Comm'n Mar. 11, 2016) (approving utility's DSM portfolio and request for lost revenue and performance incentives, without any cap on lost revenue); *Louisiana Pub. Serv. Comm'n, Ex Parte*, No. R-31106 (Sept. 20, 2013), <http://tinyurl.com/LAPublicServComm> (authorizing a lost contribution to fixed cost mechanism for efficiency programs in its "Quick Start" Energy Efficiency rules for electric and gas utilities); *In Re: Proposal of the Mississippi Pub. Serv. Comm'n to Possibly Amend Certain Rules & Regulations Governing Pub. Util. Serv.*, No. 2010-AD-2, 2013 WL 4047511, (Miss. Pub. Serv. Comm'n July 11, 2013) (adopting Rule 29, which authorized cost recovery of incremental program costs and the lost contribution to fixed cost); Missouri Energy Efficiency Investment Act, Mo. Ann. Stat. § 393.1075 (authorizing utilities to file pans to recover a portion of the net benefits of demand-side energy efficiency programs); Nev. Rev. Stat. Ann. § 704.785 (mandating that Public Utilities Commission adopt regulations authorizing an electric utility to recover an amount based on the measurable and verifiable effects of the implementation by the electric utility of energy efficiency and conservation programs approved by the Commission); N.C. Gen. Stat. Ann. § 62-133.9 (stating that the "Commission shall, upon petition of an electric public utility, approve an annual rider to the electric public utility's rates to recover all reasonable and prudent costs incurred for adoption and implementation of new demand-side management and new energy efficiency measures. Recoverable costs include, but are not limited to, all capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants, and operating costs."); *See also* North Carolina Utility Commission Rules R8-68 and R8-69 (adopting rules related to annual rider); Ohio Rev. Code § 4928.143(B)(2)(h) (authorizing an electric utility to submit a plan that, among other things, provides "for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs"); Okla. Admin. Code 165:35-41-4 (utility required to present "detailed explanation of the utility's request for recovery of prudently incurred program costs, recoupment and calculation of lost net revenue, and additional incentives the utility proposes it requires to make the programs workable"); S.C. Code Ann. § 58-37-20 (whereby the Public Service Commission is authorized to "establish rates and charges that

mechanisms.[9] Regardless of which lost revenue recovery mechanism they employ, none of these states have adopted any binding authority that would limit a utility's lost revenue recovery to four years, or any other set time period.

We are persuaded if a state is interested in encouraging robust utility-sponsored energy efficiency programs, sound regulatory policy compels the conclusion that full lost revenue recovery must be allowed. Arbitrarily limiting a utility's recovery to the first four years of a program's life would defeat the purpose of making the utility whole after energy efficiency programs are implemented. The better public policy is to allow the utility to recover its reasonable lost revenues for the full life of the efficiency measure. Such recovery will make the utility whole, relative to where it would have stood financially without energy efficiency programs, while at the same time, will not reward the utility for declines in electricity sales unrelated to such programs.

Notably, prior to the codification of full lost revenue recovery through SEA 340 and SEA 412, the Commission has allowed utilities full lost revenue recovery on several occasions. *See, e.g.*, *Petition of N. Indiana Pub. Serv. Co. for Approval of Elec. Demand Side Mgmt. Programs to Be Effective Jan. 1, 2015 Through Dec. 31, 2015*, 44496, 2014 WL 6466719, at *22 (Nov. 12, 2014) (authorizing NIPSCO to recover lost revenues for the remainder of the useful lives of the program measures, while expressly declining to limit the recovery period to the lesser of two

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ensure that the net income of an electrical or gas utility regulated by the commission after implementation of specific cost-effective energy conservation measures is at least as high as the net income would have been if the energy conservation measures had not been implemented."); *See, e.g.*, *In re NorthWestern Corporation d/b/a NorthWestern Energy for Approval of its South Dakota Demand Side Management Plan*, GE09-001 (May 11, 2010); *In Re Montana-Dakota Utilities Co.*, Docket No. 20004-65-ET-06, 2007 WL 1231445 (Wyo. Jan. 9, 2007) (authorizing a tracking adjustment mechanism, including direct lost revenue recovery).

[9] *State Electric Efficiency Regulatory Framework*, Institute for Electric Innovation Report, December 2014 (identifying the fourteen jurisdictions that had approved revenue decoupling: California, Connecticut, District of Columbia, Hawaii, Idaho, Maryland, Massachusetts, New York, Ohio, Oregon, Rhode Island, Vermont, Washington, and Wisconsin).

years or the life of the measure). Consistent with this past practice, the Commission's 1995 rules did not contain any sort of cap. Accordingly, the Commission finds that IPL's proposal for continuation of its current full lost revenue recovery via Standard Contract Rider No. 22 is consistent with applicable Indiana statutes and our DSM rules, is reasonable, and should be approved.

(3) Performance Incentives. IPL proposes continuation of the shared savings incentive mechanism approved in Cause No. 44497. This incentive mechanism allows IPL to retain, as financial incentive, 15% of net UCT benefits, with the majority of such benefits (85%) going to customers. CAC opposes any incentives, but recommends that if an incentive is approved, it should be based on multiple performance metrics, be subject to a financial cap, and be contingent upon lost revenue recovery being limited to the shorter of 48 months or the life of the measure. CAC provides no evidentiary or policy rationale for its position; Mr. Kelly simply cites recent Commission orders which have denied financial incentives in Section 9 cases.

Financial incentives for DSM are recognized in the Commission's rules as a way to "eliminate or offset regulatory or financial bias against DSM, or in favor of supply-side resources. . . . ."[10] Public service commissions in other jurisdictions have also recognized the important role that financial incentives play in encouraging effective DSM programs. *See, e.g.*, *In Re: Proposal of the Mississippi Pub. Serv. Comm'n*, 2010AD2, 2013 WL 4047511, at *11 (Miss. P.S.C. July 11, 2013) (finding that in order "[t]o address disincentives for energy efficiency investments, the utilities may propose an approach to earn a return on energy efficiency investments though a shared savings or other performance based incentive mechanism to make these investments more like other investments on which utilities earn a return"); *In the Matter of Application of Duke Energy Carolinas, LLC*, E-7, 2013 WL 5870222, at *26 (N.C.

[10] 170 IAC 4-8-3

Util. Comm'n Oct. 29, 2013) (recognizing that "a shared savings mechanism rewards the utility for the pursuit and achievement of cost-effective EE and DSM").

As with program cost recovery and lost revenue recovery, financial incentives are part of the "three-legged stool" that is necessary for demand-side resources to be placed on more of a level playing field with supply-side resources. As with program cost recovery and lost revenue recovery, both SEA 340 and our DSM rules allow for financial incentives. Moreover, without mandated energy savings goals, if anything, incentives have become more important, not less important.

While we have recently rejected the use of financial incentives in Section 9 cases, we agree with IPL that its position is different is several critical ways. IPL is requesting approval of the third year of a three-year DSM plan, and it makes sense to authorize the same incentives for such; nothing material has changed with respect to IPL's offering of DSM programs in 2017, as compared to 2015 and 2016; IPL could not feasibly prepare a new IRP and a Section 10 case for its 2017 plan; the approach used for IPL's 2017 (and 2015-2016) DSM planning is reasonable, even if IRP modeling is evolving and improving; the amount of DSM requested in 2017 is consistent with and in the range of the amount of DSM preliminarily selected as a resource in IPL's draft 2016 IRP for 2018 through 2020; both the Commission rules and Section 9 allow for financial incentives; and last but not least, IPL has consistently pursued and achieved robust DSM programs and results for over 20 years, and should be rewarded, not penalized, for doing so.

As for the structure of incentives that should be approved in this case, we note that our DSM rules specifically allow for shared savings incentives. 170 IAC 4-8-7(a)(1) refers to "[g]rant[ing] a utility a percentage share of the net benefit attributable to a demand-side management program" – the very definition of a shared savings mechanism. Further, 170 IAC 4-8-7(f) specifically requires that "[a] shareholder incentive mechanism must reflect the value to the utility's customers of the supply-side resource cost avoided or deferred by the utility's DSM program minus incurred utility DSM program cost." This requirement is directly met by a shared savings mechanism.

We are not persuaded by CAC's recommendation that any shared savings incentive be accompanied by additional performance metrics, a cap, and a tie to a four-year cap on lost revenues. A shared savings incentive, coupled with approved DSM budgets in which a utility must operate, provides both an implicit floor and cap. The floor is zero, which is what the utility will earn if it fails to achieve cost-effective savings. The cap will be the product of the approved budget, combined with the cost-effectiveness the utility ultimately achieves. Similarly, additional performance metrics are not needed with a shared savings incentive. A shared savings mechanism is inherently driven by a critical performance metric – achievement of cost-effective savings. Under a shared savings incentive, the utility's incentive will be maximized by both the volume and cost-effectiveness of savings achieved. Finally, CAC's desire to tie any financial incentives to a cap on lost revenue recovery is inappropriate. Full program cost recovery, full lost revenue recovery, and a reasonable financial incentive are all necessary ingredients to encourage robust utility-sponsored DSM programs.

As with lost revenue recovery, a majority of other states utilize performance incentives in connection with utility-sponsored DSM,[11] which corroborates Indiana's position that financial incentives are an important aspect of robust energy efficiency programs. For all the foregoing

[11] According to the Edison Foundation, in 2014, 29 states authorized performance incentives (and 2 states were considering performance incentives). *See State Electric Efficiency Regulatory Frameworks, IEI Report*, December 2014, published by the Edison Foundation's Institute for Electric Innovation.

reasons, we find that continuation of IPL's current shared savings mechanism is reasonable and should be approved.

(4) Tariff Changes. IPL requested approval of necessary tariff changes to effectuate approval of the 2017 DSM Portfolio and associated approved ratemaking treatment. No party to this proceeding opposed IPL's proposal to update the formula and definitions used in Standard Contract Rider 22 – Demand Side Management Adjustment Factors to effectuate these changes. The Commission accordingly finds that IPL's proposed changes to its tariff should be approved.

(5) Request for Initiation of Generic Proceedings. CAC requested that the Commission open an investigation into investor-owned utilities' electric DSM rider filings to create consistency in the format and methodologies of each filing and to simplify these schedules wherever possible. CAC recommends this investigation also include a review of lost revenues. CAC cited no evidence in support of its recommendation indicating that such an investigation into DSM rider filings is needed. If CAC believes that a utility's DSM rider filings are unclear or confusing, it can make recommendations for improvements within such individual rider filings. With regard to lost revenues, we note that the legislature in SEA 340 and SEA 412 made clear that lost revenues, along with program costs and performance incentives, are legitimate costs eligible for recovery through rates. Moreover, the Commission currently has a pending rulemaking addressing IRP and DSM issues. Accordingly, we see no need to initiate an investigation into either utilities' DSM rider filings or lost revenues.

(6) Small Business Impact. The Commission must consider in accordance with 170 IAC 4-8-8, the impact that such a plan as IPL's 2017 DSM Portfolio may give an unfair competitive advantage to IPL in the provision of energy efficiency programs. The Commission accepts Mr. Elliot's testimony, which noted that IPL and its energy service providers will work with a number of trade allies and small businesses to support outreach and delivery of the programs as proposed in the 2017 Portfolio. Therefore, the Commission concludes that IPL's plan will not provide an unfair competitive advantage as contemplated by in 170 IAC 4-8-8.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1) Petitioner's proposed one-year extension of its current DSM Portfolio for 2017, based on its 2015-2017 Action Plan, is hereby approved, as described above, to be effective from January 1, 2017 through the later of December 31, 2017, or the date of our order in a future case addressing Petitioner's proposed post-2017 DSM programs and plan;

2) Petitioner is hereby granted authority to recover its 2017 DSM Portfolio costs (including direct costs, indirect costs, EM&V costs, and emerging technology costs) up to a total amount of $24,773,000 (which includes 10% of direct costs as spending flexibility), through Petitioner's Standard Contract Rider No. 22;

3) Petitioner is hereby granted authority to recover lost revenues resulting from implementation of its 2017 DSM Portfolio, as proposed by Petitioner (and subject to reconciliation per EM&V results), through its Standard Contract Rider No. 22;

4) Petitioner is hereby granted authority to recover a shared savings incentive associated with its 2017 DSM Plan, as proposed by Petitioner, through its Standard Contract Rider No. 22;

5) Petitioner is hereby granted authority to utilize its proposed evaluation, measurement and verification processes for its 2017 DSM Plan;

6) Petitioner is hereby authorized to make necessary tariff changes to effectuate approval of the 2017 DSM Plan and associated ratemaking treatment;

7) Petitioner is hereby authorized to continue to utilize the IPL Oversight Board in its current composition to administer the 2017 DSM Plan;

8) The IPL Oversight Board shall have authority to transfer funds between programs, utilize an additional 10% of direct program costs in spending flexibility, and add, modify, or terminate programs based on cost-effectiveness;

9) The Commission will not launch a generic investigation into utilities' rider filings or lost revenues; and

10) IPL is directed to file a petition with the Commission for approval of proposed post-2017 DSM programs no later than May 31, 2017.

STEPHAN, FREEMAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED:

**I hereby certify that the above is a true
and correct copy of the Order as approved.**

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Brenda A. Howe, Secretary to the Commission

Attachment 5.6

INDIANAPOLIS POWER & LIGHT COMPANY 2016 DSM MARKET POTENTIAL STUDY

ENERGY EFFICIENCY AND DEMAND RESPONSE POTENTIAL FOR 2018-2037

FINAL REPORT

Prepared for:
Indianapolis Power and Light

October 11, 2016

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EXECUTIVE SUMMARY

Indianapolis Power & Light Company (IPL) contracted with Applied Energy Group (AEG) to conduct an Energy Efficiency and Demand Response Market Potential Study to assess the future potential for energy and peak demand savings through its customer programs. The market potential study is part of a larger effort to provide assistance in IPL's program planning and integrated resource planning process.

The key objectives of the study were to:

- Develop credible and transparent electric energy efficiency (EE) and demand response (DR) potential estimates by customer class for the time period of 2018 through 2037 within the Indianapolis Power & Light 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 savings potential was bundled into blocks of DSM resources that are interpretable and selectable by the IRP modeling software.
- 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 TRM and IPL's EM&V results for improving energy efficiency. The study consisted of two primary components: a full energy efficiency potential analysis at the measure level and a separate demand response analysis.

ENERGY EFFICIENCY POTENTIAL

DEFINITIONS

In this study, the energy efficiency potential estimates represent net savings[1] developed into several levels of potential. There are four potential levels: technical, economic, maximum achievable and realistic achievable. These are determined at the measure-level before the development of a detailed Action Plan that considers delivery mechanisms and program costs. Technical and economic potential are both theoretical limits to efficiency savings and would not be realizable in actual programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described in more detail below.

- **Technical Potential** is the theoretical upper limit of energy efficiency potential, assuming that customers adopt all feasible measures regardless of cost or customer preference. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.
- **Economic Potential** represents the adoption of all ***cost-effective*** energy efficiency measures. Cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the costs of the delivering the measure. If the benefits outweigh

[1] "Net" savings mean that the baseline forecast includes the effects of free riders and naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option, both with and without taking an incentive.

the costs (the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.

- **Maximum Achievable Potential (MAP)** estimates 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. As such, maximum achievable potential establishes a theoretical 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. This leads measures in MAP to be less cost effective than in RAP, described below.
- **Realistic Achievable Potential (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.

EE Analysis Approach Overview

To perform the EE potential analysis, AEG used a detailed, bottom-up approach following the major steps listed below.

1. Establish objectives, as described already in the previous section
2. Perform a market characterization to describe sector-level electricity use for the residential, commercial and industrial sectors for the base year, 2015.
3. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2015 through 2037.
4. Define and characterize energy efficiency and demand response measures to be applied to all sectors, segments, and end uses.
5. Estimate technical and economic potential at the measure level for 2018-2037.
6. Estimate achievable potential at the measure level for 2018-2037.
7. Building the bundles of EE for IRP modeling.

These results are then synthesized and presented in this report, as well as packaged and prepared to inform the IRP and 2018-2020 program planning initiatives covered under separate efforts and reports.

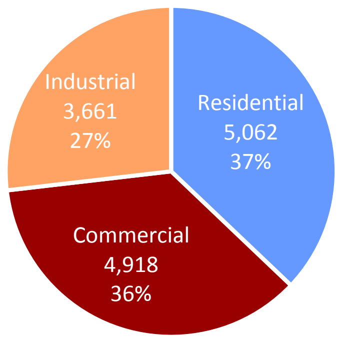
Market Characterization

Total electricity use for the residential, commercial, and industrial sectors for IPL in 2015 was 13,641 GWh. This includes customers who are eligible to opt-out of utility programs. In terms of peak demand[2], the total summer system peak in 2015 was 2,690 MW and winter peak was 2,462 MW. All usage statistics and DSM impacts are presented at the customer meter.

The three sectors have relatively equivalent energy consumption, with residential at 37%, commercial at 36% and industrial at 27%. The commercial and industrial sectors are defined based on NAICS code and visual inspection of billing data to insure they represent commercial businesses and industrial facilities.

[2]Annual use, as well as summer and winter peak demand, are presented in weather normalized megawatts at the meter.

Sector Level Electricity Use in 2015 Base Year

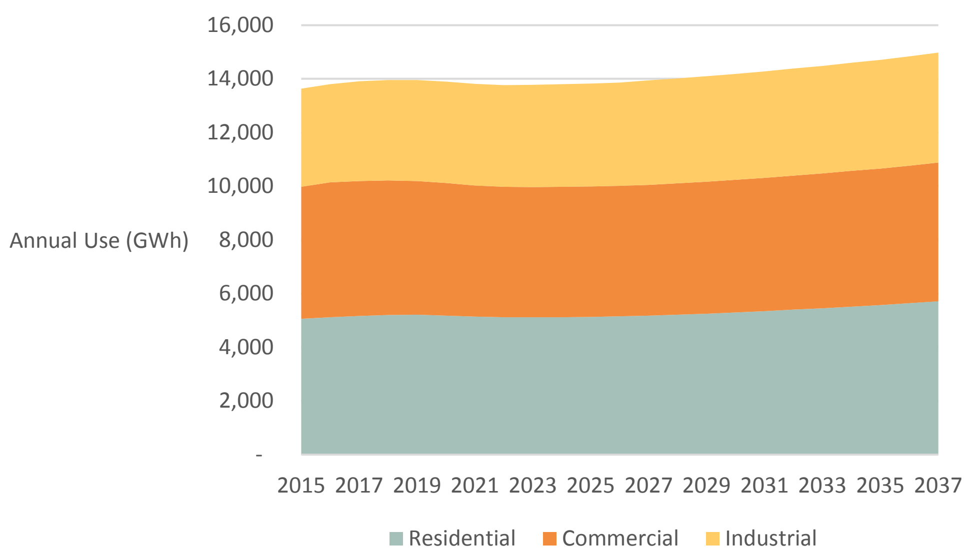


Segment	Annual Use (GWh)	% of Sales	Summer Peak (MW)	Winter Peak (MW)
Residential	5,062	37%	1,141	1,170
Commercial	4,918	36%	941	805
Industrial	3,661	27%	609	487
Total	**13,641**	**100%**	**2,690**	**2,462**

EE Baseline Projection

Prior to developing estimates of energy-efficiency potential, AEG developed a baseline end-use projection to quantify what the consumption is likely going to be in the future absent any efficiency programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes that past programs are no longer active and installing new measures in the future. All such possible savings from future programs are instead meant to be captured by the potential estimates. The baseline energy projection is shown below.

Baseline Energy Projection by Sector (GWh)



Energy Efficiency Potential Results

The study estimated energy-efficiency potential for the next program cycle (2018-2020) through 2037. The table below presents the savings estimates for selected years. Realistic achievable potential for the 2018-20 program cycle averages 83 GWh per year of 0.6% of the baseline projection. This represents roughly one third of economic potential and one fourth of technical potential. These estimates are net since the baseline accounts for the impacts of appliance standards, building codes and naturally occurring energy efficiency.

Achievable potential estimates (MAP and RAP) ***exclude*** savings estimates for customers who have opted out of IPL programs as of January 2016. Estimates of technical and economic potential includes savings estimates from opt-out customers.

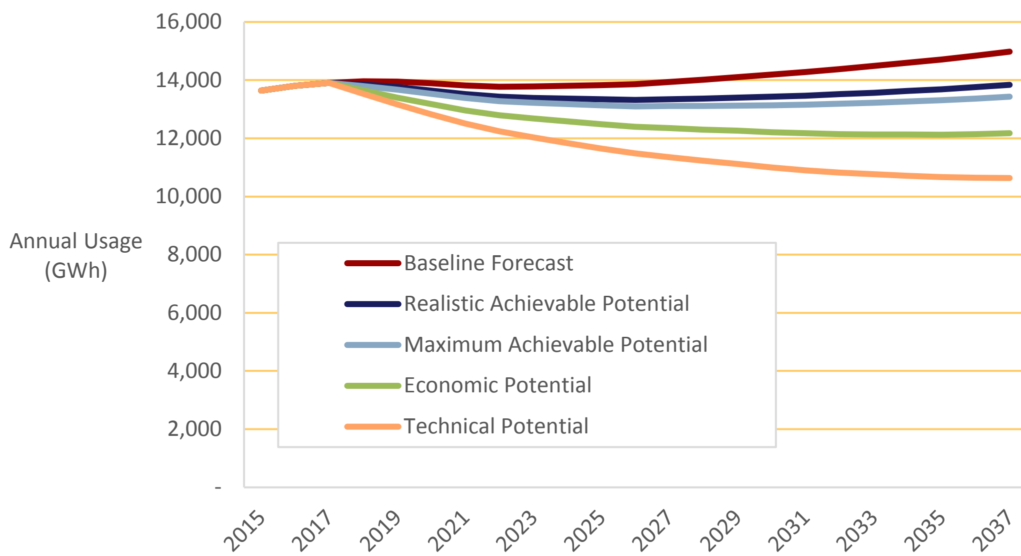
The table also includes new incremental savings, accounting for all new installations as well as any re-installations that are deployed to make up for measures that have expired in the prior year.

Summary of All-Sector Cumulative and Incremental EE Potential

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**13,958**	**13,953**	**13,893**	**13,940**	**14,979**
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	112	193	249	594	1,136
Maximum Achievable Potential	159	280	363	833	1,543
Economic Potential	310	550	717	1,586	2,806
Technical Potential	433	786	1,065	2,586	4,344
Cumulative as % of Baseline					
Realistic Achievable Potential	0.8%	1.4%	1.8%	4.3%	7.6%
Maximum Achievable Potential	1.1%	2.0%	2.6%	6.0%	10.3%
Economic Potential	2.2%	3.9%	5.2%	11.4%	18.7%
Technical Potential	3.1%	5.6%	7.7%	18.5%	29.0%
Incremental Net Savings (GWh)					
Realistic Achievable Potential	112	109	89	110	159
Maximum Achievable Potential	159	152	120	143	203
Economic Potential	310	295	238	257	342
Technical Potential	433	410	351	373	476
Incremental as % of Baseline					
Realistic Achievable Potential	0.8%	0.8%	0.6%	0.8%	1.1%
Maximum Achievable Potential	1.1%	1.1%	0.9%	1.0%	1.4%
Economic Potential	2.2%	2.1%	1.7%	1.8%	2.3%
Technical Potential	3.1%	2.9%	2.5%	2.7%	3.2%

The subsequent figure shows a line graph of energy use projections for the baseline and all potential cases. Realistic achievable potential over the 20-year time horizon is expected to completely offset load growth.

All Sector Baseline Projection and EE Projection Summary (Annual Use, GWh)

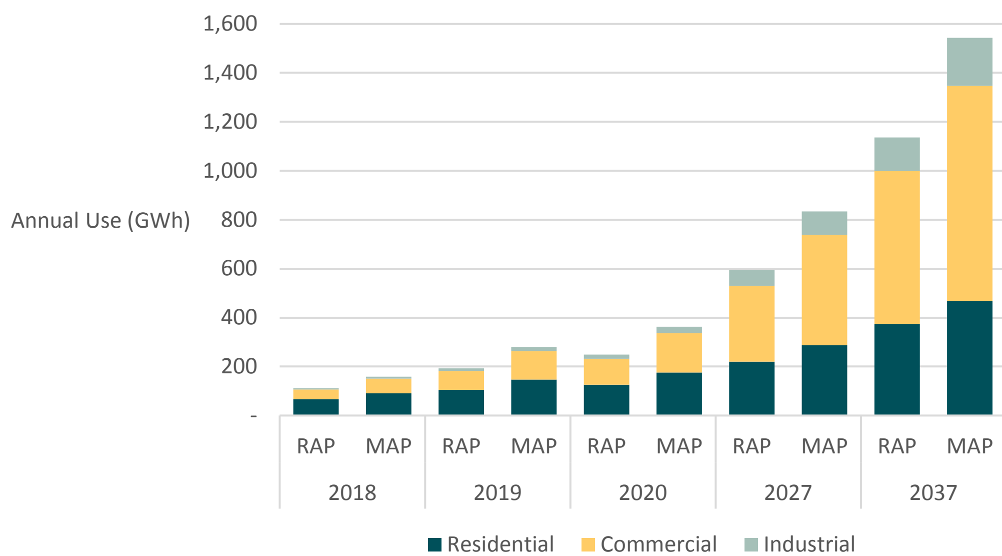


The table and figure below summarize the range of electric achievable potential by sector. The residential sector provides the most potential savings early in the projection, but the commercial sector surpasses it after 2021 and has nearly twice the 20-year potential of the residential sector. The industrial sector contributes the fewest savings. Since a number of the largest industrial customers have opted out from DSM programs, the savings here come largely from the remaining, somewhat smaller facilities.

Achievable EE Potential by Sector and Achievable Case (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**13,958**	**13,953**	**13,893**	**13,940**	**14,979**
Cumulative Net Savings (GWh) – Realistic Achievable Potential					
Residential	67	105	126	220	375
Commercial	39	77	106	309	624
Industrial	5	11	17	64	137
Total	112	193	249	594	1,136
Cumulative Net Savings (GWh) – Maximum Achievable Potential					
Residential	91	147	176	286	469
Commercial	60	117	161	452	879
Industrial	8	17	26	95	195
Total	159	280	363	833	1,543

Cumulative Achievable EE Potential by Sector (Annual Energy, GWh)



Demand Response Potential

As a part of this DSM Market Potential Study, AEG conducted IPL's first formal demand response (DR) potential analysis to understand the achievable peak demand savings from peak-focused demand response resources. Similar to the EE modeling described above, AEG developed inputs to represent DR as a Resource in the IPL Integrated Resource Planning (IRP) process.

DR Analysis Approach Overview

The steps are similar to the EE analysis and they are:

- Define the relevant DR resource options
- Characterize the market
- Develop DR program assumptions which include participation rates, per-participant savings, and program costs
- Estimate levels of DR potential. As with EE potential, we estimated several levels of potential: a standalone estimate of potential for each option and achievable potential for the cost-effective options.

ACHIEVABLE DR POTENTIAL

Three DR options were determined to be cost-effective in our analysis: Residential Direct Load Control (DLC) Central Air Conditioning, Residential DLC Water Heating and C&I Curtailment Agreements. Results for these three programs are shown below.

Summer peak demand savings potential starts around 35 MW at the beginning of the study, primarily from the existing air conditioning load control program, and rises to 114.8 MW in 2037 for the RAP case and 138.5 MW for the MAP case. This corresponds to a reduction of 3.8% and 4.6% respectively from IPL's projected 2037 summer system peak.

Summary of Summer Demand Response Savings

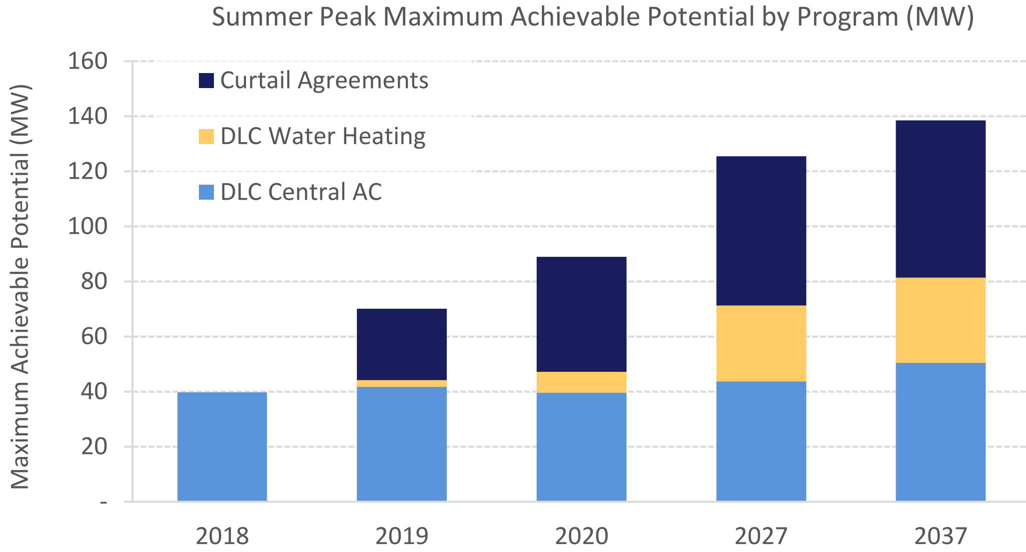
	2018	2019	2020	2027	2037
Baseline Projection (Summer MW)	2,758	2,761	2,773	2,884	3,037
Potential Savings (MW)					
Realistic Achievable Potential	35.9	59.1	75.3	103.6	114.8
Maximum Achievable Potential	39.8	70.1	89.0	125.5	138.5
Potential Savings (% of baseline)					
Realistic Achievable Potential	1.3%	2.1%	2.7%	3.6%	3.8%
Maximum Achievable Potential	1.4%	2.5%	3.2%	4.4%	4.6%

The table below presents summer peak savings by sector and DR option for the two achievable potential cases, while the figure shows results for realistic achievable potential. In the early years of the forecast, DLC Central AC provides the highest savings because this program is already in place and additional savings are relatively small. Over the forecast horizon, DLC Water Heating and Curtailment Agreements ramp up to full-scale programs that rival the cooling program for savings. Figure 3-4 illustrates the results for realistic achievable potential.

For the winter peak, only DLC Water Heating provides achievable potential savings and they are at the same level as for the summer peak.

