TESTIMONY OF SCOTT PARK
DIRECTOR IRP & ANALYTICS - MIDWEST
DUKE ENERGY PROGRESS, INC.
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 44734 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott Park, and my business address is 400 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company"), as Director, IRP & Analytics – Midwest.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts degree in Economics from Brigham Young University in December of 1992. In May 1997, I received a Master of Business Administration degree from Carnegie Mellon University with a specialization in Finance and Marketing.

From June of 1997 to July of 1999, I was employed by Southern Company Energy Marketing in Atlanta, Georgia. While there, I worked on a joint venture with Vastar Resources and structured wholesale transactions in the western United States.

From July of 1999 to September of 2001, I was employed by Pacific Gas & Electric in Bethesda, Maryland. While there, I structured wholesale transactions in the western United States.

In September of 2001, I joined Progress Energy in Raleigh, North Carolina, structuring wholesale transactions in the Carolinas and Florida. In 2009, I began a three year project managing the group that administered Progress Energy's Department of Energy Smart Grid Grant. For most of 2012, I worked in the Fuels Department evaluating various fuel strategies and transactions. Starting in late 2012, I have been in the Duke Energy Integrated Resource Planning and Analytics Department and assumed my current position in May of 2013.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the Company's 2015 Integrated Resource Plan ("IRP") analyses and how the proposed Naval Support Activity ("NSA") Crane Solar Facility ("Crane Solar Facility") is consistent with Duke Energy Indiana's preferred resource portfolio from the 2015 IRP.

II. DUKE ENERGY INDIANA'S INTEGRATED RESOURCE PLAN

Q. WHAT IS AN IRP?

A. An Integrated Resource Plan is a formal plan for meeting future utility load requirements that includes the utility's assessment of a variety of demand-side and supply-side resources to reliably and cost-effectively meet customer electricity needs. Indiana electric generating utilities are required to submit such formal plans bi-annually. Although the formal or "official" IRPs are a regulatory requirement, in reality they typically reflect and document the planning analysis we generally would perform on an ongoing basis in the absence of this regulatory requirement. The goal of the IRP process is to determine an optimal combination of resources that can be used to reliably and cost-effectively meet customers' future electric service requirements.

The IRP process involves taking a myriad of resource options, and through screening and analysis, methodically funneling down until an optimal combination of feasible and economic alternatives that will reliably meet the anticipated future customer loads is reached.

Q. WHEN DID DUKE ENERGY INDIANA SUBMIT ITS MOST CURRENT IRP?

A. Duke Energy Indiana submitted its 2015 IRP on November 2, 2015.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBITS 3-A AND 3-B.

A. Petitioner's Exhibit 3-A is a copy of Volume 1 of the public version of Duke Energy Indiana's 2015 IRP. Petitioner's Exhibit 3-B is a copy of Volume 2 of the public version of Duke Energy Indiana's 2015 IRP.

Q. DOES THE 2015 IRP ADDRESS THE CRANE SOLAR FACILITY?

A. Yes. The Company's 2015 IRP includes the addition of 20 MW of solar-powered generation in 2016 (see Petitioner's Exhibit 3-A, Table 1-B, page 21 of 279). Although this resource addition did not necessarily contemplate the proposed Crane Solar Facility specifically, it reflected that our preferred resource portfolio included a solar addition of this general size. At the time the IRP was submitted, this proposed project had not been finalized with NSA Crane. For that reason, we instead generally discuss the Company's interest in a project such as the Crane Solar Facility. On page 105 of 279, for example, Duke Energy Indiana stated:

> In addition, Duke Energy Indiana is exploring potential additions of renewable energy sources, possibly located on customer sites or in areas in need of grid support. The renewable energy sources could be paired with energy storage, be part of a micro-grid, or be standalone. The Company believes that making investments in smaller, carbon-free energy sources in the near term makes sense, particularly given the increasing number of environmental regulations and related uncertainty. To the extent we are facing a carbon-constrained future, such investments will serve to support the state's carbon reduction goal, while also providing Duke Energy Indiana with valuable experience in managing and integrating renewables, storage and micro-grids with its generation portfolio.

Q. IS CONSTRUCTION OF THE CRANE SOLAR FACILITY CONSISTENT WITH THE COMPANY'S 2015 IRP?

A. Yes.

Q. WHAT IS THE ANTICIPATED CAPACITY FACTOR OF THE PROPOSED CRANE SOLAR FACILITY?

A. The anticipated net capacity factor is 22.24%.

Q. PLEASE EXPLAIN HOW THE CRANE SOLAR FACILITY WILL BE USED TO SERVE THE CAPACITY AND RESERVE MARGIN NEEDS OF DUKE ENERGY INDIANA'S CUSTOMERS.

A. Just as we do for other Duke Energy Indiana owned generation, we will determine the appropriate capacity contribution that will be provided by the Crane Solar Facility and would use that capacity to cover our load and reserve margin needs, and if we have additional capacity, we would offer it into the MISO capacity market. MISO determines the capacity value of renewable generation, such as solar, on an annual basis using an average of historical metered output during hours 15–17 in the months of June-August. Initially, as we do not yet have historical data, we plan to count 50% of nameplate capacity (8.5 MW) as peak load capacity in Year 1 for the Crane Solar Facility in accordance with current MISO guidance. Based on solar profile modeling, we anticipate that the MISO calculated peak load capacity for successive years will be approximately 10.8 MW.

III. CERTIFICATE OF NEED REQUIREMENTS

Q. WHAT CONSIDERATIONS ARE REQUIRED BY THE CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") STATUTE, INDIANA CODE § 8-1-8.5-4(2), PRIOR TO THE COMMISSION GRANTING A CPCN?

A. This statute requires consideration of conservation, load management, renewable energy, cogeneration, refurbishment, purchased power, interchange power, power pooling, and joint ownership. I address each of these below.

Q. DID DUKE ENERGY INDIANA CONSIDER CONSERVATION AND LOAD MANAGEMENT IN THE ANALYSES PERFORMED FOR THIS PROCEEDING?

A. Yes, we did. As part of the IRP and ongoing projections of capacity needs, Duke Energy Indiana analyzes the impacts associated with new Energy Efficiency ("EE") or Demand Response ("DR") programs and any changes in existing EE or DR programs. The portfolio of existing and proposed EE and DR programs is evaluated to examine the impact on the generation plan if the current set of programs were to continue and proposed programs were added. The projected incremental load impacts of all programs are then incorporated into the generation portfolio optimization process.

Q. DID DUKE ENERGY INDIANA EXPLICITLY CONSIDER RENEWABLE ENERGY RESOURCES IN THE ANALYSES PERFORMED FOR THIS PROCEEDING?

A. Yes. In addition to the fact that the Crane Solar Facility investment itself is an investment in renewable energy, our modeling allowed for the selection of a range of renewable alternatives including wind, solar, and biomass. The optimization model was allowed to select additional levels of renewables above any minimum requirement when it was economical.

Q. DID DUKE ENERGY INDIANA CONSIDER COGENERATION IN THE ANALYSES PERFORMED FOR THIS PROCEEDING?

A. Yes, we did. Cogeneration has been an option for customers since 1978 under the Public Utilities Regulatory Policies Act. A customer's decision to install cogeneration will be based on the economics of comparing the cost of the cogeneration facilities plus the ongoing operating costs (including whatever fuel is used in the facility) against the cost savings for whatever energy source currently is used to serve the process (gas, electricity or other) and the revenue that can be generated from the sale of the surplus power. Duke Energy Indiana's 2015 IRP included a standardized cogeneration plant as a resource option for selection by System Optimizer during the portfolio development model runs. The operating characteristics of this resource option were specified using representative data from potential cogeneration projects studied by the Company.

Q. DID DUKE ENERGY INDIANA CONSIDER REFURBISHMENT OF EXISTING FACILITIES?

A. Yes, we did. As described and accepted by this Commission in Cause No. 37414; Cause Nos. 38809 and 37417-S2; Cause No. 39175; Cause No. 39312; and Cause No. 41924, the Company has had a refurbishment or Engineering Condition Assessment Program ("ECAP") for a number of years. With this program, Duke Energy Indiana intends to maintain its generating units, where economically feasible, at their current level of capacity and reliability. The Company has performed its ECAP assessment on a number of units, and has taken many of the steps necessary to preserve the existing capacity. We have, in fact, incorporated much of what we learned about our units into our ongoing maintenance program.

Q. DID DUKE ENERGY INDIANA CONSIDER THE PURCHASE OF MARKET CAPACITY IN ITS ANALYSES?

A. Yes. We assumed the use of short-term capacity purchases to meet the Midcontinent Independent System Operator ("MISO") resource adequacy requirements until new generation could be built. Our analyses use an annual levelized cost methodology (in \$/kW-year) for the capital cost of new generation that serves as a proxy for annual capacity payments for long-term purchased capacity. The rationale for this assumption is that, in the long run, the cost of purchased capacity will approach the cost of new capacity.

Q. IS INTERCHANGE POWER A VIABLE SUBSTITUTE FOR THE CRANE SOLAR FACILITY?

A. No. Almost by definition, interchange (essentially, hourly spot) purchases are not a good substitute for (and cannot be depended upon to take the place of) firm capacity, such as on-system generating resources and reliability purchases. In addition, MISO does not allow such purchases to be applied towards a company's MISO resource adequacy requirements.

Q. IS POWER POOLING A VIABLE ALTERNATIVE TO THE CRANE SOLAR FACILITY?

A. No. The current MISO market is very effective at utilizing the existing capacity resources in the region, so I do not believe that power pooling would provide any further benefits. Therefore, it is not a viable alternative to serve Duke Energy Indiana's current capacity needs.

Q. DID DUKE ENERGY INDIANA CONSIDER JOINT OWNERSHIP OF THIS PROJECT?

A. Given that Duke Energy Indiana's customer, NSA Crane, offered its land for use specifically to Duke Energy Indiana and given the relative size of the Crane Solar Facility and its interconnection with Duke Energy Indiana transmission, joint ownership of the Crane Solar Facility was not considered. In addition, growing Duke Energy Indiana's percentage of capacity and energy provided by renewable resources will be instrumental in any compliance strategy for the EPA's Clean Power Plan or other future regulatory restriction on CO_2 emissions. Because all capacity is needed to serve Duke Energy Indiana customer needs, joint ownership of the Crane Solar Facility is not a good option.

IV. CONCLUSION

Q. IS THE PROPOSED CRANE SOLAR FACILITY CONSISTENT WITH THE STATE UTILTY FORECAST GROUP'S ("SUFG") MOST RECENT FORECAST?

A. The SUFG published its most recent forecast in November 2015.[1] It states that it forecasts "electricity usage to grow at a rate of 1.17 percent per year over the 20 years of the forecast" and that "Peak electricity demand is projected to grow at an average rate of 1.13 percent annually." November 2015 SUFG Forecast at 1-1. The SUFG explains that this "corresponds to about 235 megawatts (MW) of increased peak demand per year." *Id*. Therefore, although the SUFG does not advocate for specific types of resource additions, the Crane Solar Facility addition is consistent with its projected growth in electricity demand.

Q. BASED ON YOUR ANALYSES, DO YOU BELIEVE THAT INCURRING THE CRANE SOLAR FACILITY COSTS IS A REASONABLE OPTION FOR SERVING THE CAPACITY AND ENERGY NEEDS OF DUKE ENERGY INDIANA'S CUSTOMERS?

A. Yes, the proposed Crane Solar Facility is a reasonable and prudent investment, and gives us the opportunity to learn and gain experience with the integration of both solar energy and potentially, microgrids (depending on the outcome of the feasibility

[1] The SUFG's Indiana Energy Projections 2015 referenced in this testimony can be accessed at https://www.purdue.edu/discoverypark/energy/SUFG/publications.php

study) on Duke Energy Indiana's system. It also provides a step towards additional diversification of Duke Energy Indiana's generation mix, as well as a small shift of our portfolio to greener options.

Q. WERE PETITIONER'S EXHIBITS 3-A AND 3-B PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?

A. Yes, it does.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: ______________________ Dated: 1-14-16
Scott Park

The Duke Energy Indiana 2015 Integrated Resource Plan

Public Version

November 1, 2015

Volume 1

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Integrated Resource Plan – Abbreviations

Activated Carbon Injection	ACI
American Clean Energy and Security Act	ACES
Architecture and Engineering	A&E
Auction Clearing Price	ACP
Behind the Meter Generation	BTMG
Best Available Control Technology	BACT
Calcium Bromide	$CaBr_2$
Carbon Capture and Storage	CCS
Carbon Dioxide	CO_2
Certificate of Public Convenience and Necessity	CPCN
Clean Air Act	CAA
Clean Air Act Amendments	CAAA
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Clean Air Transport Rule	CATR
Clean Energy Legislation	CEL
Coal Combustion Residuals	CCR
Combined Cycle (natural gas-fired)	CC
Combustion Turbine (natural gas-fired)	CT
Community Energy Storage	CES
Compact Fluorescent Light bulbs	CFL
Compressed Air Energy Storage	CAES
Consumer Price Index	CPI
Cross State Air Pollution Rule	CSAPR
Demand Response	DR
Demand Side Management	DSM
Duke Energy Indiana	Company
Effluent Limitation Guidelines	ELG
Electric Generating Unit	EGU
Electric Power Research Institute	EPRI
Electronically Commutated Fan Motors	ECM
Energy Efficiency	EE
Environmental Protection Agency	EPA
Equivalent Forced Outage Rate Excluding Events Outside of Management Control	$XEFOR_d$
Federal Energy Regulatory Commission	FERC
Fixed Resource Adequacy Plan	FRAP
Flue Gas Desulphurization	FGD
Generating Availability Data System	GADS
Gigawatt-hours	GWh
Greenhouse Gas	GHG
Hazardous Air Pollutant	HAP
Heat Recovery Steam Generator	HRSG
Heating, Ventilation and Air Conditioning	HVAC
High Load Factor	HLF
Indiana	IN

Indiana Department of Environmental Management	IDEM
Indiana Municipal Power Agency	IMPA
Indiana Utility Regulatory Commission	IURC
Installed Capacity	ICAP
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Joint Transmission System	JTS
Kilowatt	kW
Kilowatt-hours	kWh
Load Serving Entity	LSE
Load, Capacity, and Reserve Margin Table	LCR Table
Loss of Load Expectation	LOLE
Low Load Factor	LLF
Low NO_x Burners	LNB
Maximum Achievable Control Technology	MACT
Maximum Net Dependable Capacity	MNDC
Mega Volt-Amps Reactive	MVAR
Megawatt	MW
Megawatt-hours	MWh
Mercury and Air Toxics Standard	MATS
Midcontinent Independent System Operator, Inc.	MISO
Millions of British Thermal Units	MMBtu
MISO Transmission Expansion Planning	MTEP
National Ambient Air Quality Standards	NAAQS
National Energy Technology Laboratory	NETL
National Oceanic and Atmospheric Administration	NOAA
National Pollutant Discharge Elimination System	NPDES
Net Present Value	NPV
New Source Performance Standard	NSPS
New Source Review	NSR
Nitrogen Oxide	NO_x
North American Industry Classification System	NAICS
North Carolina/South Carolina	NC/SC
Nuclear Regulatory Commission	NRC
Ohio/Kentucky	OH/KY
Operation and Maintenance Costs	O&M
Other Public Authorities	OPA
Particulate Matter	PM
Parts Per Billion	PPB
Personalized Energy Report	PER
Planning Reserve Margin	PRM
Planning Resource Margin Requirement	PRMR
Planning Resources Auction	PRA
Power Purchase Agreement	PPA
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Pulverized Coal	PC
Ratepayer Impact Measure	RIM
Regional Transmission Organization	RTO
Reliability*First* Corporation	RFC

Renewable Energy Certificates	REC
Renewable Energy Portfolio Standard	REPS
Research, Development and Delivery	RD&D
Resource Conservation Recovery Act	RCRA
Selective Catalytic Reduction	SCR
Selective Non-Catalytic Reduction	SNCR
Short Term Implementation Plan	STIP
Small Modular Reactor	SMU
State Implementation Plan	SIP
State Utility Forecasting Group	SUFG
Sulfur Dioxide	SO_2
System Optimizer	SO
Technology Assessment Guide	TAG
Third Party Administrator	TPA
Total Resource Cost	TRC
Unforced Capacity	UCAP
Utility Cost Test	UCT
Volt-Amps Reactive	VAR
Wabash Valley Power Association, Inc.	WVPA
Zonal Resource Credit	ZRC

1. EXECUTIVE SUMMARY

A. OVERVIEW

Duke Energy Indiana (Company) is Indiana's largest electric utility, serving approximately 800,000 electric customers in 69 of Indiana's 92 counties covering North Central, Central, and Southern Indiana. Its service area spans 22,000 square miles and includes Bloomington, Terre Haute, and Lafayette, and suburban areas near Indianapolis, Louisville, and Cincinnati.

The Company has a legal obligation and corporate commitment to reliably and economically meet its customers' energy needs. Duke Energy Indiana utilizes a resource planning process to identify the best options to serve customers' future energy and capacity needs, incorporating both quantitative analysis and qualitative considerations. For example, quantitative analysis provides insights into future risks and uncertainties associated with the load forecast, fuel and energy costs, and renewable energy resource options. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, and the stage of technology deployment are also important factors to consider as long-term decisions are made regarding new resources. The end result is a resource plan that serves as an important tool to guide the Company in making business decisions to meet customers' near-term and long-term energy needs.