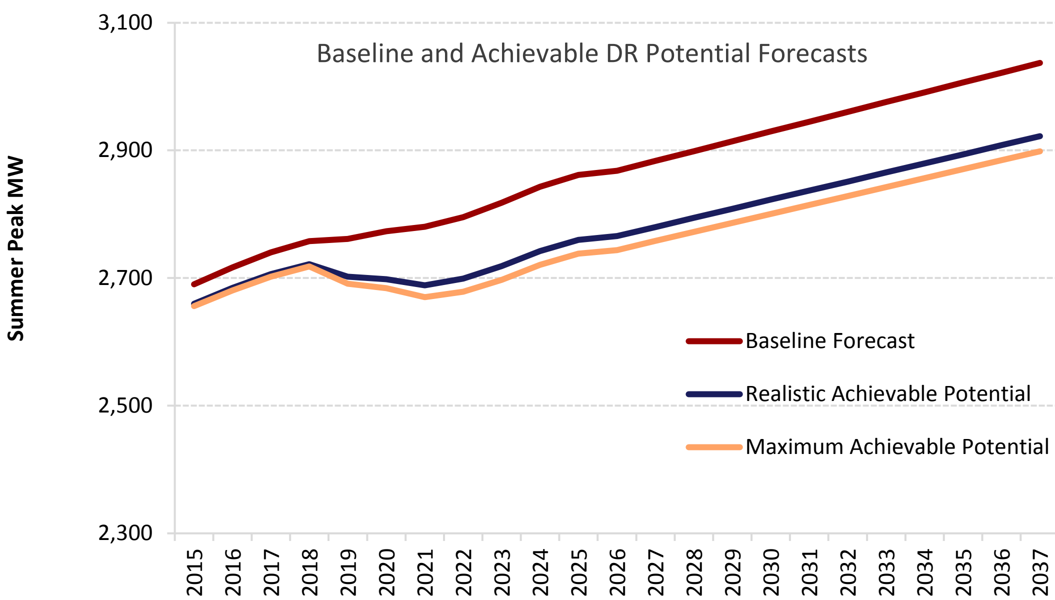
Summer Peak Achievable Potential by Sector and DR Option

		2018	2019	2020	2027	2037
Baseline Projection (Summer MW)		**2,758**	**2,761**	**2,773**	**2,884**	**3,037**
Realistic Achievable Potential (MW)		**35.9**	**59.1**	**75.3**	**103.6**	**114.8**
Residential	DLC Central AC	35.9	37.8	38.3	42.3	48.8
	DLC Water Heating	-	1.9	5.7	20.7	23.2
Large C&I	Curtail Agreements	-	19.5	31.3	40.7	42.9
Maximum Achievable Potential (MW)		**39.8**	**70.1**	**89.0**	**125.5**	**138.5**
Residential	DLC Central AC	39.8	41.7	39.6	43.7	50.5
	DLC Water Heating	-	2.5	7.6	27.5	30.9
Large C&I	Curtail Agreements	-	26.0	41.7	54.3	57.1



Realistic Achievable Potential by DR Option

The figure below shows the impact of potential DR savings on the summer peak-demand forecast. The gap between the baseline and achievable potential between 2017 and 2019 is savings from existing IPL DR programs. The savings increase in 2019 as the existing resources expand and new programs ramp up, that is: Residential DLC Water Heating and Curtailment Agreements.



Development of IRP Inputs

From the results of the DSM Market Potential Analysis, AEG also developed inputs for IPL to use in the current integrated resource planning (IRP) modeling effort. For both EE and DR, "blocks" of resources were prepared from the Maximum Achievable Potential cases from 2018 to 2037. The more aggressive MAP case was used instead of the RAP case as a reflection of the high value and importance that IPL assigns to DSM as a resource to enhance environmental and customer satisfaction outcomes in addition to the economic outcomes that are core to the IRP process.

Each set of DSM blocks that were presented to the IRP was also processed in the cost-effectiveness and planning software DSMore in order to translate the annual estimates from the potential study into hourly streams of values and prepare in a file and data format amenable to the IRP team.

We briefly describe the EE and DR blocks in respective sections below. Please see the IRP report and documentation itself for more detail on this process and which blocks of resources were actually selected by the IRP when considered alongside supply-side options under the various scenarios and world views.

Energy Efficiency IRP Blocks

For the EE analysis, all measures in the maximum achievable potential case were bundled into groupings by three possible variables as detailed in the table below: similar end-use load shapes, levelized cost of saved energy, and year of installation. The years of installation separated the nearest 3-year implementation cycle from the remaining 17 years of the planning horizon. The permutations of these variables created 42 possible blocks into which the potential savings and program budgets of each measure were allocated. By coincidence, it happened that four of these blocks were null sets or empty, and therefore 38 blocks were translated into IRP inputs, translated into the appropriate format using DSMore, and handed off to the IRP team.

Demand Response IRP Blocks

For the DR analysis, all measures and options were bundled into IRP groupings using the participation levels from the maximum achievable potential case. The DR blocks were also separated into the same years of installation categories as the EE resources described above (2018-2020 and 2021-2037). The permutations of these variables created 12 possible blocks into which the potential savings and program budgets of each DR program were allocated. These 12 blocks were translated into the appropriate format using DSMore and handed off to the IRP team.

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1

Introduction

Indianapolis Power & Light Company (IPL) contracted with Applied Energy Group (AEG) to conduct an Energy Efficiency and Demand Response Market Potential Study to assess the future potential for energy and peak demand savings through its customer programs. The market potential study is part of a larger effort to provide assistance in IPL's program planning and integrated resource planning process.

The key objectives of the study were to:

- Develop credible and transparent electric energy efficiency (EE) and demand response (DR) potential estimates by customer class for the time period of 2018 through 2037 within the Indianapolis Power & Light 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 savings potential was bundled into blocks of DSM resources that are interpretable and selectable by the IRP modeling software.
- 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.

Abbreviation and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
ACS	American Community Survey
AEO	Annual Energy Outlook forecast developed by EIA
AHAM	Association of Home Appliance Manufacturers
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
B/C Ratio	Benefit to Cost Ratio
BEST	AEG's Building Energy Simulation Tool
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CFL	Compact Fluorescent Lamp
DHW	Domestic Hot Water
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EUL	Estimated Useful Life
EUI	Energy Usage Intensity
FERC	Federal Energy Regulatory Commission
HH	Household
HID	High Intensity Discharge Lamps
HVAC	Heating Ventilation and Air Conditioning
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
LED	Light Emitting Diode lamp
LoadMAP™	AEG's Load Management Analysis and Planning tool
MW	Megawatt
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Participant Cost Test
RIM	Ratepayer Impact Measure
RTU	Roof top Unit
TRC	Total Resource Cost test
UCT	Utility Cost Test
UEC	Unit Energy Consumption
WH	Water heater

2

ENERGY EFFICIENCY ASSESSMENT

This section describes in detail the assessment of energy-efficiency potential. It begins with a description of the analysis approach and the data sources used in the assessment. Then it presents the results for each step in the process, concluding with the potential estimates.

EE ANALYSIS APPROACH

OVERVIEW

To perform the EE analysis, AEG used a detailed, bottom-up approach, illustrated in Figure 2-1, following the major steps listed below. We describe these steps in more detail throughout the remainder of this section.

1. Establish objectives, described in the previous section
2. Perform a market characterization to describe sector-level electricity use for the residential, commercial and industrial sectors for the base year, 2015.
3. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2015 through 2037.
4. Define and characterize energy efficiency and demand response measures to be applied to all sectors, segments, and end uses.
5. Estimate technical and economic potential at the measure level for 2018-2037.
6. Estimate achievable potential at the measure level for 2018-2037.
7. Building the bundles of EE for IRP modeling.

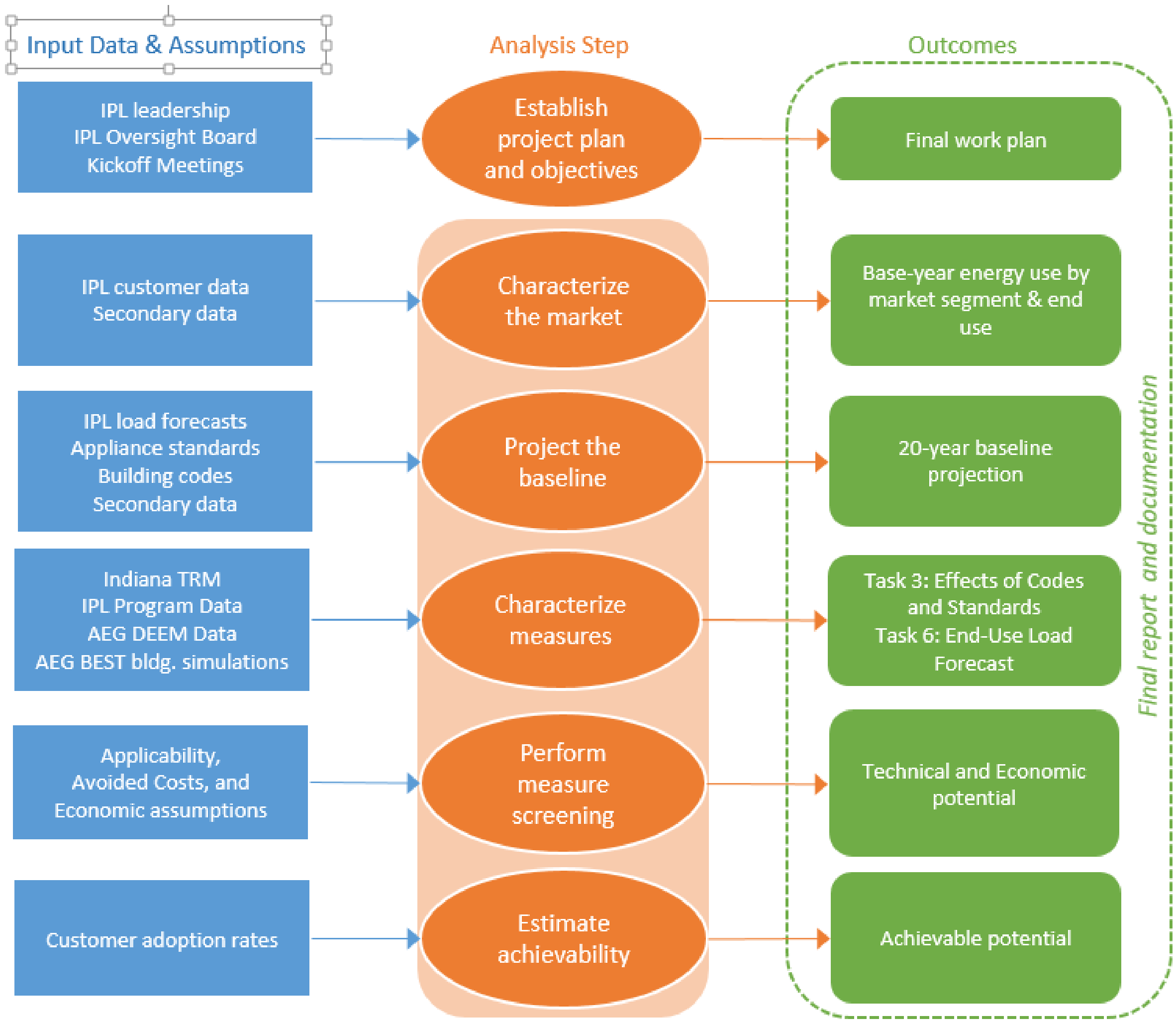

Figure 2-1 Analysis Framework

Definition of Potential

In this study, the energy efficiency potential estimates represent net savings[3] developed into several levels of potential. There are four potential levels: technical, economic, maximum achievable and realistic achievable. These are determined at the measure-level before the development of a detailed Action Plan that considers delivery mechanisms and program costs. Technical and economic potential are both theoretical limits to efficiency savings and would not be realizable in actual programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described in more detail below.

- **Technical Potential** is the theoretical upper limit of energy efficiency potential, assuming that customers adopt all feasible measures regardless of cost or customer preference. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.
- **Economic Potential** represents the adoption of all ***cost-effective*** energy efficiency measures. Cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime

[3] "Net" savings mean that the baseline forecast includes the effects of free riders and naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option.

energy and capacity benefits to the costs of the delivering the measure. If the benefits outweigh the costs (the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.

- **Maximum Achievable Potential (MAP)** estimates 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. Maximum Achievable Potential 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. This leads measures in MAP to be less cost effective than in RAP, described below.
- **Realistic Achievable Potential (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.

LoadMAP Model

For the measure-level energy efficiency potential analysis, AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 4.0 to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for more than 50 potential studies in the past five years. Built in Microsoft Excel®, the LoadMAP framework is both accessible and transparent and has the following key features.

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND[4]) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.

[4] Electric Power Research Institute's Residential End-use Energy Planning System (REEPS) and Commercial End-use Planning System (COMMEND)

- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type, income level, or business type).

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides projections of total energy use and energy-efficiency savings associated with the various types of potential.

MARKET CHARACTERIZATION APPROACH

In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used.

Segmentation for Modeling Purposes

The characterization begins with a segmentation of IPL's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. The segmentation scheme for this project is presented in Table 2-1.

Table 2-1 Overview of IPL EE Analysis Segmentation Scheme

Dimension	Segmentation Variables	Description
1	Sector	Residential, Commercial and Industrial
2	Segment	**Residential**: single family, multifamily, single family – electric heat, multifamily electric heat **Commercial**: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, miscellaneous **Industrial**: chemicals and pharmaceutical, food products, transportation and other industrial
3	Vintage	Existing and new construction
4	End uses	Cooling, lighting, water heat, motors, etc. (as appropriate)
5	Appliances/end uses and technologies	Technologies such as lamp type, air conditioning equipment, motors by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, we then performed a high-level market characterization of electricity sales in the base year, 2015, to allocate sales to each customer segment. We used IPL billing and customer data, IPL market research and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, energy consumption, and peak demand matched the IPL system totals from 2015 billing data. This information provided control totals at a sector level for calibrating the LoadMAP model to known data for the base-year.

Separating residential customers and energy use from non-residential customers and energy use is straightforward because we could utilize rate codes to isolate the residential sector. The non-residential sector is more challenging. For the EE assessment, we want to characterize customers and energy use by business type, so we used NAICS codes from the billing system, together with visual inspection of the largest commercial and industrial customers, to assign customers to building types.

Market Profile

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- **Market size** is a representation of the number of customers in the segment. For the residential sector, it is number of households. The commercial sector is floor space measured in square feet and the industrial sector is number of employees.
- **Saturations** define the fraction of homes, square feet, or employees with the various technologies (e.g., homes with electric space heating).
- **UEC (unit energy consumption) or EUI (energy-use index)** describes the amount of energy consumed annually by a specific technology in buildings that have the technology. The UECs are expressed in kWh per household for the residential sector and EUIs are expressed in kWh per square foot and kWh per employee for the commercial and industrial sectors, respectively.
- **Annual energy intensity** represents the average energy use for the technology across all homes, floor space, or employees in 2015. The residential sector intensity is computed as the product of the saturation and the UEC. The commercial and industrial sector intensity is computed as the product of the saturation and the EUI.
- **Annual usage** is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in GWh.
- **Summer and winter peak demand** for each technology are calculated using peak fractions of annual energy use developed using IPL's system peak data and AEG's EnergyShape end-use load shape library.

Baseline Projection Approach

The next step was to develop the baseline projection of annual electricity use, summer peak demand, and winter peak demand for 2015 through 2037 by customer segment and end use without new utility programs. The end-use projection includes the relatively certain impacts of known and adopted legislation, as well as codes and standards that will unfold over the study timeframe. All such legislation and mandates that were finalized as of January 31, 2016 are included in the baseline. The baseline projection is the foundation for the analysis and is the metric against which potential savings are measured.

Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Known and adopted legislation
- Naturally occurring efficiency improvements, which include purchases of high-efficiency equipment options by early adopters.

AEG also developed a baseline projection for summer and winter peak by applying the peak fractions from the energy market profiles to the annual energy forecast in each year.

EE Measure Analysis Approach

This section describes the framework for the energy efficiency measure analysis. The framework, shown in Figure 2-2 involves identifying a list of energy efficiency measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening.

A comprehensive list of energy efficiency and demand response measures was developed for each customer sector, drawing upon IPL's current programs, AEG's measure database, and measure lists developed from previous studies. The list of measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. Special focus was given to including the latest available data on emerging technologies from AEG's in-depth research and participation in technical working groups all over the nation. This includes recent evolutions in LED lighting, heat pump technologies, smart thermostats, behavioral research, and smart control systems; all of which are included in this study.

Each measure was characterized with energy and demand savings, incremental cost, effective useful life, and other performance factors, drawing upon data from the Indiana Technical Reference Manual version 2.2, AEG measure database, and well-vetted national and regional sources. We performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential, utilizing the measure information along with IPL's avoided cost data.

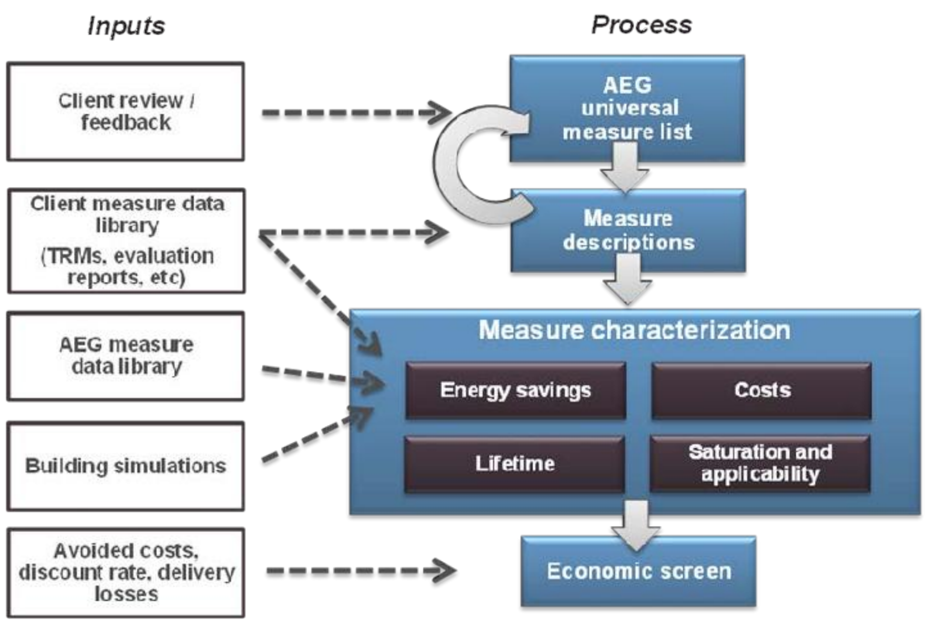

Figure 2-2 Approach for Energy Efficiency Measure Assessment

The selected measures are categorized into two types according to the LoadMAP taxonomy:

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR refrigerator that replaces a standard efficiency refrigerator. For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of central air conditioners, this list begins with the current federal standard SEER 13 unit and spans a broad spectrum up to a maximum efficiency of a SEER 24 unit.
- **Non-equipment measures** save energy by reducing the need for delivered energy, but do not involve replacement or purchase of major end-use equipment (such as a refrigerator). An example would be a programmable thermostat that is pre-set to run heating and cooling systems only when people are home. Non-equipment measures can apply to more than one end use. For instance, wall insulation will affect the energy use of both space heating and cooling. Non-equipment measures typically fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, energy management system)
    - Equipment maintenance (cleaning filters, changing set-points)
    - Whole-building design (building orientation, passive solar lighting)

- Commissioning and retro commissioning (monitoring of building energy systems)

Representative EE Measure Data Inputs

To provide an example of the energy-efficiency measure data, Table 2-2 and Table 2-3 present examples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential central air conditioning (A/C) in single-family homes. Table 2-2 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market.

Table 2-2 Example of Equipment Measures for Central AC – Single Family Home, Existing

Efficiency Level	Useful Life	Equipment Cost	Base Year Energy Usage (kWh/yr)	On Market	Off Market
SEER 13.0	18	$1,022	2,162	2015	2037
SEER 14.0	18	$1,309	1,932	2015	2037
SEER 15.0	18	$1,597	1,984	2015	2037
SEER 16.0	18	$1,884	1,912	2015	2037
SEER 17.0	18	$2,172	1,849	2015	2037
SEER 18.0	18	$2,462	1,792	2015	2037
SEER 21.0	18	$3,216	1,655	2015	2037
SEER 24.0 Ductless, Var.Ref.Flow	18	$3,512	1,608	2015	2037

Table 2-3 lists some of the non-equipment measures applicable to A/C in an existing single-family home. All measures are evaluated for cost-effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings and costs are calculated for each year of the study and depend on the base year saturation of the measure, the applicability[5] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 2-3 Example of Non-Equipment Measure– Single Family Home, Existing

End Use	Measure	Saturation in 2015[6]	Applica-bility	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Cooling	Insulation - Ceiling	49%	81%	25	$380	1%
Cooling	Ducting - Repair and Sealing	60%	75%	18	$453	4%
Cooling	Windows - High Eff/ENERGY STAR	26%	50%	25	$305	12%

Approach for Cost-effectiveness Screening of EE Measures

Only measures that are cost-effective were included in economic and achievable measure-level potential. Measures were first screened for cost-effectiveness within LoadMAP for inclusion in the economic and achievable potential scenarios. LoadMAP utilized the *Total Resource Cost Test* (TRC) test for measure-level cost-effectiveness screening (i.e., a TRC benefit-cost ratio of at least 1.0). The

[5] The applicability factors take into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes where there is insufficient space in the attic or there is no attic at all.

[6] Note that saturation levels reflected for the base year change over time as more measures are adopted.

LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — of the years in the projection.

The TRC test is the primary method of assessing the cost-effectiveness of energy efficient measures that has been used across the United States for over twenty-five years. TRC measures the net costs and benefits of an energy efficiency program as a resource option based on the total costs of the measure, including both the participant's and the utility's costs. This test represents the combination of the effects of a program on both participating and non-participating customers.

Three other benefit-cost tests were calculated to analyze measure-level cost-effectiveness from different perspectives:

- *Participant Cost Test* quantifies the benefits and costs to the customer due to program participation.
- *Ratepayer Impact Measure Cost Test* measures what happens to a customer's rates due to changes in utility revenues and operating costs.
- *Utility Cost Test* measures the net costs of a measure as a resource option based on the costs incurred by the program administrator, excluding any net costs incurred by the participant.

It is important to note that the economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the kilowatt-hour (kWh) savings potential of a measure, kWh consumption with the measure applied must be compared to the kWh consumption of a baseline condition. Also, if multiple equipment measures have B/C ratios greater than or equal to 1.0, the most efficient technology is selected by the economic screen.

Measures that are cost-effective within LoadMAP are included in the economic and achievable potential cases.

EE Potential

The approach we used to calculate the energy efficiency potential adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies.[7] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying energy efficiency potential.

The potential was estimated for the period from 2018 through 2037 to align with IPL's DSM regulatory schedule. This is the 20-year period that corresponds with IPL's next integrated resource plan.

The calculation of **Technical** and **Economic Potential** is a straightforward algorithm, phasing in the theoretical maximum efficiency units and screening them for cost-effective economics. To develop estimates for **Achievable Potential**, we develop market adoption rates for each measure in each year that specify the percentage of customers that will select the efficient, economic options.

Data Development

This section details the data sources used in this study and describes how these sources were applied. In general, data was adapted to local conditions, for example, by using local sources for measure data and local weather for building simulations.

Data Sources

The data sources are organized into the following categories:

- Indianapolis Power & Light Company data
- Energy efficiency measure data

[7] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

- AEG's databases and analysis tools
- Other secondary data and reports

Indianapolis Power & Light Company Data

Our highest priority data sources for this study were those that were specific to IPL.

- **IPL customer data:** IPL provided 2015 residential customers and usage data as well as nonresidential billing data. The nonresidential billing data was utilized to develop customer counts and energy use for each commercial and industrial segment and also included an analysis of SIC and NAICS information to assist in market segmentation and categorization.
- **Load forecasts:** IPL provided its most recent load and peak forecasts. IPL also provided an economic growth forecast by sector and electric load forecast by sector.
- **Economic information:** IPL provided a forecast of avoided costs[8], forecast of retail electricity rates by sector, discount rate, and line loss factor.
- **Indianapolis Power & Light Company's** 2015 Multi-family Direct Install ("MFDI") Program: Current State Analysis Report
- **Additional Indianapolis Power & Light program implementation and evaluation data**: IPL provided information about past and current DSM programs, including program descriptions, goals, and achievements to date.

Energy Efficiency Measure Data

Several sources of data were used to characterize the energy efficiency measures. We used the following national and well-vetted regional data sources and supplemented with AEG's data sources to fill in any gaps.

- **Appliance and Equipment Standards.** The study utilized data from the U.S. Department of Energy,[9] Energy Star[10] and the Consortium for Energy Efficiency[11] to determine baseline savings as well as efficient savings.
- **Indiana Technical Reference Manual.** Indiana Demand Side Management Coordination Committee, EM&V Subcommittee. Version 2.2, dated July 28, 2015. Prepared by Cadmus Group, Inc.

AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools has been incorporated into the analysis and deliverables for this study.

- **AEG Energy Market Profiles**: For more than 10 years, AEG staff has maintained profiles of end-use consumption for the residential, commercial and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use, customer segment and end use for 10 regions in the United States. The Energy Information Administration surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- **Building Energy Simulation Tool (BEST).** AEG's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- **AEG's EnergyShape™:** This database of load shapes includes the following:

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[8] Avoided costs are sourced from ABB, IPL's consultant for integrated resource modeling.

[9] U.S. Department of Energy. Current Rulemakings and Notices. http://energy.gov/eere/buildings/current-rulemakings-and-notices

[10] Energy Star. Product Specifications and Partner Commitments Search. http://www.energystar.gov/products/spec/

[11] Consortium for Energy Efficiency. Program Resources. https://www.cee1.org/

  - Residential – electric load shapes for ten regions, three housing types, 13 end uses
  - Nonresidential – electric load shapes for nine regions, 54 building types, ten end uses

- **AEG's Database of Energy Efficiency Measures (DEEM):** AEG maintains an extensive database of existing and emerging measures for our studies. Our database draws upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology Forecast Updates – Residential and Nonresidential Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data**.**
- **Recent studies.** AEG has conducted numerous studies of EE potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies, which include NIPSCO, Indiana Michigan Power, PacifiCorp, Vectren Energy, and Ameren Illinois. In addition, we used the information about impacts of building codes and appliance standards from recent reports for the Edison Electric Institute.[12]

Other Secondary Data

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- **Annual Energy Outlook.** The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2015 AEO.
- **American Community Survey.** The US Census American Community Survey is an ongoing survey that provides data every year on household characteristics.
- **Local Weather Data:** Weather from NOAA's National Climatic Data Center for Indiana was used as the basis for building simulations.
- **Other relevant regional sources:** These include reports from the Consortium for Energy Efficiency, the EPA, and the American Council for an Energy-Efficient Economy.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of electricity use and households/floor space for the residential, commercial and industrial sectors, we used IPL billing data and secondary data.

- For the residential sector, AEG estimated the numbers of customers and the average energy use per customer for each segment based on IPL's 2015 residential sales data. Low income customers were identified from the American Community Survey and allocated to a housing type based upon IPL-specific data on customers that receive energy assistance.
- For the commercial and industrial sectors, AEG estimated the sales by segment based on IPL 2015 customer billing data.

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-4. To develop the market profiles for each segment, we used the following approach:

1. Develop control totals for each segment. These include market size, segment-level annual electricity use, and annual intensity.

[12] AEG staff has prepared three white papers on the topic of factors that affect U.S. electricity consumption, including appliance standards and building codes. Links to all three white papers are provided:
http://www.edisonfoundation.net/IEE/Documents/IEE_RohmundApplianceStandardsEfficiencyCodes1209.pdf
http://www.edisonfoundation.net/iee/Documents/IEE_CodesandStandardsAssessment_2010-2025_UPDATE.pdf.
http://www.edisonfoundation.net/iee/Documents/IEE_FactorsAffectingUSElecConsumption_Final.pdf

2. Utilize the results of AEG's Energy Market Profiles database to develop existing appliance saturations, appliance and equipment characteristics, and building characteristics. We also incorporated secondary sources to supplement and corroborate the data.
3. Ensure calibration to control totals for annual electricity sales in each sector and segment.
4. Compare and cross-check with other recent AEG studies.
5. Work with IPL staff to vet the data against their knowledge and experience.

Table 2-4 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings and commercial floor space, industrial employment	IPL billing data AEO 2015
Annual intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	IPL billing data AEG's Energy Market Profiles AEO 2015 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of commercial floor space/employment with technology	AEG's Energy Market Profiles Other recent studies
UEC/EUI for each end-use technology	UEC: Annual electricity use in homes and buildings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	HVAC uses: BEST simulations using prototypes developed for Indiana Engineering analysis AEG's DEEM Recent AEG studies AEO 2015
Appliance/equipment age distribution	Age distribution for each technology	AEG's DEEM Recent AEG studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	IPL DSM program Indiana TRM AEG's DEEM AEO 2015 Recent AEG studies
Peak factors	Share of technology energy use that occurs during the system peak hour	IPL system peak AEG's EnergyShape database

Data Application for Baseline Projection

Table 2-5summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector for existing dwellings/buildings as well as new construction.

We implemented assumptions for known future equipment standards as of December 2015, as shown in Table 2-6 and Table 2-7 for the respective sectors. The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-5 Data Needs for the Baseline Projection and Potential Estimates in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial and industrial sectors	IPL load forecast AEO 2015 economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2015 regional forecast assumptions[13] Appliance/efficiency standards analysis IPL DSM program and evaluation reports
Electricity prices	Forecast of average energy and capacity avoided costs and retail prices	IPL forecast

Table 2-6 Residential Electric Equipment Standards[14]

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Central AC	SEER 13										
Room AC	EER 11.0										
Electric Resistance	Space Heating										
Heat Pump	SEER 14.0/HSPF 8.0										
Water Heater (<=55 gallons)	EF 0.95										
Water Heater (>55 gallons)	Heat Pump Water Heater										
Screw-in/Pin Lamps	Advanced Incandescent (20 lumens/watt)					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
Refrigerator	25% more efficient										
Freezer	25% more efficient										
Clothes Washer	MEF 1.72 for top loader			MEF 2.0 for top loader							
Clothes Dryer	5% more efficient (EF 3.17)										
Furnace Fans	Conventional				40% more efficient						

[13] We developed baseline purchase decisions using the Energy Information Agency's AEO 2015, which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of naturally occurring conservation or effects of future programs that may be embedded in the AEO forecasts.

[14] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-7 Commercial and Industrial Electric Equipment Standards

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		EER 11.9								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
High Intensity Discharge	EPACT 2005		Metal Halide Ballast Improvement								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		10-38% more efficient								
Reach-in	EPACT 2005		40% more efficient								
Glass Door Display	EPACT 2005		12-28% more efficient								
Open Display Case	EPACT 2005		10-20% more efficient								
Ice maker	EPACT 2005			15% more efficient							
Pre-rinse Spray Valve	1.6 GPM				1.0 GPM						
Motors	EISA 2007	Expanded EISA 2007									

Energy Efficiency Measure Data Analysis

Table 2-8 details the energy-efficiency data inputs to the LoadMAP model. It describes each input and identifies the key sources used in the IPL analysis.

Data Application for Cost Effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. All cost and benefit values were analyzed as real 2015 dollars. We used proprietary projections of avoided cost values provided by IPL and applied a discount rate provided by IPL in real dollars to all future cash flows. Note that the status of the Clean Power Plan is still in flux at the time of this analysis and therefore was not specifically considered; however the projections of avoided cost include estimates of carbon emission costs. All impacts in this report are presented at the customer meter. Line losses were used to gross impacts up to the generator for the purposes of cost-effectiveness testing.

Table 2-8 Data Needs for the Measure Characterization in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Indiana TRM BEST AEG's DEEM AEO 2015 Other secondary sources
Peak Demand Impacts	Savings during the peak demand periods are specified for each electric measure. These impacts relate to the energy savings and depend on the extent to which each measure is coincident with the system peak.	Indiana TRM BEST AEG's DEEM AEG EnergyShape
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-unit basis. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Indiana TRM AEG's DEEM AEO 2015 RS Means Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Indiana TRM AEG's DEEM AEO 2015 Other secondary sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	Indiana TRM AEG's DEEM Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Achievable Potential Estimation

To estimate achievable potential, two sets of parameters are needed to represent customer decision making behavior with respect to energy-efficiency choices.

- **Technical diffusion curves for non-equipment measures.** Equipment measures are installed in our modeling process when existing units fail according to the stock accounting algorithms. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the projection (instantaneous potential), they are phased in according to adoption schedules over the timeline of the study that generally align with the diffusion of similar equipment measures.
- **Achievable adoption rates** Customer adoption rates or take rates are applied to Economic potential to estimate two levels of Achievable Potential (Realistic and Maximum), as described in Section 2. These rates were developed based on program benchmarking, IPL program achievements in the near term, and market research and evaluation analyses conducted by AEG in the Midwest and around the nation. AEG mapped these adoption rates to all measures in the modeling universe.