The resource planning objective is to develop a robust economic strategy for meeting customers' needs in a dynamic and uncertain environment. Uncertainty is a critical concern when dealing with emerging environmental regulations, load growth or decline, and fuel and power prices. Furthermore, particularly in light of the rapidly changing environmental regulations currently impacting our resource planning process, the Integrated Resource Plan (IRP or the Plan) is more like a compass than a road map by providing general direction at this time while leaving the specific tactical resource decisions to Commission filings using then current information. While we have always explained that the IRP is a "snapshot in time," that is especially true this year. For example, while the Company has modeled the EPA's proposed Clean Power Plan (CPP) rule, the final rule differs so much from the proposed rule, the modeling performed to date does not accurately reflect current circumstances and as such, must already be updated. Major changes in the 2015 from the 2013 IRP follow.

INCREASED NUMBER OF SCENARIOS

The 2015 IRP features seven discrete and internally consistent scenarios that enhance analytical robustness by covering a wider range of possible futures. A consulting firm performed the macro-economic modeling for each scenario using a suite of equilibrium models that defined a set of internally consistent assumptions. The seven scenarios arranged in three groups are:

Core Scenarios

1. No Carbon Regulation
2. Carbon Tax
3. Proposed Clean Power Plan (P-CPP)[1]

Change of Outlook Scenarios

4. Delayed Carbon Regulation
5. Repealed Carbon Regulation

Stakeholder-Inspired Scenarios

6. Climate Change
7. Increased Customer Choice

UNCERTAINTY IN A CARBON-CONSTRAINED FUTURE

In 2014, the EPA proposed carbon dioxide (CO_2) emission limits for new coal-fired electric generating units (EGU) that would effectively prohibit their construction without carbon capture and storage (CCS) technology. In August 2015, the EPA finalized a rule to regulate CO_2 emissions from existing coal-fired EGUs, and its impact is still under review. Due to the lead-time required for IRP preparation, analysis of the Clean Power Plan (CPP) was limited to the proposed rule. Despite the litigation regarding the final rule that will likely ensue, the Company believes it is prudent to plan for the possibility of a carbon-constrained future. To address this possibility, the Company continues to evaluate portfolios under a range of carbon regulations.

The Company considered a wide range of CO_2 cost assumptions in its group of scenarios. The Carbon Tax Scenario begins with $17/ton in 2020 and increases to $57/ton by 2035, with a

[1] This is the EPS's November 2014 proposed version of the rule, not the final Clean Power Plan rule.

related sensitivity growing to $114/ton by 2035. The No Carbon Regulation Scenario has a $0/ton CO_2 cost in all years. The P-CPP Rule does not have an explicit tax on carbon emissions but forces portfolios to meet certain requirements.

We believe our current range of CO_2 prices, including a zero price in the No Carbon Regulation Scenario, is appropriate given the outcome of past debates over federal climate change legislation, the uncertainty surrounding future U.S. climate change policy, and our belief that to be politically acceptable, climate change policy would need to be moderate. If or when there is additional clarity around future legislative or regulatory climate change policy, the Company will adjust its assumptions related to carbon emissions as needed. As previously stated, the Company already plans to perform updated modeling to better reflect the now-final CPP rule, and will continue to revise its modeling as more is known about a state implementation plan or otherwise.

COMPLIANCE WITH NEW EPA REGULATIONS

Additional emerging environmental regulations that will impact the Company's retirement and investment decisions include new water quality standards, fish impingement and entrainment standards, the Coal Combustion Residuals (CCR) rule and the new Sulfur Dioxide (SO_2), Particulate Matter (PM) and Ozone National Ambient Air Quality Standards (NAAQS). All compliance assumptions were reviewed and updated for consistency with other IRP assumptions. As rules impacting Duke Energy Indiana are proposed or finalized in 2015 and 2016, the Company will develop a compliance strategy and seek any necessary regulatory approvals.

RETIRMENT ANALYSIS

Retirement analysis for the generation fleet was included in overall optimization modeling. The model optimizes retirement decisions and resource additions simultaneously.

MODELING ENERGY EFFICIENCY (EE) PROGRAMS AS A SUPPLY SIDE RESOURCE

Based on stakeholder and Commission staff recommendations, EE was modeled as a supply-side resource. This is particularly challenging due to the way EE is included in the load forecasting process, the uncertainty of EE forecasting, and combining EE programs into a bundle that can be modeled with supply side resources like natural gas fired combined cycle or solar resources.

CHANGES IN THE PROJECTED LOAD FORECAST

Comparing the 2015 load forecast with 2013, the total energy and peak capacity need for Duke Energy Indiana decreased across all customer classes primarily due to the impact of the weak economic recovery on demand by residential and commercial class customers. While long-term trends point toward recovery, 2015 energy usage has not returned to pre-2008 levels. Summer peak capacity needs have returned more quickly, with summer peak demand expected to grow at just under 1% annually for most scenarios.

The rest of this Executive Summary presents an overview of the scenarios and portfolios used to determine the preferred resource plan. Further details regarding the planning process, issues, uncertainties, and alternative plans are presented in following chapters. See Appendix H For the location of information required by the Commission's October 4, 2012 Proposed IRP Rules.

B. PLANNING PROCESS RESULTS

The most prudent approach to address uncertainties is to create a plan that is robust under various future scenarios. Also, the Company must maintain flexibility to adjust to evolving regulatory, economic, environmental, and operating circumstances. The planning process included scenario analysis. Macro-level driving forces discussed in stakeholder meetings informed the development of seven distinct, internally consistent scenarios.

Seven Scenarios

No Carbon Regulation

- No carbon tax/price or regulation
- Moderate levels of environmental regulation
- No Renewable Energy Portfolio Standard (REPS)

Carbon Tax

- Carbon tax $17/ton in 2020, rising to $57/ton
- Increased levels of environmental regulation
- 5% REPS

Proposed Clean Power Plan

- Carbon reduced 20% from 2012 emission
- Increased levels of environmental regulation
- 5% REPS

Delayed Carbon Regulation

- No Carbon Regulation scenario until 2025
- Carbon regulation by carbon tax delayed until 2025
- Demonstrates impact of delayed carbon regulation

Repealed Carbon Regulation

- Carbon Tax scenario until 2025
- Carbon regulation by tax delayed until repealed in 2025
- Demonstrates impact of repeal of carbon regulation

Increased Customer Choice

- Carbon Tax scenario basis
- Roof top solar serves additional 1% of load per year beginning 2020
- Customers adopt higher levels of EE
- New utility-scale generation provided by merchant generators

Climate Change

- Higher summer temperatures increase demand and prices for power and fuel
- Carbon tax same as Carbon Tax scenario
- Even hotter summer 2019 and "polar vortex" 2020, and every 5 years thereafter, causing higher prices

Nine Portfolios

Once the specific modeling assumptions for each scenario were determined, a capacity expansion model was used to optimize a portfolio for that scenario. Nine portfolios organized in three groups were evaluated to further increase the robustness of the planning analysis. The first group was developed as part of the optimization of the assumptions defined by the first three scenarios (No Carbon Regulation, Carbon Tax and Proposed Clean Power Plan):

Optimized Resource Plans

1. No Carbon Regulation Portfolio
2. Carbon Tax Portfolio
3. P-CPP Portfolio

The second group was developed by adding additional combined cycle (CC) capacity to the portfolios above. This was done to evaluate the impact of adding additional gas generation on cost, carbon emissions and power market interaction.

Combined Cycle Resource Plans

4. No Carbon Tax Portfolio with additional CC
5. Carbon Tax Portfolio with additional CC
6. P-CPP Portfolio with additional CC

The third group was based on the input from stakeholders as part of the IRP stakeholder process.

Stakeholder-Inspired Resource Plans

7. Stakeholder Distributed Generation Portfolio
8. Stakeholder Green Utility Portfolio
9. High Renewables Portfolio

Table 1-A includes more detail for each portfolio. Figure 1-A shows how the capacity and energy in each portfolio changes over time. Capacity and energy percentages shown for portfolios 1, 2 and 3 are based on their performance in the scenario used to develop each portfolio: No Carbon Regulation, Carbon Tax and Proposed Clean Power Plan, respectively. Portfolios 4, 5 and 6 are variations of portfolios 1, 2 and 3 and thus, the capacity and energy percentages are also tied to the same three associated scenarios. Portfolios 7, 8 and 9 capacity and energy percentages reflect their performance in the Carbon Tax scenario which provided the basis for their design.

Table 1-A: Portfolio Details

NO CARBON REGULATION PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832	208	208	208	208
CHP	44	29	15		
CC					
EE & IVVC	244 / 3.1%	124 / 1.9%	105 / 3.2%	11 / 3.2%	4 / 3.1%
Solar					
Wind					
Biomass					

RETIREMENTS					
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			

CARBON TAX PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	416			208
CHP	15	15			
CC	448				448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	10	140	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

PROPOSED CLEAN POWER PLAN PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	208		208	208
CHP	44	29	15		
CC	448	448			
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	20	130	120	
Wind	450		300	100	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

NO CARBON TAX PORTFOLIO WITH ADDITIONAL CC CAPACITY

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	416			208	208
CHP	44	29	15		
CC	448	448			
EE & IVVC	244 / 3.1%	124 / 1.9%	105 / 3.2%	11 / 3.2%	4 / 3.1%
Solar					
Wind					
Biomass					

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			

CARBON TAX PORTFOLIO WITH ADDITIONAL CC CAPACITY

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	15	15			
CC	896	448			448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

PROPOSED CLEAN POWER PLAN PORTFOLIO WITH ADDITIONAL CC

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	44	29	15		
CC	896	896			
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		300	100	50
Biomass	14	2	6	6	

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

STAKEHOLDER DISTRIBUTED GENERATION PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832		208		624
CHP	667	160	290	15	203
CC	1,344		896		448
EE & IVVC	725 / 8.8%	171 / 2.5%	239 / 5.7%	134 / 7.1%	181 / 8.8%
Nuclear	140				140
Battery	370		180	90	100
Solar	2,480	670	970	420	420
Wind	2,050	450	800	550	250
Biomass	353	106	162	60	25

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4	Gib5 Cay1,2 Gib1		Gib2,3
MW	(4,283)	(1,114)	(1,909)		(1,260)

STAKEHOLDER GREEN UTILITY PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832	208	624		
CHP	261	29	73	73	87
CC	1,344		896		448
EE & IVVC	635 / 7.8%	171 / 2.5%	209 / 5.3%	134 / 6.7%	121 / 7.8%
Solar	930	40	380	300	210
Wind	800		250	300	250
Biomass	14	4	4	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4	Gib5 Cay1,2		Gib1
MW	(3,023)	(1,114)	(1,279)		(630)

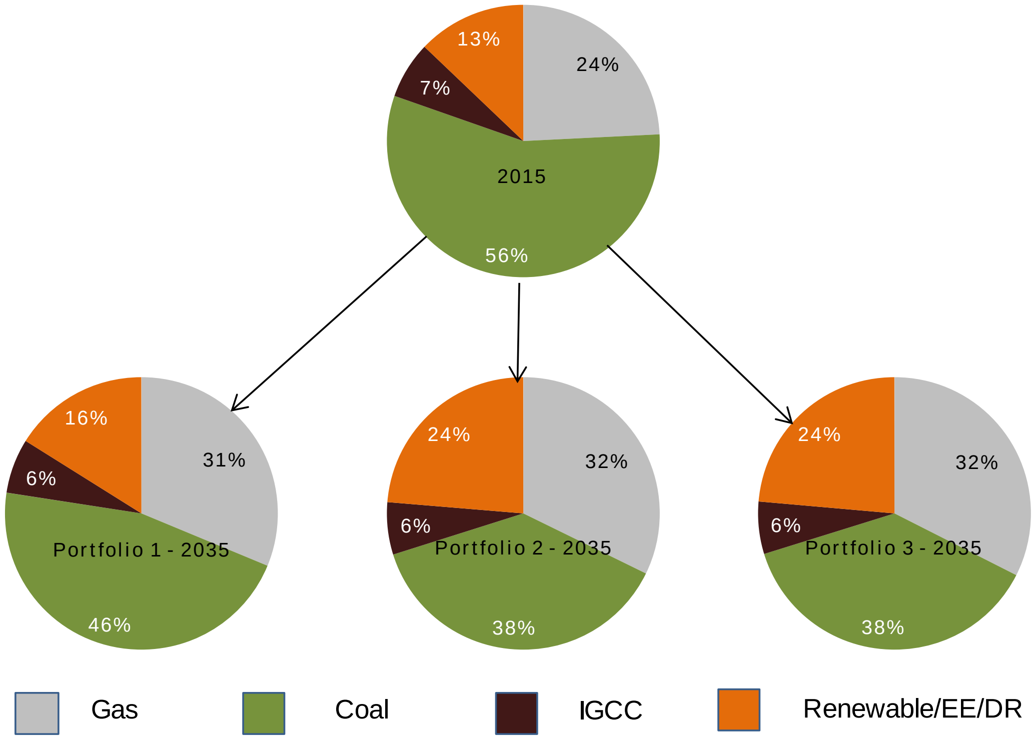
HIGH RENEWABLES PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	416		208	
CHP	29	15	15		
CC	448				448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	1,010	20	130	260	600
Wind	2,300		300	500	1,500
Biomass	14	2	8	4	

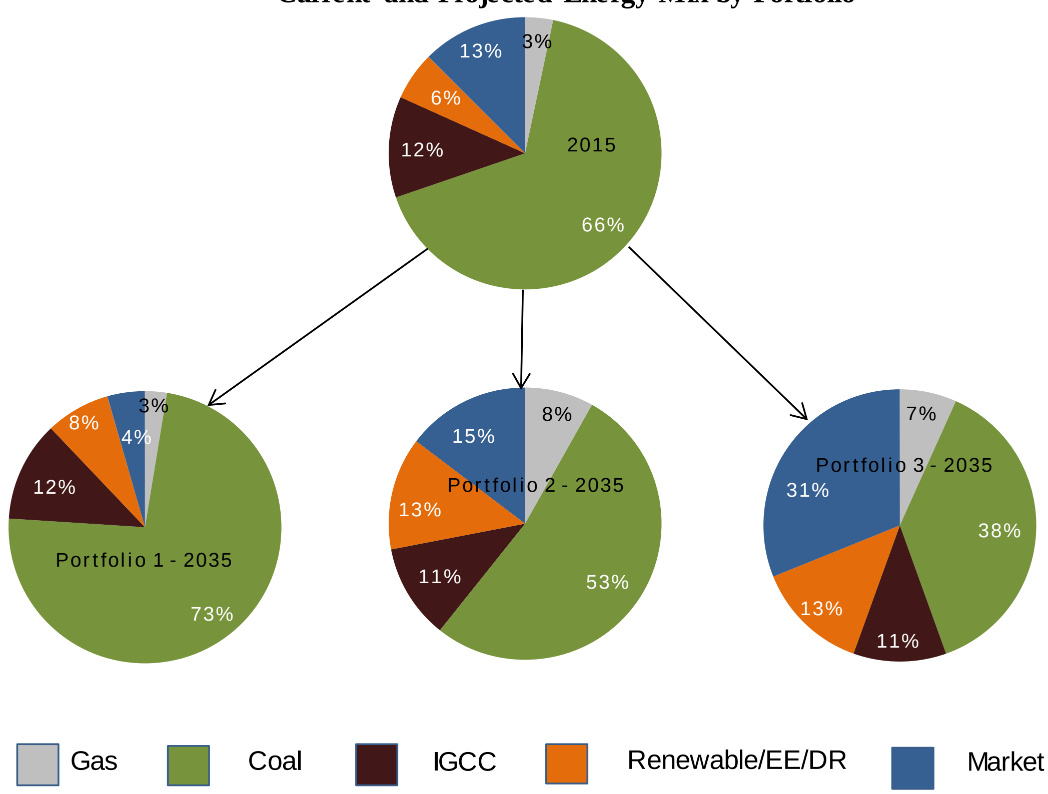
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

Figure 1-A: Generation Mix 2015 and 2035

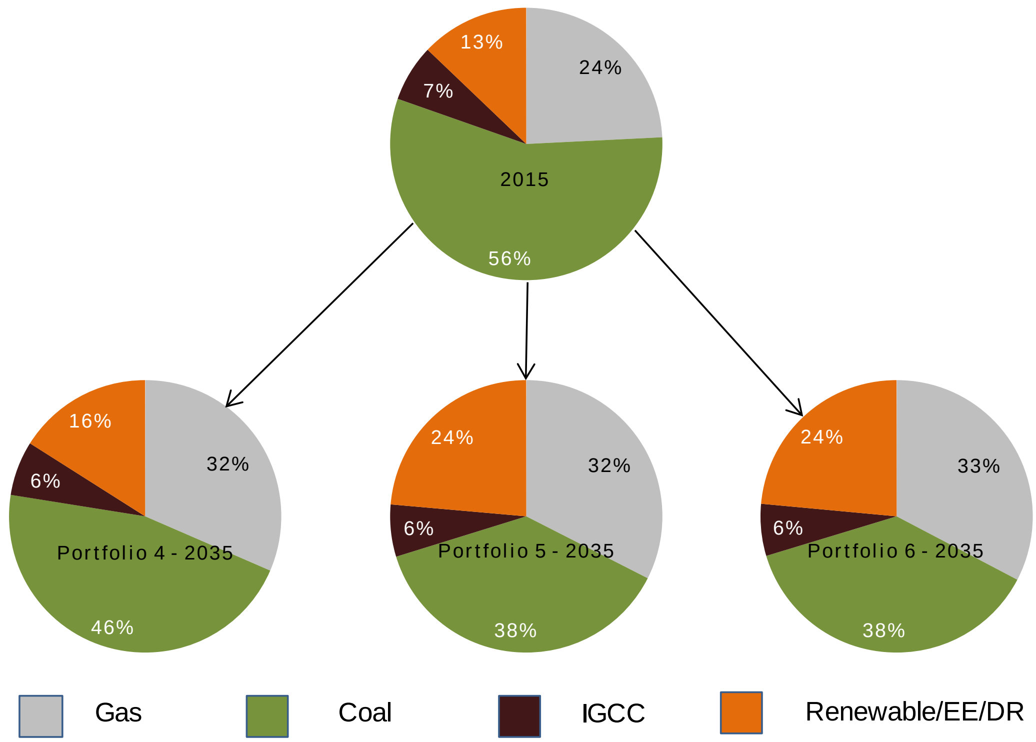
Current and Projected Capacity Mix by Portfolio