  Note that in the study's reference case, the C&I take rates were then adjusted downward to reflect the fact that large C&I opt out customers who have selected not to participate in EE programs are not eligible for programs, measures, and associated savings potential. The adoption rates were reduced by an amount proportional to the respective amount of base-year total energy in each

C&I segment that has already opted out of programs as of the time of the study. This results in commercial adoption rates being adjusted downward by approximately 20% and industrial downward by approximately 50%. Realistic and Maximum Achievable adoption rates for the Reference Case are presented in Appendix B.

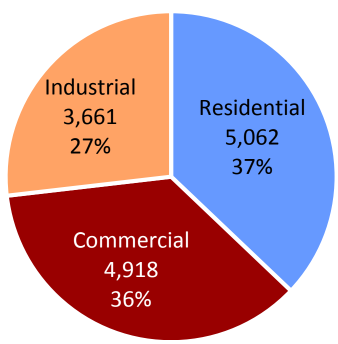
AEG also conducted a sensitivity case (see the end of Chapter 6) in which the C&I opt outs were re-enrolled into EE program eligibility. Here, the adjustments to the adoption rates were removed to reflect the inclusion of the C&I opt out customers.

Market Characterization and Market Profile

This section describes how customers in the IPL service territory use electricity in the base year of the study, 2015. It begins with a high-level summary of energy use across all sectors and then delves into each sector in more detail.

Energy Use Summary

Total electricity use for the residential, commercial, and industrial sectors for IPL in 2015 was 13,641 GWh. As shown in Figure 2-3, the three sectors have relatively equivalent energy consumption, with residential at 37%, commercial at 36% and industrial at 27%. In terms of peak demand, the total summer system peak in 2015 was 2,690 MW and winter peak was 2,462 MW. The residential sector has the highest contribution to peak. This is due to the high peak coincidence and healthy saturation of air conditioning equipment. All usage statistics and DSM impacts are presented at the customer meter.



Segment	Annual Use (GWh)	% of Sales	Summer Peak (MW)	Winter Peak (MW)
Residential	5,062	37%	1,141	1,170
Commercial	4,918	36%	941	805
Industrial	3,661	27%	609	487
Total	13,641	100%	2,690	2,462

Figure 2-3 Sector Level Electricity Use in 2015 Base Year

Residential

The total number of households and residential electricity sales for the service territory were obtained from IPL's customer database. The first step was to allocate total residential sector customers and sales into four segments. These segments are: Single Family Non-Electric Heat, Multifamily Non-Electric Heat, Single Family Electric Heat, and Multifamily Electric Heat. AEG adjusted the number of customers and usage in each segment based on IPL's billing data for customers on electric heat rates and all reported residential energy sales in 2015. In 2015, there were 429,245 households in the IPL territory that used a total of 5,062 GWh with a summer peak demand of 1,141 MW. The average use per customer (or household) of 11,792 kWh is relatively close to the national average. AEG allocated these totals into four residential segments and the values are shown in Table 2-9.

Table 2-9 IPL Residential Sector Control Totals

Segment	Number of Customers	Electricity Use (GWh)	% of Annual Use	Annual Use / Customer (kWh/HH)	Summer Peak (MW)	Winter Peak (MW)
Single Family	235,142	2,533	50%	10,773	720	484
Multifamily	43,885	222	4%	5,063	53	49
Single Family - Elect Heat	88,045	1,798	36%	20,425	289	489
Multifamily - Elect Heat	62,172	508	10%	8,170	79	149
Total	**429,245**	**5,062**	**100%**	**11,792**	**1,141**	**1,170**

Residential Energy Market Profile

As described in the previous chapter, the market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector as a whole is presented in Table 2-10 below. Segment-specific market profiles are presented in Appendix A.

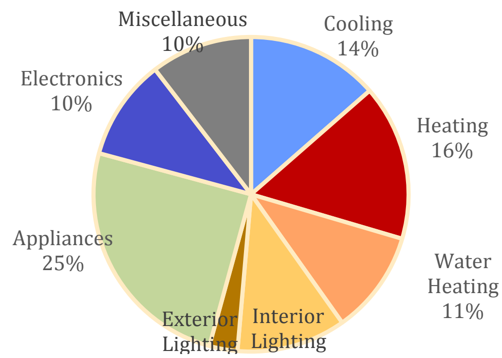


Figure 2-4 Residential Sector Electricity Use by End Use, 2015

Three main electricity end uses —appliances, space heating, and space cooling —account for 45% of total use shown in Figure 2-4 Appliances include refrigerators, freezers, stoves, clothes washers, clothes dryers, dishwashers, and microwaves. The remainder of the energy falls into the electronics, lighting, water heating and the miscellaneous category – which is comprised of furnace fans, pool pumps, and other “plug” loads not captured by the other end uses. Examples include hair dryers, power tools, coffee makers, etc.

Figure 2-5 presents the electricity intensities by end use and housing type. The average household intensity of all IPL homes is 11,792 kWh. Single-family electric homes have the highest use per customer at 20,425 kWh/year, which reflects a large saturation of electric heating.

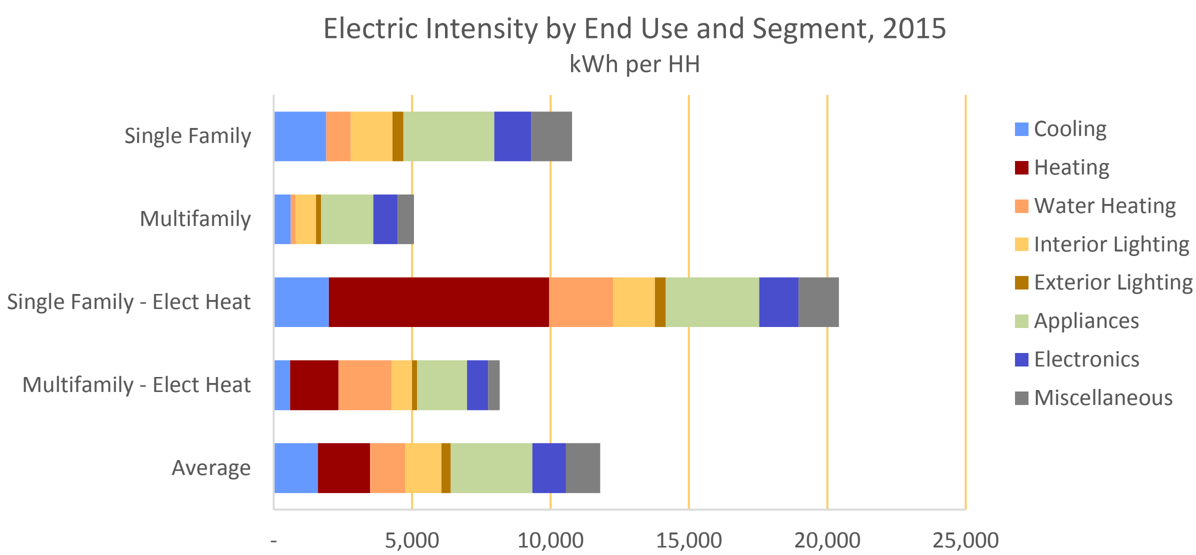


Figure 2-5 Residential Sector Electricity Intensity by End Use and Segment (kWh/HH, 2015)

Table 2-10 Average Market Profile for the Residential Sector, 2015

End Use	Technology	Saturation	UEC (kWh/HH)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	54.2%	2,047	1,109	475.9
Cooling	Room AC	19.9%	705	140	60.2
Cooling	Air-Source Heat Pump	15.0%	2,241	337	144.5
Cooling	Geothermal Heat Pump	0.9%	1,520	14	5.8
Heating	Electric Room Heat	12.6%	1,974	249	106.7
Heating	Electric Furnace	6.5%	10,424	678	290.9
Heating	Air-Source Heat Pump	15.0%	6,187	929	398.7
Heating	Geothermal Heat Pump	0.9%	3,576	32	13.6
Water Heating	Water Heater <= 55 Gal	28.2%	3,006	847	363.7
Water Heating	Water Heater > 55 Gal	13.1%	3,097	405	173.9
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%	89	76	32.8
Appliances	Clothes Dryer	77.3%	798	617	264.6
Appliances	Dishwasher	58.5%	400	234	100.4
Appliances	Refrigerator	100.0%	747	747	320.6
Appliances	Freezer	37.2%	602	224	96.0
Appliances	Second Refrigerator	29.8%	1,086	323	138.7
Appliances	Stove	61.6%	436	269	115.3
Appliances	Microwave	104.5%	131	137	58.7
Appliances	Dehumidifier	27.9%	628	175	75.1
Appliances	Air Purifier	12.6%	1,115	140	60.1
Electronics	Personal Computers	58.9%	179	105	45.2
Electronics	Monitor	69.8%	75	53	22.6
Electronics	Laptops	161.5%	47	76	32.5
Electronics	TVs	292.5%	161	470	202.0
Electronics	Printer/Fax/Copier	102.1%	62	63	27.0
Electronics	Set top Boxes/DVRs	313.8%	111	349	150.0
Electronics	Devices and Gadgets	100.0%	106	106	45.7
Miscellaneous	Pool Pump	4.8%	1,431	68	29.3
Miscellaneous	Pool Heater	0.3%	1,438	5	2.1
Miscellaneous	Furnace Fan	61.0%	747	456	195.6
Miscellaneous	Bathroom Exhaust Fan	32.6%	148	48	20.6
Miscellaneous	Well pump	9.4%	589	55	23.7
Miscellaneous	Miscellaneous	100.0%	597	597	256.2
Total				**11,792**	**5,061.6**

Commercial

The first step in developing the commercial market profile was to allocate total commercial customers and sales into eleven segments. These segments are: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous. The total electric energy consumed by commercial customers in IPL's service area in 2015 was 4,918 GWh. The average intensity of use was 13.3 kWh/square foot.

A Note on Opt-Out Customers

Indiana legislation allows large C&I customers that meet size and eligibility requirements to opt out of energy efficiency programs. For purposes of this study, we maintain all customers in the baseline control totals and market characterization, but identify the portion of opt-out load – based on opt-out forms received as of January 1, 2016 – which allows us to remove them downstream from program participation as appropriate in the achievable potential cases. The removal and adjustment will take place according to the energy allocations indicated in the table below.

Table 2-11 IPL Commercial Sector Control Totals

Segment	Total Electricity Use (GWH)	% of Annual Use	Avg. Use/ Square Foot (kWh/ ft²)	Electricity Use by Opt-Out Customers (GWh)	% of Energy Use by Opt-Out Customers	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Small Office	608	12.4%	15.1	101	49	608	12.4%
Large Office	812	16.5%	17.6	129	93	812	16.5%
Restaurant	361	7.3%	35.5	60	31	361	7.3%
Retail	579	11.8%	14.6	127	38	579	11.8%
Grocery	239	4.9%	48.6	35	31	239	4.9%
College	251	5.1%	12.5	56	115	251	5.1%
School	251	5.1%	8.4	79	16	251	5.1%
Health	684	13.9%	26.5	112	26	684	13.9%
Lodging	142	2.9%	15.0	17	169	142	2.9%
Warehouse	142	2.9%	6.4	44	-	142	2.9%
Misc.	849	17.3%	7.1	182	-	849	17.3%
Total	4,918	100.0%	13.3	941	567	4,918	100.0%

Commercial Energy Market Profile

Figure 2-6 presents the commercial sector by end use across all building types in 2015. Lighting and HVAC end uses dominate the usage.

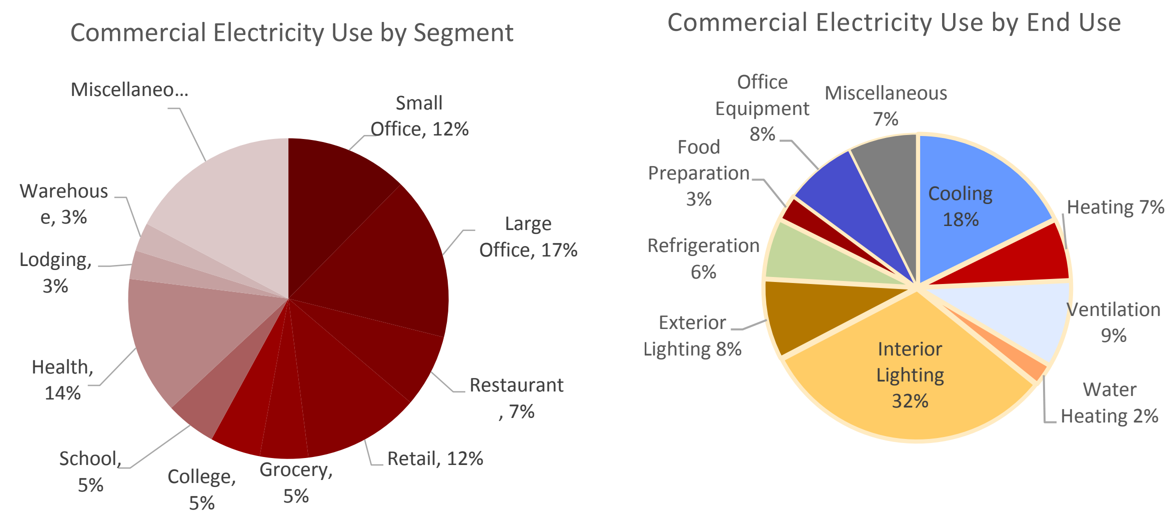


Figure 2-6 Commercial Sector Electricity Use, 2015

The grocery and restaurant segments are highest in terms of electricity use per square feet due to the concentration high use food preparation equipment and refrigeration end uses, as shown in Figure 2-7.

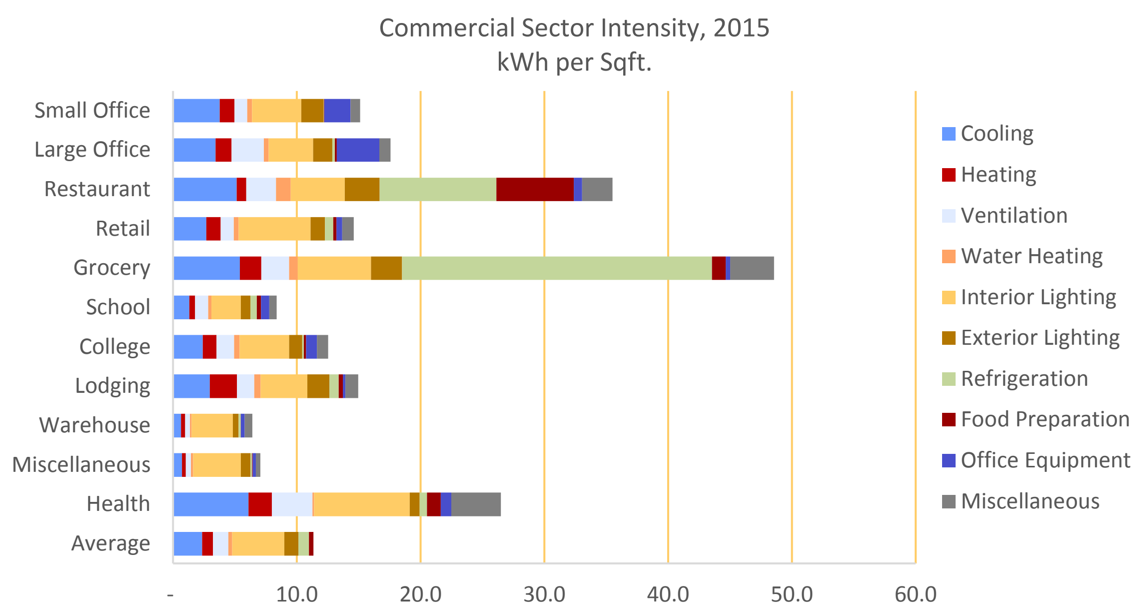


Figure 2-7 Commercial Sector Electricity Intensity by End Use and Segment (kWh/Sqft, 2015)

Table 2-12 Average Market Profile for the Commercial Sector, 2015

End Use	Technology	Saturation	EUI (kWh/Sqft)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	12.6%	2.96	0.37	137.3
Cooling	Water-Cooled Chiller	16.0%	3.74	0.60	219.8
Cooling	RTU	23.5%	4.04	0.95	349.6
Cooling	Central AC	4.9%	3.96	0.19	71.5
Cooling	Room AC	2.2%	3.46	0.08	27.8
Cooling	Air-Source Heat Pump	2.4%	3.98	0.09	35.0
Cooling	Geothermal Heat Pump	1.0%	2.71	0.03	10.4
Cooling	PTHP	1.6%	3.34	0.05	19.9
Heating	Electric Furnace	7.8%	5.97	0.47	172.5
Heating	Electric Room Heat	2.6%	5.77	0.15	54.6
Heating	Air-Source Heat Pump	2.4%	5.65	0.13	49.8
Heating	Geothermal Heat Pump	1.0%	4.61	0.05	17.6
Heating	PTHP	1.6%	4.60	0.07	27.4
Ventilation	Ventilation	100.0%	1.23	1.23	453.7
Water Heating	Water Heater	29.6%	1.04	0.31	113.4
Interior Lighting	Screw-in	100.0%	0.60	0.60	222.2
Interior Lighting	High-Bay Fixtures	100.0%	1.41	1.41	521.3
Interior Lighting	Linear Lighting	100.0%	2.20	2.20	809.4
Exterior Lighting	Screw-in	100.0%	0.10	0.10	38.6
Exterior Lighting	Area Lighting	100.0%	0.85	0.85	314.6
Exterior Lighting	Linear Lighting	100.0%	0.18	0.18	66.8
Refrigeration	Walk-in Refrig/Freezer	8.1%	1.26	0.10	37.4
Refrigeration	Reach-in Refrig/Freezer	12.3%	0.36	0.04	16.5
Refrigeration	Glass Door Display	40.8%	0.37	0.15	55.0
Refrigeration	Open Display Case	9.7%	4.12	0.40	147.7
Refrigeration	Icemaker	27.5%	0.48	0.13	48.3
Refrigeration	Vending Machine	15.6%	0.21	0.03	12.0
Food Preparation	Oven	14.5%	0.31	0.04	16.6
Food Preparation	Fryer	8.4%	0.73	0.06	22.7
Food Preparation	Dishwasher	25.9%	0.76	0.20	72.4
Food Preparation	Hot Food Container	12.4%	0.09	0.01	4.0
Food Preparation	Steamer	3.4%	0.67	0.02	8.4
Food Preparation	Griddle	8.3%	0.41	0.03	12.7
Office Equipment	Desktop Computer	100.0%	0.61	0.61	223.5
Office Equipment	Laptop	98.2%	0.09	0.09	31.8
Office Equipment	Server	71.9%	0.17	0.12	45.0
Office Equipment	Monitor	100.0%	0.11	0.11	39.4
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	24.6
Office Equipment	POS Terminal	54.8%	0.04	0.02	7.7
Miscellaneous	Non-HVAC Motors	10.1%	0.20	0.02	7.6
Miscellaneous	Other Miscellaneous	100.0%	0.95	0.95	352.1
Total				**13.34**	**4,918.3**

INDUSTRIAL

The industrial sector contributed 3,661 GWh of sales in 2015, only slightly less than either the residential and commercial sectors. As is discussed in the commercial section above, several large C&I customers have opted out of IPL's energy efficiency programs. These customers and their usage are included in the base year market characterization and the control totals shown below.

Table 2-13 IPL Industrial Sector Control Totals

Segment	Total Electricity Use (GWh)	% of Total Usage	Electricity Use by Opt-Out Customers (GWh)	% of Energy Use by Opt-Out Customers	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Chemicals & Pharmaceutical	732	20%	564	77.0%	86	101
Food Products	362	10%	259	71.5%	45	49
Transportation	490	13%	447	91.3%	83	65
Other Industrial	2,077	57%	593	28.6%	395	272
Total	**3,661**	**100%**	**1,863**	**50.9%**	**609**	**487**

Industrial Energy Market Profile

As described above, market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the industrial sector is presented in Table 2-14. Segment-specific market profiles are presented in Appendix A.

Figure 2-8 shows the distribution of annual electricity consumption by sector and by end use for all industrial customers. Motors are the largest overall end use for the industrial sector, accounting for 44% of energy use. Note that this end use includes a wide range of industrial equipment, such as air compressors and refrigeration compressors, pumps, conveyor motors, and fans. The process end use accounts for 21% of annual energy use, which includes heating, cooling, refrigeration, and electro-chemical processes.

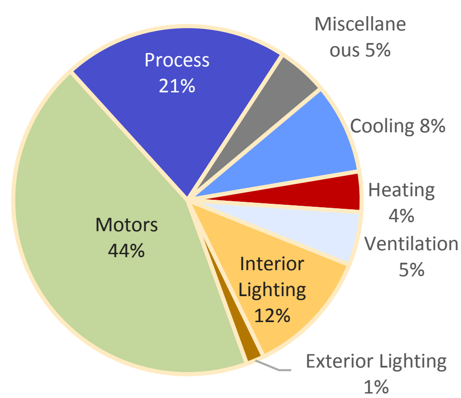


Figure 2-8 Industrial Sector Electricity Use by End Use, 2015

Table 2-14 Average Market Profile for the Industrial Sector, 2015

End Use	Technology	Saturation	EUI (kWh/Employee)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.2%	24,231	522	31.4
Cooling	Water-Cooled Chiller	2.0%	22,845	457	27.5
Cooling	RTU	10.6%	39,256	4,171	250.8
Cooling	Air-Source Heat Pump	0.0%	39,256	0	0.0
Cooling	Geothermal Heat Pump	0.0%	26,184	0	0.0
Heating	Electric Furnace	1.7%	99,832	1,676	100.7
Heating	Electric Room Heat	0.7%	87,596	612	36.8
Heating	Air-Source Heat Pump	0.0%	74,874	0	0.0
Heating	Geothermal Heat Pump	0.0%	49,941	0	0.0
Ventilation	Ventilation	100.0%	3,023	3,023	181.7
Interior Lighting	Screw-in	100.0%	329	329	19.8
Interior Lighting	High-Bay Fixtures	100.0%	5,863	5,863	352.4
Interior Lighting	Linear Lighting	100.0%	955	955	57.4
Exterior Lighting	Screw-in	100.0%	43	43	2.6
Exterior Lighting	Area Lighting	100.0%	809	809	48.6
Exterior Lighting	Linear Lighting	100.0%	166	166	10.0
Motors	Pumps	100.0%	6,078	6,078	365.4
Motors	Fans & Blowers	100.0%	4,040	4,040	242.8
Motors	Compressed Air	100.0%	5,106	5,106	307.0
Motors	Conveyors	100.0%	10,078	10,078	605.8
Motors	Other Motors	100.0%	1,374	1,374	82.6
Process	Process Heating	100.0%	6,355	6,355	382.0
Process	Process Cooling	100.0%	2,526	2,526	151.9
Process	Process Refrigeration	100.0%	2,526	2,526	151.9
Process	Process Electrochemical	100.0%	769	769	46.2
Process	Process Other	100.0%	569	569	34.2
Miscellaneous	Miscellaneous	100.0%	2,851	2,851	171.4
Total				60,898	3,660.8

BASELINE PROJECTION

Prior to developing estimates of energy-efficiency potential, AEG developed a baseline end-use projection to quantify what the consumption is likely going to be in the future absent any efficiency programs. The savings from past programs are embedded in the projection, but the baseline projection assumes that program are no longer active and installing new measures in the future. All such possible savings from future programs are instead meant to be captured by the potential estimates.

The baseline projection incorporates assumptions about:

- Customer and economic growth
- Appliance or equipment standards and building codes with past or future enactment dates already mandated and on the books (see Section 2)
- Forecasts of future electricity prices and other drivers of consumption
- Trends in fuel shares and equipment saturations

- Naturally occurring energy efficiency, which reflects the purchase of high efficiency options over and above the prevailing minimum standards by early adopters outside of utility programs.

Although it aligns closely, the baseline projection for this study is not IPL's official load forecast. Rather it was developed within the potential modeling framework to serve as the metric against which DSM potentials are measured. This chapter presents the baseline projections AEG developed for this study.

Below, AEG presents the baseline projections for each sector, which include projections of annual use in GWh and summer peak demand in MW as well as a summary across all sectors. Over all for the IPL service territory the baseline projection increases 10% by 2037 with an approximate average annual growth rate of 0.5% per year.

Summary of Baseline Projection

Table 2-15 All Sector Baseline Projection for Selected Years (GWh)

Segment	2015	2018	2019	2020	2027	2027	% Change 15'-37'
Residential	5,062	5,197	5,209	5,177	5,176	5,720	13%
Commercial	4,918	5,025	4,987	4,945	4,879	5,163	5%
Industrial	3,661	3,736	3,757	3,772	3,885	4,096	12%
Total	13,641	13,958	13,953	13,893	13,940	14,979	10%

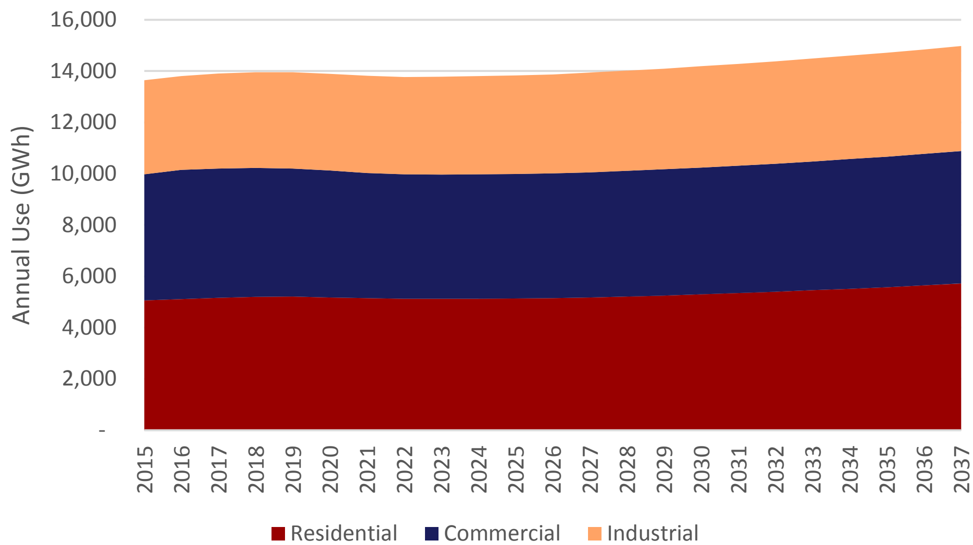


Figure 2-9 All Sector Baseline Projection (GWh)

Residential Baseline Projection

Table 2-16 and Figure 2-10 present the baseline projection for electricity at the end-use level for the residential sector as a whole. Overall, residential use increases from 5,062 GWh in 2014 to 5,720 GWh in 2037, an increase of 13%. This reflects a moderate customer growth forecast. Figure 2-11 presents the baseline projection of annual electricity use per household. This projection is in general alignment with IPL's residential load forecast. Specific observations include:

1. Lighting use decreases throughout the time period as the second tier of lighting standards from the Energy Independence and Security Act of 2007 (EISA) come into effect in 2020.
2. Appliance energy use experiences significant efficiency gains from new standards, but this is offset by customer growth.

3. Growth in use in electronics is substantial and reflects an increase in the saturation of electronics and new types of gadgets in spite of the trend toward smaller and more mobile devices.
4. Growth in other miscellaneous use is also substantial. This end use grows consistently over time as new technologies and appliances are added to the market year after year. AEG incorporates future growth assumptions that are consistent with the Annual Energy Outlook.

Table 2-16 Residential Baseline Projection by End Use (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change (15-37)
Cooling	686	710	715	720	774	833	21.4%
Heating	810	849	858	867	961	1,044	28.8%
Water Heating	538	534	531	528	515	533	-0.9%
Interior Lighting	567	578	539	499	307	292	-48.5%
Exterior Lighting	146	139	123	108	62	62	-58.0%
Appliances	1,262	1,298	1,305	1,312	1,372	1,427	13.0%
Electronics	525	537	532	531	617	713	35.9%
Miscellaneous	528	564	573	582	693	816	54.7%
Total	5,062	5,209	5,177	5,146	5,301	5,720	13.0%

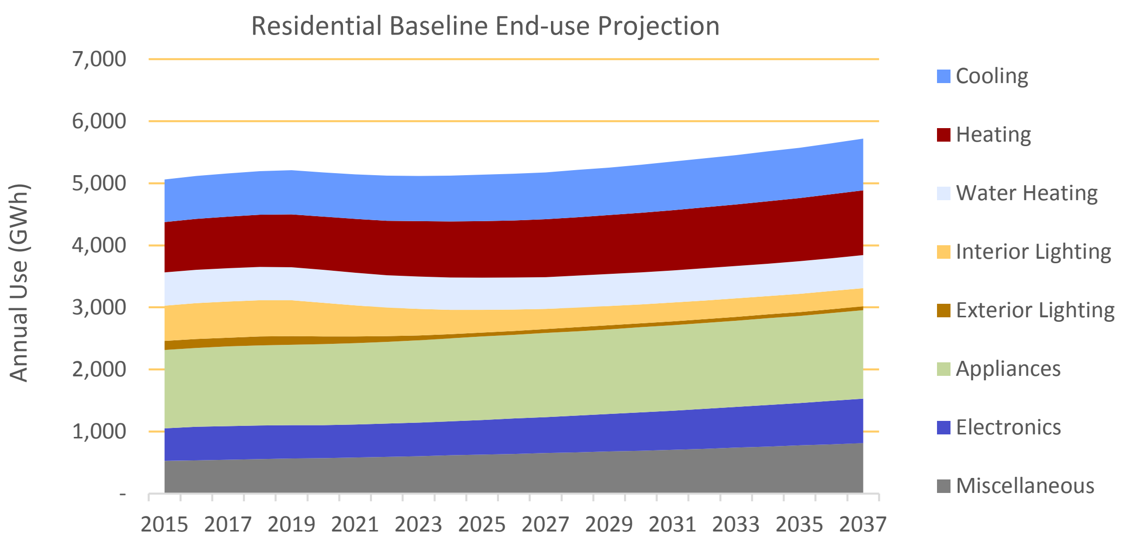


Figure 2-10 Residential Baseline Projection

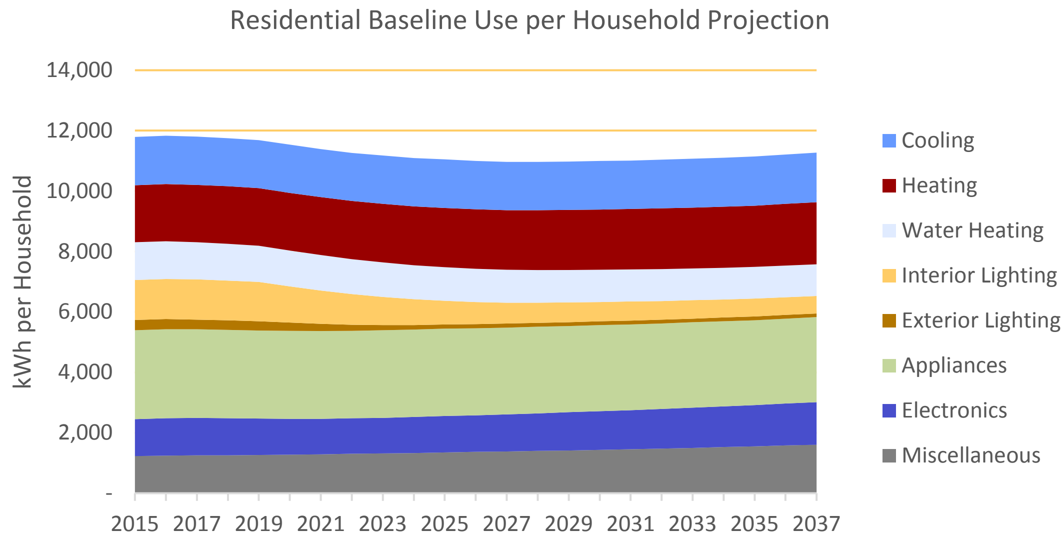


Figure 2-11 Residential Baseline Use-per-household Projection

Commercial Baseline Projection

Annual electricity use in the commercial sector grows during the overall projection horizon, starting at 4,918 GWh in 2015, and increasing to 5,163 in 2037 representing a 5% growth. Table 2-17 and Figure 2-12 present the baseline projection at the end-use level for the commercial sector as a whole. Usage in lighting is declining slightly throughout the projection, due largely to the phasing in of codes and standards such as the EISA 2007 lighting standards.

Table 2-17 Commercial Baseline Projection by End Use (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change (15-37)
Cooling	871	879	875	869	880	910	4.5%
Heating	322	331	331	329	338	347	8.0%
Ventilation	454	445	440	435	427	441	-2.8%
Water Heating	113	116	115	115	119	124	9.1%
Interior Lighting	1,553	1,519	1,477	1,428	1,297	1,275	-18.0%
Exterior Lighting	420	415	408	399	375	370	-11.9%
Refrigeration	317	314	311	306	289	288	-9.0%
Food Preparation	137	139	138	137	140	144	5.5%
Office Equipment	372	384	384	384	406	433	16.0%
Miscellaneous	360	446	465	482	670	830	130.8%
Total	**4,918**	**4,987**	**4,945**	**4,885**	**4,941**	**5,163**	**5.0%**

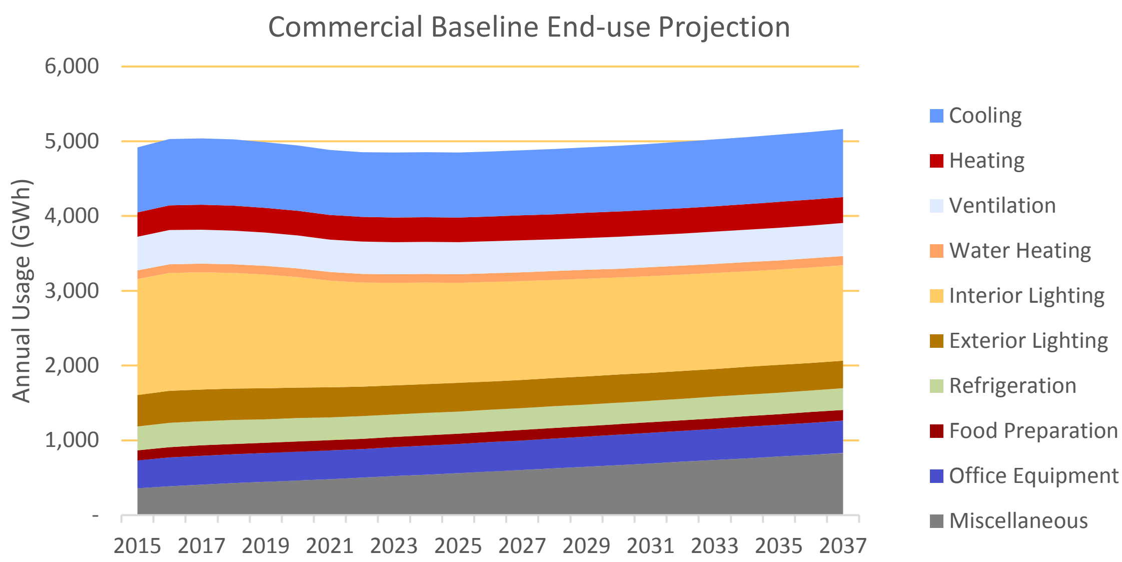


Figure 2-12 Commercial Baseline Projection

Figure 2-13 presents the intensity projection by end use for the Commercial sector. While there is modest growth in the overall baseline projection, the energy intensity decreases from 13.3 kWh/sqft to 12.7 kWh/sqft, a 4.5% reduction.

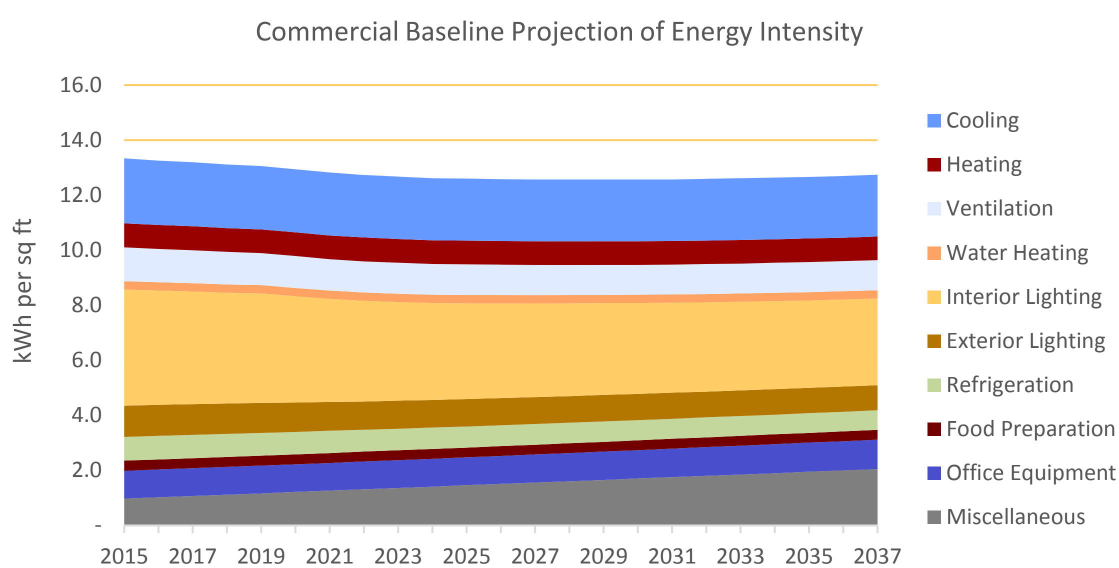


Figure 2-13 Commercial Baseline Projection of Energy Intensity

Industrial Baseline Projection

Annual electricity use in the industrial sector grows during the overall projection horizon, starting at 3,661 GWh in 2015, and increasing to 4,096 in 2037 representing moderate 20-year growth of 11.9%. Figure 2-14 and Table 2-18 present the baseline projection at the end-use level for the industrial sector as a whole.

Table 2-18 Industrial Baseline Projection by End Use (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change (15-37)
Cooling	310	305	304	302	298	299	-3.3%
Heating	137	145	147	148	157	171	24.2%
Ventilation	182	180	179	179	176	177	-2.6%
Interior Lighting	430	440	440	439	447	464	8.0%
Exterior Lighting	61	63	62	62	62	63	3.0%
Motors	1,604	1,647	1,654	1,659	1,702	1,778	10.9%
Process	766	787	790	793	813	850	10.9%
Miscellaneous	171	191	195	200	231	294	71.4%
Total	**3,661**	**3,757**	**3,772**	**3,782**	**3,885**	**4,096**	**11.9%**

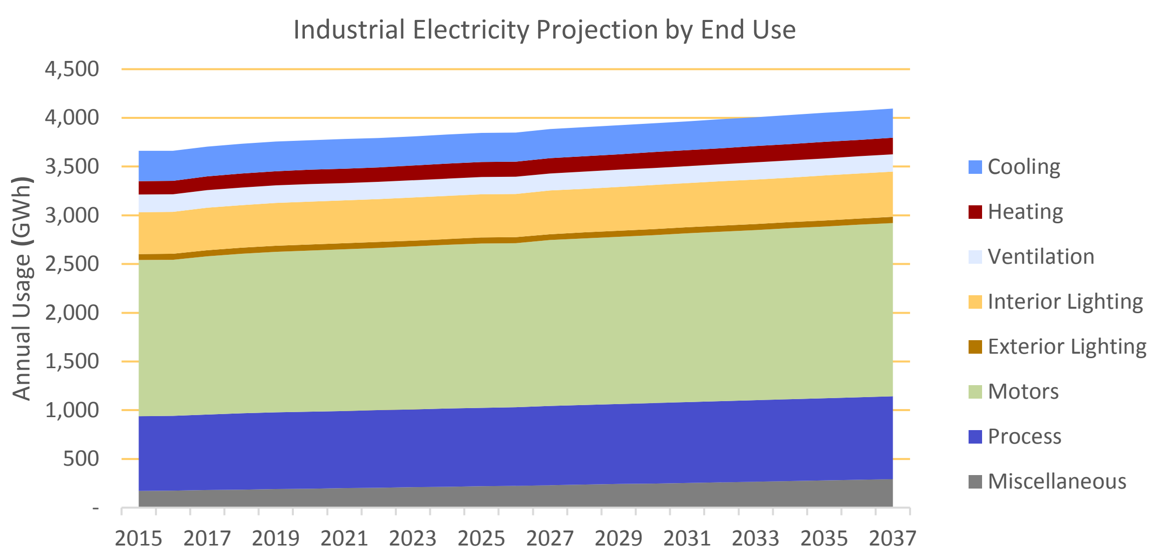


Figure 2-14 Industrial Sector Electricity Projection by End Use (GWh 2015)

Energy Efficiency Potential

Measure-level energy efficiency potential for IPL, presented below, considers the EE measures without program implementation and delivery concerns. The annual energy savings are in GWh and the summer peak demand savings in MW for select years. Year-by-year savings data are available in the LoadMAP model, which was provided to IPL at the conclusion of the study.

A summary of all-sector annual energy and summer peak demand savings is shown first, followed by details for each sector.

Summary of EE Potential Across All-Sectors

Throughout the remainder of this section, annual energy savings are presented first, followed by peak demand for summer and winter.

Summary of Annual Energy Savings

Table 2-19 and Figure 2-15 summarize the EE savings in terms of annual energy use for all measures for the levels of potential relative to the baseline projection. Figure 2-16 displays the EE projections.

- Technical potential reflects the adoption of all EE measures regardless of cost-effectiveness. First-year savings are 433 GWh, or 3.1% of the baseline projection. Cumulative gross savings in 2020 are 1,065 GWh, or 7.7% of the baseline. By 2037 cumulative savings reach 4,344 GWh, or 29% of the baseline.
- Economic potential reflects the savings when the most efficient cost-effective measures are taken by all customers. The first-year savings in 2018 are 310 GWh, or 2.2% of the baseline projection. By 2020, cumulative savings reach 717 GWh, or 5.2% of the baseline. By 2037, cumulative savings reach 2,806 GWh, or 18.7% of the baseline projection.
- Maximum Achievable potential refines the economic potential by taking into the account the maximum expected participation and customer preferences without budget constraints. The first-year savings in 2018 are 159 GWh, or 1.1% of the baseline projection. By 2020, cumulative savings reach 363 GWh, or 2.6% of the baseline. By 2037, cumulative savings reach 1,543 GWh, or 10.3% of the baseline projection.
- Realistic Achievable potential further refines maximum achievable potential by considering budgetary constraints and what could be realistically achievable with participation and awareness. It shows 112 GWh savings in the first year, or 0.8% of the baseline and by 2020 cumulative savings reach 249 GWh, or 1.8% of the baseline projection. By 2037, cumulative savings reach 1,136 GWh, or 7.6% of the baseline projection. This results in average annual savings of 0.8% of the baseline each year.

We also include new incremental savings in this table, accounting for all new installs as well as re-installations that must be deployed to make up for measures that have expired in the prior year. There are numerous ways to represent and format the potential results, so we provide this additional perspective only for the all-sector energy savings results in this section. Again, full detail is available in the LoadMAP model set which has been provided to IPL.

Table 2-19 Summary of All-Sector Cumulative and Incremental EE Potential

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	112	193	249	594	1,136
Maximum Achievable Potential	159	280	363	833	1,543
Economic Potential	310	550	717	1,586	2,806
Technical Potential	433	786	1,065	2,586	4,344
Cumulative as % of Baseline					
Realistic Achievable Potential	0.8%	1.4%	1.8%	4.3%	7.6%
Maximum Achievable Potential	1.1%	2.0%	2.6%	6.0%	10.3%
Economic Potential	2.2%	3.9%	5.2%	11.4%	18.7%
Technical Potential	3.1%	5.6%	7.7%	18.5%	29.0%
Incremental Net Savings (GWh)					
Realistic Achievable Potential	112	109	89	110	159
Maximum Achievable Potential	159	152	120	143	203
Economic Potential	310	295	238	257	342
Technical Potential	433	410	351	373	476
Incremental as % of Baseline					
Realistic Achievable Potential	0.8%	0.8%	0.6%	0.8%	1.1%
Maximum Achievable Potential	1.1%	1.1%	0.9%	1.0%	1.4%
Economic Potential	2.2%	2.1%	1.7%	1.8%	2.3%
Technical Potential	3.1%	2.9%	2.5%	2.7%	3.2%

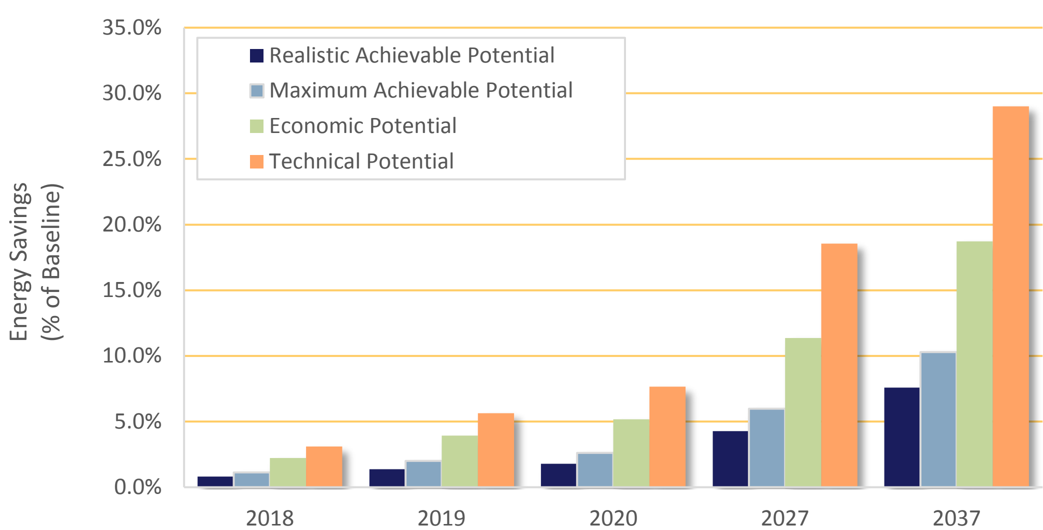


Figure 2-15 Summary of Cumulative EE Potential as % of Baseline Projection

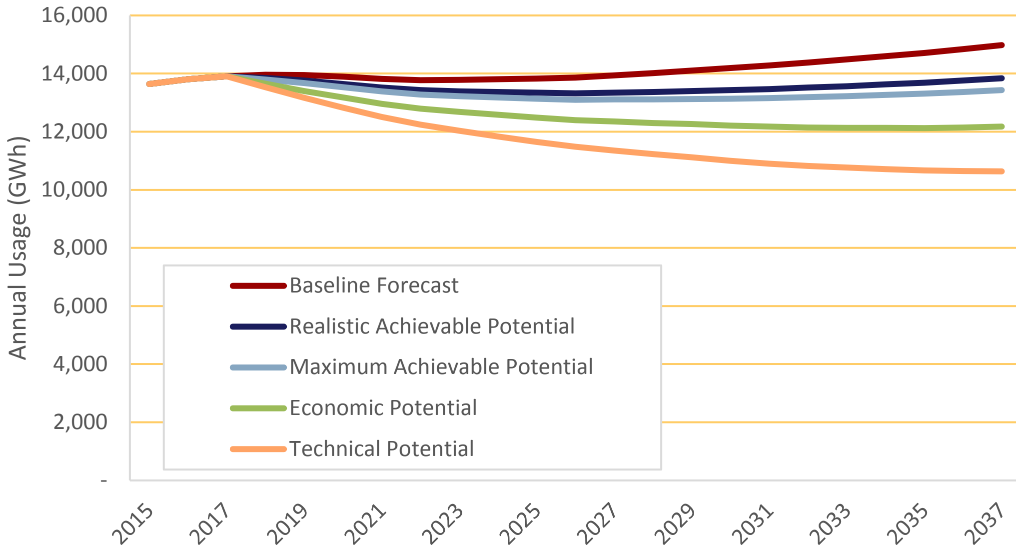


Figure 2-16 All-Sector Baseline Projection and EE Projection Summary (Annual Energy, GWh)

Summary of Annual Peak Demand Savings

Table 2-20 summarizes the summer peak demand savings from all EE measures for three levels of potential relative to the baseline projection[15].

- Technical potential for summer peak demand savings is 179 MW in 2020, or 6.5% of the baseline projection. This increases to 857 MW by 2037, or 28.8% of the summer peak baseline projection.
- Economic potential is estimated to be 117 MW or 4.3% reduction in the 2020 summer peak demand baseline projection. In 2037, savings are 546 MW or 18.3% of the summer peak baseline projection.
- Maximum Achievable Potential is 56 MW by 2020 or 2.1% of the baseline projection. By 2037, cumulative saving reach 293 MW or 9.8% of the baseline projection.
- Realistic Achievable potential is 40 MW by 2020, or 1.5% of the baseline projection. By 2037, cumulative savings reach 221 MW, or 7.4% of the baseline projection.

[15] The savings from Demand Response programs are shown in Chapter 7. The Demand Response potential analysis was done separately from the Energy Efficiency analysis.

Table 2-20 Summary of Cumulative EE Summer Peak Savings Potential

	2018	2019	2020	2027	2037
Baseline Projection (MW)	2,743	2,741	2,735	2,771	2,978
Cumulative Net Savings (MW)					
Realistic Achievable Potential	18	30	40	108	221
Maximum Achievable Potential	25	43	56	148	293
Economic Potential	50	87	117	295	546
Technical Potential	72	129	179	486	857
Cumulative Savings (% of Baseline)					
Realistic Achievable Potential	0.7%	1.1%	1.5%	3.9%	7.4%
Maximum Achievable Potential	0.9%	1.6%	2.1%	5.3%	9.8%
Economic Potential	1.8%	3.2%	4.3%	10.6%	18.3%
Technical Potential	2.6%	4.7%	6.5%	17.5%	28.8%
Incremental Net Savings (MW)					
Realistic Achievable Potential	18	17	14	20	31
Maximum Achievable Potential	25	23	19	25	38
Economic Potential	50	47	39	48	67
Technical Potential	72	67	59	70	94
Incremental Savings (% of Baseline)					
Realistic Achievable Potential	0.7%	0.6%	0.5%	0.7%	1.0%
Maximum Achievable Potential	0.9%	0.8%	0.7%	0.9%	1.3%
Economic Potential	1.8%	1.7%	1.4%	1.7%	2.2%
Technical Potential	2.6%	2.5%	2.2%	2.5%	3.2%

Table 2-21 summarizes the winter peak demand savings from all EE measures for three levels of potential relative to the baseline projection[16].

- Technical potential for winter peak demand savings is 182 MW in 2020, or 7.3% of the baseline projection. This increases to 593 MW by 2036, or 22.5% of the winter peak baseline projection.
- Economic potential is estimated to be 144 MW or 5.7% reduction in the 2020 winter peak demand baseline projection. In 2037, savings are 399 MW or 15.1% of the winter peak baseline projection.
- Maximum Achievable potential is 75 MW by 2020 or 3.0% of the baseline projection. By 2037, potential reaches 229 MW, or 8.7% of the baseline projection.
- Realistic Achievable potential is 51 MW by 2020, or 2.0% of the baseline projection. By 2037, cumulative savings reach 169 MW, or 6.4% of the baseline projection.

[16] The savings from Demand Response programs are shown in Chapter 3. The Demand Response potential analysis was done separately from the Energy Efficiency analysis.

Table 2-21 Summary of Cumulative EE Winter Peak Demand Potential

	2018	2019	2020	2027	2037
Baseline Projection (MW)	2,523	2,523	2,505	2,470	2,637
Cumulative Net Savings (MW)					
Realistic Achievable Potential	24	42	51	98	169
Maximum Achievable Potential	35	61	75	136	229
Economic Potential	66	116	144	244	399
Technical Potential	79	141	182	367	593
Cumulative Savings (% of Baseline)					
Realistic Achievable Potential	1.0%	1.6%	2.0%	4.0%	6.4%
Maximum Achievable Potential	1.4%	2.4%	3.0%	5.5%	8.7%
Economic Potential	2.6%	4.6%	5.7%	9.9%	15.1%
Technical Potential	3.1%	5.6%	7.3%	14.9%	22.5%
Incremental Net Savings (MW)					
Realistic Achievable Potential	24	23	18	18	24
Maximum Achievable Potential	35	33	25	23	30
Economic Potential	66	62	48	39	49
Technical Potential	79	74	60	53	65
Incremental Savings (% of Baseline)					
Realistic Achievable Potential	1.0%	0.9%	0.7%	0.7%	0.9%
Maximum Achievable Potential	1.4%	1.3%	1.0%	0.9%	1.1%
Economic Potential	2.6%	2.5%	1.9%	1.6%	1.8%
Technical Potential	3.1%	2.9%	2.4%	2.1%	2.5%

Summary of EE Potential by Sector

Table 2-22 and Figure 2-17 summarize the range of electric achievable potential by sector. Residential provides the most savings potential early in the forecast horizon, but Commercial surpasses it after 2021, and has nearly double the 20-year potential of Residential. The industrial sector contributes the fewest savings. Since a number of the largest industrial customers have opted out from DSM programs, the savings here come largely from the remaining, somewhat smaller facilities.

Table 2-22 Achievable EE Potential by Sector and Achievable Case (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh) – Realistic Achievable Potential					
Residential	67	105	126	220	375
Commercial	39	77	106	309	624
Industrial	5	11	17	64	137
Total	112	193	249	594	1,136
Cumulative Net Savings (GWh) – Maximum Achievable Potential					
Residential	91	147	176	286	469
Commercial	60	117	161	452	879
Industrial	8	17	26	95	195
Total	159	280	363	833	1,543

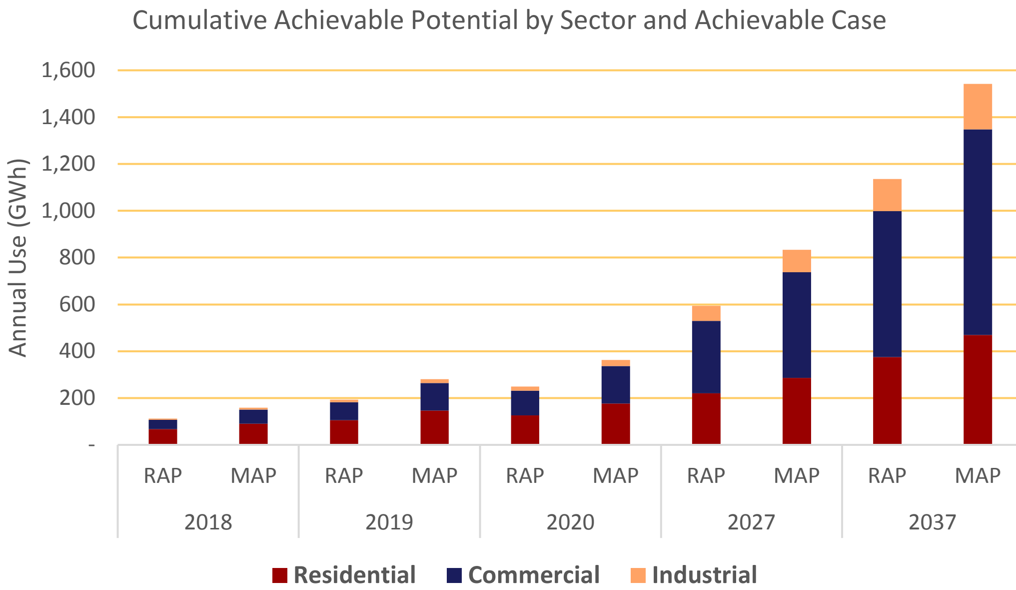


Figure 2-17 Cumulative Achievable EE Potential by Sector (Annual Energy, GWh)

RESIDENTIAL EE POTENTIAL

Table 2-23 and Figure 2-18 present estimates for measure-level EE potential for the residential sector in terms of annual energy savings. Realistic achievable potential in the first year, 2018 is 67 GWh, or 1.3% of the baseline projection. By 2037, cumulative savings are 375 GWh, or 6.6% of the baseline projection. Over the entire study, realistic achievable potential represents roughly 42% of economic potential and maximum achievable represents 60%.

Table 2-23 Residential EE Potential (Annual Energy, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**5,197**	**5,209**	**5,177**	**5,176**	**5,720**
Cumulative Savings (GWh)					
Realistic Achievable Potential	67	105	126	220	375
Maximum Achievable Potential	91	147	176	286	469
Economic Potential	174	283	344	528	847
Technical Potential	221	375	481	984	1,582
Energy Savings (% of Baseline)					
Realistic Achievable Potential	1.3%	2.0%	2.4%	4.3%	6.6%
Maximum Achievable Potential	1.7%	2.8%	3.4%	5.5%	8.2%
Economic Potential	3.3%	5.4%	6.6%	10.2%	14.8%
Technical Potential	4.2%	7.2%	9.3%	19.0%	27.7%

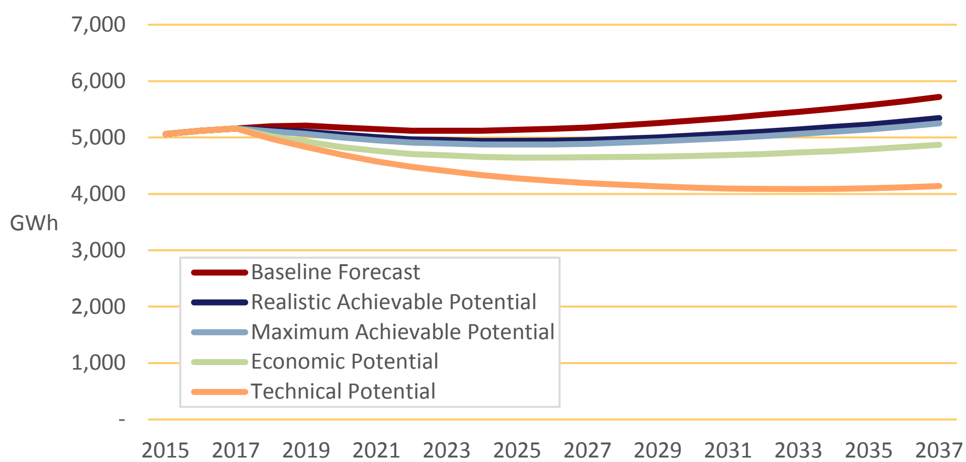


Figure 2-18 Residential Projections (Annual Energy, GWh)

Table 2-24 identifies the top 20 residential measures from the perspective of annual energy savings in 2021. The top measure is interior screw in lighting as a result of purchases of LED lamps, which are cost effective throughout the projection horizon. LED lamps maintained savings throughout the projection due to an anticipated reduction in costs and more efficient options coming online later. AEG modeled emerging LED lamp technology with lower costs and higher efficacies that come on the market later in the projection.

Table 2-24 Residential Top Measures in 2020 (Annual Energy, GWh)

Rank	Measure / Technology	2020 Cumulative	% of Total
1	Interior Lighting - General Service Screw-In LED	43.8	34.8%
2	Behavioral Programs	27.1	21.5%
3	Exterior Lighting - Screw-in LED	16.6	13.2%
4	Interior Lighting - Exempted Screw-In LED	11.6	9.2%
5	HVAC - Air-Source Heat Pump upgrade	4.2	3.3%
6	Thermostat - WIFI	3.7	3.0%
7	Refrigerator - Decommissioning and Recycling	2.6	2.0%
8	Freezer - Decommissioning and Recycling	2.0	1.6%
9	Appliances – Efficient Air Purifier	1.5	1.2%
10	Windows - High Efficiency	1.1	0.9%
11	Windows - Install Reflective Film	1.1	0.9%
12	Appliances - Refrigerator	0.9	0.7%
13	Central Heat Pump - Maintenance	0.8	0.7%
14	Cooling - Central AC upgrade	0.8	0.6%
15	Water Heater - Temperature Setback	0.7	0.6%
16	Insulation – Ceiling	0.7	0.6%
17	Appliances – Efficient Dehumidifier	0.7	0.5%
18	Whole-House Fan - Installation	0.7	0.5%
19	Central AC - Maintenance	0.6	0.5%
20	Room AC - Removal of Second Unit	0.6	0.5%
	Total	121.6	96.7%
	Total RAP savings in 2020	**125.8**	**100%**

Figure 2-19 and Figure 2-20 present projections of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a substantial portion of the savings throughout the projection horizon, but the share declines over time as the market is transformed. The same is true for exterior lighting. Savings from cooling measures and appliances are steadily increasing throughout the projection

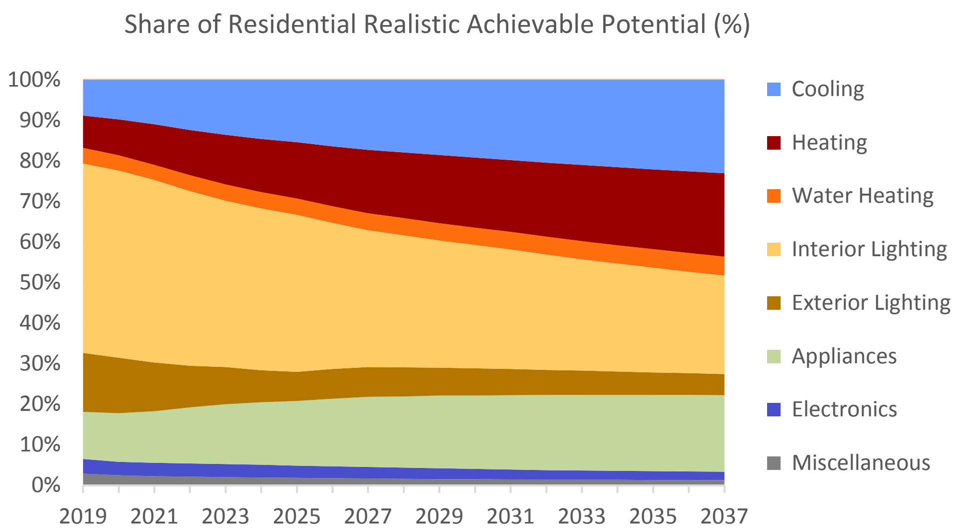


Figure 2-19 Share of Residential Realistic Achievable Potential by End Use (%)

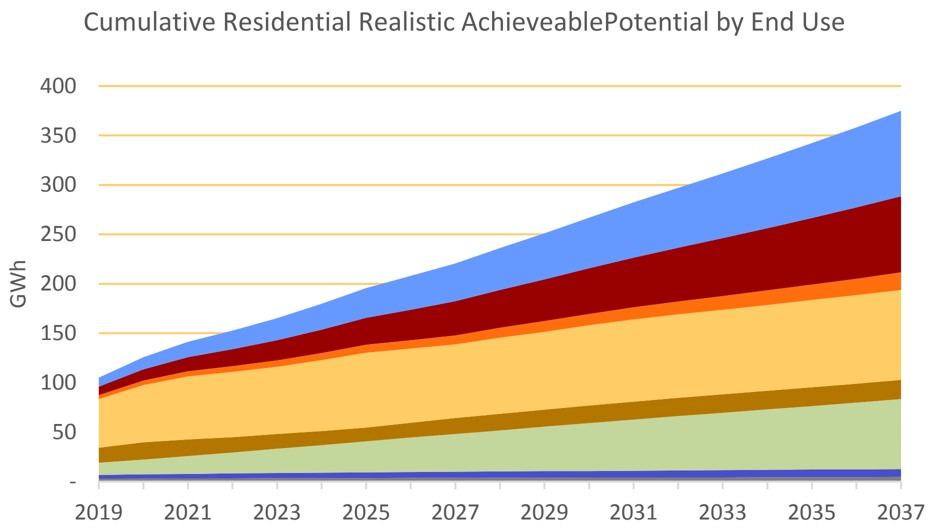


Figure 2-20 Cumulative Residential Realistic Achievable potential by End Use (GWh)

Commercial EE Potential

Table 2-25 and Figure 2-21 present estimates for measure-level EE potential for the commercial sector in terms of annual energy savings. Realistic achievable potential in the first year, 2018 is 39 GWh, or 0.8% of the baseline projection. From 2018 to 2020, Cumulative Net realistic achievable potential energy savings are 106 GWh, or 2.1% of the baseline. By 2037, cumulative savings are 624 GWh, or 12.1% of the baseline projection. Over the entire study, realistic achievable potential represents roughly 44% of economic potential and maximum achievable represents 55%. These numbers include the effect of adjusting participation rates in RAP and MAP, and therefore the resulting potential savings, downward by about 20% to account for large commercial customers who have opted out of programs.