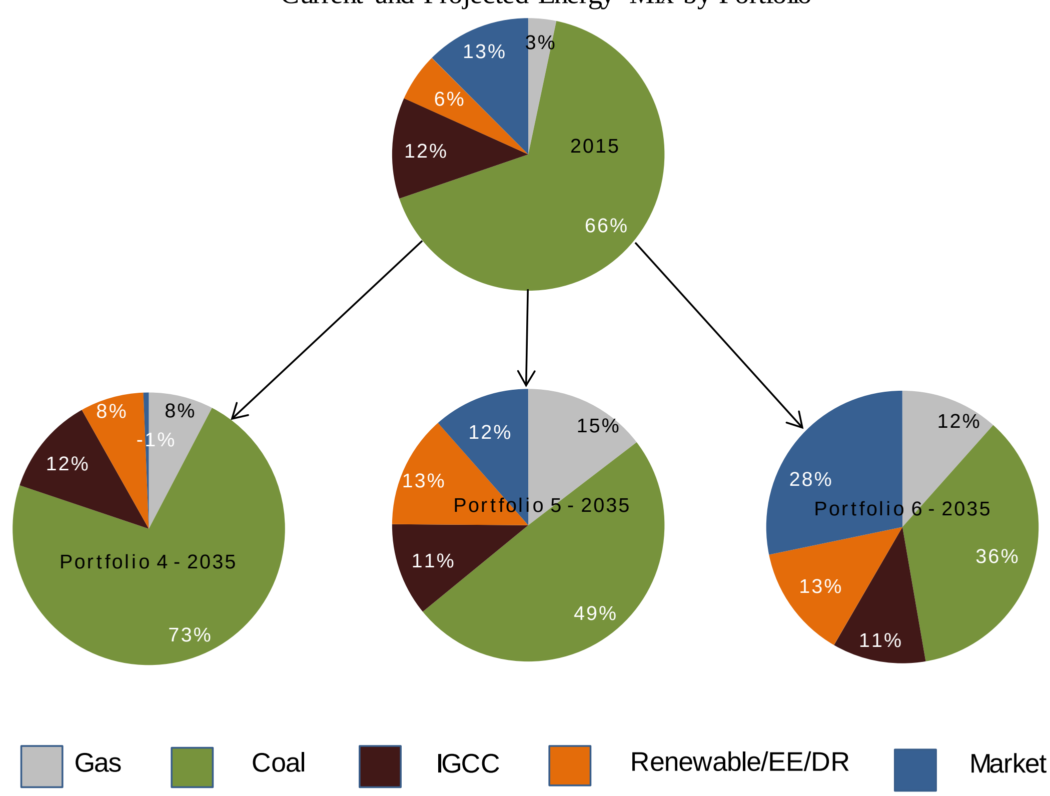
Current and Projected Energy Mix by Portfolio



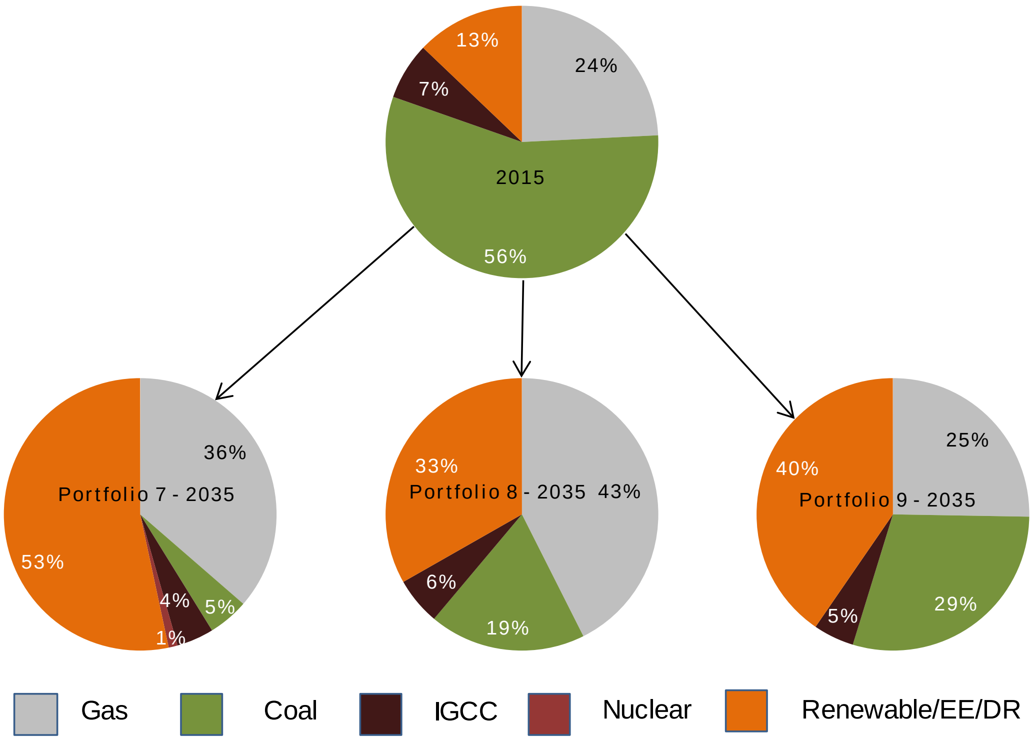
Current and Projected Capacity Mix by Portfolio



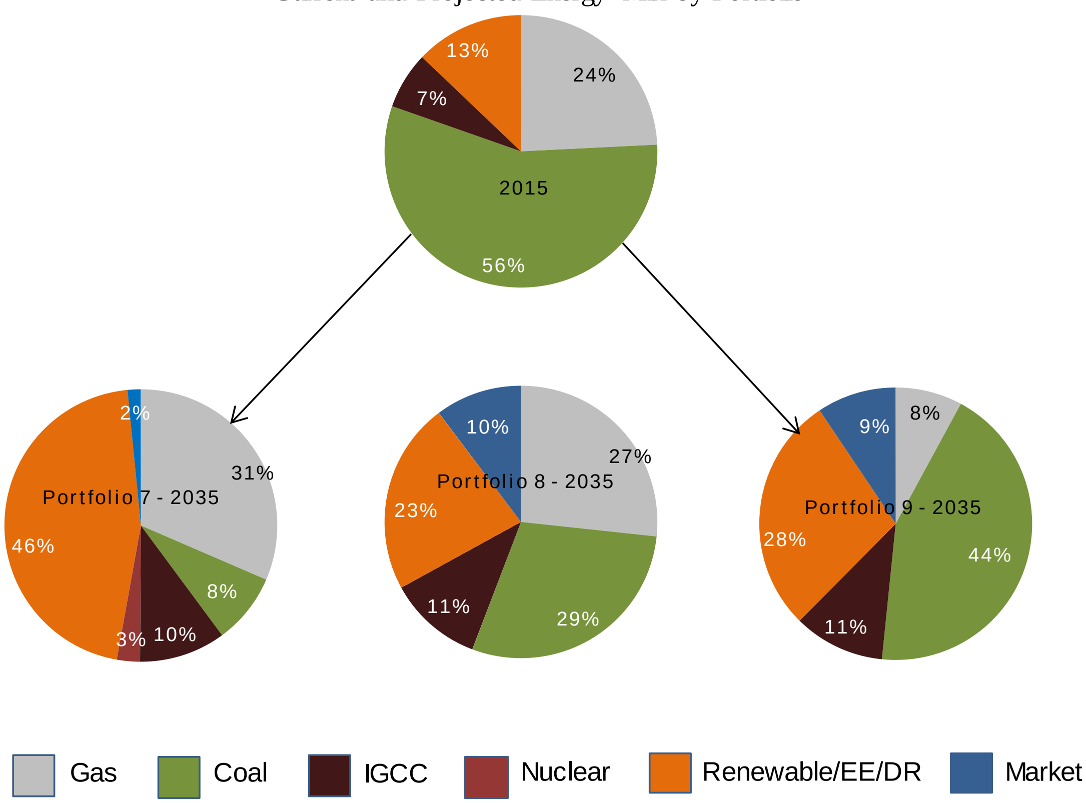
Current and Projected Energy Mix by Portfolio



Current and Projected Capacity Mix by Portfolio



Current and Projected Energy Mix by Portfolio



The objective of the IRP is to produce a robust portfolio that meets load obligation while minimizing the Present Value Revenue Requirements (PVRR) at a reasonable level of risk, subject to laws and regulations, reliability and adequacy requirements, and operational feasibility. Also, the selected plan must meet MISO's 13.6% reserve margin requirement. Based on its superior performance in scenario and sensitivity analyses, the Carbon Tax Portfolio with Additional CC was selected by Duke Energy Indiana as the preferred resource plan. This portfolio stands out due its combination of relatively low cost with lower exposure to market risk. Also, it enables the transition to a generating portfolio that has the flexibility to either comply with the final CPP rule or perform well without no carbon regulation.

<u>Short Term:</u>

As can be seen in Table 1-A, the Carbon Tax Portfolio with Additional CC retires Wabash River units 2-6, oil fired CT generation and Gallagher units 2 and 4, while adding CHP, EE, IVVC, solar, biomass and CC resources. Overall, the smaller and less environmentally-controlled generation being retired is replaced by newer, more environmentally friendly technologies that will serve customers well regardless of whether there is future carbon regulation.

<u>Long Term:</u>

Longer term, this portfolio can add more renewable and CC generation if carbon regulation remains in force. If carbon regulation is repealed, this portfolio can make additions of more traditional generation (primarily gas turbine technology) to minimize customer costs.

An overview of the preferred resource plan is summarized in Table 1-B.

TABLE 1-B
DUKE ENERGY INDIANA INTEGRATED RESOURCE PLAN
PORTFOLIO AND RECOMMENDED PLAN (2015-2035)

Year	Retirements	Additions	Renewables (Nameplate MW) [1]			Notable, Near-term Environmental Control Upgrades [2]
			Wind	Solar	Biomass	
2015						
2016	Wabash River 2-6 (668 MW)			20		
2017				20		Ash handling/Landfill upgrades: Cayuga 1-2 & Gibson 1-5
2018	Connersville 1&2 CT (86 MW) Mi-Wabash 1-3,5-6 CT (80 MW)					
2019	Gallagher 2 & 4 (280 MW)					
2020		CC 448 MW Cogen 15MW		10	2	
2021				10	2	
2022			50	20		
2023			50	30	2	
2024			50	30	2	
2025				30		
2026			50	20	2	
2027			50	30		
2028			100	30	2	
2029			50	30	2	
2030				10		
2031	Gibson 5 (310 MW)	CC 448 MW				
2032						
2033		CT 208 MW				
2034						
2035			50			
Total MW	1424	1119	450	290	14	

1: Wind and solar MW represent nameplate capacity.
2: Additional likely or potential control requirements include additives for mercury control, water treatment and intake structure modifications in the 2016 -2023 time frame.

2. SYSTEM OVERVIEW, OBJECTIVES AND PROCESS

A. INTRODUCTION

This chapter explains the objectives of and process used to develop the 2015 Duke Energy Indiana IRP. In the IRP process, modeling includes firm electric loads, supply-side and EE resources, and environmental compliance measures.

B. CHARACTERISTICS OF GENERATING AND TRANSMISSION CAPABILITIES

The total installed net summer generation capability owned or purchased by Duke Energy Indiana is currently 7,507 MW.[2] This capacity consists of 4,765 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 285 MW of natural gas-fired CC capacity, 45 MW of hydroelectric capacity[3], and 1,804 MW of natural gas-fired or oil-fired peaking capacity. Also included is a power purchase agreement with Benton County Wind Farm (100 MW, with a 13 MW contribution to peak modeled).

The coal-fired steam capacity consists of 14 units at four stations (Gibson, Cayuga, Gallagher and Wabash River). The syngas/natural combined cycle capacity is comprised of two syngas/natural gas-fired combustion turbines and one steam turbine at the Edwardsport Integrated Gasification Combined Cycle (IGCC) station. The CC capacity consists of a single unit comprised of three natural gas-fired combustion turbines and two steam turbines at the Noblesville Station. The hydroelectric generation is a run-of-river facility comprised of three units at Markland on the Ohio River. The peaking capacity consists of seven oil-fired diesels at the Cayuga and Wabash River stations, seven oil-fired CT units at Connersville and Miami-Wabash, and 24 natural gas-fired CTs at five stations (Cayuga, Henry County, Madison, Vermillion, and Wheatland). One of these natural gas-fired units has oil back-up. Duke Energy Indiana also provides steam service to one industrial customer from Cayuga, which reduces Duke Energy Indiana’s net capability to serve electric load by approximately 20 MW.

[2] Excluding the ownership interests of IMPA (155 MW) and WVPA (155 MW) in Gibson Unit 5, and the ownership interest of WVPA (213 MW) in Vermillion, but including the non-jurisdictional portion of Henry County (50MW) associated with a long-term contract.

[3] Duke Energy Indiana intends to file a proposal in the near term to the Commission to modernize Markland Hydroelectric Station, thus increasing its carbon-free output.

The Duke Energy Midwest bulk transmission system is comprised of the 345 kilovolt (kV) and 138 kV systems of Duke Energy Ohio and the 345 kV, 230 kV, and 138 kV systems of Duke Energy Indiana. The bulk transmission system delivers bulk power into, from, and across Duke Energy Midwest's service area. This bulk power is distributed to numerous substations that supply lower voltage sub-transmission systems, distribution circuits, or directly serve large customer loads. Because of the numerous interconnections with neighboring local balancing areas, the Duke Energy Midwest transmission system increases electric system reliability and decreases costs to customers by permitting the exchange of power and energy with other utilities on an emergency or economic basis.

As of December 2014, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 850 circuit miles of 345 kV lines, 775 circuit miles of 230 kV lines and 1439 circuit miles of 138 kV lines. Duke Energy Indiana, Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Association (WVPA) own the Joint Transmission System (JTS) in Indiana. The three co-owners have rights to use the JTS. Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and Vectren) plus Duke Energy Ohio.

Duke Energy Indiana is a member of the Midcontinent Independent System Operator, Inc. (MISO) and is subject to the overview and coordination mechanisms of MISO. All of Duke Energy Indiana's transmission facilities, including those transmission facilities owned by WVPA and IMPA but operated and maintained by Duke Energy Indiana, are included in these MISO planning processes.

C. <u>OBJECTIVES</u>

An IRP process generally encompasses an assessment of a variety of supply-side, EE, and environmental compliance alternatives leading to the formation of a diversified, long-term, cost-effective portfolio of options intended to satisfy the electricity demands of customers located within a service territory. The purpose of this IRP is to outline a strategy to furnish these electric energy services over a 20-year planning horizon.

The planning process is dynamic and adaptable to changing conditions. This resource plan represents one possible outcome based on a single snapshot in time along this continuum. While it is the most appropriate resource plan at this point in time, good business practice requires Duke Energy Indiana to continue to study the options and make adjustments as necessary to reflect improved information and changing circumstances. In an effort to be better prepared for these circumstances, the Company performed scenario and sensitivity analyses that measure the impact of CO_2 and other anticipated environmental regulations, customer load, renewable energy requirements, and fuel prices under seven future scenarios.

The major objectives of the Integrated Resource Plan presented in this submission are to:

- Provide adequate, reliable, and economic service to customers while meeting all environmental requirements
- Maintain the flexibility and ability to alter the plan in the future as circumstances change
- Choose a near-term plan that is robust over a wide variety of possible futures
- Minimize risks (such as wholesale market risks, reliability risks, *etc*.)

D. <u>ASSUMPTIONS</u>

The analysis performed to prepare this IRP covers the period 2015-2035. The base planning assumptions include:

- EE – The Company received approval for its 2015 EE portfolio under Cause No. 43955 DSM-3 and is currently implementing that portfolio for 2015. In addition, the Company has filed a proposed portfolio of EE programs under Cause No. 43955 DSM-3 and awaits approval. For the purpose of this IRP, the EE forecast is based on the expected implementation of the portfolio proposed in Cause No. 43955 DSM-3 and assumptions for future EE forecasts are based on this proposed portfolio. Further details of the methodology used to forecast beyond 2018 are included in other sections within this IRP.
- Renewable Energy – Although there is not currently an Indiana or federal REPS, the Company believes it is prudent to plan for one. The carbon regulation scenarios initiate a REPS in 2020, with a minimum of 5% by 2030. A small percentage of solar projects were accelerated in the 2016 to 2020 timeframe for installation and operation knowledge, which would enable access to any early reduction credits included in the final CPP.

- Carbon-Constrained Future – Although there is continued legislative and regulatory uncertainty surrounding future carbon emissions requirements, the ongoing interest in such restrictions requires the IRP to include costs for potential carbon taxes, allowances, and the CPP. The Carbon Tax Scenario begins with $17/ton in 2020, increasing to $57/ton by 2035, and the Proposed CPP Scenario includes a 20% reduction in carbon emissions.
- New Environmental Regulations – The estimated capital and operation and maintenance impacts of multiple new and proposed environmental regulations were included:
  - Final EPA MATS Rule[4] - Created emission limits for hazardous air pollutants (including mercury, non-mercury metals, and acid gases) starting April 16, 2015. Control upgrades varied by station ranging from fuel and process chemical additives to new SCR installations. One-year compliance extensions were granted for several Duke Energy Indiana units to allow sufficient time to implement control technologies or to relieve transmission reliability issues before pending retirements.
  - Final 1-hour 75ppb SO_2 National Ambient Air Quality Standard (NAAQS) – Potential to further limit the amount of SO_2 that can be emitted from a facility. Currently, only the Wabash River station is in a non-attainment region, requiring near-term action by January 1, 2017. Future designations could be promulgated in the late 2017 – 2020 timeframe.
  - Future reductions to the Ozone NAAQS – Potential for additional NO_x reductions in the post 2017 timeframe to meet a new lower ozone standard.
  - Final Cross-State Air Pollution Rule (CSAPR) – Two-phased cap-and-trade program designed to limit the total annual and summertime NO_x and annual SO_2 emissions from Eastern U.S. electric generating facilities. Phase I was implemented on January 1, 2015 and Phase II takes effect on January 1, 2017.
  - Final Fish Impingement and Entrainment Standards (316(b) rule) – Effective October 14, 2014, this rule intends to reduce the amount of fish impinged on the intake screen or entrained through the condenser cooling water system. Compliance requirements

[4] The MATS rule was recently remanded by the Supreme Court to the D.C. Circuit for further proceedings. Despite the Supreme Court's decision, the MATS rule remains in effect pending further action by the D.C. Circuit, meaning that all affected sources must continue to meet the rule requirements except where compliance extensions have been granted.

range from barrier nets to intake structure modifications with fine mesh screen installations to closed-cycle re-circulating cooling systems.

- Final Coal Combustion Residuals Rule (CCR) – Regulates a generating power plant's new and existing landfills and surface impoundments used to store or dispose of CCRs. The rule became effective October 19, 2015, and will lead to closure of surface impoundments, conversion to dry handling of fly ash and bottom ash, and the need for additional landfill capacity.
- Final Steam Electric Limitation Guidelines (ELG) – The final rule was signed Sept. 30, 2015 and will be effective 60-days after publication in the Federal Register. The rule revises a station's waste water discharge permit by establishing technology limits based on the performance of the best technology available selected by the EPA. Compliance with the rule likely involves upgrading of waste water treatment systems.
- Final Waters of the United States – The Clean Water Act (CWA) provides federal jurisdiction over waters defined as "the waters of the United States" (WOTUS) and is overseen by both EPA and United States Army Corps of Engineers. Once a body of water is classified as WOTUS, it is then subject to numerous CWA programs. Effective August 28, 2015, the definition of WOTUS was extended to include additional waters. On October 9, 2015, the Sixth Circuit issued a nationwide, temporary stay of the rule while it determines whether the courts of appeal or district courts have jurisdiction over challenges filed by states and private parties. A longer stay may be requested later. While the stay is in effect, the previous definition of WOTUS will be applied.
- Final Greenhouse Gas Rule (Clean Power Plan) – The Clean Power Plan (CPP) rule was proposed on June 18, 2014 and finalized on August 3, 2015. The rule intends to regulate CO_2 emissions through State or Federal implementation programs. The final rule is expected to be published in the Federal Register in October 2015 (too late to include in this year's IRP modeling, although the proposed rule was modeled.)

Risks from uncertainties are addressed by scenario and sensitivity analyses and qualitative reasoning in Chapters 5, 6, and 8. The Company's financial departments provided the after-tax effective discount rate of 6.92% and escalation rate of 2.5%.

Reliability Criteria

Reliability*First* Resource Adequacy

Duke Energy Indiana's reserve requirements are impacted by Reliability*First*, which has adopted a Resource Planning Reserve Requirement Standard that the Loss of Load Expectation (LOLE) due to resource inadequacy cannot exceed one day in ten years (0.1 day per year). This Standard is applicable to the Planning Coordinator, which is MISO for Duke Energy Indiana.

MISO Module E-1 Resource Requirements

The MISO Tariff includes a long-term resource adequacy requirement similar to that of Reliability*First*. Beginning with Planning Year June 1, 2009 – May 31, 2010, the LOLE standard became enforceable under MISO's tariff, with financial consequences for violating it.[5]

The Planning Reserve Margin (PRM) that is assigned to each load serving entity (LSE) is on a UCAP (*i.e.*, unforced capacity) basis. The PRM on an ICAP (*i.e.*, installed capacity) basis is translated to PRM_{UCAP} using the MISO system average equivalent forced outage rate excluding events outside of management control ($XEFOR_d$).[6] Each capacity resource is valued at its UCAP rating (*i.e.*, ICAP rating multiplied by 1 minus the unit-specific $XEFOR_d$).

Beginning with Planning Year 2013/14, MISO instituted an annual capacity construct with locational capacity requirements. Each LSE is required to have Zonal Resource Credits (ZRCs)[7] equivalent to $1+PRM_{UCAP}$ multiplied by the annual forecasted peak load coincident with MISO's peak. For the 2015/16 Planning Year, the Company is required to meet a PRM_{UCAP} of 7.1%. However, for IRP purposes, PRM_{UCAP} is restated to an equivalent Installed Capacity Reserve Margin (RM_{ICAP}) target (*i.e.*, the historical method used by Duke Energy Indiana) for modeling purposes. For Planning Year 2015/16, the applicable RM_{ICAP} is 14.9%.[8]

[5] The deficiency charges are based on the Cost of New Entry (CONE). The 2015/16 CONE value for Zone 6 (which includes Indiana) is $90,010 per MW-year.

[6] $PRM_{UCAP} = (1 – \text{MISO Average } XEFOR_d)(1 + PRM_{ICAP}) – 1$

[7] 1 ZRC is equal to 1 MW of UCAP capacity for generators or Behind The Meter Generation (BTMG) in a particular Zone.

[8] $RM_{ICAP} = \text{Coincidence Factor X } [(PRM_{UCAP} +1) / (1 – \text{Duke Energy Indiana Average } XEFOR_d)] – 1$

For longer-term planning, the RM_{ICAP} should be adjusted for known future changes such as the retirement of Wabash River 2-5 and suspension of Wabash River 6[9] (due to MATS compliance). Therefore, the minimum Reserve Margin criterion in this IRP analysis is 13.6%, based on the Planning Year 2015/16 PRM_{UCAP} and Duke Energy Indiana's coincidence with the MISO peak. To the extent that the actual PRM_{UCAP} for future Planning Years differs from that for Planning Year 2015/16, Duke Energy Indiana may require either a higher or lower level of reserves than what is shown in this IRP.

E. PLANNING PROCESS

Every two years, Duke Energy Indiana prepares an IRP pursuant to the definition given in the proposed amendments to Indiana Administrative Code Rule 7, Guideline for Integrated Resource Planning by an Electric Utility. The process used to develop the IRP consisted of organizational, analytical, and stakeholder processes.

Organizational Process

Development of an IRP requires a high level of communication across key functional areas. Duke Energy Indiana's IRP Team consists of experts in the following key functional areas: electric load forecasting, resource (supply) planning, retail marketing (EE program development and evaluation), environmental compliance planning, environmental policy, financial, fuel planning and procurement, engineering and construction, and transmission and distribution planning. It is the Team's responsibility to examine the Indiana IRP rules and conduct the necessary analyses to comply with the filing requirements.

A key step in the preparation of the IRP is the integration of the electric load forecast with supply-side, environmental compliance, and EE options. In addition, it is important to conduct the integration while incorporating interrelationships with other areas.

Analytical Process

Some of the following steps can be performed in parallel.

1. Develop planning objectives and assumptions.

[9] Although WR 6 must cease operating on coal due to the MATS rule, Duke Energy Indiana continues to evaluate the conversion of WR 6 from coal- to gas-fired. That is why it is referred to as a "suspension" herein.

2. Prepare the electric load forecast (Chapter 3).
3. Identify and screen cost-effective EE resource options (Chapter 4).
4. Identify and screen cost-effective supply-side resource options (Chapter 5).
5. Identify and screen cost-effective environmental compliance options (Chapter 6).
6. Integrate the EE, supply-side and environmental compliance options (Chapter 8).
7. Perform final scenario and sensitivity analyses on the integrated resource alternatives and recommend a plan (Chapter 8).
8. Determine the best way to implement the recommended plan (Chapter 8, Appendix D).

Stakeholder Process

In response to the proposed rule, Duke Energy Indiana has conducted four stakeholder meetings to discuss the IRP process and gather stakeholder input.

Stakeholder Meeting #1 – March 17, 2015

- Background on stakeholder process
- Scenario Planning

Stakeholder Meeting #2 – June 4, 2015

- Scenario and resource discussion
- Portfolio development exercise

Stakeholder Meeting #3 – August 4, 2015

- Scenario and portfolio review
- Preliminary modeling results
- Sensitivity exercise

Stakeholder Meeting #4 - October 16, 2015

- Scenario and portfolio review
- Final modeling results
- Decision and Risk Management discussion
- Presentation of preferred portfolio and short term implementation plan

Materials covered and meeting summaries are included in Volume 2 and are posted on the company's website at: http://www.duke-energy.com/indiana/in-irp-2015.asp

3. ELECTRIC LOAD FORECAST

A. GENERAL

Duke Energy Indiana is the state's largest electric utility, serving approximately 800,000 electric customers in 69 of Indiana's 92 counties covering North Central, Central, and Southern Indiana. Its service area spans 22,000 square miles and includes the cities of Bloomington, Terre Haute, and Lafayette, and suburban areas near Indianapolis, Louisville and Cincinnati.

The electric energy and peak demand forecasts of the Duke Energy Indiana service territory are prepared each year by a staff that is shared with the other Duke Energy affiliated utilities. While the Duke Energy Indiana load forecast is developed independently of the projections for other Duke Energy served territories, the overall methodology is the same. Duke Energy Indiana does not perform joint load forecasts with non-affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of non-affiliated utilities.

B. FORECAST METHODOLOGY

Energy is a key commodity in the overall level of economic activity. As residential, commercial, and industrial economic activity increases or decreases, the use of energy, or more specifically electricity, should increase or decrease, respectively. This linkage to economic activity is important to the development of long-range energy forecasts. For this reason, forecasts of the national and local economic drivers are key ingredients to energy forecasts. The general framework of the electric energy and peak demand forecast includes national and service area economic forecasts and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's Analytics, a national economic consulting firm. Similarly, the history and forecast of key economic and demographic concepts for the Duke Energy Indiana service area economy is obtained from Moody's Analytics. The service area forecast and energy and peak models are used to produce the electric load forecast.

1. Service Area Economy

Duke Energy Indiana provides electric service to customers in portions of 69 counties in North Central, Central and Southern Indiana. On a retail sales basis, Duke Energy Indiana provides electric service to 5 percent or more of the population in 61 of these counties. Duke Energy Indiana's service area includes numerous municipal utilities and Rural Electric Membership Cooperatives (REMCs), some of which are Duke Energy Indiana’s wholesale customers.

There are five major dimensions to measuring the service area economy: employment, income, inflation, output and population. Forecasts of employment are delivered by North American Industry Classification System (NAICS) code and aggregated to major sectors such as commercial and industrial. Income for the local economy is forecasted for wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments. Combining these forecasts produces the forecast of income less transfer payments. Inflation is measured by changes in the Consumer Price Index (CPI). Output is filtered into an Industrial Production index due to the importance of manufacturing to Indiana economic activity. Population projections are aggregated from forecasts by age-cohort. Taken all together, this information serves as input to the energy and peak load forecast models.

2. Electric Energy Forecast

The following sections provide the specifications of the econometric equations developed to forecast electricity sales for Duke Energy Indiana. Several sectors comprise the Duke Energy Indiana Electric Load Forecast Model. Forecasts are prepared for electricity sales to the residential, commercial, industrial, governmental, other, and wholesale energy sectors. Additionally, projections are made for summer and winter peak demands.

Residential Sector - The two components of the residential sector energy forecast are the number of residential customers and energy use per customer. The forecast of total residential sales is developed by multiplying the forecasts of these two components.

Customers - The number of electric residential customers (households) is affected by population as measured by households. This relationship is represented as follows:

(1) Number of Residential Customers = f (Population).

f = function of.

Because the number of customers changes gradually over time in response to changes in population and real per capita income, this adjustment process is modeled using lag structures.

Residential Use Per Customer - The key drivers of energy use per customer are real (i.e. inflation-adjusted) per-household income, real electricity prices and the combined impact of numerous other determinants as tracked by the Energy Information Administration (EIA). These include the saturation and efficiency of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather. The forecast number of residential customers is also an input in this model.

(2) Energy usage per Customer = f (Real Income per household, Residential Appliance intensity, Real Average Electric Price , Cooling and Heating Degree Days, Residential Customers).

Commercial Sector - Commercial electricity usage changes with the level of non-manufacturing GDP, real electricity price, and weather impacts. There are also the combined impact of numerous other determinants as tracked by the EIA, which are commercial saturations and efficiencies as scaled by square footages for different commercial activity sectors. Time series testing indicated that usage of a logarithmic trend was appropriate. The model is formulated as follows:

(3) Commercial Sales = f (Real non-manufacturing GDP, Real Average Electric Price, Billed Heating and Cooling Degree Days, logarithmic trend).

Industrial Sector - Electricity use by industrial customers is primarily dependent on the level of industrial production, employment of workers in manufacturing, and the impacts of real electricity prices. The general model of industrial sales is formulated on a per-billing-day basis as follows:

(4) Industrial Sales/Billing Days = f (Industrial Production Index, Manufacturing employment, Real Average Electric Price).

Governmental Sector – The term Other Public Authorities (OPA) indicates customers involved and/or affiliated with federal, state or local government. Electricity usage is related to governmental employment, the real price of electricity, and heating and cooling degree days. The general model of OPA sales is formulated on a per-billing-day basis as follows:

(5) OPA Sales/billing day = f (Governmental Employment, Real Average Electric Price, Billed Cooling and Heating Degree Days).

Other Sector – The Company provides electricity for municipal activities such as street lighting and traffic signals. This sector is forecasted using EIA seasonally-adjusted trends.

Total Retail Electricity Sales - The five sector forecasts are transformed from billing month to calendar month quantities and summed to produce the projection of total retail electricity sales.

Wholesale - Duke Energy Indiana provides electricity on a contract basis to various wholesale customers. Wholesale customers' loads are forecasted using specifications contained within the contracts, MISO price forecasts, and historical trend analysis.

Total System Sendout/Net Energy For Load - Upon completion of the total electric sales forecast, the total Duke Energy Indiana system sendout or net energy for load forecast is prepared. This requires that all the individual sector forecasts be combined along with forecasts of Wholesale sales and system losses. Sector forecasts that are weather-dependent are weather-normalized to eliminate the impact of non-normal weather in actual historic electricity sales. After the system sendout forecast is completed, the peak load forecast can be prepared.

Peak Load - Forecasts of summer and winter peak demands are developed using econometric models that account for the end-use data relevant to the peak. For summer months, the cooling and base end uses are most relevant, and for winter, heating and base end uses are relevant. A single equation is estimated for each month to model the impact of all three kinds of end uses. Heating end uses are calculated by applying estimating coefficients from heating degree days to the Residential and Commercial Models. Cooling end uses are calculated by applying estimating coefficients from Cooling degree days to the Residential and Commercial Models.

Base end uses are a sum of the remainder of residential and commercial energy as well as Industrial, Governmental, and Other energy.

The peak forecasting model is designed to represent closely the relationship of weather to peak loads by incorporating the average daily temperature on the day of monthly peak.

(6) Peak = f (Cooling End-use X Weather Factors, Heating End-use X Weather factors, Base End uses).

Peak Forecast Procedure – The summer peak most often occurs in July or August in the afternoon (June and September peaks have also occurred) and the winter peak most often occurs in January (with December or February also possible; both morning and evening peaks are possible). Since the energy model produces forecasts under the assumption of normal weather, the forecast of sendout is "weather-normalized" by design. However, the unlikely occurrence of a system peak in April, May, October, or November motivates weighting observations from these months at ½ weight in the estimation (so that the model will allow for greater error in forecasting those peaks and be more demanding in fitting the peaks to the main peak months) while offsetting with additional weight on July/August and Dec/January observations. Once predicted peaks are produced by this model for retail sales, coincident peak Wholesale figures are added to produce the system peak.

C. ASSUMPTIONS

1. Macro Assumptions

It is generally assumed that the Duke Energy Indiana service area economy will tend to co-move with the national economy over the forecast period. Duke Energy Indiana uses a long-term forecast of the national and state economies prepared by Moody’s Analytics.