Table 2-25 Commercial DSM Potential (Annual Energy, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	5,025	4,987	4,945	4,879	5,163
Cumulative Savings (GWh)					
Realistic Achievable Potential	39	77	106	309	624
Maximum Achievable Potential	60	117	161	452	879
Economic Potential	114	219	303	809	1,470
Technical Potential	157	301	420	1,103	1,870
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.8%	1.5%	2.1%	6.3%	12.1%
Maximum Achievable Potential	1.2%	2.3%	3.3%	9.3%	17.0%
Economic Potential	2.3%	4.4%	6.1%	16.6%	28.5%
Technical Potential	3.1%	6.0%	8.5%	22.6%	36.2%

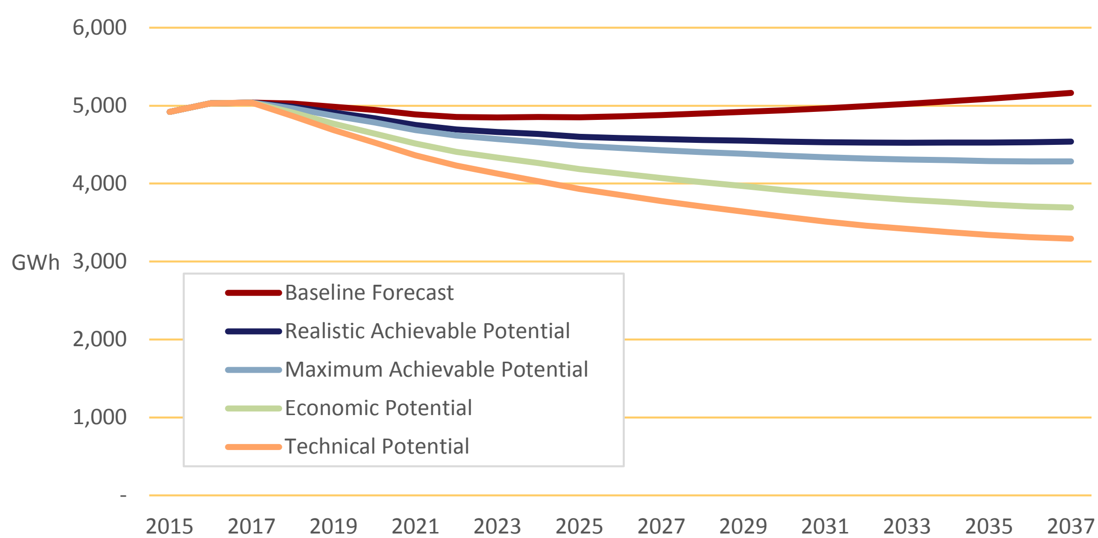


Figure 2-21 Commercial Sector Projections (Annual Energy, GWh)

Table 2-26 identifies the top 20 commercial measures from the perspective of annual energy savings in 2020. The top measures are all manners of lighting upgrades to LED technologies, which are increasingly cost effective as performance and efficacy increases while prices decline throughout the projection. Other non-lighting measures like HVAC and ventilation enhancements make up a large portion of the remaining savings.

Table 2-26 Commercial Top Measures in 2020 (Annual Energy, GWh)

Rank	Measure / Technology	2020 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - Screw-in LED	23.5	22.1%
2	Interior Lighting - Linear Lighting LED	12.8	12.1%
3	Interior Lighting - High-Bay Fixtures LED	9.2	8.7%
4	Exterior Lighting - Area Lighting LED	8.3	7.8%
5	Interior Lighting - Occupancy Sensors	7.8	7.4%
6	Retro-commissioning	4.9	4.7%
7	Office Equipment - Desktop Computer	4.4	4.1%
8	Ventilation – System & Equipment Enhancement	3.2	3.0%
9	Exterior Lighting - Screw-in LED	3.0	2.8%
10	Cooling - Water-Cooled Chiller Upgrade	2.6	2.5%
11	HVAC – Economizer	2.0	1.9%
12	Ventilation - Variable Speed Control	1.8	1.7%
13	Chiller - Chilled Water Reset	1.8	1.7%
14	Cooling - Air-Cooled Chiller Upgrade	1.8	1.7%
15	Grocery - Display Case - LED Lighting	1.3	1.2%
16	Interior Fluorescent - Bi-Level Fixture	1.2	1.2%
17	Office Equipment – Server	1.2	1.1%
18	Water Heating – Heat Pump Water Heater	1.1	1.0%
19	Interior Fluorescent - Delamp and Install Reflectors	1.0	1.0%
20	Ventilation - Demand Controlled	0.9	0.9%
	Total	**93.9**	**88.5%**
	Total RAP savings in 2020	**106.2**	**100.0%**

Figure 2-22 and Figure 2-23 present projections of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a large majority of the savings throughout the projection, but the share slightly declines over time as the market is transformed. Savings from cooling measures and ventilation are steadily increasing throughout the projection.

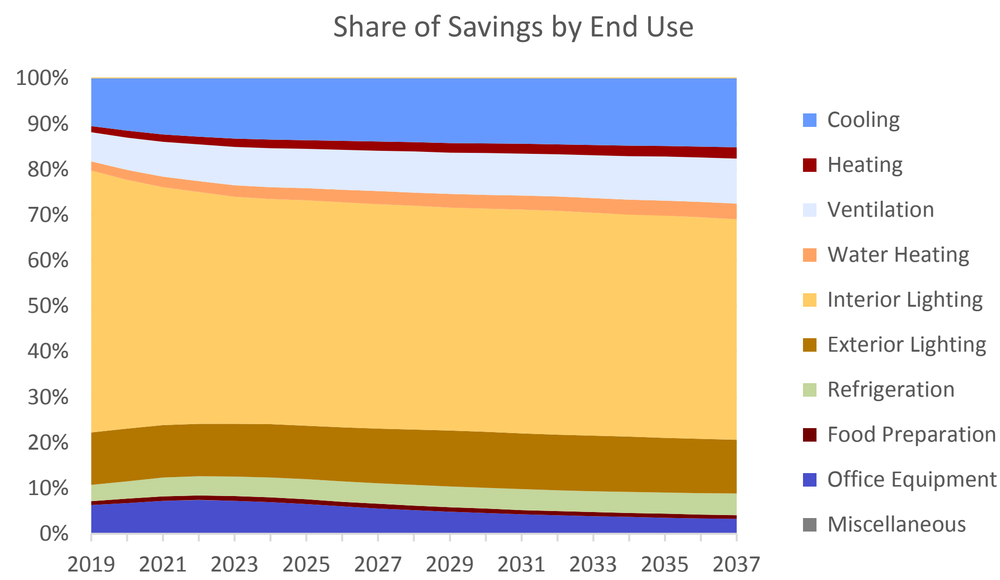


Figure 2-22 Share of Commercial Realistic Achievable Potential by End Use (%)

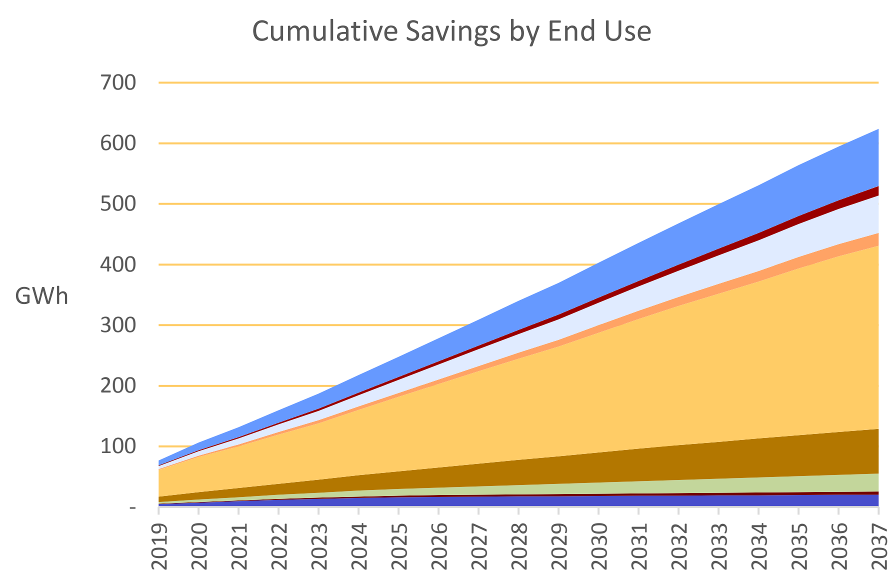


Figure 2-23 Cumulative Commercial Realistic Achievable potential by End Use (GWh)

Industrial EE Potential

Table 2-27 and Figure 2-24 present estimates for measure-level EE potential for the industrial sector in terms of annual energy savings. From 2018 to 2020, cumulative realistic achievable potential energy savings are 17 GWh, or 0.5% of the baseline. In 2037, the cumulative realistic achievable savings reaches 137 GWh, or 3.3% of baseline savings. Over the entire study, realistic achievable potential represents roughly 28% of economic potential and maximum achievable represents 40%. These numbers include the effect of adjusting participation rates in RAP and MAP, and therefore the resulting potential savings, downward by about 50% to account for large industrial customers who have opted out of programs.

Table 2-27 Industrial DSM Potential (Annual Energy, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	**3,736**	**3,757**	**3,772**	**3,885**	**4,096**
Cumulative Savings (GWh)					
Realistic Achievable Potential	5	11	17	64	137
Maximum Achievable Potential	8	17	26	95	195
Economic Potential	23	47	71	248	489
Technical Potential	56	110	164	498	892
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.1%	0.3%	0.5%	1.7%	3.3%
Maximum Achievable Potential	0.2%	0.4%	0.7%	2.5%	4.8%
Economic Potential	0.6%	1.2%	1.9%	6.4%	11.9%
Technical Potential	1.5%	2.9%	4.3%	12.8%	21.8%

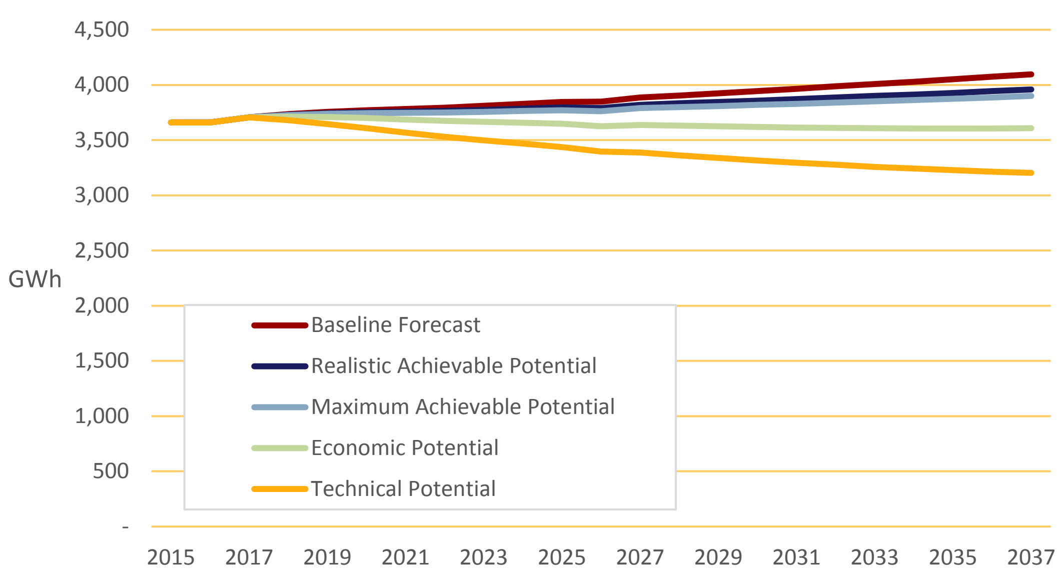


Figure 2-24 Industrial DSM Potential Projections (Annual Energy, GWh)

Table 2-28 identifies the top 20 industrial measures from the perspective of annual energy savings in 2020. The top measure is interior high bay lighting LED replacements as a result of the large number of such fixtures available in industrial facilities. Variable Speed Drives on pumping systems is the number two ranked measure in 2020 comprising 13% of the total potential. Other pumping system, fan system, lighting, and ventilation measures round out the top 20 measures.

Table 2-28 Industrial Top Measures in 2020 (Annual Energy, GWh)

Rank	Measure / Technology	2021 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - High-Bay Fixtures LED	5.1	29.9%
2	Pumping System - Variable Speed Drive	2.2	13.0%
3	HVAC – Economizer	1.6	9.1%
4	Interior Lighting - Screw-in LED	1.4	8.2%
5	Insulation - Wall Cavity	0.9	5.1%
6	Exterior Lighting - Area Lighting LED	0.8	4.8%
7	Pumping System - System Optimization	0.7	4.0%
8	Interior Lighting - Linear Lighting LED	0.6	3.5%
9	Compressed Air - Leak Management Program	0.5	3.1%
10	Ventilation - System & Equipment Enhancement	0.5	3.0%
11	Ventilation - Variable Speed Control	0.5	3.0%
12	Fan System - Flow Optimization	0.4	2.3%
13	Interior Fluorescent - Delamp and Install Reflectors	0.3	1.8%
14	Cooling - Air-Cooled Chiller	0.3	1.8%
15	Cooling - Water-Cooled Chiller	0.3	1.8%
16	Chiller - Chilled Water Reset	0.3	1.6%
17	Thermostat - Programmable	0.2	0.9%
18	RTU - Maintenance	0.1	0.7%
19	Exterior Lighting - Screw-in	0.1	0.6%
20	Exterior Lighting - Linear Lighting	0.1	0.4%
	Total	**17.0**	**98.8%**
	Total RAP savings in 2020	**17.2**	**100%**

Figure 2-25 and Figure 2-26 present projections of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting, Motor-related, and HVAC-related measures account for most of the savings throughout the projection.

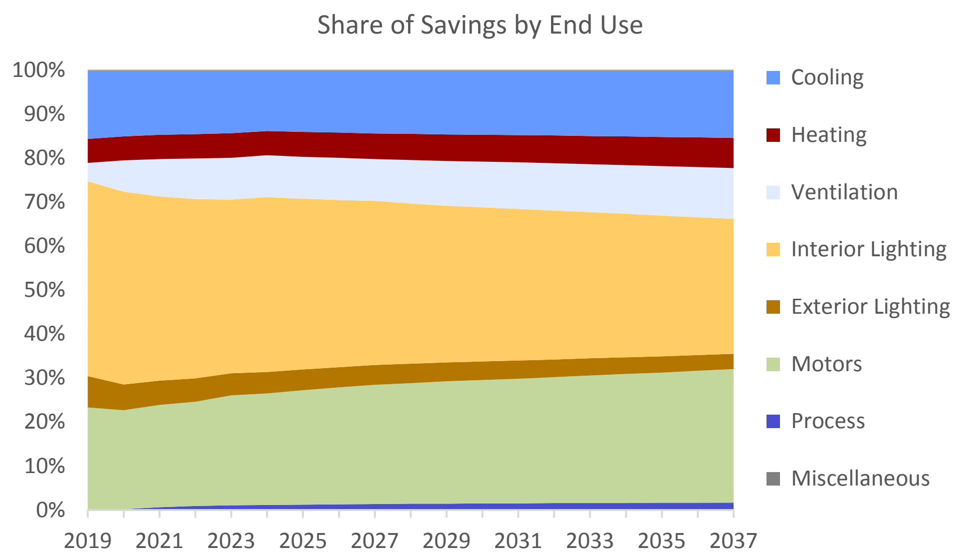


Figure 2-25 Share of Industrial Realistic Achievable Potential by End Use (%)

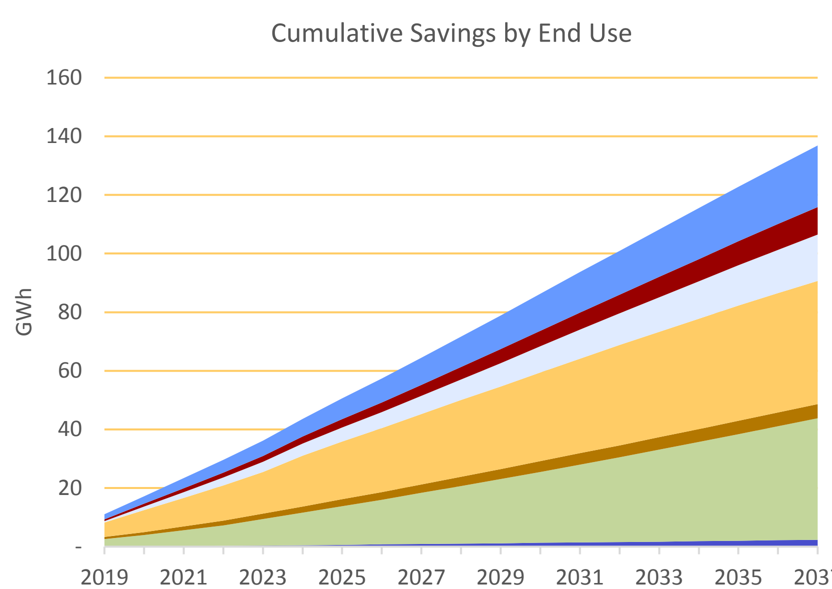


Figure 2-26 Cumulative Industrial Realistic Achievable potential by End Use (GWh)

Opt-Out Customer Sensitivity Analysis

As mentioned above, Indiana regulations allow large C&I customers that meet size and eligibility requirements to opt out of energy efficiency programs. For purposes of this study, we maintain all customers in the baseline control totals, market characterization, technical, and economic potential cases; but identify the portion of opt-out load – based on opt-out forms received as of January 1, 2016 – which allows us to remove them from program participation as appropriate in the maximum and realistic achievable potential cases.

The reference case presented above follows all these assumptions. At present, we provide a sensitivity analysis that shows the effect on the savings potential if these customers had not chosen to opt-out and were still eligible for EE program participation.

Table 2-29 and Figure 2-27 present estimates for measure-level EE potential by sector in terms of cumulative annual energy savings. "Re-enrollment of Opt-out customers" in this sensitivity case raises Commercial realistic and maximum achievable potential by about 20% and Industrial potential by about 50%. This results in an increase of the entire portfolio in year 3 savings (2020) of about 12%, from 249 GWh to 280 GWh.

Table 2-29 Realistic Achievable EE Potential by Sector and Opt Out Status (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh) – Reference Case: Opt-out customers Excluded					
Residential	67	105	126	220	375
Commercial	39	77	106	309	624
Industrial	5	11	17	64	137
Total	112	193	249	594	1,136
Cumulative Net Savings (GWh) – Sensitivity Case: If Opt-out customers Participating					
Residential	67	105	126	220	375
Commercial	48	93	128	374	754
Industrial	8	17	26	97	207
Total	123	215	280	691	1,335
RAP Savings (% of Baseline)					
Reference Case: Opt-out Excluded	0.8%	1.4%	1.8%	4.3%	7.6%
Sensitivity Case: Opt-out Included	0.9%	1.5%	2.0%	5.0%	8.9%

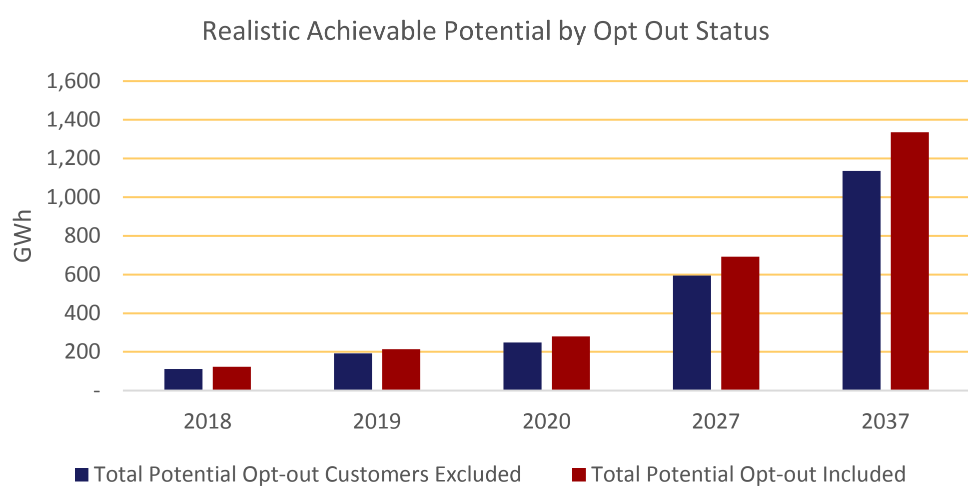


Figure 2-27 Cumulative Realistic Achievable EE Potential by Opt Out Status (Annual Energy, GWh)

The same trends are visible in MAP that appear in RAP. Table 2-30 and Figure 2-28 show that adding opt-out customers back to programs results in an increase of the entire portfolio in year 3 savings (2020) of about 13%, from 363 GWh to 410 GWh.

Table 2-30 Maximum Achievable EE Potential by Sector and Opt Out Status (Annual Use, GWh)

	2018	2019	2020	2027	2037
Baseline Projection (GWh)	13,958	13,953	13,893	13,940	14,979
Cumulative Net Savings (GWh) – Reference Case: Opt-out customers Excluded					
Residential	91	147	176	286	469
Commercial	60	117	161	452	879
Industrial	8	17	26	95	195
Total	159	280	363	833	1,543
Cumulative Net Savings (GWh) – Sensitivity Case: If Opt-out customers Participating					
Residential	91	147	176	286	469
Commercial	73	141	194	546	1,062
Industrial	12	25	39	144	295
Total	175	313	410	976	1,825
MAP Savings (% of Baseline)					
Reference Case: Opt-out Excluded	1.1%	2.0%	2.6%	6.0%	10.3%
Sensitivity Case: Opt-out Included	1.3%	2.2%	2.9%	7.0%	12.2%

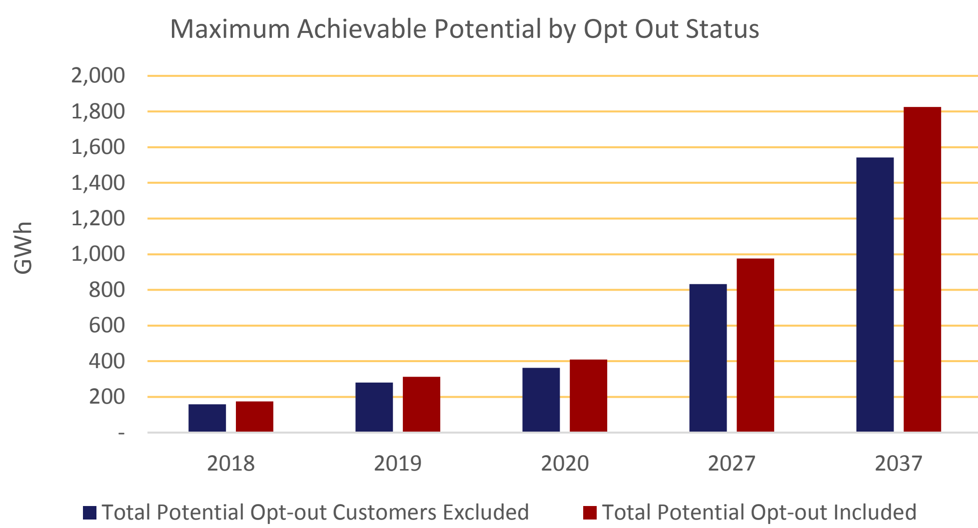


Figure 2-28 Cumulative Maximum Achievable EE Potential by Opt Out Status (Annual Energy, GWh)

3

Demand Response Potential

As a part of this DSM Market Potential Study, AEG conducted IPL's first formal demand response (DR) potential analysis to understand the peak demand savings that could be achieved from peak-focused demand response resources. Similar to the EE modeling described above, AEG developed inputs to represent DR as a Resource in the IPL Integrated Resource Planning (IRP) process. This chapter will present the analysis process, key modeling assumptions, and potential results.

DR Analysis Approach

The structure and process for the demand response potential assessment is similar to the energy efficiency potential analysis. They key difference is that demand response requires a program to induce savings (i.e., there is no naturally occurring DR). The major steps are listed below and described in detail in this chapter.

- Define the relevant DR resource options
- Characterize the market and develop baseline projection
- Develop DR program assumptions
- Estimate DR potential

Identify Demand Response Options

This study considers a comprehensive list of DR programs available in the DSM marketplace today and projected into the 20-year study time horizon. We briefly describe each of those options in Table 3-1.

Table 3-1 List of Demand Response Program Options

Program Option	Eligible Customer Segments	Description / Mechanism
DLC Central AC DLC Room AC DLC Water Heating DLC Space Heating	Residential, Small C&I	Direct load control switch installed on customer's equipment and operated remotely, typically by radio frequency (RF) signal, to reduce specific end-use loads.
DLC Smart Appliances	Residential, Small C&I	Internet-enabled control of operational cycles of white goods appliances.
DLC Smart Thermostats	Residential, Small C&I	Internet-enabled control of thermostat set points.
Curtailment Agreements	Large C&I	Customers enact their customized, mandatory curtailment plan. May use stand-by generation. Penalties apply for non-performance. Various contractual payment and penalty structures used, can result in the resource being "firm" or "non-firm."
Ice Energy Storage	Small C&I	Peak shifting of space cooling loads using stored ice.
Battery Energy Storage	All	Peak shifting of loads using batteries on the customer side of the meter (stored electrochemical energy).
Electric Vehicle DLC Smart Chargers	Residential	Smart, connected EV chargers that would automate vehicle charging such that it occurred preferentially during overnight, off-peak hours.

PROGRAM PARTICIPATION HIERARCHY

To avoid double counting of load reduction impacts, program-eligibility criteria were defined to ensure that customers do not participate in mutually exclusive programs at the same time. For example, small C&I customers cannot participate in the DLC Central AC program and the Ice Energy Storage program since both of them would target the same load from the same end use for curtailment on the same days. Table 3-2 shows the participation hierarchy by customer sector for applicable DR options.

With the hierarchy activated, each successive resource has a newly updated pool of eligible participants where customers enrolled in previously-stacked, competing resource options have been removed. The resources' participation rates are then applied to that pool, rather than the whole pool.

Table 3-2 Participation Hierarchy in DR options by Customer Sector

	Customer Sector	Residential	Small C&I	Large C&I
Loaded First	DLC Central AC	x	x	
	DLC Space Heating	x	x	
	DLC Water Heating	x	x	
	DLC Smart Thermostats	x		
	DLC Smart Appliances	x		
	DLC Room AC	x		
	Ice Energy Storage		x	
	Curtail Agreements			x
	DLC Elec Vehicle Charging	x		
Loaded Last	Battery Energy Storage	x	x	x

MARKET CHARACTERIZATION

The analysis begins with segmentation of the IPL customer base and a description of how customers use energy in the peak hour.

Segmentation of Customers for DR Analysis

The market segmentation scheme for the DR analysis is fairly simple. The first dimension of customer segmentation is by sector and the second dimension is by customer size. The residential sector is considered a single group – designated by the customer population used for the EE portion of the IPL analysis. The C&I sectors are segmented into Small C&I and Large C&I, with a breakpoint of 200 kW per customer that separates the smaller customers that are amenable to direct load control type program from larger customers that exceed the minimum recruitment threshold to make them attractive and economical for Curtailment/Aggregation DR programs.

Unlike the EE portion of the analysis, opt-out customers are included throughout the DR potential analysis, as the relevant legislation for opt-out eligibility only applies to energy efficiency programs.

BASELINE CUSTOMER AND COINCIDENT PEAK PROJECTION

The next step was to define the baseline projection for the number of customers and peak demand for each customer segment. Consistent with the EE potential analysis, the base year is 2015 and is characterized by using IPL's 2015 billing data. The baseline projection incorporates IPL's forecasts of summer peak demand and customer counts from 2015 through 2037. IPL's total customer count projections were allocated to correspond to the segmentation scheme defined above. IPL also provided their summer and winter peak demand projections with impacts of future DSM programs removed (same method as EE analysis above). The total system peak demand was allocated to the segments in a similar manner as the customer counts above.[17] Table 3-3 presents baseline projections for customers, summer peak and winter peak.

Table 3-3 Baseline Projections by Segment for DR Analysis

	2015	2018	2019	2020	2027	2037
Number of Customers						
Residential	429,245	442,283	445,545	448,755	471,784	507,251
Small C&I	51,920	52,224	52,283	52,339	52,824	53,541
Large C&I	4,784	4,914	4,935	4,951	5,100	5,329
Total	485,950	499,420	502,762	506,044	529,708	566,121
Coincident Summer Peak Projection by Segment (MW @ Meter)						
Residential	1,141	1,170	1,171	1,176	1,223	1,288
Small C&I	332	340	341	342	356	375
Large C&I	1,217	1,248	1,249	1,255	1,305	1,374
Total	2,690	2,758	2,761	2,773	2,884	3,037
Coincident Winter Peak Projection by Segment (MW @ Meter)						
Residential	1,170	1,196	1,195	1,192	1,218	1,251
Small C&I	277	283	283	282	288	296
Large C&I	1,015	1,037	1,036	1,034	1,056	1,085
Total	2,462	2,516	2,513	2,509	2,562	2,633

DR Program Key Assumptions

The next step is to develop the key data elements for the potential calculations: per-customer load reduction, customer participation levels, and program costs.

Peak Demand Reduction Impacts

The per-customer load reduction at system peak, multiplied by the total number of participating customers, provides the potential demand savings estimate. DLC Central AC impacts are sourced from IPL's latest Air Conditioning Load Management evaluation reports and represent a weighted average of single family and multi-family household impacts. The remaining program impacts were developed through secondary research. Impacts per customer are assumed to be equivalent for the realistic and maximum achievable potential cases. The assumptions used in the model for per-customer summer and winter peak savings are shown in Table 3-4 below.

[17] Because of differing methodologies, models and segmentation, the system peak demand projections used in the DR analysis is slightly different than that used in the EE analysis. This small difference does not, materially affect the outcome of the study.

Table 3-4 Per-Customer Load Reduction by Option

Customer Sector	Option	Unit	Summer Peak Reduction	Winter Peak Reduction
Residential	DLC Central AC	kW @meter	0.70	n/a
Residential	DLC Space Heating	kW @meter	n/a	1.55
Residential	DLC Water Heating	kW @meter	0.58	0.58
Residential	DLC Smart Thermostats	kW @meter	0.35	0.30
Residential	DLC Smart Appliances	kW @meter	0.17	0.17
Residential	DLC Room AC	kW @meter	0.35	-
Residential	DLC Elec Vehicle Charging	kW @meter	0.92	0.92
Residential	Battery Energy Storage	kW @meter	2.00	2.00
Small C&I	DLC Central AC	kW @meter	1.20	n/a
Small C&I	DLC Space Heating	kW @meter	n/a	2.66
Small C&I	DLC Water Heating	kW @meter	0.99	0.99
Small C&I	Ice Energy Storage	kW @meter	5.00	-
Small C&I	Battery Energy Storage	kW @meter	2.00	2.00
Large C&I	Curtail Agreements	*% of Peak*	*21%*	-
Large C&I	Battery Energy Storage	kW @meter	15.00	15.00

Program Participation Rates

The participation rates estimate the percent of eligible customers who take part in a given program in a given year. Note that a customer is not considered eligible if they don't have the relevant equipment or are already participating in a mutually exclusive program. The DLC Central AC participation was scaled to current IPL (ACLM) program achievements and planned targets. The remaining programs were developed by researching DR programs at utilities similar to IPL in size and region.