2. Local Assumptions

With regard to the local economy, the Duke Energy Indiana service area has traditionally been strongly influenced by the level of manufacturing activity. While manufacturing employment declines over the forecast period, increasing manufacturing productivity and economic growth causes total manufacturing output and industrial energy sales to increase. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. This reflects a continuation of the trend toward the service industries and fundamental change that is occurring in manufacturing and other basic industries.

Duke Energy Indiana is also affected by national population trends. The average age of the U.S. population is rising due to stagnant birth rates and lengthening life expectancies. As a result, the portion of the population of the Duke Energy Indiana service area that is over age 65 increases over the forecast period. Over the period 2015 to 2025, Duke Energy Indiana's population is expected to increase at an annual average rate of 0.6 percent. Nationally, population is expected to grow at an annual rate of 0.9 percent over the same period, with much of the difference accounted for by net outmigration of people from Indiana. This outmigration affects Indiana more than it affects the Duke service area: among the four counties that lost 1,000 or more residents to net outmigration from 2010-2012, only one (Elkhart County) has any part in the Duke Energy Indiana service territory. For consistency, the Moody's forecast for state population is used despite this deficiency.

The residential sector is the largest in terms of total existing customers and total new customers per year. Within the Duke Energy Indiana service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is relatively stagnant, with a slight decrease expected over the planning period.

3. Customer Self-Generation

Over time, several industrial and some commercial customers have inquired about cogeneration, the concurrent production of electricity and steam for process heat. Cogeneration has been installed in a few cases. No additional behind-the-meter cogeneration units are assumed to be built or operated within the Company's service area during the forecast period.

In the area of other self-generation, several units are in place within Duke Energy Indiana's service territory to provide a source of emergency backup electricity. Where economical, a number of these units participate and are represented under Duke Energy Indiana's CallOption program under PowerShare®.

4. Post Estimation Adjustments

Expected developments in Electric Vehicle (EV) usage and EE load reduction achievements are expected to affect the forecast substantially. An EV forecast provided by the Duke Energy Renewables team is used to adjust both residential and commercial forecasts.

A new process for reflecting the impacts of Utility Energy Efficiency Programs (UEE) on the forecast was introduced in Spring 2015. In the latest forecast the concept of program 'Measure Life' was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE so as to represent the extent to which UEE programs reduce load that would have otherwise not been reduced. With statistically adjusted end-use models, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits, which reduces the forecasted load due to energy efficiency adoption. Because we incorporate data on saturations and efficiencies of the relevant end-uses for residential and commercial customers, these program achievements are implicitly built in to the predictive variables of our models beginning in the year when roll-off is complete.

D. <u>DATABASE DOCUMENTATION</u>

1. Economic Data

The major series of data in the economic forecast are employment, income, output, demographics, national production, and national employment, provided by Moody's Analytics.

<u>Employment</u> - State-wide employment statistics are used by industry for both the manufacturing and non-manufacturing categories.

<u>Income</u> - Updates of historical local income data series are gathered at the state level. This is performed for total personal income, which includes dividends, interest and rent; wage and salary disbursements plus other labor income; non-farm proprietors' income; transfer payments; and personal contributions for social insurance.

Output – These are GDP and Industrial Production variables at the state level.

Population - Population statistics are gathered at the state level.

Manufacturing Activity – Manufacturing GDP and employment statistics are obtained for the Indiana region. This information is utilized in the forecast of industrial sales.

2. Energy and Peak Data

The majority of data required to develop the electricity sales and peak forecasts is obtained from the Duke Energy Indiana service area economic data provided by Moody's Analytics, from Duke Energy Indiana financial reports and research groups, and from national sources. With regard to the national sources of information, generally all national information is obtained from Moody's Analytics. However, local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

The major groups of data that are used in developing the energy forecasts are: kilowatt-hour sales by customer class, number of customers, use-per-customer, electricity prices, natural gas prices, appliance saturations, and local weather data.

Kilowatt-hour Sales and Revenue – Monthly historical sales and revenue data monthly by rate class is aggregated into the residential, commercial, industrial, OPA, and other sales sectors. In the industrial sector, sales data for each manufacturing NAICS category are collected. Statistics regarding sales and revenue for each wholesale customer are also collected. From the sales and revenue information, average electricity prices by FERC sector is calculated. A forecast of these prices is prepared by the Duke Energy fundamental forecast team. Historical energy at time of peak is computed from hourly data using a database of annual sales collected internally.

Number of Customers - The number of customers by sector, on a monthly basis, is obtained from Duke Energy Indiana records. Average electricity use per customer is calculated from the sales and customer data.

Natural Gas Prices - Natural gas prices are provided by Moody's Analytics.

Saturation of Appliances - The saturation of appliances within the service area is provided via customer surveys conducted by the Company's Market Research group and the EIA.

Local Weather Data

Local climatologic data are provided by NOAA for the Indianapolis reporting station.

Peak Weather Data

The weather conditions associated with the monthly peak load are collected from NOAA hourly and daily data. The weather variables that influence the summer peak are peak day and prior day maximum temperature, and peak day morning low temperature and humidity. The weather influence on the winter peak is measured by the low temperatures and the associated wind speed. The variables selected are dependent on whether it is a morning or an evening peak load.

An average of peak weather conditions is used as the basis for the weather component in the preparation of the peak load forecast as previously discussed. Using historical data for the single weather occurrence on the summer peak day and the single weather occurrence on the winter peak day in each year, an average extreme peak condition is computed for each season.

3. Forecast Data

Projections of national and local employment, income, industrial production, and population, as well as natural gas and electricity prices, are model inputs. The projections for employment, income, industrial production and population are obtained from Moody's Analytics.

Population – The sales forecast uses the Moody's Analytics population projections for Indiana.

Natural Gas Price – If needed, the forecast of natural gas prices is provided by the corporate fundamental forecast team.

Electricity Prices - The projected change in electricity prices over the forecast interval is derived from company records and from the EIA.

E. <u>REGRESSION ANALYSIS</u>

Ordinary least-squares is the principal regression technique used to estimate economic/behavioral relationships among the relevant variables. This econometric technique performs quantitative analysis of economic behavior through attributing variation in a dependent variable to changes in various independent variables. Based upon their relationship with the dependent variable, several independent variables are tested in the regression models, with the final models chosen based upon their statistical strength and logical consistency. Estimation techniques are modified to reflect that the data used are time series data, i.e. have a temporal relationship with each other.

F. <u>FORECASTED DEMAND AND ENERGY</u>

On the following figures, the loads for Duke Energy Indiana are provided.

1. Service Area Energy Forecasts

Figure 3-B contains the energy forecast for Duke Energy Indiana's service area.

Residential use for the twenty-year forecast period is expected to increase an average of 1.4 percent per year; Commercial use, 1.5 percent per year; and Industrial use, 0.5 percent per year. The summation of the forecast across each sector and including losses results in an annual forecast growth rate of 0.7 percent for Net Energy for Load. Net Energy for Load and its growth rate are impacted by Sales for Resale due to the length of contracts with wholesale customers.

2. System Seasonal Peak Load Forecast

Figure 3-C contains forecasts of summer and winter peaks for the Company's service area. The tables show the summer and succeeding winter peaks, the summer peaks being the predominant ones historically. Projected growth in the summer peak demand for the Duke Energy Indiana system is 0.8% percent. Projected growth in the winter peak demand is 0.5 percent.

3. Controllable and Interruptible Loads

The impact of controllable load is not included in the forecast. The amount of load reduction depends on the Company's request for controllable load curtailment and the customers' responses. See Chapter Four for a complete discussion of the impacts of interruptible and other demand response programs.

4. Load Factor

Figure 3-A below shows the annual percentage load factor for Duke Energy Indiana. It shows the relationship between Net Energy for Load, Figure 3-B and the annual peak, Figure 3-C.

Figure 3-A

Year	Load Factor
2015	63.3%
2016	63.1%
2017	62.4%
2018	62.5%
2019	62.6%
2020	62.7%
2021	62.7%
2022	62.8%
2023	62.9%
2024	62.9%
2025	62.8%
2026	62.8%
2027	62.7%
2028	62.6%
2029	62.6%
2030	62.6%
2031	62.4%
2032	62.2%
2033	62.2%
2034	62.3%
2035	62.3%

5. Range of Forecasts

The high and low range was determined by applying the standard error of the FERC-class estimation models using a 95% confidence interval, Figure 3-D.

6. Comparison of Forecast to Past Forecasts

Several noteworthy changes in the information available to Duke Energy Indiana concerning future economic conditions resulted in small changes to energy and peak load forecasts. The long-term forecast for Net Energy for Load (Table 3-B) has decreased slightly (2.9% less in 2033) from the 2013 forecast, mostly attributed to substantial downward revisions in forecast demand from residential and commercial customers that more than offsets an increase in forecasted industrial class sales.

The economy in mid-2015 is recovering, with—as measured by GDP growth—two disappointing winters in the rearview mirror. Industrial customers, particularly, are suffering because of the strong dollar, which tips the scales against them in competing against foreign alternatives both at-home and abroad. Government employment is 20,000 jobs below its peak, even while the rest of the economy has already recovered to peak job levels of 2007.

Many economic indicators increased and are now at significantly higher levels than at any time since the start of the financial crisis and recession. The University of Michigan consumer confidence index continued rising throughout the summer, and reports from the National Federation of Independent Business and the beige book have business owners more optimistic. The Federal Reserve ponders an increase in interest rates, but the strength of wage and GDP growth that would assure the prudence of such a change has not been attained.

Expectations for near-term wholesale demand have decreased since wholesale customers are expected to take more energy directly from MISO. Along with decreases in total energy, forecasts for future peak load have also decreased. Much of this is attributed to expectations of rapid increases in offsetting EE, particularly for the next several years.

Figure 3-B

Duke Energy Indiana

Service Area Energy Forecast (Magawatt Hours) (a)

		(1)	(2)	(3)	(4)	(5)		(6)	(7)	(8) = sum (1) thru (7)	(9)	(10) = (8) + (9)
		Rural and Residential	**Commercial**	**Industrial**	**Street Lighting**	**Governmental**	**Retail**	**Resale (b)**	**Customer Use**	**Total Consumption**	**Losses and Unaccounted for (c)**	**Net Energy for Load**
-5	2010	9,609,251	6,228,528	10,081,641	53,878	2,256,283	28,229,582	7,037,905	37,959	35,305,446	1,913,888	37,219,334
-4	2011	9,316,050	6,155,986	10,236,733	53,601	2,203,288	27,965,657	6,559,747	35,142	34,560,547	1,181,158	35,741,705
-3	2012	8,867,465	6,152,090	10,411,454	53,182	2,162,219	27,646,409	6,582,115	32,338	34,260,862	601,535	34,862,397
-2	2013	9,170,203	6,192,148	10,388,543	52,840	2,160,703	27,964,437	6,431,189	37,474	34,433,100	539,022	34,972,122
-1	2014	9,245,016	6,170,069	10,629,435	52,835	2,126,793	28,224,148	5,967,499	38,755	34,230,402	1,143,635	35,374,037
0	2015	9,222,928	6,349,219	10,806,099	53,171	2,189,689	28,621,107	3,750,701	38,755	32,410,563	2,297,245	34,707,807
1	2016	9,320,501	6,407,670	10,943,042	53,142	2,208,784	28,933,139	4,165,736	38,755	33,137,630	2,322,289	35,459,919
2	2017	9,473,920	6,469,630	11,081,334	53,086	2,207,636	29,285,606	4,132,458	38,755	33,456,818	2,350,580	35,807,398
3	2018	9,736,516	6,580,722	11,146,928	53,029	2,197,382	29,714,577	4,154,281	38,755	33,907,612	2,385,011	36,292,623
4	2019	9,885,820	6,649,415	11,272,929	52,973	2,192,959	30,054,095	4,157,868	38,755	34,250,718	2,412,262	36,662,980
5	2020	9,828,636	6,574,156	11,481,562	52,917	2,183,308	30,120,579	4,348,582	38,755	34,507,915	2,417,598	36,925,513
6	2021	9,875,304	6,583,576	11,529,741	52,860	2,171,778	30,213,258	4,298,838	38,755	34,550,851	2,425,037	36,975,888
7	2022	9,938,005	6,654,634	11,588,687	52,804	2,170,802	30,404,931	4,339,142	38,755	34,782,829	2,440,421	37,223,250
8	2023	10,006,458	6,750,383	11,653,345	52,747	2,173,046	30,635,978	4,342,859	38,755	35,017,592	2,458,966	37,476,558
9	2024	10,058,998	6,825,181	11,750,795	52,691	2,180,084	30,867,749	4,361,716	38,755	35,268,220	2,477,569	37,745,789
10	2025	10,132,626	6,887,960	11,750,559	52,634	2,174,666	30,998,446	4,313,430	38,755	35,350,631	2,488,059	37,838,690
11	2026	10,193,424	6,930,131	11,796,491	52,578	2,174,965	31,147,588	4,354,040	38,755	35,540,384	2,500,030	38,040,414
12	2027	10,263,921	6,973,534	11,831,139	52,521	2,173,262	31,294,377	4,357,971	38,755	35,691,103	2,511,812	38,202,915
13	2028	10,329,088	7,019,165	11,923,841	52,465	2,180,442	31,505,002	4,377,244	38,755	35,921,001	2,528,717	38,449,718
14	2029	10,389,238	7,053,195	11,975,466	52,409	2,177,714	31,648,021	4,328,815	38,755	36,015,591	2,540,197	38,555,788
15	2030	10,493,707	7,105,118	11,996,806	52,352	2,172,182	31,820,166	4,370,869	38,755	36,229,790	2,554,014	38,783,804
16	2031	10,611,338	7,177,485	12,020,283	52,296	2,175,892	32,037,294	4,375,743	38,755	36,451,792	2,571,441	39,023,233
17	2032	10,707,476	7,235,971	12,094,975	52,239	2,186,151	32,276,812	4,395,471	38,755	36,711,038	2,590,666	39,301,704
18	2033	10,840,787	7,305,795	12,092,940	52,183	2,183,302	32,475,008	4,348,653	38,755	36,862,416	2,606,574	39,468,990
19	2034	10,956,436	7,358,617	12,140,488	52,126	2,186,234	32,693,902	4,390,513	38,755	37,123,170	2,624,143	39,747,313
20	2035	11,072,823	7,416,687	12,184,944	52,070	2,187,024	32,913,548	4,395,566	38,755	37,347,869	2,641,773	39,989,642

(a) Figures in years -5 thru -1 reflect the impact of energy efficiency programs and have not been weather normalized.
(a) Figures in years 0 thru 20 reflect the impact of historical energy efficiency programs--but not achievements made after 2014--and are based on weather normal projections.
(b) Sales to wholesale customers.
(c) Line losses and other energy unaccounted for. 0.6%

Figure 3-C

Duke Energy Indiana

SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) (a)

		SUMMER			WINTER (d)		
	YEAR	LOAD	CHANGE (b)	PERCENT CHANGE (c)	LOAD	CHANGE (b)	PERCENT CHANGE (c)
-5	2010	6,476			5,896		
-4	2011	6,749	273	4.2	5,603	-293	-5.0
-3	2012	6,494	-255	-3.8	5,763	160	2.9
-2	2013	6,229	-265	-3.9	6,038	275	4.9
-1	2014	6,130	-99	-1.5	6,107	69	1.2
0	2015	6,259	129	2.1	5,678	-429	-7.0
1	2016	6,401	142	2.3	5,857	179	3.2
2	2017	6,535	134	2.1	5,873	16	0.3
3	2018	6,613	78	1.2	5,926	53	0.9
4	2019	6,662	49	0.7	5,932	6	0.1
5	2020	6,705	43	0.6	5,899	-33	-0.6
6	2021	6,732	27	0.4	5,954	55	0.9
7	2022	6,769	36	0.5	5,987	33	0.5
8	2023	6,805	37	0.5	6,009	22	0.4
9	2024	6,836	31	0.5	5,974	-35	-0.6
10	2025	6,881	45	0.7	6,053	79	1.3
11	2026	6,916	35	0.5	6,060	7	0.1
12	2027	6,960	44	0.6	6,085	25	0.4
13	2028	6,992	32	0.5	6,116	30	0.5
14	2029	7,035	43	0.6	6,108	-8	-0.1
15	2030	7,075	39	0.6	6,134	26	0.4
16	2031	7,137	62	0.9	6,164	30	0.5
17	2032	7,193	56	0.8	6,123	-41	-0.7
18	2033	7,246	53	0.7	6,202	79	1.3
19	2034	7,288	42	0.6	6,228	27	0.4
20	2035	7,330	42	0.6	6,274	46	0.7
CAGR		0.79%			0.50%		

(a) Figures in years -5 thru -1 reflect the impact of historical energy efficiency and demand response, and numbers have not been weather normalized.

(a, cont'd) Figures in years 0 thru 20 reflect the impact of historical energy efficiency subject to a roll-off schedule, represent peak demand before demand response, and numbers are weather normal.

(b) Difference between reporting year and previous year.

(c) Difference expressed as a percent of previous year.

(d) Winter load reference is to peak loads which occur in the following winter; winter 2014 peak is estimated based on best available data during summer 2015

Figure 3-D
Duke Energy Indiana
Range of Forecasts

	Energy Forecast (Megawatt Hours) (Net Energy for Load)			Peak Load Forecast (MW)		
	Low	Most Likely	High	Low	Most Likely	High
2015	34,575,707	34,707,807	34,839,907	6,235	6,259	6,283
2016	35,185,462	35,459,919	35,734,377	6,352	6,401	6,451
2017	35,393,872	35,807,398	36,220,925	6,459	6,535	6,611
2018	35,874,843	36,292,623	36,710,403	6,537	6,613	6,690
2019	36,243,458	36,662,980	37,082,503	6,586	6,662	6,739
2020	36,509,085	36,925,513	37,341,942	6,630	6,705	6,781
2021	36,555,349	36,975,888	37,396,428	6,656	6,732	6,809
2022	36,796,623	37,223,250	37,649,877	6,691	6,769	6,846
2023	37,043,288	37,476,558	37,909,828	6,727	6,805	6,884
2024	37,303,872	37,745,789	38,187,705	6,756	6,836	6,916
2025	37,386,694	37,838,690	38,290,686	6,799	6,881	6,963
2026	37,577,342	38,040,414	38,503,485	6,832	6,916	7,000
2027	37,727,383	38,202,915	38,678,447	6,873	6,960	7,046
2028	37,961,948	38,449,718	38,937,488	6,903	6,992	7,080
2029	38,052,992	38,555,788	39,058,584	6,943	7,035	7,127
2030	38,263,196	38,783,804	39,304,411	6,980	7,075	7,170
2031	38,494,987	39,023,233	39,551,479	7,040	7,137	7,234
2032	38,763,958	39,301,704	39,839,450	7,094	7,193	7,291
2033	38,921,237	39,468,990	40,016,743	7,146	7,246	7,347
2034	39,188,420	39,747,313	40,306,207	7,186	7,288	7,391
2035	39,417,962	39,989,642	40,561,322	7,225	7,330	7,435

Figure 3-E Annual System Energy Scenarios – Megawatthours

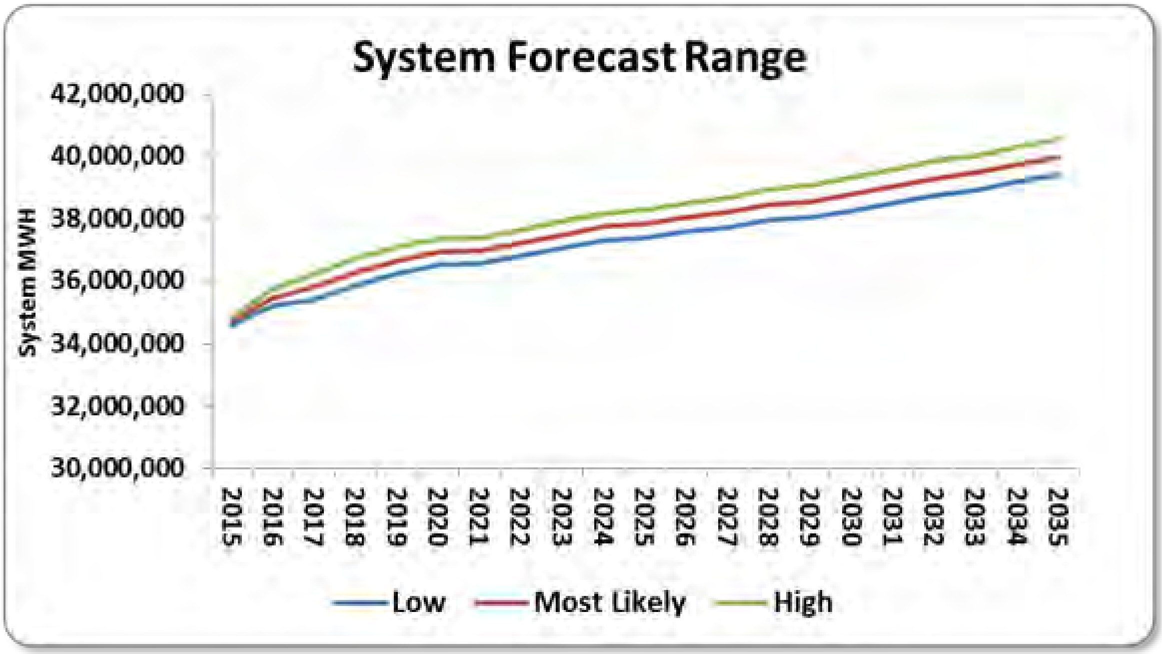
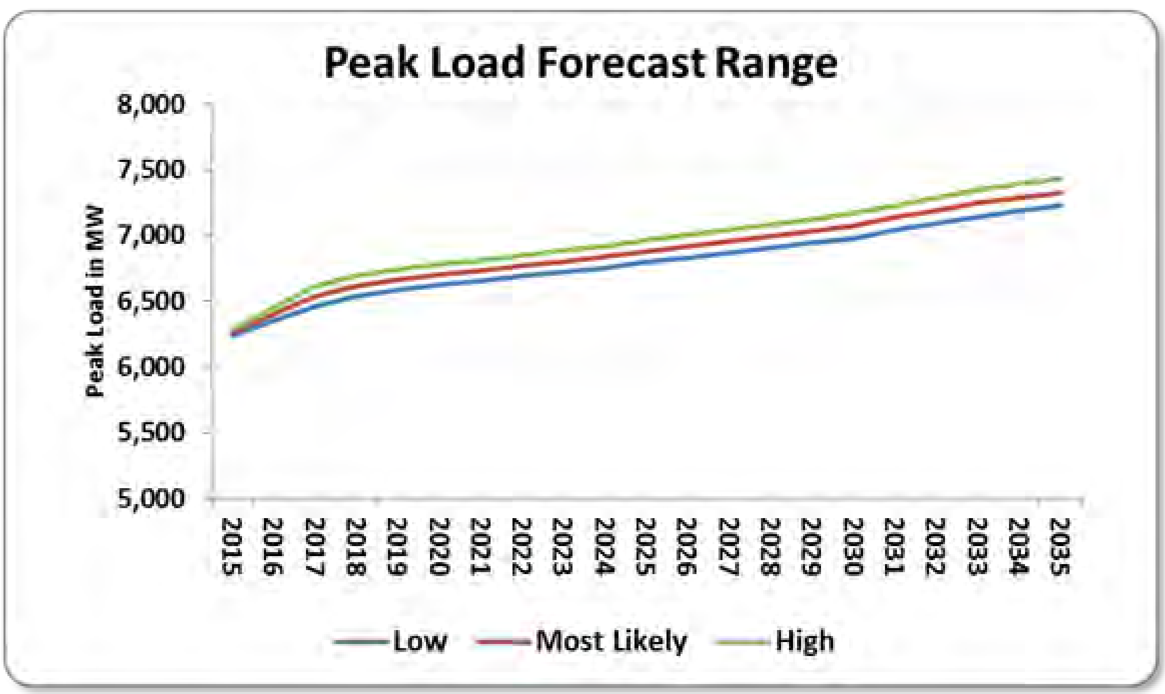


Figure 3-F Annual System Peak Scenarios – Megawatts



4. ENERGY EFFICIENCY RESOURCES

A. INTRODUCTION

As part of the IRP, Duke Energy Indiana analyzes the impacts associated with new EE or DR programs and any changes in existing EE or DR programs. The portfolio of existing and proposed EE and DR programs is evaluated within the IRP to examine the impact on the generation plan if the current set of programs were to continue and proposed programs were added. Additionally, all proposed and current EE and DR programs are screened for cost-effectiveness. The projected load impacts of all programs are then incorporated into the optimization process of the IRP analysis as discussed further below.

B. HISTORY OF DUKE ENERGY INDIANA'S PROGRAMS

Duke Energy Indiana has a long history associated with the implementation of EE and DR programs. Duke Energy Indiana's EE and DR programs have been offered since 1991 and are designed to help reduce demand on the Duke Energy Indiana system during times of peak load and reduce energy consumption during peak and off-peak hours. Demand response programs include customer-specific contract options and innovative pricing programs. Implementing cost-effective EE and DR programs helps reduce overall long-term supply costs. Duke Energy Indiana's EE and DR programs are primarily selected for implementation based upon their cost-effectiveness; however, there may be programs, such as a low income program, that are chosen for implementation due to desirability from an educational and/or social perspective.

C. CURRENT ENERGY EFFICIENCY PROGRAMS

Duke Energy Indiana's Energy Efficiency (EE) 2015 program portfolio was approved by the Commission in Cause No. 43955 – DSM2. For periods 2016-18 the portfolio reflects the programs that were filed for approval in Cause No. 43955 – DSM3.

1. Residential Programs

The following programs are either currently offered in 2015 or an application has been filed for approval in Cause No. 43955 – DSM3 to continue to offer these and future programs.

Smart $aver® Residential

The Residential Smart $aver® program has been expanded to contain measures to help customers improve efficiency of their HVAC system, building shell, in-ground swimming pool filtration, water heating, and indoor and outdoor lighting. The HVAC measures in this program have been modified and expanded to include a tiered incentive structure along with two add-on optional efficiency measures customers can choose to combine with equipment replacement that further improve the efficiency of the HVAC system.

HVAC Equipment

Cash incentives are provided for installing high efficiency heat pump or air conditioner systems. The incentives vary based on the efficiency rating of the equipment. Two optional measures, quality installation and smart thermostat, provide additional incentives when equipment is being replaced. This program establishes relationships with home builders and HVAC contractors who interface directly with residential customers when equipment is selected. Trade allies adhere to program requirements and submit incentive applications for qualified equipment installations. Incentives for new home construction are paid to the home builder, but the builder has the option to pass the incentive on to the customer.

HVAC Tune ups

This low cost measure provides customers and trade allies a documented approach to ensuring optimal efficiency is maintained for residential heat pump and air conditioning systems. Qualified technicians follow approved diagnostic testing and measurement to determine the current efficiency of the system. If the results determine that the system is operating inefficiently and steps are taken to improve the efficiency, the customer can qualify for an incentive. Trade allies submit incentive applications with supporting documentation of the pre and post diagnostic test results following successful completion of service. A heat pump or air conditioner system can qualify for an incentive one time over its life.

Duct Sealing

Program incentives are provided to customers that have a certified contractor seal the home's duct system to reduce air leakage. Trained technicians utilize diagnostic equipment and proven procedures to seal leaks which can reduce energy bills and improve comfort. Trade allies submit incentive applications following successful completion of duct sealing measure. The duct sealing incentive will be paid one time per duct system.

Attic Insulation and Sealing

Program incentives are provided to customers that have a trained participating contractor to seal and insulate the home’s attic. Trained technicians utilize diagnostic equipment and proven procedures to identify and seal attic penetrations to improve the homes comfort and to reduce energy bills. After the sealing process is complete, attic insulation is installed to provide protection from higher attic temperatures. Trade allies submit incentive applications following successful completion of insulation and air sealing within the attic. The attic insulation and air sealing incentive is available one time per household. This program is available to homeowners currently residing in a single-family residence, condominium, townhome or duplex.

Weather sensitive electrical loads represent the largest impact for high electric bills for most customers. These HVAC and building shell measures help customers reduce energy usage while improving comfort. The measures allow customers to make the most economical energy investment for their home while having confidence in the cost saving benefits.

Trade allies are important to this program success because they interface with the customer during the equipment purchase decision- making event which can have a significant impact on annual energy usage. The majority of trade ally marketing is conducted through personal outreach activities such as: face-to-face, phone, electronic and direct mail. Trade ally engagement is supplemented with general customer awareness of this program through email, direct mail and bill inserts. Duke Energy’s website and ad words are also used to improve program awareness and knowledge.

Heat Pump Water Heating

Cash incentives are provided to encourage the adoption and installation of high efficiency heat pump water heaters in new or existing residences with electric water heating. Duke

Energy served homeowners currently residing in or building a single family residence, condominium, or duplex home are eligible for this program. Installation of a high efficiency heat pump water heater will result in a $350 incentive. Duke Energy program personnel establish relationships with home builders, plumbing contractors, and national home improvement retailers who interface directly with residential customers. Incentives are paid directly to the customer following the installation of a qualified heat pump water heater by a participating contractor and approval of a completed application.

Proactive marketing channels will be used to generate awareness and educate customers on the benefits of heat pump water heaters. Promotion channels will include: bill inserts, retailer point-of-sale signage, direct mail, email, and Duke Energy website.

<u>Variable-speed Pool Pump</u>

Cash incentives are provided to encourage the adoption and installation of energy efficient, variable-speed pool pumps for the main filtration of in-ground residential swimming pools. Duke Energy served homeowners currently residing in or building a single family residence with an in-ground swimming pool are eligible for this program. Installation of a high efficiency, variable-speed pool pump will result in a $300 incentive. Duke Energy program personnel establish relationships with home builders and pool professionals who interface directly with residential customers. Incentives are paid directly to the customer following the installation of a qualified variable-speed pool pump by a participating contractor and approval of a completed application.

Proactive marketing channels will be used to generate awareness and educate customers on the benefits of variable-speed pool pumps. Promotion channels will include: bill inserts, trade ally collateral, direct mail, email, and Duke Energy website.

<u>Residential Lighting</u>

The Residential Lighting measures within the Smart Saver Program have three basic components, a standard CFL offer, an online Specialty Lighting offer and a retail-based LED lighting offer. Measure descriptions are provided below.

CFL

The CFLs program is designed to increase the energy efficiency of residential customers by offering customers CFLs to install in high-use fixtures within their homes. The CFLs are offered through an on-demand ordering platform, enabling eligible customers to request CFLs and have them shipped directly to their homes. Eligibility and participation limits are based on past participation in the CFLs program and other Duke Energy programs distributing CFLs. The maximum number of bulbs available for each customer is 15, but customers may choose to order less. Bulbs are available in 3, 6, 8, 12 and 15 pack kits that have a mixture of 13 and 18 watt bulbs. Customers have the flexibility to order and track their shipment through three separate channels:

Telephone: Customers call a toll-free number to access the Interactive Voice Response (IVR) system. Both English and Spanish-speaking customers may easily validate their account, determine their eligibility and place their CFL order over the phone.

Duke Energy Web Site: Customers can complete the ordering process online. Eligibility rules and frequently asked questions are also available.

Online Services ("OLS"): Customers who participate in the Online Services program are encouraged to order their CFLs through the Duke Energy web site, if they are eligible.

The benefits of providing these three distinct channels include:

- Improved customer experience
- Advanced inventory management
- Simplified program coordination
- Enhanced reporting
- Increased program participation
- Reduced program costs

Specialty Lighting

The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes.

The Savings Store offers a variety of CFLs and Light Emitting Diodes lamps ("LEDs") including; Reflectors, Globes, Candelabra, 3 Way, Dimmable and A-Line type bulbs. Duke Energy incentive levels vary by bulb type and the customer pays the difference, including shipping. The maximum number of incentivized bulbs available for each household varies with the different categories listed above depending on how many of each bulb type the average home is likely to have, but customers may choose to order more without the Duke incentive. Currently, residential customers can check eligibility and shop for specialty bulbs through three separate channels:

Duke Energy Web Site: Customers can go online to visit the Saving Store and purchase specialty bulbs. Frequently asked questions and a savings calculator are available to help customers understand how much they can save and how sustainable they can be by purchasing and using CFL and LED lighting.

Online Services: Customers enrolled in the Company's Online Services may visit the Savings Store and purchase specialty bulbs. At login, eligible customers are intercepted with the Savings Store offer. Customers can choose to "Shop Now" or "No Thanks". Additional links within OLS are also available for customers to access the Savings Store.

Telephone: Customers may call a toll free number to contact the programs third-party vendor directly to place their orders.

The Savings Store is managed by a third party vendor, Energy Federation Inc. ("EFI"). EFI is responsible for maintaining the Savings Store website and fulfilling customer purchases. The Savings Store landing page provides information about the store, lighting products, account information and order history. Support features include a toll free number, package tracking and frequently asked questions.

An educational tool is available to help customers with their purchase decisions. The interactive tool provides information on bulb types, application types, savings calculator, lighting benefits, understanding watts versus lumens (includes a video) and recycling/safety tips. Each wireframe within the educational tool provides insight on the types of bulbs customers can purchase and/or provides answers to questions they have about the products or savings.

Duke Energy residential customers with an active residential account are eligible to participate and must agree to terms and conditions, including the condition that all bulbs will be installed at the accounts premise address, to participate in this program.

This program provides discounted lighting products for residential customers to help them reduce their energy usage while maintaining comfortable lighting atmosphere. Lighting education assists customers in determining the best application for lighting alternatives and emerging technologies.

The primary goal for this program is to help customers lower their energy bills and to remove inefficient equipment from the electric grid. This program educates customers about energy consumption related to lighting and how it compares to high efficiency alternatives.

This program will implement an integrated approach to marketing which may include, but not limited to:

- Direct mail
- Bill inserts/messaging
- Community/trade events
- Digital and broadcast media

Retail Lighting

This upstream, buy-down, retail-based lighting program works through lighting manufacturers and retailers to offer discounts for incentivized LEDs and energy-efficient fixtures at retail stores. Retailers such as Home Depot, Lowe's, Sam's Club, Walmart and Costco will be evaluated at the store level for inclusion in this program.

This program encourages customers to adopt energy efficient lighting through incentives on a wide range of LED products, including Reflectors, Globes, Candelabra, 3 Way, Dimmable and A-Line type bulbs, as well as fixtures. Customer education is imperative to ensure they are purchasing the correct bulb for the application to obtain high satisfaction with energy efficient lighting products, ensuring subsequent energy efficient purchases. The incentive amount varies by product type and the customer pays the difference as well as any applicable taxes. Pack limits will be in place and enforced to the best of the retailers' ability.