New DR programs need time to ramp up and reach a steady state. During ramp up, customer education, marketing and recruitment take place, as well as the physical implementation and installation of any hardware, software, telemetry, or other equipment required. For IPL, it is assumed that programs ramp up to steady state over five years, typical of industry experience.

Table 3-5 shows the assumed participation in DR options for two scenarios (realistic and maximum achievable potential, or RAP and MAP) by customer sector. All programs, except IPL's existing DLC Central AC and soon-to-be piloted DLC Smart Thermostat programs are set to begin ramping up in year 2 of the study (2019) to allow sufficient time for planning, procurement, and contracting.

Table 3-5 DR Participation Rates by Option and Customer Sector (percent of eligible customers)

Customer Sector	Program	Steady State Participation Rate	
		RAP	MAP
Residential	DLC Central AC	13%	15%
Residential	DLC Space Heating	15%	20%
Residential	DLC Water Heating	15%	20%
Residential	DLC Smart Thermostats	5%	10%
Residential	DLC Smart Appliances	5%	6%
Residential	DLC Room AC	13%	15%
Residential	DLC Elec Vehicle Charging	15%	20%
Residential	Battery Energy Storage	1%	3%
Small C&I	DLC Central AC	6%	8%
Small C&I	DLC Space Heating	3%	4%
Small C&I	DLC Water Heating	3%	4%
Small C&I	Ice Energy Storage	3%	4%
Large C&I	Curtail Agreements	15%	20%
Large C&I	Battery Energy Storage	1%	3%

Program Costs

Program costs include fixed and variable cost elements for numerous aspects of program delivery: program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives. These assumptions are based on actual program costs from existing or past IPL programs and, for new programs, based on actual AEG program implementation experience, experience in developing program costs for other similar studies, and secondary research. The assumptions are detailed in AEG's DR Modeling Tool provided to IPL at the conclusion of the study.

Estimating DR Potential

As with the EE analysis, we estimated several levels of potential as defined below:

- **Standalone DR potential**. In this case, each DR option is assessed independently, without regard for the participation hierarchy, and assuming maximum expected participation (equivalent to the MAP case for EE). This gives the maximum savings that could be attained for each option. It also allows us to consider a first-level estimate of cost-effectiveness. Programs that have a benefit-cost ratio of 1.0 or greater pass into the estimation of achievable potential.[18]
- **Maximum achievable DR potential.** The case is analogous to the MAP in the EE analysis. It considers only those programs that pass the first-level cost-effectiveness screen and assumes the highest level of customer participation. For both achievable potential cases, we apply the participation hierarchy to restrict customer participation to only one DR option. Cost-effectiveness is tested once again and the savings from cost-effective programs is included.

[18] Technical and Economic Potential are not useful theoretical concepts for Demand Response analyses because these resources are inherently based on customer behaviors and program activity. Therefore, it is necessary to include an assumption about levels of customer adoption and participation, which does not appear in the definition of technical or economic potential.

- **Realistic achievable DR potential**. This case is the same as maximum achievable DR potential except that more realistic customer participation rates are assumed. Again, only those options that are cost-effective are included in the savings estimates.

Cost-effectiveness Screening

For each case, the DR options are assessed for cost-effectiveness using the TRC test, which uses avoided costs, discount rate, and line losses provided by IPL. As mentioned above, the costs are made up of program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives.

The cost-effectiveness of individual DR options are assessed with different program-start years until the first cost-effective year is identified. Demand savings are realized only in years the option is cost-effective. Once an option is deployed, benefit-to-cost ratios are estimated for each contiguous program cycle independently throughout the study time period.

Program Lifetime

Calculation of cost effectiveness requires an assumption about DR program lifetimes. Table 3-6 presents lifetime assumptions by DR option. The Curtailment Agreement lifetime is based on the typical contract term used by third-party DR aggregator firms, which is three to five years.

Table 3-6 DR Program Life Assumptions

DR Option	Lifetime (Years)
Direct Load Control	10
Ice Energy Storage	20
Battery Energy Storage	12
Curtailment Agreement	3

Demand Response Potential Estimates

In the remainder of this section, we present estimates for the three cases described above. It is important to note that potential in 2018 is essentially comprised of savings from existing IPL programs, which means the incremental new potential occurs in 2019 and beyond. , and is smaller than the cumulative total by the amount of savings that IPL is already implementing. All impacts are presented at the customer meter.

Standalone DR Potential

Savings estimates and cost-effectiveness results for the standalone case for summer and winter are presented in Table 3-7 below. Figure 3-1 shows cumulative summer-peak savings. The programs with solid-color bars are cost-effective, while those with a pattern are not cost-effective. Table 3-8 presents program costs for each option.

In summer, the programs with the largest potential are DLC Central AC, DLC Water Heating, and Large C&I Curtailment Agreements, each of which is cost effective. Recall that about 35 MW of DLC Central AC in 2019 comes from IPL's existing programs.[19] In winter, the only cost-effective, applicable program is DLC water heating.

Based on these results, three program options move forward into the calculation of achievable potential in the following section:

- DLC Central AC
- DLC Water heating
- Curtailment agreements

[19] Note that the DLC CAC savings from existing program participants are treated in the IRP analysis separately from new participants, and the existing level of savings is pre-determined to be included throughout the 20 years. Existing DLC resources are highly cost-effective since only operation and maintenance costs are required to keep the programs running.

Table 3-7 Standalone DR Program Potential (Peak MW)

Sector	DR Option	Season	2018	2019	2020	2027	2037	20 Yr TRC
Residential	DLC Central AC	S	39.8	41.7	39.6	43.7	50.5	**2.00**
	DLC Space Heating	W	-	5.7	17.5	64.0	73.7	**0.08**
	DLC Water Heating	S&W	-	2.5	7.6	27.5	30.9	**1.83**
	DLC Smart Thermostats	S	1.1	3.4	7.8	11.4	12.9	**0.72**
	DLC Smart Thermostats	W	1.0	2.9	6.8	9.8	11.1	**0.72**
	DLC Smart Appliances	S&W	-	0.5	1.4	4.8	5.2	**0.99**
	DLC Room AC	S	-	0.5	1.6	5.4	5.5	**0.86**
	DLC Elec Vehicle Charging	S&W	-	0.0	0.0	0.2	0.4	**0.35**
	Battery Energy Storage	S&W	-	2.6	8.0	28.0	30.1	**0.59**
Small C&I	DLC Central AC	S	1.8	2.0	2.0	2.0	2.1	**1.37**
	DLC Space Heating	W	-	0.2	0.5	1.8	1.9	**0.08**
	DLC Water Heating	S&W	-	0.0	0.1	0.2	0.2	**1.11**
	Ice Energy Storage	S	-	0.4	1.2	4.0	4.1	**0.78**
	Battery Energy Storage	S	-	0.3	0.9	3.1	3.2	**0.45**
Large C&I	Curtailment Agreements	S	-	26.0	41.7	54.3	57.1	**1.62**
	Battery Energy Storage	W	-	0.2	0.7	2.3	2.4	**0.67**

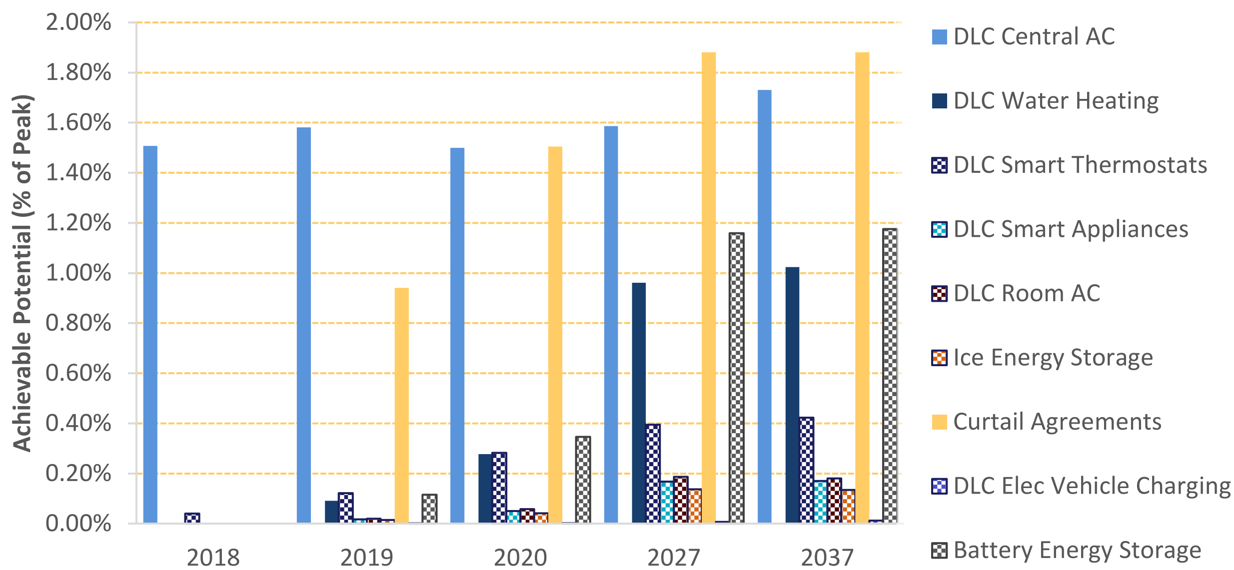


Figure 3-1 Standalone DR Program Potential -- Summer Peak Savings

Table 3-8 Program Costs for Standalone DR Program Potential

Option	Summer MW Potential in Year 20	System Wtd Avg Levelized $/kW (2018-2037)	2018 – 2037 Average Spend per Year (Million $)	20 Year TRC
Residential DLC Central AC	50.5	$59.71	$2.64	2.00
Residential DLC Space Heating	*73.7**	*$34.67**	*$1.81**	0.08
Residential DLC Water Heating	30.9	$71.04	$1.55	1.83
Residential DLC Smart Thermostats	12.9	$178.81	$1.71	0.72
Residential DLC Smart Appliances	5.2	$182.04	$0.59	0.99
Residential DLC Room AC	5.5	$148.25	$0.63	0.86
Residential DLC Elec Vehicle Charging	0.4	$524.84	$0.10	0.35
Residential Battery Energy Storage	30.1	$213.19	$3.96	0.59
C&I DLC Central AC	2.1	$86.70	$0.17	1.37
C&I DLC Space Heating	*1.9**	*$33.18**	*$0.05**	0.08
C&I DLC Water Heating	0.2	$117.55	$0.02	1.11
C&I Curtail Agreements	57.1	$77.70	$3.88	1.62
C&I Ice Energy Storage	4.1	$160.68	$0.41	0.78
C&I Battery Energy Storage	5.6	$238.96	$1.12	0.52

**DLC Space Heating impacts and costs provided for winter instead of summer as other options in table*

Achievable DR Potential

In this section, the potential savings are presented for programs in a real-life, integrated basis with the participation hierarchy in effect to prevent double-counting of customer impacts in overlapping programs. Table 3-9 presents the aggregate demand response potential from DR options for the RAP and MAP in the summer season. Peak demand savings potential starts around 35 MW at the beginning of the study and rises to 114.8 MW in 2037 for the RAP case and 138.5 MW for the MAP case. This corresponds to a reduction of 3.8% and 4.6% respectively from IPL's projected 2037 summer system peak.

Table 3-9 Summary of Summer Demand Response Savings

	2018	2019	2020	2027	2037
Baseline Projection (Summer MW)	2,758	2,761	2,773	2,884	3,037
Potential Savings (MW)					
Realistic Achievable Potential	35.9	59.1	75.3	103.6	114.8
Maximum Achievable Potential	39.8	70.1	89.0	125.5	138.5
Potential Savings (% of baseline)					
Realistic Achievable Potential	1.3%	2.1%	2.7%	3.6%	3.8%
Maximum Achievable Potential	1.4%	2.5%	3.2%	4.4%	4.6%

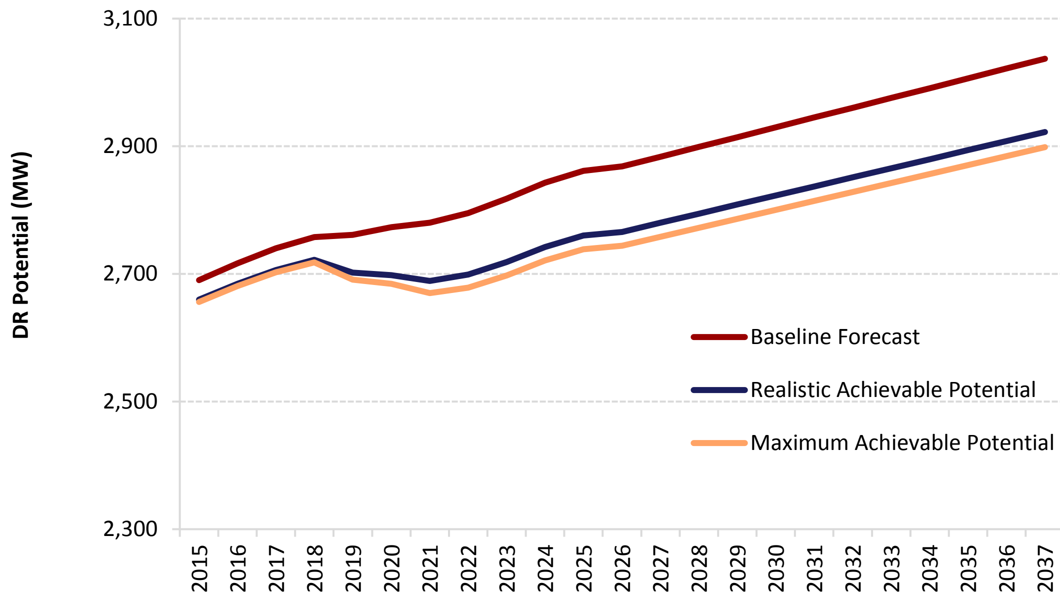


Figure 3-2 Baseline and Achievable DR Potential Forecasts

Table 3-10 presents summer peak savings by sector and DR option for realistic achievable potential and maximum achievable potential respectively. As in the standalone case, all three programs are cost-effective.

In the early years of the forecast, DLC Central AC provides the highest savings because this program is already in place and additional savings are relatively small. Over the forecast horizon, DLC Water Heating and Curtailment Agreements ramp up to full-scale programs that rival the cooling program for savings. Figure 3-4 illustrates the results for realistic achievable potential.

For the winter peak, only DLC Water Heating provides savings and they are at the same level as for the summer peak.

Table 3-10 Summer Peak Achievable Potential by Sector and DR Option

		2018	2019	2020	2027	2037
Baseline Projection (Summer MW)		**2,758**	**2,761**	**2,773**	**2,884**	**3,037**
Realistic Achievable Potential (MW)		**35.9**	**59.1**	**75.3**	**103.6**	**114.8**
Residential	DLC Central AC	35.9	37.8	38.3	42.3	48.8
	DLC Water Heating	-	1.9	5.7	20.7	23.2
Large C&I	Curtail Agreements	-	19.5	31.3	40.7	42.9
Maximum Achievable Potential (MW)		**39.8**	**70.1**	**89.0**	**125.5**	**138.5**
Residential	DLC Central AC	39.8	41.7	39.6	43.7	50.5
	DLC Water Heating	-	2.5	7.6	27.5	30.9
Large C&I	Curtail Agreements	-	26.0	41.7	54.3	57.1

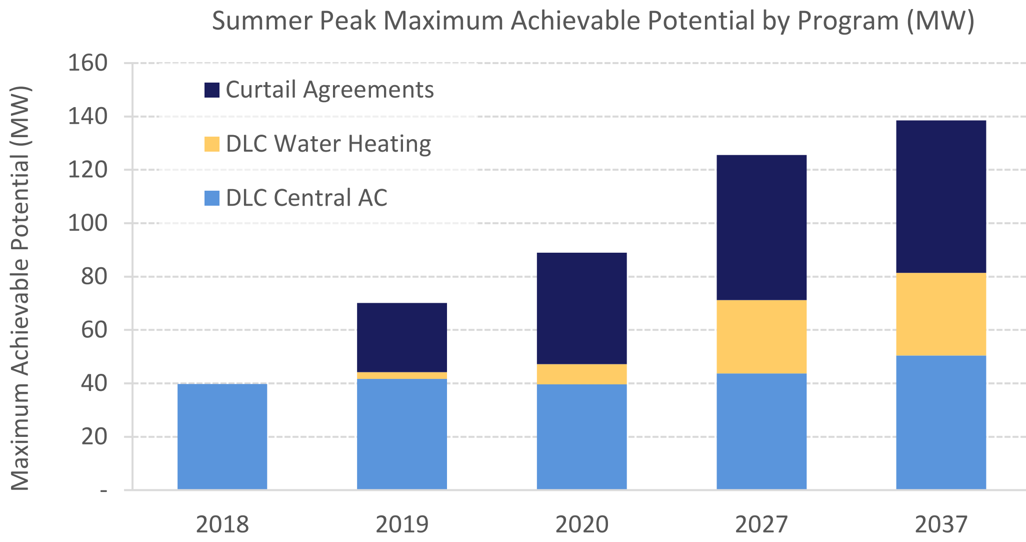


Figure 3-3 Maximum Achievable Potential by DR Option

Program Costs for Achievable Potential

Table 3-11 presents cost estimates for the achievable potential cases in terms of levelized cost per kW and of average annual program budget. Savings in 2037 are provided for reference.

- Cumulative program costs for the realistic achievable portfolio of DR options is approximately $135.14 million over 2018-2037, delivering 115 MW savings in 2037. Average program costs for 2018-2037 for IPL to achieve this level of savings are estimated to be $6.6 million per year. Levelized costs over the study timeframe for the integrated, cost-effective portfolios are estimated to range from $60/kW-year to $78/kW-year.
- For the maximum achievable portfolio cumulative program costs for the realistic achievable portfolio of DR options is approximately $164.01million over 2018-2037, delivering 139 MW savings in 2037. Average program costs for 2018-2037 for IPL to achieve this level of savings are estimated to be $8 million per year. Levelized costs over the study timeframe for the integrated, cost-effective portfolios are estimated to range from $59/kW-year to $77/kW-year.

Table 3-11 Achievable Potential Program Costs

Option	Summer MW Potential in Year 20	System Wtd Avg Levelized $/kW (2018-2037)	Total Cost 2018 – 2037 (Million $)	2018 – 2037 Average Spend per Year (Million $)
Realistic Achievable Potential				
Res DLC Central AC	48.8	$60.11	$53.33	$2.55
Res DLC Water Heating	23.2	$71.41	$23.40	$1.17
C&I Curtail Agreements	42.9	$77.93	$58.41	$2.92
Total	**114.8**		**$135.14**	**$6.64**
Maximum Achievable Potential				
Res DLC Central AC	50.5	$59.71	$55.33	$2.64
Res DLC Water Heating	30.9	$71.04	$31.03	$1.55
C&I Curtail Agreements	57.1	$77.70	$77.65	$3.88
Total	**138.5**		**$164.01**	**$8.07**

Table 3-12 shows annual program costs by DR option for the achievable potential cases. The high costs in the beginning of the projection are due to the start-up costs of launching the programs such as deploying infrastructure, installing equipment, recruiting participants, and marketing/education efforts. These eventually level out as the programs reach a steady-state, at which time the costs transition to maintenance costs and the payment of customer incentives. These will rise slightly over time as participation grows more slowly.

Table 3-12 Achievable Potential Incremental Program Costs

	2018	2019	2020	2027	2037
Realistic Achievable Potential					
Total Incremental Spend (Million $)	**$2.53**	**$4.89**	**$6.29**	**$6.62**	**$7.27**
DLC Central AC	$2.53	$2.60	$2.26	$2.49	$2.85
DLC Water Heating	-	$0.75	$1.59	$0.96	$1.08
Curtail Agreements	-	$1.54	$2.45	$3.17	$3.34
Maximum Achievable Potential					
Total Incremental Spend (Million $)	**$2.75**	**$5.85**	**$7.53**	**$8.06**	**$8.81**
DLC Central AC	$2.75	$2.82	$2.18	$2.57	$2.95
DLC Water Heating	-	$1.00	$2.11	$1.28	$1.43
Curtail Agreements	-	$2.04	$3.25	$4.21	$4.44

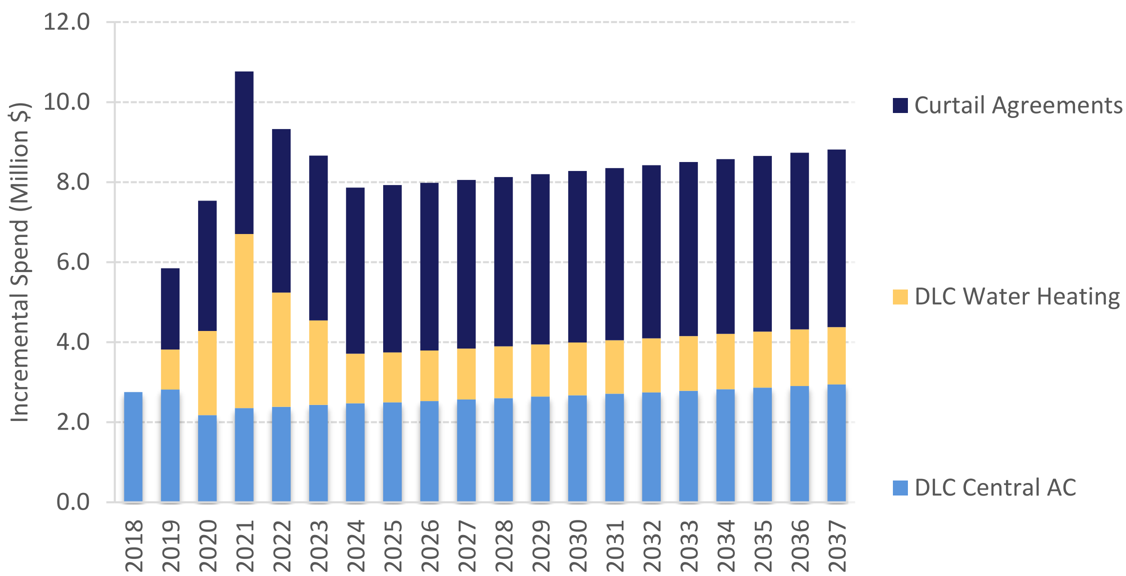


Figure 3-4 Annual Maximum Achievable Potential Program Costs

4

Development of IRP Inputs

From the results of the DSM Market Potential Analysis, AEG also developed inputs for IPL to use in the current integrated resource planning (IRP) modeling effort. This section explains the development of the IRP inputs that were presented to IPL upon conclusion of the EE and DR potential modeling.

"Blocks" of both EE and DR resources were prepared from the Maximum Achievable Potential cases from 2018 to 2037. The more aggressive MAP case was used instead of the RAP case as a reflection of the high value and importance that IPL assigns to DSM as a resource to enhance environmental and customer satisfaction outcomes in addition to the economic outcomes that are core to the IRP process.

Each set of DSM blocks that were presented to the IRP was also processed in the cost-effectiveness and planning software DSMore in order to translate the annual estimates from the potential study into hourly streams of values and prepare in a file and data format amenable to the IRP team.

We briefly describe the EE and DR blocks in respective sections below. Please see the IRP report and documentation itself for more detail on this process and which blocks of resources were actually selected by the IRP when considered alongside supply-side options under the various scenarios and world views.

Energy Efficiency IRP Blocks

For the EE analysis, all measures in the maximum achievable potential case were bundled into groupings by three possible variables as detailed in the table below: similar end-use load shapes, levelized cost of saved energy, and year of installation. The years of installation separated the nearest 3-year implementation cycle from the remaining 17 years of the planning horizon. The permutations of these variables created 42 possible blocks into which the potential savings and program budgets of each measure were allocated. By coincidence, it happened that four of these blocks were null sets or empty, and therefore 38 blocks were translated into IRP inputs, translated into the appropriate format using DSMore, and handed off to the IRP team.

Table 4-1 Variables Used to Distinguish Blocks of EE Measures for IRP Inputs

End Use Load Shapes	Levelized Utility Cost per MWh	Year of installation
Res Other	(up to $30/MWh)	2018-2020
Res HVAC	($30-60/MWh)	2021-2037
Res Lighting	($60+ /MWh)	
Bus HVAC		
Bus Lighting		
Bus Other		
Bus Process		

Demand Response IRP Blocks

For the DR analysis, all measures and options were bundled into IRP groupings using the participation levels from the maximum achievable potential case, with rationale and discussion as shown in Table 4-2 below.

Six DR program input blocks 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). The permutations of these variables created 12 possible blocks into which the potential savings and program budgets of each DR program were allocated. These 12 blocks were translated into the appropriate format using DSMore and handed off to the IRP team.

Table 4-2 Development of DR Program Blocks for IRP Inputs

Program Option	Segment	Rationale for passing to 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		

A Note on DR Energy Impacts: Given the small number of hours impacted by DR programs, most in this analysis are assumed to receive credit or avoided-cost-value for energy savings during all event hours. In other words, they are assumed to have 0% rebound or snapback from pre-cooling, re-charging off-peak, or other activities that would increase energy usage before or after a DR event. Battery and Ice Energy storage, however, are assumed to have 100% rebound effect since all of the energy used during events must be re-charged when the events are over. Also, Smart Thermostat DLC programs in the potential study were analyzed based solely on peak demand savings. Before handing off to the IRP, energy savings assumptions of 300 annual kWh per unit were added to Smart Thermostats during the DSMore translation step.

A

Appendix A - Market Profiles

Table A-1 Average Market Profile for the Residential Single Family

End Use	Technology	Saturation	EUI (kWh)	Intensity(kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	71%	2,471	1,766	415	411
Cooling	Room AC	19%	737	138	32	32
Cooling	Air-Source Heat Pump	0%	2,357	-	-	-
Cooling	Geothermal Heat Pump	0%	1,732	-	-	-
Heating	Electric Room Heat	0%	6,526	-	-	-
Heating	Electric Furnace	0%	4,110	-	-	-
Heating	Air-Source Heat Pump	0%	7,347	-	-	-
Heating	Geothermal Heat Pump	0%	12,490	-	-	-
Water Heating	Water Heater <= 55 Gal	20%	3,149	624	147	12
Water Heating	Water Heater > 55 Gal	8%	3,329	255	60	5
Interior Lighting	General Service Screw-In	100%	1,047	1,047	246	20
Interior Lighting	Linear Lighting	100%	100	100	23	2
Interior Lighting	Exempted Screw-In	100%	364	364	86	7
Ext. Lighting	Screw-in	100%	393	393	92	8
Appliances	Clothes Washer	96%	89	86	20	3
Appliances	Clothes Dryer	81%	820	668	157	22
Appliances	Dishwasher	63%	404	255	60	8
Appliances	Refrigerator	100%	758	758	178	25
Appliances	Freezer	49%	604	297	70	10
Appliances	Second Refrigerator	40%	1,088	434	102	14
Appliances	Stove	53%	495	263	62	9
Appliances	Microwave	106%	133	140	33	5
Appliances	Dehumidifier	35%	630	219	52	7
Appliances	Air Purifier	14%	1,126	155	37	5
Electronics	Personal Computers	69%	180	124	29	5
Electronics	Monitor	82%	76	62	15	3
Electronics	Laptops	168%	47	79	19	3
Electronics	TVs	308%	163	501	118	21
Electronics	Printer/Fax/Copier	118%	62	73	17	3
Electronics	Set top Boxes/DVRs	342%	112	384	90	16
Electronics	Devices and Gadgets	100%	108	108	25	4
Miscellaneous	Pool Pump	6%	1,431	90	21	4
Miscellaneous	Pool Heater	1%	1,438	8	2	0
Miscellaneous	Furnace Fan	86%	802	689	162	28
Miscellaneous	Bathroom Exhaust Fan	39%	148	58	14	2
Miscellaneous	Well pump	12%	589	73	17	3
Miscellaneous	Miscellaneous	100%	562	562	132	23
	Total			**10,773**	**2,533**	**720**

Table A-2 Average Market Profile for the Residential Multifamily

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	53%	713	378	17	16
Cooling	Room AC	35%	673	239	10	10
Cooling	Air-Source Heat Pump	0%	680	-	-	-
Cooling	Geothermal Heat Pump	0%	500	-	-	-
Heating	Electric Room Heat	0%	1,510	-	-	-
Heating	Electric Furnace	0%	951	-	-	-
Heating	Air-Source Heat Pump	0%	1,700	-	-	-
Heating	Geothermal Heat Pump	0%	2,476	-	-	-
Water Heating	Water Heater <= 55 Gal	4%	2,669	101	4	0
Water Heating	Water Heater > 55 Gal	3%	2,821	76	3	0
Interior Lighting	General Service Screw-In	100%	670	670	29	2
Interior Lighting	Linear Lighting	100%	31	31	1	0
Interior Lighting	Exempted Screw-In	100%	39	39	2	0
Ext. Lighting	Screw-in	100%	182	182	8	1
Appliances	Clothes Washer	56%	89	50	2	0
Appliances	Clothes Dryer	47%	729	343	15	2
Appliances	Dishwasher	42%	404	172	8	1
Appliances	Refrigerator	100%	754	754	33	5
Appliances	Freezer	12%	602	71	3	0
Appliances	Second Refrigerator	4%	1,082	44	2	0
Appliances	Stove	58%	302	173	8	1
Appliances	Microwave	101%	133	133	6	1
Appliances	Dehumidifier	7%	630	43	2	0
Appliances	Air Purifier	9%	1,126	98	4	1
Electronics	Personal Computers	40%	180	72	3	1
Electronics	Monitor	48%	76	36	2	0
Electronics	Laptops	122%	47	58	3	0
Electronics	TVs	204%	163	332	15	2
Electronics	Printer/Fax/Copier	77%	62	47	2	0
Electronics	Set top Boxes/DVRs	206%	112	231	10	2
Electronics	Devices and Gadgets	100%	108	108	5	1
Miscellaneous	Pool Pump	0%	1,431	-	-	-
Miscellaneous	Pool Heater	0%	1,438	-	-	-
Miscellaneous	Furnace Fan	73%	428	312	14	2
Miscellaneous	Bathroom Exhaust Fan	13%	148	19	1	0
Miscellaneous	Well pump	0%	584	-	-	-
Miscellaneous	Miscellaneous	100%	252	252	11	2
	Total			**5,063**	**222**	**720**