A vendor will be utilized to implement this program. This vendor will be an industry leader and will leverage their existing relationships and systems established with the participating retailers and manufacturers. Additionally, the vendor will have a field team in place to promote and monitor this program at the participating retail locations. A toll free call center and website will be hosted by the vendor to provide program information to Duke Energy customers. The website will include a retailer locator where customers can enter their zip code and search for retailers and specific bulb and fixture types in their area. A tool available to customers is an interactive savings calculator, which will explain the different types of lighting technologies, help guide customers to the appropriate bulb/s for their application and provide an estimate of energy and monetary savings. Eligible program participants include Duke Energy residential customers.

The primary goals for this program are to help customers lower their energy bills and to remove inefficient equipment from the electric grid. This program educates customers about energy consumption attributed to lighting and how to reduce their consumption by using high efficiency alternatives.

This program will implement an integrated marketing plan which may include, but is not limited to:

- Point of Purchase materials at the participating retailer locations
- Duke Energy and Program website
- General Awareness Campaigns
    - Bill Inserts
    - Email

  - Digital advertising
  - Paid advertising/mass media
  - Out of Home advertising
- Advertised events at key retailers including:
  - Direct mail
  - Email
  - Paid advertising/mass media (radio, newspaper, etc.)
  - Social media
  - In Store materials (fliers, bag stuffers, posters, banners, etc.)
- Community outreach events (home shows, sporting events, cultural events, etc.)

These marketing efforts are designed to create customer awareness of this program, to educate customers on energy saving opportunities and to emphasize the convenience of Program participation. Additionally, marketing efforts related to advertised in-store events are designed to motivate customer participation.

<u>Save Energy and Water Kit</u>

The Save Energy and Water Kit ("SEWK") is designed to increase the energy efficiency of residential customers by offering customers Low Flow Water Fixtures and Insulated Pipe Tape to install in high-use fixtures within their homes. These energy saving devices will be offered to eligible customers and by opting in, customers can have these devices shipped directly to their homes, free of charge. Eligibility is based on past campaign participation (including this Program and any other programs offering low flow devices that Duke Energy has offered to Indiana customers) and the customer must have an electric water heater. Customers receive a kit with varying amounts, based on the size of the home, of the following devices: low flow bath and kitchen aerators, low flow shower heads and insulated pipe tape. The kit also includes directions and items to help with installation.

The overall strategy of this program is to reach residential customers who have not adopted low flow water devices and water heating pipe insulation. Duke Energy will educate customers on the benefits of using low flow water devices and saving the energy used to heat water, while addressing barriers for consumers who have not participated in this program.

Duke Energy will market the SEWK program through various promotional channels which may include direct mail, email and through an online store. The response will be tracked and monitored.

This program implementation vendor is EFI, who will receive and fulfill orders and provide support for damaged and missing orders. EFI will maintain a call center for this program to answer questions and take orders.

Appliance Recycling

Appliance Recycling promotes the removal and responsible disposal of operating refrigerators and freezers from Duke Energy Indiana residential customers. This program recycles approximately 95% of the material from the harvested appliances. The refrigerator or freezer must have a capacity of at least 10 cubic feet but not more than 30 cubic feet. This program includes a free pick up at the customer's home and provides a cash incentive for qualified appliances.

Eligible Program participants include Duke Energy Indiana residential customers who own operating refrigerators and freezers used in individually metered residences. Participants will receive an incentive per eligible unit in 4 to 6 weeks of appliance pickup & recycle. Customers can recycle up to 2 eligible units within a 12 month period.

This program removes less efficient appliances from the electric grid and educates customers about the cost of operating older refrigerators and freezers. Many customers don't think about the cost of operating refrigerators or freezers because these 24/7 appliances function in the background without direct interaction with customers. This program provides convenient in-home pick up and responsibly disposes of the appliance materials without impacting the environment.

The primary goal for this program is to help customers lower their energy bills and to remove inefficient equipment from the electric grid. This program educates customers about appliance energy consumption and how it compares to high efficiency alternatives.

This program will implement an integrated approach to marketing this Program which may include, but not limited to:

- Direct mail
- Bill inserts/messaging
- Community events
- Retail point-of sale
- Digital and broadcast media

Low Income Neighborhood

The Low Income Neighborhood assists low-income customers in reducing energy costs through energy education and installation of energy efficient measures. The primary goal of this program is to empower low-income customers to better manage their energy usage.

Customers participating in this program will receive a walk-through energy assessment and one-on-one education. Additionally, the customer receives a comprehensive package of energy efficient measures. Each measure listed below is installed or provided to the extent the measure is identified as energy efficiency opportunity based on the results of the energy assessment.

1. Compact Fluorescent Bulbs - Up to 15 compact fluorescent bulbs to replace incandescent bulbs.
2. Electric Water Heater Wrap and Insulation for Water Pipes.
3. Electric Water Heater Temperature Check and Adjustment.
4. Low-Flow Faucet Aerators - Up to three low-flow faucet aerators.
5. Low-Flow Showerheads - Up to two low-flow showerheads.
6. Wall Plate Thermometer.

7. HVAC Winterization Kits – Up to three winterization HVAC kits for wall/window air conditioning units will be provided along with education on the proper use, installation and value of the winterization kit as a method of stopping air infiltration.
8. HVAC Filters - A one-year supply of HVAC filters will be provided along with instructions on the proper method for installing a replacement filter.
9. Change Filter Calendar.
10. Air Infiltration Reduction Measures - Weather stripping, door sweeps, caulk, foam sealant and clear patch tape will be installed to reduce or stop air infiltration around doors, windows, attic hatches and plumbing penetrations.

Targeted low-income neighborhoods qualify for this program if approximately 50% of the households have incomes of 0%-200% of the Federal Poverty Guidelines. Duke Energy analyzes electric usage data to prioritize neighborhoods that have the greatest need and highest propensity to participate. While the goal is to serve neighborhoods where the majority of residents are low-income, this program is available to all Duke customers in the defined neighborhood. This program is available to both homeowners and renters occupying single family and multi-family dwellings in the target neighborhoods with electric service provided by Duke Energy.

The community approach offered by this program offers the following benefits:

- Community wide involvement raises awareness of energy efficiency opportunities
- Community leaders provide a trusted voice
- Greater acceptance is possible when neighbors and friends go through this program together
- Efficiencies are gained by working in the same close proximity for longer periods of time
- More resources are available to the individual participants to meet their needs
- Enrolling is simple
- Implementation of measures is fast and easy
- Timely tracking and reporting of activity
- Flexibility in community events can achieve greater success

The primary goal for this program is to empower low-income customers to better manage their energy bills. Duke Energy will engage low-income customers on a personal basis using a grass roots marketing approach to gain their trust. Crucial steps include providing customers with free energy saving measures and educating them on how to manage their energy needs. After a one-on-one education session, energy efficiency technicians provide customers with leave-behind materials to emphasize the measures installed, the importance of each measure, and how to maintain the measure.

The marketing strategy for this program will focus on a grassroots approach. Below are some of the marketing tactics Duke Energy may utilize to meet participation goals:

- Door-to-door canvassing
- Direct mail
- Flyers
- Social media
- Door hangers
- Yard signs
- Press releases
- Community presentations and partnerships
- Inclusion in community publications such as newsletters, etc.

<u>Agency Assistance Portal</u>

The Agency Assistance Portal assists low-income customers in reducing energy costs through providing energy efficiency kits to eligible customers. Customers participating in this program will receive a package of 12 CFLs delivered to the customer’s home.

Customers are eligible for this program if they apply for the federally funded Low Income Home Energy Assistance Program through a low-income agency. This program is available to both homeowners and renters occupying single family and multi-family dwellings with electric service provided by Duke Energy.

By utilizing local agencies where low-income customers seek assistance, Duke Energy can target customers most in need for energy savings.

The primary goal for this program is to empower low-income customers to better manage their energy bills. Duke Energy will utilize low income agencies who distribute LIHEAP funds to administer this program.

The marketing strategy for this program will focus on utilizing the low-income agencies as the primary method of informing customers. Duke Energy will provide table tents and posters for agencies to place on display within their offices.

Low Income Weatherization

The Low Income Weatherization program is designed to help Duke Energy Indiana income-qualified customers reduce their energy consumption and lower their energy cost. This Program will specifically focus on customers that meet the income qualification level (*i.e.*, income below 200% of the federal poverty level). This program will provide direct installation of weatherization and energy-efficiency measures including refrigerator and furnace replacement. This program will also educate Duke Energy Indiana income-qualified customers on their energy usage and other opportunities that can help reduce energy consumption and lower energy costs. Duke Energy partners with the Indiana Community Action Association to provide customers weatherization services.

This program will operate on a tier system, consisting of Tier 1 and Tier 2.

Tier 1 services are:

- Electric Heating System Tune-up & Cleaning
- Electric Heating System repair up to $600
- Water Heater Wrap for electric water heaters
- Pipe Wrap
- Cleaning of electric dryer vents
- Energy Star Compact Fluorescent Light Bulbs
- Low-flow shower heads and aerators
- Weather-stripping doors & windows
- Refrigerator testing/replacement
- Energy Education

Tier Two services are:

- All Tier One Services and Air Sealing Measures plus:
  - Additional cost effective measures using the NEAT audit where the energy savings pay for the measure over the life of the measure as determined by a standard heat loss/economic calculation. Such items can include but are not limited to attic insulation, wall insulation, crawl space insulation, and floor insulation.
  - Heating system and air conditioning tune and clean and/or repair.

The marketing strategy for this program will focus on utilizing low income agencies as the primary method for recruiting and informing customers of this program. Additional marketing will include mailers, flyers and direct contact between agencies and customers.

Multifamily Energy Efficiency Products & Services

The Multifamily Energy Efficiency Products & Services program will allow Duke Energy Indiana to utilize an alternative delivery channel which targets multifamily apartment complexes. Often times, neither property managers/owners or tenants are motivated to make energy efficiency improvements because they either don't pay the electric bill or the residence is considered temporary. This Program bridges this gap by educating property managers/owners about benefits and provides a low cost/no cost solution for improving the efficiency of the apartments. Franklin Energy is the implementation vendor who delivers this program. They are in charge of all aspects of this program which include outreach, direct installations and customer care.

This program offers properties the option of direct install service by Franklin Energy crews. However, Property Managers also have the option of using their own property maintenance crews to complete the installations (Do-It-Yourself or "DIY").

This program's installation measures include:

- Energy Efficiency Lighting - This program uses a tiered structure based on apartment size to determine the number of lighting measures installed in apartments.
- Kitchen Faucet Aerators*

- Bathroom Faucet Aerators*
- Low Flow Showerhead*
- Hot Water Pipe wrap*

*Water measures are only available if water is heated electrically

Promotion of this program is primarily focused on personalized outreach to targeted property managers/owners where each unit is individually metered and has electric water heat. Program collateral stresses the benefits of this program to property managers that are motivated by higher occupancy rates, lower water bills and lower tenant turnover. In addition, tenants will be informed about this program benefits and how it will help reduce their energy costs.

Once enrolled, this program provides property managers with a variety of marketing tools to create awareness of this program to their tenants. These include Program posters to leave in common areas and letters to each tenant informing them of what is being installed and when the installation will take place. Tenants are provided an educational leave-behind brochure when the installation is complete. The brochure provides additional details on the installed measures as well as a tear-off customer satisfaction survey to fill out and mail back to Duke Energy to provide valuable Program feedback.

Measures are installed during scheduled direct install visits Program crews or routine maintenance visits by property personnel. In the case of direct installs, crews carry tablets to keep track of what is installed in each apartment. In the case of DIY installations, the Property Manager maintenance crew tracks the number of measures installed and reports them back to this program.

After installations are complete, Quality Assurance (“QA”) inspections are conducted on approximately 20% of properties that completed installations in a given month. The QA inspections are conducted by an independent third party.

Residential Energy Assessments

Residential Energy Assessments are free in-home assessments designed to help customers reduce energy usage and energy cost. An energy specialist completes a 60 to 90 minute walk through assessment of the home and analyzes energy usage specific to the home to identify energy saving opportunities. The Building Performance Institute ("BPI") certified energy specialist provides and discusses a customized report to the customer that identifies actions the customer can take to increase energy efficiency in their home. The recommendations will range from behavioral changes to equipment modifications that can save energy and reduce cost. The primary goal is to empower customers to better manage their energy usage.

Example recommendations might include the following:

- Turning off vampire load equipment when not in use
- Turning off lights when not in the room
- Using energy efficient lighting in light fixtures
- Using a programmable thermostat to better manage heating and cooling usage
- Replacing older equipment
- Adding insulation and sealing the home

Customers receive an Energy Efficiency Kit with a variety of measures that can be directly installed by the energy specialist at the time of the assessment. The kit may include measures such as energy efficient lighting, low flow water measures, outlet/switch gaskets, weather stripping and energy saving tips. This program targets Duke Energy residential customers that own a single family home with at least 4 months of billing history. Program Benefits Include:

- Offering a personal touch directly to the customer positively influences customer satisfaction
- Providing the expertise of a BPI certified energy specialist raises awareness of efficiency opportunities

- Educating and empowering customers how to use less energy provides a personalized experience, reduces cost, builds trust and positively impacts the environment.

Important components of this program include providing customers with free energy saving measures and educating them on how to manage their energy needs. After conducting the analysis, the energy specialist provides a one-on-one education session with the customer reviewing a customized report as well as leave-behind materials to emphasize the measures installed, the importance of each measure, and how to maintain the measure.

Program participation is primarily driven through targeted mailings to pre-qualified residential customers; however, for those who elect to receive offers electronically email marketing will be used to supplement. Additional channels to include but not limited to online awareness via the Duke Energy website as well as through online services will promote Program participation as well.

<u>My Home Energy Report</u>

The Home Energy Report ("MyHER") is an energy efficiency program based on behavioral science to motivate energy efficient behavior. This program uses peer group of homes of similar size, age, type of heating fuel and geography to highlight the customer's variance in energy use when compared to the "Average Home" and "Efficient Home" of the peer group to engage the customer. The energy usage data features easy to read charts and visuals that illustrate how a customer's home performed in the last month and trended over the year as compared to the sample set via print and online channels. Further social motivation is introduced by establishing a value for an "Energy Efficient Home" within the peer group, as customers closest to the average are unlikely to be motivated to change their behavior.

As customers receive subsequent reports and or engage online, they learn more about their specific energy use and how they match up to their peer group. Targeted energy efficiency tips are offered to provide customers actionable ideas for reducing energy. The usage recommendations are relevant to the specific season the report is arriving in homes and provides low to no cost recommendations along with recommendations that require some investment by the customer. To encourage persistence, product specific offer rebates or audit follow-ups from other Duke Energy Indiana Programs are offered to customers based on their energy profile.

The MyHER is sent via direct mail to targeted customers with desirable characteristics who are likely to respond to the information. The reports are distributed up to 8 times per year; The MyHER Interactive portal offers customers an opportunity to further engage with their energy usage. Customers can:

- Set energy saving goals and track their progress on those goals
- See their energy use disaggregated in to how they use energy in their home on a monthly and annual basis.
- Ask an expert questions
- Post tips they have found useful and effective

Online participants will have access 24 hours per day, 7 days a week to login and view personalized usage and comparative data along with customized tips and recommendations. The offer is presented to customers as an opt-out which allows customers to elect to not receive the reports.

Providing the comparative data via print will not be marketed or require advertising. Providing the comparative data via online channels will initially be marketed through channels such as, but not limited to, direct mail and online channels. Marketing communication will be flexible and adaptable as online behavior will be evaluated consistently for engagement and response levels.

Energy Efficiency Education Program for Schools

The Energy Efficiency Education Program for Schools is available to school-age children enrolled in public and private schools who reside in households served by Duke Energy Indiana (the "Company"). The primary goal of this program is to educate students on the importance of energy conservation and teach them how to lower energy bills in their homes.

This program includes both an energy saving curriculum for the school classroom and an Energy Efficiency Starter kit at no cost to the participating student household.

This program provides an important message about energy efficiency through an innovative delivery channel for children. Principals and teachers are provided a curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The vendor serves as the primary point of contact with the school and delivers this program. The curriculum creatively engages students to learn energy saving behaviors in school and empowers the students to help their families save energy at home. Teachers receive supplemental educational material for their classroom and student take home assignments. All workbooks, assignments and activities meet state curriculum requirements.

As part of the curriculum, students are encouraged to complete a home energy survey with their family to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures that can be easily implemented to reduce home energy consumption. The kits are available at no cost to all student households at participating schools, including customers and non-customers. The kits can be ordered online, or by phone or paper enrollment. When the Energy Efficiency Survey is completed and eligibility is determined, the kit is shipped and received within two to four weeks to the student household. The kit includes items such as energy efficient lighting and water measures along with an energy saving tips booklet.

The Company works through the vendor to deliver marketing efforts for outreach to schools. The marketing channels may include but are not limited to:

- Direct mail
- Email
- Website
- Events or assemblies
- Printed materials for classrooms
- Social media promotions

These marketing efforts are designed to engage students and their families in energy conservation behavior and provide energy saving opportunities for their households with the kits. Program participation is driven by student households that elect to receive the Energy Efficiency Starter Kit.