Table A-3 Average Market Profile for the Residential Single Family Electric Heat

End Use	Technology	Saturation	EUI (kWh)	Intensity(kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	10%	2,471	252	22	22
Cooling	Room AC	9%	737	64	6	6
Cooling	Air-Source Heat Pump	68%	2,357	1,609	142	140
Cooling	Geothermal Heat Pump	4%	1,732	62	5	5
Heating	Electric Room Heat	68%	6,526	4,454	392	-
Heating	Electric Furnace	4%	4,110	148	13	-
Heating	Air-Source Heat Pump	3%	7,347	219	19	-
Heating	Geothermal Heat Pump	25%	12,490	3,142	277	-
Water Heating	Water Heater <= 55 Gal	52%	3,149	1,640	144	12
Water Heating	Water Heater > 55 Gal	20%	3,329	672	59	5
Interior Lighting	General Service Screw-In	100%	1,047	1,047	92	8
Interior Lighting	Linear Lighting	100%	100	100	9	1
Interior Lighting	Exempted Screw-In	100%	364	364	32	3
Ext. Lighting	Screw-in	100%	393	393	35	3
Appliances	Clothes Washer	97%	89	87	8	1
Appliances	Clothes Dryer	96%	820	788	69	10
Appliances	Dishwasher	65%	404	261	23	3
Appliances	Refrigerator	100%	758	758	67	9
Appliances	Freezer	37%	604	226	20	3
Appliances	Second Refrigerator	34%	1,088	370	33	5
Appliances	Stove	75%	495	369	33	5
Appliances	Microwave	106%	133	140	12	2
Appliances	Dehumidifier	35%	630	219	19	3
Appliances	Air Purifier	14%	1,126	155	14	2
Electronics	Personal Computers	65%	180	118	10	2
Electronics	Monitor	77%	76	59	5	1
Electronics	Laptops	192%	47	91	8	1
Electronics	TVs	342%	163	556	49	9
Electronics	Printer/Fax/Copier	112%	62	69	6	1
Electronics	Set top Boxes/DVRs	379%	112	426	37	7
Electronics	Devices and Gadgets	100%	108	108	10	2
Miscellaneous	Pool Pump	7%	1,431	93	8	1
Miscellaneous	Pool Heater	0%	1,438	4	0	0
Miscellaneous	Furnace Fan	25%	802	202	18	3
Miscellaneous	Bathroom Exhaust Fan	39%	148	58	5	1
Miscellaneous	Well pump	12%	589	73	6	1
Miscellaneous	Miscellaneous	100%	1,029	1,029	91	16
	Total			**20,425**	**1,798**	**289**

Table A-4 Average Market Profile for the Residential Multi-family Electric Heat

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ HH)	Usage (GWh)	Summer Peak (MW)
Cooling	Central AC	52%	682	353	22	22
Cooling	Room AC	29%	643	188	12	12
Cooling	Air-Source Heat Pump	7%	650	46	3	3
Cooling	Geothermal Heat Pump	1%	478	5	0	0
Heating	Electric Room Heat	7%	1,510	106	-	-
Heating	Electric Furnace	1%	951	10	-	-
Heating	Air-Source Heat Pump	83%	1,700	1,406	-	-
Heating	Geothermal Heat Pump	9%	2,476	229	-	-
Water Heating	Water Heater <= 55 Gal	43%	2,535	1,096	6	6
Water Heating	Water Heater > 55 Gal	31%	2,680	826	5	5
Interior Lighting	General Service Screw-In	100%	670	670	3	3
Interior Lighting	Linear Lighting	100%	31	31	0	0
Interior Lighting	Exempted Screw-In	100%	39	39	0	0
Ext. Lighting	Screw-in	100%	182	182	1	1
Appliances	Clothes Washer	53%	81	43	0	0
Appliances	Clothes Dryer	56%	660	373	3	3
Appliances	Dishwasher	43%	365	159	1	1
Appliances	Refrigerator	100%	682	682	6	6
Appliances	Freezer	9%	545	49	0	0
Appliances	Second Refrigerator	3%	979	34	0	0
Appliances	Stove	78%	273	214	2	2
Appliances	Microwave	101%	120	121	1	1
Appliances	Dehumidifier	7%	570	39	0	0
Appliances	Air Purifier	9%	1,018	89	1	1
Electronics	Personal Computers	25%	163	41	0	0
Electronics	Monitor	30%	69	20	0	0
Electronics	Laptops	123%	43	53	1	1
Electronics	TVs	227%	147	333	3	3
Electronics	Printer/Fax/Copier	47%	56	27	0	0
Electronics	Set top Boxes/DVRs	193%	102	196	2	2
Electronics	Devices and Gadgets	100%	98	98	1	1
Miscellaneous	Pool Pump	0%	1,295	-	-	-
Miscellaneous	Pool Heater	0%	1,301	-	-	-
Miscellaneous	Furnace Fan	9%	387	36	0	0
Miscellaneous	Bathroom Exhaust Fan	13%	134	17	0	0
Miscellaneous	Well pump	0%	528	-	-	-
Miscellaneous	Miscellaneous	100%	363	363	4	4
	Total			**8,170**	**508**	**79**

Table A-5 Average Market Profile for the Commercial, Small Office 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	3.7%	5.19	0.19	7.80	2.3
Cooling	Water-Cooled Chiller	0.2%	5.46	0.01	0.40	0.1
Cooling	RTU	55.3%	4.93	2.72	109.69	32.7
Cooling	Central AC	10.9%	4.93	0.54	21.63	6.4
Cooling	Room AC	1.0%	3.71	0.04	1.50	0.4
Cooling	Air-Source Heat Pump	4.6%	4.93	0.23	9.16	2.7
Cooling	Geothermal Heat Pump	0.2%	3.29	0.00	0.20	0.1
Cooling	PTHP	1.0%	3.71	0.04	1.48	0.4
Heating	Electric Furnace	13.3%	6.21	0.82	33.17	-
Heating	Electric Room Heat	0.8%	5.92	0.05	2.02	-
Heating	Air-Source Heat Pump	4.6%	5.74	0.26	10.66	-
Heating	Geothermal Heat Pump	0.2%	4.79	0.01	0.29	-
Heating	PTHP	1.0%	5.16	0.05	2.07	-
Ventilation	Ventilation	100.0%	1.03	1.03	41.37	5.0
Water Heating	Water Heater	50.1%	0.77	0.39	15.54	2.2
Interior Lighting	Screw-in	100.0%	0.44	0.44	17.74	3.3
Interior Lighting	High-Bay Fixtures	100.0%	2.19	2.19	88.28	16.6
Interior Lighting	Linear Lighting	100.0%	1.34	1.34	53.76	10.1
Ext. Lighting	Screw-in	100.0%	0.16	0.16	6.54	0.1
Ext. Lighting	Area Lighting	100.0%	1.58	1.58	63.50	0.9
Ext. Lighting	Linear Lighting	100.0%	0.09	0.09	3.58	0.0
Refrigeration	Walk-in Refrig./Frz.	0.0%	1.75	-	-	-
Refrigeration	Reach-in Refrig./Frz	1.0%	0.39	0.00	0.15	0.0
Refrigeration	Glass Door Display	3.9%	0.40	0.02	0.63	0.1
Refrigeration	Open Display Case	0.3%	2.39	0.01	0.25	0.0
Refrigeration	Icemaker	0.3%	0.66	0.00	0.07	0.0
Refrigeration	Vending Machine	0.1%	0.31	0.00	0.02	0.0
Food Preparation	Oven	0.0%	1.29	-	-	-
Food Preparation	Fryer	0.0%	1.86	-	-	-
Food Preparation	Dishwasher	0.2%	2.56	0.01	0.26	0.1
Food Preparation	Hot Food Container	0.0%	0.35	-	-	-
Food Preparation	Steamer	0.3%	1.88	0.01	0.24	0.1
Food Preparation	Griddle	0.4%	1.82	0.01	0.27	0.1
Office Equipment	Desktop Computer	100.0%	1.25	1.25	50.45	6.9
Office Equipment	Laptop	100.0%	0.19	0.19	7.79	1.1
Office Equipment	Server	66.0%	0.37	0.24	9.79	1.3
Office Equipment	Monitor	100.0%	0.22	0.22	8.90	1.2
Office Equipment	Printer/Copier/Fax	100.0%	0.17	0.17	6.91	0.9
Office Equipment	POS Terminal	35.5%	0.10	0.03	1.41	0.2
Miscellaneous	Non-HVAC Motors	13.1%	0.21	0.03	1.13	0.2
Miscellaneous	Other Miscellaneous	100.0%	0.74	0.74	29.67	5.1
	Total			**15.1**	**608.31**	**100.8**

Table A-6 Average Market Profile for the Commercial, Large Office 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	33.7%	4.12	1.39	64.23	19.2
Cooling	Water-Cooled Chiller	18.4%	4.22	0.78	35.89	10.7
Cooling	RTU	15.4%	5.19	0.80	36.88	11.0
Cooling	Central AC	3.8%	5.19	0.19	9.01	2.7
Cooling	Room AC	1.7%	3.91	0.07	3.11	0.9
Cooling	Air-Source Heat Pump	2.5%	5.19	0.13	6.08	1.8
Cooling	Geothermal Heat Pump	0.2%	3.46	0.01	0.38	0.1
Cooling	PTHP	2.0%	3.91	0.08	3.69	1.1
Heating	Electric Furnace	19.4%	5.33	1.03	47.73	-
Heating	Electric Room Heat	1.1%	5.08	0.06	2.68	-
Heating	Air-Source Heat Pump	2.5%	4.47	0.11	5.24	-
Heating	Geothermal Heat Pump	0.2%	3.79	0.01	0.42	-
Heating	PTHP	2.0%	4.02	0.08	3.80	-
Ventilation	Ventilation	100.0%	2.59	2.59	119.85	14.5
Water Heating	Water Heater	46.9%	0.86	0.41	18.74	2.6
Interior Lighting	Screw-in	100.0%	0.41	0.41	18.88	3.5
Interior Lighting	High-Bay Fixtures	100.0%	2.40	2.40	111.00	20.8
Interior Lighting	Linear Lighting	100.0%	0.77	0.77	35.78	6.7
Ext. Lighting	Screw-in	100.0%	0.10	0.10	4.42	0.1
Ext. Lighting	Area Lighting	100.0%	1.28	1.28	59.08	0.8
Ext. Lighting	Linear Lighting	100.0%	0.18	0.18	8.32	0.1
Refrigeration	Walk-in Refrig./Frz.	1.4%	1.31	0.02	0.85	0.1
Refrigeration	Reach-in Refrig./Frz	8.4%	0.29	0.02	1.14	0.2
Refrigeration	Glass Door Display	34.4%	0.30	0.10	4.79	0.7
Refrigeration	Open Display Case	2.3%	1.78	0.04	1.93	0.3
Refrigeration	Icemaker	2.3%	0.49	0.01	0.53	0.1
Refrigeration	Vending Machine	1.2%	0.23	0.00	0.13	0.0
Food Preparation	Oven	0.0%	0.78	-	-	-
Food Preparation	Fryer	0.0%	1.13	-	-	-
Food Preparation	Dishwasher	3.2%	1.56	0.05	2.30	0.6
Food Preparation	Hot Food Container	0.0%	0.21	-	-	-
Food Preparation	Steamer	4.1%	1.15	0.05	2.16	0.5
Food Preparation	Griddle	4.6%	1.11	0.05	2.38	0.6
Office Equipment	Desktop Computer	100.0%	2.26	2.26	104.36	14.2
Office Equipment	Laptop	100.0%	0.35	0.35	16.11	2.2
Office Equipment	Server	97.9%	0.22	0.22	10.02	1.4
Office Equipment	Monitor	100.0%	0.40	0.40	18.42	2.5
Office Equipment	Printer/Copier/Fax	100.0%	0.21	0.21	9.52	1.3
Office Equipment	POS Terminal	35.5%	0.03	0.01	0.48	0.1
Miscellaneous	Non-HVAC Motors	13.1%	0.22	0.03	1.33	0.2
Miscellaneous	Other Miscellaneous	100.0%	0.87	0.87	40.32	7.0
	Total			**17.6**	**811.99**	**128**.6

Table A-7 Average Market Profile for the Commercial, Restaurant 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	18.6%	6.64	1.24	12.57	5.2
Cooling	Water-Cooled Chiller	0.0%	6.50	-	-	-
Cooling	RTU	40.2%	7.73	3.11	31.63	13.0
Cooling	Central AC	3.2%	7.73	0.25	2.52	1.0
Cooling	Room AC	3.2%	5.82	0.18	1.88	0.8
Cooling	Air-Source Heat Pump	1.8%	7.73	0.14	1.41	0.6
Cooling	Geothermal Heat Pump	4.0%	5.16	0.20	2.08	0.9
Cooling	PTHP	0.5%	5.82	0.03	0.29	0.1
Heating	Electric Furnace	3.1%	8.69	0.27	2.75	-
Heating	Electric Room Heat	1.8%	8.27	0.15	1.55	-
Heating	Air-Source Heat Pump	1.8%	6.74	0.12	1.23	-
Heating	Geothermal Heat Pump	4.0%	5.20	0.21	2.09	-
Heating	PTHP	0.5%	6.06	0.03	0.31	-
Ventilation	Ventilation	100.0%	2.39	2.39	24.31	2.5
Water Heating	Water Heater	14.0%	8.49	1.19	12.07	1.6
Interior Lighting	Screw-in	100.0%	1.42	1.42	14.41	2.1
Interior Lighting	High-Bay Fixtures	100.0%	1.23	1.23	12.51	1.9
Interior Lighting	Linear Lighting	100.0%	1.72	1.72	17.53	2.6
Ext. Lighting	Screw-in	100.0%	0.28	0.28	2.81	0.0
Ext. Lighting	Area Lighting	100.0%	2.14	2.14	21.77	0.3
Ext. Lighting	Linear Lighting	100.0%	0.40	0.40	4.10	0.1
Refrigeration	Walk-in Refrig./Frz.	24.4%	8.44	2.06	20.96	2.8
Refrigeration	Reach-in Refrig./Frz	16.0%	3.79	0.61	6.16	0.8
Refrigeration	Glass Door Display	68.6%	1.94	1.33	13.56	1.8
Refrigeration	Open Display Case	26.0%	11.52	3.00	30.49	4.0
Refrigeration	Icemaker	75.9%	3.18	2.42	24.59	3.3
Refrigeration	Vending Machine	0.0%	1.50	-	-	-
Food Preparation	Oven	10.1%	7.60	0.77	7.80	1.2
Food Preparation	Fryer	12.7%	10.99	1.40	14.21	2.2
Food Preparation	Dishwasher	40.7%	7.56	3.08	31.29	4.9
Food Preparation	Hot Food Container	18.8%	1.03	0.19	1.98	0.3
Food Preparation	Steamer	7.1%	5.54	0.40	4.03	0.6
Food Preparation	Griddle	7.9%	5.38	0.42	4.30	0.7
Office Equipment	Desktop Computer	100.0%	0.28	0.28	2.89	0.4
Office Equipment	Laptop	100.0%	0.04	0.04	0.36	0.0
Office Equipment	Server	54.6%	0.33	0.18	1.86	0.2
Office Equipment	Monitor	100.0%	0.05	0.05	0.51	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.63	0.1
Office Equipment	POS Terminal	83.2%	0.09	0.07	0.75	0.1
Miscellaneous	Non-HVAC Motors	14.1%	0.65	0.09	0.93	0.1
Miscellaneous	Other Miscellaneous	100.0%	2.35	2.35	23.89	3.3
Total				**35.5**	**361.00**	**59.8**

Table A-8 Average Market Profile for the Commercial, Retail 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	14.0%	2.87	0.40	15.99	9.9
Cooling	Water-Cooled Chiller	4.0%	3.02	0.12	4.78	2.9
Cooling	RTU	25.5%	5.04	1.28	50.96	31.4
Cooling	Central AC	9.4%	5.04	0.47	18.79	11.6
Cooling	Room AC	4.0%	3.79	0.15	6.02	3.7
Cooling	Air-Source Heat Pump	2.8%	5.04	0.14	5.64	3.5
Cooling	Geothermal Heat Pump	2.6%	3.36	0.09	3.48	2.1
Cooling	PTHP	0.3%	3.79	0.01	0.50	0.3
Heating	Electric Furnace	7.7%	7.38	0.57	22.46	-
Heating	Electric Room Heat	4.3%	6.48	0.28	11.01	-
Heating	Air-Source Heat Pump	2.8%	6.19	0.17	6.93	-
Heating	Geothermal Heat Pump	2.6%	5.51	0.14	5.70	-
Heating	PTHP	0.3%	5.57	0.02	0.74	-
Ventilation	Ventilation	100.0%	1.06	1.06	42.09	4.6
Water Heating	Water Heater	43.3%	0.86	0.37	14.76	1.9
Interior Lighting	Screw-in	100.0%	0.97	0.97	38.43	6.7
Interior Lighting	High-Bay Fixtures	100.0%	3.40	3.40	135.07	23.6
Interior Lighting	Linear Lighting	100.0%	1.44	1.44	57.26	10.0
Ext. Lighting	Screw-in	100.0%	0.24	0.24	9.44	0.1
Ext. Lighting	Area Lighting	100.0%	0.84	0.84	33.51	0.5
Ext. Lighting	Linear Lighting	100.0%	0.08	0.08	3.17	0.0
Refrigeration	Walk-in Refrig./Frz.	0.0%	2.09	-	-	-
Refrigeration	Reach-in Refrig./Frz	29.4%	0.47	0.14	5.48	0.7
Refrigeration	Glass Door Display	38.7%	0.48	0.19	7.39	1.0
Refrigeration	Open Display Case	7.8%	2.85	0.22	8.83	1.2
Refrigeration	Icemaker	4.0%	0.79	0.03	1.24	0.2
Refrigeration	Vending Machine	12.7%	0.74	0.09	3.73	0.5
Food Preparation	Oven	3.9%	0.84	0.03	1.30	0.3
Food Preparation	Fryer	2.5%	1.22	0.03	1.20	0.2
Food Preparation	Dishwasher	11.6%	1.67	0.19	7.68	1.5
Food Preparation	Hot Food Container	0.0%	0.23	-	-	-
Food Preparation	Steamer	0.0%	1.23	-	-	-
Food Preparation	Griddle	0.0%	1.19	-	-	-
Office Equipment	Desktop Computer	100.0%	0.18	0.18	7.11	1.0
Office Equipment	Laptop	100.0%	0.03	0.03	1.10	0.2
Office Equipment	Server	78.4%	0.21	0.17	6.56	0.9
Office Equipment	Monitor	100.0%	0.03	0.03	1.25	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.78	0.1
Office Equipment	POS Terminal	81.9%	0.06	0.05	1.83	0.3
Miscellaneous	Non-HVAC Motors	11.0%	0.21	0.02	0.93	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.91	0.91	36.26	5.8
Total				**14.6**	**579.42**	**127.1**

Table A-9 Average Market Profile for the Commercial, Grocery2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	5.2%	4.64	0.24	1.19	0.4
Cooling	Water-Cooled Chiller	0.0%	4.88	-	-	-
Cooling	RTU	39.4%	8.14	3.21	15.83	5.3
Cooling	Central AC	14.8%	8.12	1.20	5.94	2.0
Cooling	Room AC	0.0%	6.13	-	-	-
Cooling	Air-Source Heat Pump	5.7%	8.12	0.46	2.29	0.8
Cooling	Geothermal Heat Pump	0.0%	5.42	-	-	-
Cooling	PTHP	4.6%	6.13	0.28	1.39	0.5
Heating	Electric Furnace	5.7%	9.88	0.56	2.78	-
Heating	Electric Room Heat	3.1%	9.41	0.29	1.45	-
Heating	Air-Source Heat Pump	5.7%	8.83	0.50	2.49	-
Heating	Geothermal Heat Pump	0.0%	7.36	-	-	-
Heating	PTHP	4.6%	7.94	0.37	1.80	-
Ventilation	Ventilation	100.0%	2.25	2.25	11.08	1.2
Water Heating	Water Heater	29.9%	2.36	0.70	3.47	0.4
Interior Lighting	Screw-in	100.0%	0.53	0.53	2.63	0.4
Interior Lighting	High-Bay Fixtures	100.0%	4.34	4.34	21.42	3.1
Interior Lighting	Linear Lighting	100.0%	1.03	1.03	5.07	0.7
Ext. Lighting	Screw-in	100.0%	0.36	0.36	1.79	0.0
Ext. Lighting	Area Lighting	100.0%	1.78	1.78	8.80	0.1
Ext. Lighting	Linear Lighting	100.0%	0.38	0.38	1.88	0.0
Refrigeration	Walk-in Refrig./Frz.	16.6%	5.45	0.90	4.46	0.6
Refrigeration	Reach-in Refrig./Frz	6.6%	0.35	0.02	0.11	0.0
Refrigeration	Glass Door Display	97.6%	3.58	3.50	17.25	2.3
Refrigeration	Open Display Case	95.6%	21.24	20.31	100.17	13.5
Refrigeration	Icemaker	66.6%	0.29	0.20	0.96	0.1
Refrigeration	Vending Machine	36.5%	0.28	0.10	0.50	0.1
Food Preparation	Oven	28.3%	0.75	0.21	1.04	0.1
Food Preparation	Fryer	28.3%	1.08	0.31	1.51	0.2
Food Preparation	Dishwasher	22.4%	1.48	0.33	1.64	0.2
Food Preparation	Hot Food Container	68.7%	0.20	0.14	0.69	0.1
Food Preparation	Steamer	0.0%	1.09	-	-	-
Food Preparation	Griddle	12.5%	1.06	0.13	0.65	0.1
Office Equipment	Desktop Computer	100.0%	0.17	0.17	0.84	0.1
Office Equipment	Laptop	64.0%	0.03	0.02	0.08	0.0
Office Equipment	Server	66.3%	0.10	0.07	0.33	0.0
Office Equipment	Monitor	100.0%	0.03	0.03	0.15	0.0
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.09	0.0
Office Equipment	POS Terminal	100.0%	0.07	0.07	0.33	0.0
Miscellaneous	Non-HVAC Motors	14.8%	0.86	0.13	0.63	0.1
Miscellaneous	Other Miscellaneous	100.0%	3.40	3.40	16.75	2.1
Total				**48.6**	**239.47**	**34.7**

Table A-10 Average Market Profile for the Commercial, College 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	4.1%	4.31	0.18	3.55	2.2
Cooling	Water-Cooled Chiller	32.5%	5.26	1.71	34.23	21.6
Cooling	RTU	8.9%	3.73	0.33	6.67	4.2
Cooling	Central AC	0.0%	3.73	-	-	-
Cooling	Room AC	2.0%	2.81	0.06	1.15	0.7
Cooling	Air-Source Heat Pump	2.0%	3.73	0.08	1.52	1.0
Cooling	Geothermal Heat Pump	1.4%	2.49	0.04	0.72	0.5
Cooling	PTHP	0.0%	2.81	-	-	-
Heating	Electric Furnace	7.4%	11.19	0.83	16.60	-
Heating	Electric Room Heat	0.0%	10.65	-	-	-
Heating	Air-Source Heat Pump	2.0%	9.18	0.19	3.75	-
Heating	Geothermal Heat Pump	1.4%	7.11	0.10	2.05	-
Heating	PTHP	0.0%	8.26	-	-	-
Ventilation	Ventilation	100.0%	1.43	1.43	28.70	3.1
Water Heating	Water Heater	22.2%	1.96	0.44	8.71	1.3
Interior Lighting	Screw-in	100.0%	0.14	0.14	2.81	0.5
Interior Lighting	High-Bay Fixtures	100.0%	2.44	2.44	48.73	8.7
Interior Lighting	Linear Lighting	100.0%	1.41	1.41	28.25	5.1
Ext. Lighting	Screw-in	100.0%	0.02	0.02	0.40	0.0
Ext. Lighting	Area Lighting	100.0%	0.29	0.29	5.75	0.1
Ext. Lighting	Linear Lighting	100.0%	0.75	0.75	14.99	0.2
Refrigeration	Walk-in Refrig./Frz.	2.5%	0.24	0.01	0.12	0.0
Refrigeration	Reach-in Refrig./Frz	13.2%	0.11	0.01	0.29	0.0
Refrigeration	Glass Door Display	97.2%	0.06	0.05	1.08	0.2
Refrigeration	Open Display Case	4.8%	0.33	0.02	0.32	0.0
Refrigeration	Icemaker	28.2%	0.18	0.05	1.03	0.1
Refrigeration	Vending Machine	8.8%	0.09	0.01	0.15	0.0
Food Preparation	Oven	48.8%	0.06	0.03	0.61	0.1
Food Preparation	Fryer	48.8%	0.09	0.04	0.88	0.2
Food Preparation	Dishwasher	55.0%	0.12	0.07	1.37	0.3
Food Preparation	Hot Food Container	54.2%	0.02	0.01	0.18	0.0
Food Preparation	Steamer	13.4%	0.09	0.01	0.24	0.1
Food Preparation	Griddle	13.4%	0.09	0.01	0.24	0.1
Office Equipment	Desktop Computer	100.0%	0.62	0.62	12.31	1.6
Office Equipment	Laptop	100.0%	0.03	0.03	0.57	0.1
Office Equipment	Server	37.1%	0.07	0.03	0.54	0.1
Office Equipment	Monitor	100.0%	0.11	0.11	2.17	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.08	0.08	1.68	0.2
Office Equipment	POS Terminal	32.9%	0.02	0.01	0.16	0.0
Miscellaneous	Non-HVAC Motors	4.7%	0.21	0.01	0.20	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.89	0.89	17.85	3.0
	Total			**12.5**	**250.54**	**55.8**

Table A-11 Average Market Profile for the Commercial, School 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	5.4%	3.87	0.21	6.21	8.0
Cooling	Water-Cooled Chiller	4.2%	4.72	0.20	5.99	7.7
Cooling	RTU	22.5%	3.35	0.75	22.52	29.1
Cooling	Central AC	1.3%	3.35	0.04	1.32	1.7
Cooling	Room AC	1.4%	2.52	0.03	1.02	1.3
Cooling	Air-Source Heat Pump	1.5%	3.35	0.05	1.51	1.9
Cooling	Geothermal Heat Pump	1.4%	2.23	0.03	0.94	1.2
Cooling	PTHP	0.0%	2.52	-	-	-
Heating	Electric Furnace	2.5%	9.91	0.24	7.32	0.0
Heating	Electric Room Heat	0.0%	9.44	-	-	-
Heating	Air-Source Heat Pump	1.5%	8.13	0.12	3.66	0.0
Heating	Geothermal Heat Pump	1.4%	6.30	0.09	2.64	0.0
Heating	PTHP	0.0%	7.32	-	-	-
Ventilation	Ventilation	100.0%	1.07	1.07	31.87	3.5
Water Heating	Water Heater	16.5%	1.48	0.24	7.31	0.9
Interior Lighting	Screw-in	100.0%	0.30	0.30	9.07	1.8
Interior Lighting	High-Bay Fixtures	100.0%	1.43	1.43	42.80	8.4
Interior Lighting	Linear Lighting	100.0%	0.65	0.65	19.48	3.8
Ext. Lighting	Screw-in	100.0%	0.00	0.00	0.12	0.0
Ext. Lighting	Area Lighting	100.0%	0.12	0.12	3.59	0.0
Ext. Lighting	Linear Lighting	100.0%	0.66	0.66	19.64	0.3
Refrigeration	Walk-in Refrig./Frz.	19.7%	0.45	0.09	2.66	0.5
Refrigeration	Reach-in Refrig./Frz	21.3%	0.20	0.04	1.29	0.2
Refrigeration	Glass Door Display	45.1%	0.10	0.05	1.41	0.3
Refrigeration	Open Display Case	11.9%	0.62	0.07	2.19	0.4
Refrigeration	Icemaker	69.7%	0.34	0.24	7.11	1.4
Refrigeration	Vending Machine	21.8%	0.16	0.03	1.04	0.2
Food Preparation	Oven	16.6%	0.17	0.03	0.83	0.1
Food Preparation	Fryer	1.5%	0.24	0.00	0.11	0.0
Food Preparation	Dishwasher	57.0%	0.33	0.19	5.64	0.6
Food Preparation	Hot Food Container	26.3%	0.05	0.01	0.36	0.0
Food Preparation	Steamer	7.7%	0.24	0.02	0.56	0.1
Food Preparation	Griddle	29.6%	0.24	0.07	2.08	0.2
Office Equipment	Desktop Computer	100.0%	0.43	0.43	12.86	2.0
Office Equipment	Laptop	100.0%	0.03	0.03	0.79	0.1
Office Equipment	Server	96.2%	0.10	0.10	2.91	0.4
Office Equipment	Monitor	100.0%	0.08	0.08	2.27	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.05	0.05	1.41	0.2
Office Equipment	POS Terminal	21.6%	0.01	0.00	0.09	0.0
Miscellaneous	Non-HVAC Motors	4.7%	0.16	0.01	0.22	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.59	0.59	17.72	2.3
	Total			**8.4**	**250.54**	**79.4**

Table A-12 Average Market Profile for the Commercial, Health 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.9%	6.13	0.18	4.54	1.4
Cooling	Water-Cooled Chiller	64.6%	7.41	4.79	123.80	39.2
Cooling	RTU	7.7%	8.94	0.68	17.69	5.6
Cooling	Central AC	1.3%	8.94	0.12	2.99	0.9
Cooling	Room AC	1.1%	6.73	0.07	1.93	0.6
Cooling	Air-Source Heat Pump	0.9%	8.94	0.08	2.18	0.7
Cooling	Geothermal Heat Pump	1.5%	5.96	0.09	2.38	0.8
Cooling	PTHP	1.1%	6.73	0.07	1.93	0.6
Heating	Electric Furnace	4.9%	15.44	0.75	19.42	0.0
Heating	Electric Room Heat	5.1%	14.71	0.75	19.26	0.0
Heating	Air-Source Heat Pump	0.9%	12.33	0.12	3.01	0.0
Heating	Geothermal Heat Pump	1.5%	9.48	0.15	3.79	0.0
Heating	PTHP	1.1%	11.09	0.12	3.18	0.0
Ventilation	Ventilation	100.0%	3.30	3.30	85.27	10.1
Water Heating	Water Heater	4.5%	3.04	0.14	3.51	0.4
Interior Lighting	Screw-in	100.0%	0.85	0.85	21.95	3.2
Interior Lighting	High-Bay Fixtures	100.0%	4.57	4.57	118.02	17.0
Interior Lighting	Linear Lighting	100.0%	2.30	2.30	59.43	8.6
Ext. Lighting	Screw-in	100.0%	0.04	0.04	1.14	0.0
Ext. Lighting	Area Lighting	100.0%	0.66	0.66	17.17	0.2
Ext. Lighting	Linear Lighting	100.0%	0.08	0.08	2.12	0.0
Refrigeration	Walk-in Refrig./Frz.	7.7%	1.46	0.11	2.90	0.4
Refrigeration	Reach-in Refrig./Frz	7.7%	0.33	0.03	0.65	0.1
Refrigeration	Glass Door Display	50.6%	0.34	0.17	4.40	0.6
Refrigeration	Open Display Case	6.4%	2.00	0.13	3.30	0.4
Refrigeration	Icemaker	20.3%	0.55	0.11	2.89	0.4
Refrigeration	Vending Machine	26.8%	0.26	0.07	1.80	0.2
Food Preparation	Oven	17.0%	0.69	0.12	3.05	0.5
Food Preparation	Fryer	17.1%	1.00	0.17	4.43	0.7
Food Preparation	Dishwasher	50.8%	1.38	0.70	18.09	2.8
Food Preparation	Hot Food Container	12.3%	0.19	0.02	0.60	0.1
Food Preparation	Steamer	3.6%	1.01	0.04	0.94	0.1
Food Preparation	Griddle	4.9%	0.98	0.05	1.25	0.2
Office Equipment	Desktop Computer	100.0%	0.40	0.40	10.33	1.3
Office Equipment	Laptop	100.0%	0.06	0.06	1.59	0.2
Office Equipment	Server	90.0%	0.24	0.21	5.47	0.7
Office Equipment	Monitor	100.0%	0.07	0.07	1.82	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.04	0.04	1.13	0.1
Office Equipment	POS Terminal	89.8%	0.06	0.06	1.46	0.2
Miscellaneous	Non-HVAC Motors	3.2%	0.42	0.01	0.35	0.0
Miscellaneous	Other Miscellaneous	100.0%	3.99	3.99	103.19	13.9
Total				**26.5**	**684.34**	**112.5**

Table A-13 Average Market Profile for the Commercial, Lodging 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	1.6%	2.45	0.04	0.37	0.1
Cooling	Water-Cooled Chiller	36.6%	2.99	1.10	10.41	2.8
Cooling	RTU	0.0%	6.37	-	-	-
Cooling	Central AC	1.4%	6.36	0.09	0.87	0.2
Cooling	Room AC	17.6%	4.79	0.84	8.00	2.2
Cooling	Air-Source Heat Pump	1.5%	6.36	0.10	0.91	0.2
Cooling	Geothermal Heat Pump	0.0%	4.25	-	-	-
Cooling	PTHP	16.6%	4.79	0.79	7.53	2.1
Heating	Electric Furnace	0.0%	6.27	-	-	-
Heating	Electric Room Heat	24.6%	5.52	1.36	12.87	0.0
Heating	Air-Source Heat Pump	1.5%	5.26	0.08	0.75	0.0
Heating	Geothermal Heat Pump	0.0%	4.32	-	-	-
Heating	PTHP	16.6%	4.73	0.78	7.44	0.0
Ventilation	Ventilation	100.0%	1.40	1.40	13.27	1.5
Water Heating	Water Heater	10.5%	4.74	0.50	4.73	0.1
Interior Lighting	Screw-in	100.0%	1.55	1.55	14.69	2.1
Interior Lighting	High-Bay Fixtures	100.0%	0.63	0.63	6.01	0.9
Interior Lighting	Linear Lighting	100.0%	1.60	1.60	15.14	2.2
Ext. Lighting	Screw-in	100.0%	0.04	0.04	0.36	0.0
Ext. Lighting	Area Lighting	100.0%	1.73	1.73	16.42	0.2
Ext. Lighting	Linear Lighting	100.0%	0.03	0.03	0.24	0.0
Refrigeration	Walk-in Refrig./Frz.	13.3%	0.70	0.09	0.88	0.1
Refrigeration	Reach-in Refrig./Frz	13.3%	0.16	0.02	0.20	0.0
Refrigeration	Glass Door Display	11.7%	0.16	0.02	0.18	0.0
Refrigeration	Open Display Case	0.5%	0.96	0.00	0.04	0.0
Refrigeration	Icemaker	88.9%	0.53	0.47	4.47	0.7
Refrigeration	Vending Machine	57.8%	0.25	0.14	1.37	0.2
Food Preparation	Oven	42.6%	0.12	0.05	0.47	0.0
Food Preparation	Fryer	13.1%	0.17	0.02	0.21	0.0
Food Preparation	Dishwasher	90.8%	0.23	0.21	1.99	0.2
Food Preparation	Hot Food Container	6.6%	0.03	0.00	0.02	0.0
Food Preparation	Steamer	1.9%	0.17	0.00	0.03	0.0
Food Preparation	Griddle	23.4%	0.16	0.04	0.37	0.0
Office Equipment	Desktop Computer	100.0%	0.10	0.10	0.94	0.0
Office Equipment	Laptop	100.0%	0.02	0.02	0.15	0.0
Office Equipment	Server	84.0%	0.06	0.05	0.46	0.0
Office Equipment	Monitor	100.0%	0.02	0.02	0.17	0.0
Office Equipment	Printer/Copier/Fax	100.0%	0.01	0.01	0.10	0.0
Office Equipment	POS Terminal	75.4%	0.02	0.01	0.11	0.0
Miscellaneous	Non-HVAC Motors	5.7%	0.27	0.02	0.14	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.01	1.01	9.63	0.9
Total				**15.0**	**141.94**	**17.2**

Table A-14 Average Market Profile for the Commercial, Warehouse 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	4.2%	2.99	0.12	2.74	4.2
Cooling	Water-Cooled Chiller	0.0%	2.82	-	-	-
Cooling	RTU	10.3%	4.84	0.50	11.04	17.1
Cooling	Central AC	0.2%	4.84	0.01	0.24	0.4
Cooling	Room AC	0.0%	3.65	-	-	-
Cooling	Air-Source Heat Pump	0.0%	4.84	-	-	-
Cooling	Geothermal Heat Pump	0.0%	3.23	-	-	-
Cooling	PTHP	0.0%	3.65	-	-	-
Heating	Electric Furnace	2.0%	12.70	0.26	5.64	-
Heating	Electric Room Heat	0.8%	11.14	0.09	2.06	-
Heating	Air-Source Heat Pump	0.0%	10.65	-	-	-
Heating	Geothermal Heat Pump	0.0%	9.61	-	-	-
Heating	PTHP	0.0%	9.58	-	-	-
Ventilation	Ventilation	100.0%	0.37	0.37	8.23	0.9
Water Heating	Water Heater	37.2%	0.38	0.14	3.10	0.4
Interior Lighting	Screw-in	100.0%	0.15	0.15	3.38	0.7
Interior Lighting	High-Bay Fixtures	100.0%	0.45	0.45	9.83	2.1
Interior Lighting	Linear Lighting	100.0%	2.74	2.74	60.36	13.0
Ext. Lighting	Screw-in	100.0%	0.02	0.02	0.44	0.0
Ext. Lighting	Area Lighting	100.0%	0.38	0.38	8.33	0.1
Ext. Lighting	Linear Lighting	100.0%	0.08	0.08	1.71	0.0
Refrigeration	Walk-in Refrig./Frz.	0.0%	1.10	-	-	-
Refrigeration	Reach-in Refrig./Frz	0.0%	0.25	-	-	-
Refrigeration	Glass Door Display	45.4%	0.25	0.12	2.55	0.4
Refrigeration	Open Display Case	0.0%	1.51	-	-	-
Refrigeration	Icemaker	8.3%	0.42	0.03	0.76	0.1
Refrigeration	Vending Machine	6.9%	0.20	0.01	0.30	0.0
Food Preparation	Oven	0.0%	0.00	-	-	-
Food Preparation	Fryer	1.8%	0.01	0.00	0.00	0.0
Food Preparation	Dishwasher	32.9%	0.01	0.00	0.07	0.0
Food Preparation	Hot Food Container	0.0%	0.00	-	-	-
Food Preparation	Steamer	3.0%	0.01	0.00	0.00	0.0
Food Preparation	Griddle	0.0%	0.01	-	-	-
Office Equipment	Desktop Computer	100.0%	0.14	0.14	3.16	0.5
Office Equipment	Laptop	100.0%	0.02	0.02	0.39	0.1
Office Equipment	Server	64.9%	0.17	0.11	2.41	0.4
Office Equipment	Monitor	100.0%	0.03	0.03	0.56	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.35	0.1
Office Equipment	POS Terminal	3.3%	0.04	0.00	0.03	0.0
Miscellaneous	Non-HVAC Motors	8.9%	0.15	0.01	0.30	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.62	0.62	13.66	2.8
Total				**6.4**	**141.65**	**43.5**

Table A-15 Average Market Profile for the Commercial, Miscellaneous2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	12.8%	1.18	0.15	18.08	10.7
Cooling	Water-Cooled Chiller	2.9%	1.24	0.04	4.34	2.6
Cooling	RTU	18.8%	2.06	0.39	46.72	27.8
Cooling	Central AC	3.3%	2.06	0.07	8.20	4.9
Cooling	Room AC	1.3%	1.98	0.03	3.21	1.9
Cooling	Air-Source Heat Pump	1.7%	2.06	0.04	4.30	2.6
Cooling	Geothermal Heat Pump	0.1%	1.38	0.00	0.19	0.1
Cooling	PTHP	1.3%	1.98	0.03	3.08	1.8
Heating	Electric Furnace	2.0%	6.09	0.12	14.60	-
Heating	Electric Room Heat	0.2%	6.04	0.01	1.70	-
Heating	Air-Source Heat Pump	1.7%	5.77	0.10	12.03	-
Heating	Geothermal Heat Pump	0.1%	4.44	0.01	0.61	-
Heating	PTHP	1.3%	5.19	0.07	8.09	-
Ventilation	Ventilation	100.0%	0.40	0.40	47.64	5.1
Water Heating	Water Heater	23.7%	0.75	0.18	21.45	2.7
Interior Lighting	Screw-in	100.0%	0.65	0.65	78.17	17.5
Interior Lighting	High-Bay Fixtures	100.0%	1.80	1.80	215.73	48.2
Interior Lighting	Linear Lighting	100.0%	1.41	1.41	169.23	37.8
Ext. Lighting	Screw-in	100.0%	0.09	0.09	11.16	0.2
Ext. Lighting	Area Lighting	100.0%	0.64	0.64	76.69	1.1
Ext. Lighting	Linear Lighting	100.0%	0.06	0.06	7.09	0.1
Refrigeration	Walk-in Refrig./Frz.	15.4%	0.24	0.04	4.53	0.6
Refrigeration	Reach-in Refrig./Frz	15.4%	0.05	0.01	1.02	0.1
Refrigeration	Glass Door Display	25.5%	0.06	0.01	1.73	0.2
Refrigeration	Open Display Case	0.5%	0.33	0.00	0.18	0.0
Refrigeration	Icemaker	41.6%	0.09	0.04	4.61	0.6
Refrigeration	Vending Machine	28.6%	0.09	0.02	2.98	0.4
Food Preparation	Oven	29.0%	0.04	0.01	1.46	0.3
Food Preparation	Fryer	2.5%	0.06	0.00	0.18	0.0
Food Preparation	Dishwasher	20.7%	0.08	0.02	2.08	0.5
Food Preparation	Hot Food Container	10.0%	0.01	0.00	0.14	0.0
Food Preparation	Steamer	2.4%	0.06	0.00	0.18	0.0
Food Preparation	Griddle	16.0%	0.06	0.01	1.14	0.3
Office Equipment	Desktop Computer	100.0%	0.15	0.15	18.24	2.8
Office Equipment	Laptop	100.0%	0.02	0.02	2.82	0.4
Office Equipment	Server	43.6%	0.09	0.04	4.68	0.7
Office Equipment	Monitor	100.0%	0.03	0.03	3.22	0.5
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	2.00	0.3
Office Equipment	POS Terminal	37.0%	0.02	0.01	1.06	0.2
Miscellaneous	Non-HVAC Motors	11.4%	0.11	0.01	1.45	0.3
Miscellaneous	Other Miscellaneous	100.0%	0.36	0.36	43.13	8.2
Total				**7.1**	**849.11**	**181.6**

Table A-16 Average Market Profile for the Industrial Sector, Chemical and Pharmaceuticals 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	7,568.4	163.1	2.1	2.2
Cooling	Water-Cooled Chiller	2.0%	7,135.7	142.7	1.9	2.0
Cooling	RTU	10.6%	12,261.5	1,303.0	17.1	17.9
Cooling	Air-Source Heat Pump	0.0%	12,261.5	-	-	-
Cooling	Geothermal Heat Pump	0.0%	8,178.4	-	-	-
Heating	Electric Furnace	1.7%	31,182.3	523.4	6.9	-
Heating	Electric Room Heat	0.7%	27,360.5	191.0	2.5	-
Heating	Air-Source Heat Pump	0.0%	23,386.7	-	-	-
Heating	Geothermal Heat Pump	0.0%	15,598.9	-	-	-
Ventilation	Ventilation	100.0%	944.2	944.2	12.4	0.6
Interior Lighting	Screw-in	100.0%	96.3	96.3	1.3	0.1
Interior Lighting	High-Bay Fixtures	100.0%	1,718.9	1,718.9	22.6	2.3
Interior Lighting	Linear Lighting	100.0%	280.0	280.0	3.7	0.4
Ext. Lighting	Screw-in	100.0%	12.5	12.5	0.2	0.0
Ext. Lighting	Area Lighting	100.0%	237.2	237.2	3.1	0.0
Ext. Lighting	Linear Lighting	100.0%	48.6	48.6	0.6	0.0
Motors	Pumps	100.0%	10,177.1	10,177.1	133.9	12.3
Motors	Fans & Blowers	100.0%	4,650.5	4,650.5	61.2	5.6
Motors	Compressed Air	100.0%	10,783.7	10,783.7	141.9	13.0
Motors	Conveyors	100.0%	9,772.7	9,772.7	128.6	11.8
Motors	Other Motors	100.0%	1,281.1	1,281.1	16.9	1.5
Process	Process Heating	100.0%	4,165.6	4,165.6	54.8	5.0
Process	Process Cooling	100.0%	2,291.9	2,291.9	30.1	2.8
Process	Process Refrigeration	100.0%	2,291.9	2,291.9	30.1	2.8
Process	Process Electrochemical	100.0%	2,902.3	2,902.3	38.2	3.5
Process	Process Other	100.0%	440.3	440.3	5.8	0.5
Miscellaneous	Miscellaneous	100.0%	1,244.4	1,244.4	16.4	1.5
	Total			55,663	732	85.8

Table A-17 Average Market Profile for the Industrial Sector, Food Products 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	12,897.2	277.9	1.3	1.4
Cooling	Water-Cooled Chiller	2.0%	12,159.9	243.2	1.2	1.2
Cooling	RTU	10.6%	20,894.7	2,220.3	10.8	11.2
Cooling	Air-Source Heat Pump	0.0%	20,894.7	-	-	-
Cooling	Geothermal Heat Pump	0.0%	13,936.8	-	-	-
Heating	Electric Furnace	1.7%	53,137.4	891.9	4.3	-
Heating	Electric Room Heat	0.7%	46,624.7	325.5	1.6	-
Heating	Air-Source Heat Pump	0.0%	39,853.1	-	-	-
Heating	Geothermal Heat Pump	0.0%	26,582.0	-	-	-
Ventilation	Ventilation	100.0%	1,609.0	1,609.0	7.8	0.4
Interior Lighting	Screw-in	100.0%	220.5	220.5	1.1	0.1
Interior Lighting	High-Bay Fixtures	100.0%	3,933.6	3,933.6	19.1	1.9
Interior Lighting	Linear Lighting	100.0%	640.7	640.7	3.1	0.3
Ext. Lighting	Screw-in	100.0%	28.7	28.7	0.1	0.0
Ext. Lighting	Area Lighting	100.0%	542.9	542.9	2.6	0.0
Ext. Lighting	Linear Lighting	100.0%	111.2	111.2	0.5	0.0
Motors	Pumps	100.0%	5,309.4	5,309.4	25.7	2.4
Motors	Fans & Blowers	100.0%	8,827.6	8,827.6	42.8	3.9
Motors	Compressed Air	100.0%	3,395.1	3,395.1	16.5	1.5
Motors	Conveyors	100.0%	16,653.3	16,653	80.7	7.4
Motors	Other Motors	100.0%	1,703.6	1,703.6	8.3	0.8
Process	Process Heating	100.0%	5,703.7	5,703.7	27.7	2.5
Process	Process Cooling	100.0%	9,478.5	9,478.5	46.0	4.2
Process	Process Refrigeration	100.0%	9,478.5	9,478.5	46.0	4.2
Process	Process Electrochemical	100.0%	44.9	44.9	0.2	0.0
Process	Process Other	100.0%	425.1	425.1	2.1	0.2
Miscellaneous	Miscellaneous	100.0%	2,600.1	2,600.1	12.6	1.2
	Total			**74,665**	**362**	**44.9**

Table A-18 Average Market Profile for the Industrial Sector, Transportation 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	21,785.4	469.4	4.4	4.6
Cooling	Water-Cooled Chiller	2.0%	20,539.9	410.8	3.9	4.0
Cooling	RTU	10.6%	35,294.4	3,750.5	35.2	36.8
Cooling	Air-Source Heat Pump	0.0%	35,294.4	-	-	-
Cooling	Geothermal Heat Pump	0.0%	23,541.4	-	-	-
Heating	Electric Furnace	1.7%	89,757.2	1,506.6	14.2	-
Heating	Electric Room Heat	0.7%	78,756.2	549.9	5.2	-
Heating	Air-Source Heat Pump	0.0%	67,317.9	-	-	-
Heating	Geothermal Heat Pump	0.0%	44,901.1	-	-	-
Ventilation	Ventilation	100.0%	2,717.9	2,717.9	25.5	1.2
Interior Lighting	Screw-in	100.0%	317.4	317.4	3.0	0.3
Interior Lighting	High-Bay Fixtures	100.0%	5,663.0	5,663.0	53.2	5.4
Interior Lighting	Linear Lighting	100.0%	922.4	922.4	8.7	0.9
Ext. Lighting	Screw-in	100.0%	41.3	41.3	0.4	0.0
Ext. Lighting	Area Lighting	100.0%	781.6	781.6	7.3	0.0
Ext. Lighting	Linear Lighting	100.0%	160.1	160.1	1.5	0.0
Motors	Pumps	100.0%	4,055.3	4,055.3	38.1	3.5
Motors	Fans & Blowers	100.0%	2,949.3	2,949.3	27.7	2.5
Motors	Compressed Air	100.0%	3,318.0	3,318.0	31.2	2.9
Motors	Conveyors	100.0%	8,848.0	8,848.0	83.1	7.6
Motors	Other Motors	100.0%	1,272.6	1,272.6	12.0	1.1
Process	Process Heating	100.0%	7,204.3	7,204.3	67.7	6.2
Process	Process Cooling	100.0%	1,599.6	1,599.6	15.0	1.4
Process	Process Refrigeration	100.0%	1,599.6	1,599.6	15.0	1.4
Process	Process Electrochemical	100.0%	215.1	215.1	2.0	0.2
Process	Process Other	100.0%	1,177.7	1,177.7	11.1	1.0
Miscellaneous	Miscellaneous	100.0%	2,574.0	2,574.0	24.2	2.2
	Total			**52,104**	**489.6**	**83.2**

Table A-19 Average Market Profile for the Industrial Sector, Other Industrial 2015

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/ Employee)	Usage (GWh)	Summer Peak (MW)
Cooling	Air-Cooled Chiller	2.2%	33,317	717.8	23.5	24.5
Cooling	Water-Cooled Chiller	2.0%	31,408	628.2	20.5	21.4
Cooling	RTU	10.6%	53,970	5,735.0	187.6	195.8
Cooling	Air-Source Heat Pump	0.0%	53,969.9	-	-	-
Cooling	Geothermal Heat Pump	0.0%	35,997.9	-	-	-
Heating	Electric Furnace	1.7%	137,250.9	2,303.7	75.4	-
Heating	Electric Room Heat	0.7%	120,428.8	840.9	27.5	-
Heating	Air-Source Heat Pump	0.0%	102,938.1	-	-	-
Heating	Geothermal Heat Pump	0.0%	68,659.7	-	-	-
Ventilation	Ventilation	100.0%	4,156.1	4,156.1	136.0	6.3
Interior Lighting	Screw-in	100.0%	441.2	441.2	14.4	1.5
Interior Lighting	High-Bay Fixtures	100.0%	7,872.0	7,872.0	257.5	26.2
Interior Lighting	Linear Lighting	100.0%	1,282.3	1,282.3	41.9	4.3
Ext. Lighting	Screw-in	100.0%	57.3	57.3	1.9	0.0
Ext. Lighting	Area Lighting	100.0%	1,086.5	1,086.5	35.5	0.2
Ext. Lighting	Linear Lighting	100.0%	222.6	222.6	7.3	0.0
Motors	Pumps	100.0%	5,125.1	5,125.1	167.7	15.4
Motors	Fans & Blowers	100.0%	3,397.7	3,397.7	111.2	10.2
Motors	Compressed Air	100.0%	3,590.9	3,590.9	117.5	10.8
Motors	Conveyors	100.0%	9,580.1	9,580.1	313.4	28.7
Motors	Other Motors	100.0%	1,391.6	1,391.6	45.5	4.2
Process	Process Heating	100.0%	7,088.6	7,088.6	231.9	21.3
Process	Process Cooling	100.0%	1,856.7	1,856.7	60.7	5.6
Process	Process Refrigeration	100.0%	1,856.7	1,856.7	60.7	5.6
Process	Process Electrochemical	100.0%	176.9	176.9	5.8	0.5
Process	Process Other	100.0%	467.9	467.9	15.3	1.4
Miscellaneous	Miscellaneous	100.0%	3,613.9	3,613.9	118.2	10.8
	Total			**63,490**	**2,077**	**394.6**

B

APPENDIX B - MARKET ADOPTION RATES

This appendix presents the market adoption rates we applied to economic potential to estimate achievable potential for Residential, Commercial and Industrial sectors. This appendix includes market adoption rates in the file *Appendix B - Market Adoption Rates.xlsx* embedded below.

Appendix B -
Market Adoption Ra

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Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP	=	BP - CP
NPVavp	=	(BP - CP) / P
BCRP	=	BP/CP
DPP	=	min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = 1
ARIRIMt	=	FRIRIM	for t = 1
	=	(CRIMt- BRIMt)/Et	for t=2,... ,N
NPVRIM	=	BRIM — CRIM	
BCRRIM	=	BRIM /CRIM	

Total Resource Cost Test

NPVTRC	=	BTRC - CTRC
BCRTRC	=	BTRC / CTRC
LCTRC	=	LCRC / IMP

Program Administrator Cost Test

NPVpa	=	Bpa - Cpa
BCRpa	=	Bpa / Cpa
LCpa	=	LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n}\left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat	=	Avoided bill reductions on bill from alternate fuel in year t
AC:Dit	=	Rate charged for demand in costing period i in year t
AC:Eit	=	Rate charged for energy in costing period i in year t
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp	=	Benefit-cost ratio to participants
BCRRIM	=	Benefit-cost ratio for rate levels
BCRTRC	=	Benefit-cost ratio of total costs of the resource
BCRpa	=	Benefit-cost ratio of program administrator and utility costs
BIt	=	Bill increases in year t
Bj	=	Cumulative benefits to participants in year j
Bp	=	Benefit to participants
BRIM	=	Benefits to rate levels or customer bills
BRt	=	Bill reductions in year t
BTRC	=	Benefits of the program
Bpa	=	Benefits of the program
Cj	=	Cumulative costs to participants in year i

Cp	=	Costs to participants
CRIM	=	Costs to rate levels or customer bills
CTRC	=	Costs of the program
Cpa	=	Costs of the program
D	=	discount rate
ΔDgit	=	Reduction in gross billing demand in costing period i in year t
ΔDnit	=	Reduction in net demand in costing period i in year t
DPp	=	Discounted payback in years
E	=	Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	=	Reduction in gross energy use in costing period i in year t
ΔEnit	=	Reduction in net energy use in costing period i in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	=	Total discounted load impacts of the program
INCt	=	Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are > cumulative costs.
Kit	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	=	Total resource costs used for levelizing
LCTRC	=	Levelized cost per unit of the total cost of the resource
LCPA	=	Total Program Administrator costs used for levelizing
Lcpa	=	Levelized cost per unit of program administrator cost of the resource
LRIRIM	=	Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	=	Marginal cost of demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
NPVavp	=	Net present value to the average participant
NPVP	=	Net present value to all participants
NPVRIM	=	Net present value levels
NPVTRC	=	Net present value of total costs of the resource
NPVpa	=	Net present value of program administrator costs
OBIt	=	Other bill increases (i.e., customer charges, standby rates)
OBRt	=	Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	=	Number of program participants
PACat	=	Participant avoided costs in year t for alternate fuel devices

PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax • Ongoing operation and maintenance costs • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PRCt	=	Program Administrator program costs in year t
PCN	=	Net Participant Costs
RGt	=	Revenue gain from increased sales in year t
RLat	=	Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt	=	Revenue loss from reduced sales in year t
TCt	=	Tax credits in year t
UACat	=	Utility avoided supply costs for the alternate fuel in year t
UACt	=	Utility avoided supply costs in year t
PAt	=	Program Administrator costs in year t
UICt	=	Utility increased supply costs in year t

Indianapolis Power Light Company
2016 Integrated Resource Plan

Standard DSM Benefit/Cost Tests

DSM test objectives and valuation equation and components

	Standard Benefit / Cost Tests			
	RIM	TRC	UCT	Participant
Goal/Impact of test				
Minimizes Utility costs			X	
Minimizes Customer rate impacts	X			
Achieves Customer fairness	X			
Minimizes Overall/Societal costs		X		
Maximizes Participant benefit				X
Test Benefit and Cost Components				
Benefits				
Production Cost Savings (energy)	X	X	X	
Capacity Cost Savings	X	X	X	
Participant Bill Savings				X
Costs				
Lost Revenue to Utility (Customer base)	X			
Incentives paid by Utility	X		X	
Program Administrative Costs	X	X	X	
Participant Costs (investment)		X		X

B/C test ratio (equation)

Benefit/Cost test equation is ratio of marked ("X" above). Benefits and Costs expressed as present values.

*The TRC detailed above was used by AEG in the 2016 Market Potential Study to screen measures for inclusion in the IRP analysis.

*IPL will issue an RFP for implementation vendor bids for the level of DSM selected in the 2016 IRP concurrent to the IRP's filing. IPL plans to build programs based on the winning bid(s). The cost effectiveness tests described above will be used to evaluate the programs during the RFP process and for the 2018 – 2020 DSM filing.

IPL 2016 IRP

Confidential Attachment 5.9 (Loadmap DSM Measure Detail) is only available in the Confidential IRP.

IPL 2016 IRP

Confidential Attachment 5.10 (Avoided Cost Calculation) is only available in the Confidential IRP.

IPL 2016 IRP

Confidential Attachment 7.1 (Confidential Figures in Section 7) is only available in the Confidential IRP.

Indianapolis Power & Light

Base Case Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	50	75	100
Solar Existing	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43	43	43	48
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	350	500
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	150	0
Total Resources	3575	3575	3575	3575	3575	3575	3575	3537	3537	3537	3537	3537	3537	3537	3335	3335	3320	3306	3315	3345
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	75	92	104	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2789	2770	2766	2749	2746	2746	2749	2746	2750	2758	2773	2785	2801	2817	2832	2840	2861	2882	2908
Reserve Margin	27.3%	28.2%	29.0%	29.2%	30.0%	30.2%	30.2%	28.7%	28.8%	28.6%	28.2%	27.6%	27.0%	26.3%	18.4%	17.8%	16.9%	15.6%	15.0%	15.0%

Indianapolis Power & Light

Recession Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 1 Gas	0	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253	0	0	0	0
Pete 2 Gas	0	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	0	0
Pete 3 Gas	0	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592
Pete 4 Gas	0	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	650	650
Hoosier Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Total Resources	3575	3717	3717	3717	3717	3717	3717	3680	3680	3680	3680	3680	3680	3680	3478	3478	3225	3236	2985	2985
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	80	97	109	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2783	2765	2761	2749	2745	2746	2749	2746	2749	2758	2773	2785	2801	2817	2832	2840	2860	2882	2907
Reserve Margin	27.3%	33.5%	34.4%	34.6%	35.2%	35.4%	35.4%	33.8%	34.0%	33.8%	33.4%	32.7%	32.1%	31.4%	23.4%	22.8%	13.5%	13.2%	3.6%	2.7%

Indianapolis Power & Light

Robust Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class - 2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar PV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	178	389	389	480	480
Community Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.48	2.88
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150	200	250	300
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250	300
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	0	0	0	250	0
Total Resources	3575	3575	3575	3575	3575	3575	3575	3537	3537	3537	3537	3537	3537	3537	3585	3613	3640	3702	3727	3779
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	81	97	110	120	131	141	153	164	174	178	183	185	187	191	200	210	212	215	218
Peak Load - DSM Removed	2808	2783	2764	2760	2748	2744	2744	2747	2743	2746	2754	2769	2780	2796	2811	2825	2832	2852	2873	2897
Reserve Margin	27.3%	28.4%	29.3%	29.5%	30.1%	30.3%	30.3%	28.8%	28.9%	28.8%	28.4%	27.8%	27.2%	26.5%	27.5%	27.9%	28.5%	29.8%	29.7%	30.4%

Indianapolis Power & Light

Recession Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 1 Gas	0	253	253	253	253	253	253	253	253	253	253	253	253	253	253	253	0	0	0	0
Pete 2 Gas	0	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	0	0
Pete 3 Gas	0	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592
Pete 4 Gas	0	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	650	650
Hoosier Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Total Resources	3575	3717	3717	3717	3717	3717	3717	3680	3680	3680	3680	3680	3680	3680	3478	3478	3225	3236	2985	2985
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	80	97	109	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2783	2765	2761	2749	2745	2746	2749	2746	2749	2758	2773	2785	2801	2817	2832	2840	2860	2882	2907
Reserve Margin	27.3%	33.5%	34.4%	34.6%	35.2%	35.4%	35.4%	33.8%	34.0%	33.8%	33.4%	32.7%	32.1%	31.4%	23.4%	22.8%	13.5%	13.2%	3.6%	2.7%

Indianapolis Power & Light

Strengthened Economy Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 2 Gas	0	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	0	0
Pete 3 Gas	0	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592	592
Pete 4 Gas	0	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class - 2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	134	134	158	163	168	168	173	178	182	187	187	187	187	187	187	221	250
Community Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.48	2.88	2.88	2.88	4.32	6.72	9.12	11.52	13.92
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150	200	250	300
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0
Total Resources	3575	3698	3464	3598	3598	3622	3627	3595	3595	3599	3604	3609	3617	3617	3465	3516	3568	3633	3318	3349
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	81	97	110	120	131	141	153	164	174	178	183	185	187	191	200	210	212	215	218
Peak Load - DSM Removed	2808	2783	2764	2760	2748	2744	2744	2747	2743	2746	2754	2769	2780	2796	2811	2825	2832	2852	2873	2897
Reserve Margin	27.3%	32.9%	25.3%	30.3%	30.9%	32.0%	32.2%	30.9%	31.0%	31.1%	30.8%	30.4%	30.1%	29.4%	23.2%	24.4%	26.0%	27.4%	15.5%	15.6%

Indianapolis Power & Light

Adoption of DG Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
CHP	0	0	0	0	0	75	75	75	150	150	150	150	150	150	150	225	225	225	225	225
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	31	31	31	62	62	62	62	62	62	62	94	94	94	94	122
Community Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51	101	151	201	251
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0
Total Resources	3575	3575	3575	3575	3575	3681	3681	3644	3750	3750	3750	3750	3750	3750	3548	3705	3521	3583	3316	3345
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	75	92	104	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2788	2770	2766	2749	2745	2746	2749	2746	2749	2758	2773	2785	2801	2817	2832	2840	2860	2882	2907
Reserve Margin	27.3%	28.2%	29.1%	29.2%	30.0%	34.1%	34.1%	32.5%	36.5%	36.4%	35.9%	35.2%	34.6%	33.9%	25.9%	30.8%	24.0%	25.3%	15.1%	15.1%

Indianapolis Power & Light

Quick Transition Load and Resource Balance Report

Unit Planning Capacity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST2	417	417	417	417	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST3	547	547	547	547	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST4	531	531	531	531	531	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	0	0	0	0	0	0	0
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	0	0	0	0	0	0	0
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Pete 2 Gas	0	0	0	0	0	451	451	451	451	451	451	451	451	0	0	0	0	0	0	0
Pete 3 Gas	0	0	0	0	0	592	592	592	592	592	592	592	592	0	0	0	0	0	0	0
Pete 4 Gas	0	0	0	0	0	575	575	575	575	575	575	575	575	0	0	0	0	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
CC H Class - 2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00
Existing Solar	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	550	550	550	550	550	550	550
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	600	600	600	600	600	600	600
Total Resources	3575	3575	3575	3575	3575	3464	3464	3427	3427	3427	3427	3427	3427	3052	3052	3052	3052	3064	3064	3064
Original Base Peak Load Forecast	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	86	145	192	244	263	281	296	315	333	345	358	368	379	392	410	426	436	447	458
Peak Load - DSM Removed	2808	2778	2717	2678	2624	2612	2605	2604	2593	2587	2588	2594	2597	2604	2610	2616	2616	2629	2641	2658
Reserve Margin	27.3%	28.7%	31.6%	33.5%	36.2%	32.6%	33.0%	31.6%	32.2%	32.4%	32.4%	32.1%	31.9%	17.2%	16.9%	16.7%	16.7%	16.5%	16.0%	15.3%

IPL 2016 IRP

Attachment 8.2 (DSM Savings and Costs) is provided electronically.

IPL 2016 IRP

Confidential Attachment 8.3 (ABB Results) is only available in the Confidential IRP.