Power Manager®

Power Manager® is a residential load control program. It is used to reduce electricity demand by controlling residential air conditioners and electric water heaters during periods of peak demand. A load control switch is attached to the outdoor air conditioning unit of participating customers. For water heaters, the switch is installed on or near the appliance. The device enables Duke Energy Indiana to cycle central air conditioning systems off and on when the load on Duke Energy Indiana's system reaches peak levels. The water heater switch will enable Duke Energy Indiana to cycle off electric water heaters during times of high electric demand—year round.

Power Manager® is offered to residential customers that have a functional central air-conditioning system with an outside compressor unit. Customers must agree to have the control device installed on their A/C system and to allow Duke Energy Indiana to control their A/C system during Power Manager® events. If the customer also has an electric water heater, the customer may choose to also have a control device installed on or near that appliance and allow Duke Energy Indiana to control the appliance during Power Manager® events.

Participants receive a one-time enrollment incentive and a bill credit for each Power Manager® event. Customers who select Option A, which cycles their air conditioner to achieve a 1.0 kW load reduction, receive a $25 credit at installation. Customers selecting Option B, which cycles their air conditioner to achieve a 1.5 kW load reduction, receive a $35 credit at installation. The bill credit provided for each cycling event is based on: the kW reduction option selected by the customer, the number of hours of the control event and the value of electricity during the event. For each control season (May through Sept), customers will receive a minimum of $7.50 for Option A and $10 for Option B in credits. For water heaters, participating customers receive a one-time incentive of $5 and a bill credit for each Power Manager® event. Annually, customers will receive a minimum of $6 in event credits.

Power Manager® is marketed through targeted direct mail campaigns, targeted e-mail campaigns, outbound telemarketing and on Duke Energy Indiana's Web site.

The water heater switch option will be marketed to customers who have committed to receive a Power Manager® air conditioning switch and have an electric water heater. A water heater switch will only be made available to customers for who an installation, service or quality control visit is already planned to be conducted. It is not cost effective to send a technician to a customer's home for the sole purpose of installing a water heater switch.

Customers can enroll in Power Manager® by phone call, returning the enrollment form included in the marketing material, or through the Company's Web site. Duke Energy Indiana will contract with a third party to install load control switches.

Power Manager® for Apartments

Power Manager® for Apartments is a residential load control program for apartment complexes/communities. It is used to reduce electricity demand by controlling residential air conditioners and electric water heaters during periods of peak demands. A load control switch is attached to the outdoor air conditioning unit and water heater of participating customers. This enables Duke Energy Indiana to cycle central air conditioning systems off and on when the load on Duke Energy Indiana's system reaches peak levels during the cooling season. In addition, this program enables Duke Energy Indiana to cycle the electric water heaters off when the load on the system reaches peak levels—any time of year.

Power Manager® for Apartments is offered to property managers/owners of individually metered apartment units that have a functional central air-conditioning system with an outside compressor unit. The landlord must agree to have the control device installed on the A/C system and to allow Duke Energy Indiana to control their A/C system during Power Manager® events and enroll the tenants in this program. In addition, if the apartments have electric water heaters, the property managers/owners will be offered the opportunity to have load control switches installed on those appliances and enroll the tenants in this program.

The property managers/owners will receive an annual incentive for each air conditioning unit receiving a load control switch. This incentive is $5 per air conditioning switch installed. The purpose of these incentives revolves around the fact that the landlord owns the equipment, controls access to the equipment and the maintenance of the equipment. Communication about maintenance events and that a switch has been disconnected is very valuable for persistence of these measures. The most efficient way to deliver this Program (and provide savings in kW to Duke Energy and in dollars to Customers) is via these property managers/owners. In addition, the property manager/owners will receive a one-time enrollment incentive of $5 for each water heater switch installed.

In addition, the Customers (tenants) participating in this Program receive bill credits for each Power Manager® event. Customers will receive a minimum of $10.00 annually for their participation in the air conditioning part of this program. Customers who also have a water heater switch installed on their unit will receive a minimum of $6.00 annually in bill credits. After installation of the switch(es), tenants will be notified of their Program eligibility and given the opportunity to opt-out of participation.

The total bill credit provided for each cycling event is based on: the kW reduction option selected by the customer, the number of hours of the control event and the value of electricity during the event.

Power Manager® is marketed through personalized outreach to targeted property managers/owners with individually metered units. Program collateral will stress the benefits of this program to property managers that are motivated by higher occupancy rates and providing lower electric costs for their tenants. It is also planned to leverage opportunities, contacts and learnings from the Residential Multifamily Energy Efficiency Program.

Duke Energy will contract with an installation vendor, planning to utilize existing capabilities from the established Power Manager® program.

2. Non-Residential Programs

The following programs are either currently offered in 2015 or an application has been filed for approval in Cause No. 43955 – DSM3 to continue to offer these programs in the future along with adding new programs.

Smart $aver® Non-Residential Prescriptive

The Smart $aver® Non-residential Prescriptive Incentive provides incentives to commercial and industrial consumers for installation of energy efficient equipment in applications involving new construction, retrofit, and replacement of failed equipment. This program also uses incentives to encourage maintenance of existing equipment in order to reduce energy usage. Incentives are provided based on Duke Energy Indiana's cost effectiveness modeling to assure cost effectiveness over the life of the measure.

Commercial and industrial consumers can have significant energy consumption, but may lack knowledge and understanding of the benefits of high efficiency alternatives. Duke Energy Indiana's Program provides financial incentives to customers to reduce the cost of high efficiency equipment. This allows customers to realize a quicker return on investment. The savings on utility bills, allows customers to reinvest in their business. This program also increases market demand for high efficiency equipment. Because of the increased demand, dealers and distributors will stock and provide high efficient alternatives as they see increased demand for the products. Higher demand can result in lower prices.

This program promotes prescriptive incentives for the following technologies – lighting, HVAC, pumps, variable frequency drives, food services, process equipment, and information technology equipment. Equipment and incentives are predefined based on current market assumptions and Duke Energy's engineering analysis. The eligible measures, incentives and requirements for both equipment and customer eligibility are listed in the applications posted on Duke Energy's Business and Large Business websites for each technology type.

All non-residential customers served by Duke Energy in Indiana on a non-residential rate to which the Energy Efficiency Revenue Adjustment is applicable are eligible for the Smart

\$aver® program, except for those customers that choose to opt-out of the Duke Energy Program.

This program is promoted through but not limited to the following;

- Trade ally outreach
- Trade ally collateral tool kits
- Midstream Distributor channel
- Duke Energy Online Savings Store
- Duke Energy Indiana Large Account Managers
- Duke Energy Energy Efficiency Engineers
- Duke Energy segment specific workshops
- Company website

Standards continue to change and new, more efficient technologies continue to emerge in the market. The Company expects to continue to add new measures to provide incentives for customers to take advantage of a broader suite of products. The Company undertakes an annual review of technologies and efficiency levels through internal sources and with the assistance of outside technical experts. The review includes the existing technology categories as well as other emerging areas for energy efficiency.

Smart \$aver® Non-Residential Custom Incentive

Duke Energy's Smart \$aver® Nonresidential Custom Incentive offers financial assistance to qualifying commercial, industrial and institutional customers (that have not opted out of energy efficiency programs) to enhance their ability to adopt and install cost-effective electrical energy efficiency projects.

This program is designed to meet the needs of Duke Energy customers with electrical energy saving projects involving more complicated or alternative technologies, or those measures not covered by standard Prescriptive Smart \$aver Incentives.

The Custom Incentive application is for projects that are not listed on the applications for Smart $aver Prescriptive Incentives. Unlike the Prescriptive Incentives, Custom Incentives require approval prior to the customer's decision to implement the project. Proposed energy efficiency measures may be eligible for Custom Incentives if they clearly reduce electrical consumption and/or demand. There are two potential approaches for apply for Custom Incentives, Classic Custom and Custom to Go. Application documents vary slightly depending on the approach taken. The difference between the two approaches focuses on the method by which energy savings are calculated. Customers eligible for the Custom to Go calculation approach may elect to apply under the Classic approach if that is their preference.

Currently there are the following application forms that are located on the Duke Energy website under the Smart $aver Incentives (Business and Large Business tabs).

- Custom Application – Administrative Information
- Energy Savings Calculations & Basis
    - Classic Custom Approach (> 700,000 kWh <u>or</u> no applicable Custom to Go calculator)
- Variable Frequency Drives
- Energy Management Systems
- Compressed Air
- Lighting
- General (for technologies not listed above)
    - Custom to Go Calculators (< 700,000 kWh <u>and</u> Custom to Go calculator available)
- Energy Management Systems
- Additional future calculators expected to launch to enable this Program, but not yet available.

This program is promoted through but not limited to the following;

- Trade ally outreach
- Duke Energy Indiana Large Account Managers
- Duke Energy Efficiency Engineers
- Duke Energy segment specific workshops
- Company website

- Non-Residential Energy Assessments
  - Optional energy assessments are available to identify and/or evaluate energy efficiency projects and measures. The scope of an energy assessment may include but is not limited to facility energy audit, new construction/renovation energy performance simulation, system energy study and retro-commissioning service. Payments are available to offset a portion of the costs of a qualifying energy assessment. The Company may vary the percentage of energy assessment payment based on the facility size, age, equipment, and other criteria that may affect the amount of energy efficiency opportunities, and the expectation of the customer implementing recommendations identified. All, or a portion of, the energy assessment payment may be contingent on the customer implementing a minimum amount of cost effective energy efficiency measures within a set timeframe.

<u>Small Business Energy Saver</u>

The objective of the Small Business Energy Saver ("SBES") is to enable the installation of high efficiency equipment in existing small non-residential facilities. SBES is designed to offer a convenient, turn-key process for small non-residential customers and has been successful in other Company jurisdictions. Small business owners typically lack the time, upfront capital, and technical expertise to facilitate the retrofit or replacement of older equipment within their facilities. This program effectively removes these barriers by offering a turn-key energy efficiency offering which facilitates the direct installation of energy efficiency measures, and minimizes financial obstacles with significant upfront incentives from Duke Energy Indiana which offset the cost of projects.

SBES program eligibility will be limited to all active non-residential Duke Energy Indiana electric customer accounts with an average annual electric demand of 100 kW or less that are not classified as new construction. Participants may be in owner-occupied or tenant facilities with owner permission.

All aspects of SBES will be managed by a Duke Energy Indiana-authorized program vendor. Duke Energy Indiana will first provide a list of customers who meet this program eligibility requirements to this program vendor. This program vendor will then offer free, no-obligation facility energy assessments to qualifying non-residential customers. These assessments will result in recommendations of energy efficiency measures to be installed at the facility along with the projected energy savings, costs of all materials and installation, and the upfront incentive amount from Duke Energy Indiana. This program is designed as a pay-for-performance offering, meaning that this program vendor will only be compensated for energy savings produced through the installation of energy efficiency measures.

The SBES program incentive amount will be calculated per project, based upon the estimated energy savings of the energy efficiency improvements and the conditions found within the customer's facility. Incentivized measures will address major end-uses in lighting, refrigeration, and heating ventilation and air conditioning ("HVAC") applications suited for common small, non-residential facility types. Lighting measures such as high performance T8 and T5 fluorescent new fixtures and ballasts, high performance T8 and T5 retrofit kits, interior and exterior LED fixtures, screw-in CFL and LED fixtures; LED exit signs; and occupancy sensors will be offered. All lighting measures offered will be Consortium for Energy Efficiency ("CEE"), ENERGY STAR, or Design Lights Consortium ("DLC") qualified products. Refrigeration measures may include new electronically commutated ("EC") motors, anti-sweat heater controls, evaporator fan controls, LED refrigeration case lighting, beverage machine/novelty cooler controls, and automatic door closers for walk-in freezers. HVAC upgrades such as unitary, split systems, and air sourced heat pumps and programmable thermostats may be included. In anticipation of technological advancements, Duke Energy Indiana proposes the flexibility to incentivize additional cost effective measures where appropriate within the lighting, refrigeration and HVAC fields. In order to encourage participation within this hard-to-reach customer segment, Duke Energy Indiana proposes to provide an upfront customer incentive for up to 80 percent of the total cost of installed measures. Incentives will be provided based on Duke Energy Indiana's cost effectiveness modeling to ensure cost effectiveness over the life of the measures.

Upon receiving the results of the assessment, if the customer chooses to move forward, the customer will make the final determination of project scope prior to installation. This program vendor will then work with local subcontractors for the installation services. The customer will be able to schedule the installation for a convenient time directly with this program vendor. Duke Energy Indiana's incentive payment for any installed measures will be paid directly to this program vendor upon verification that the energy efficiency measure(s) have been installed. All project costs above the incentive amount will be the responsibility of the customer and paid based upon payment terms arranged between the customer and program vendor. Duke Energy Indiana intends for this program vendor to offer interest-free extended payment options to the customer, to further minimize any financial barriers to participation.

This program may be promoted through various marketing channels that include, but are not limited to:

- Direct mail (letters and postcards to qualifying customers)
- Duke Energy Indiana website
- Community outreach events
- Small Business Group outreach events
- Paid advertising/mass media
- Social media promotions

Marketing efforts will be designed to create customer awareness of this program, to educate customers on energy saving opportunities and to emphasize the convenience of participation in SBES. With SBES, Duke Energy Indiana will further our commitment to offering affordable and broad-reaching programs that simplify energy efficiency decisions for all customers.

Power Manager® for Business

Power Manager® for Business is a non-residential program that provides business customers with the opportunity to participate in demand response, earn incentives and realize optional energy efficiency benefits. This program is designed as a flexible offer that provides small-to-medium size business customers with options on device types as well as level of demand response participation. Customers first select the type of device from two available options: thermostat or switch.

Customers who opt for the thermostat will have the ability to manage their thermostat remotely via computer, tablet or smartphone. The thermostat comes with presets designed to help the business manager/owner set an efficient schedule that works for their business. This realizes additional benefits in the form of EE impacts/savings. Customers then select one of three levels of summer demand response ("DR") participation, and earn an incentive based upon that selection.

Both thermostat and switch customers have the same DR participation options, and receive the same DR incentives.

Power Manager® for Business will be offered to business customers with qualifying air conditioning systems, summer weekday energy usage and broadband/Wi-Fi internet. Customers must agree to have the control device installed on their A/C system and to allow Duke Energy Indiana to control their A/C system during Power Manager® events. Qualifying air conditioning systems include:

- Individual split air conditioning systems
- Rooftop Units
- Packaged terminal air conditioners ("PTACs")

Customers participating in this Program receive an incentive based on upon the level of demand response cycling they select:

- 30% cycling: $50 per DR summer season (per device)
- 50% cycling: $85 per DR summer season (per device)
- 75% cycling: $135 per DR summer season (per device

The incentive will be paid out after installation of the device(s) and then annually. Devices are installed at the customer premise at no charge to the customer.

Power Manager® for Business will be marketed through targeted direct mail campaigns, targeted e-mail campaigns, outbound telemarketing, on Duke Energy Indiana's Web site and via cross selling with the Small Business Energy Saver Program.

Customers can enroll in Power Manager® for Business by: phone call, returning the enrollment form included in the marketing material or through Duke Energy Indiana's Web site. Duke Energy Indiana will contract with a third-party entity to install and perform field work associated with the load control switches and thermostats.

3. Demand Response Programs

In addition to the programs approved in Cause 43955 – DSM2 and those pending approval in Cause 43955 – DSM3, Duke Energy Indiana also offers the following Demand Response programs under its Rider 70 and other special contracts:

PowerShare® CallOption

Program: PowerShare® CallOption is a non-residential demand response program. The program has components for customers to respond with load curtailment for both emergency and economic conditions and is marketed under the name PowerShare® CallOption. Customers receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated events triggered by capacity problems. Economic events are triggered on a day-ahead notification based on projections of next day market prices. Customers may "buy through" an economic event by paying the posted hourly price for the day of the event. Emergency events are triggered by MISO and provide customers notification that requires a response within 6 hours. There is no ability to buy through for emergency events.

Eligibility: Available to Customers served under Rates LLF and HLF that can provide at least 100 kW of load curtailment. Customers without load profile metering (less than 500 kW in maximum annual 30-minute demand) must pay the incremental cost of metering. Customers must enter into a service agreement.

Customer Incentive: Program participants will receive capacity credits (premiums) for loads they agree to curtail during program events. The amount of the capacity credit will depend on the offer and level of participation selected by the customer as well as the amount of load response. For actual energy curtailed during an economic event, CallOption customers will receive energy credits (event incentives). The amount of the event incentives will depend on the energy curtailed during the event and the established strike price.

Special Curtailment Contracts

Duke Energy Indiana has contracted with several of its industrial customers to reduce their demand for electricity during times of peak system demand. Currently, two contracts are in effect. These contracts allow Duke Energy Indiana to provide "as available" or "non-firm" service to those customers. Some of these contracts date back to the late 1980s and early 1990s. By the terms of these contracts, Duke Energy Indiana can interrupt those customers at times of system peak, high marginal prices, or during times of system emergencies.

These interruptible contracts contain "buy-through" features except during times of system emergency. The Company currently expects and plans for a 129 MW reduction in the load forecasts for this "as available" load. This is projected to remain available and under contract over the forecast horizon, although there is a risk that customers will not renew the interruptible provisions of their contracts when they expire.

D. PROJECTED IMPACTS

Projected impacts from EE and demand response programs were developed for a 25 year planning horizon from 2015 through 2039 as options for consideration in the IRP analytical process. In preparing the projected impact options available for selection in this IRP, the Company developed 10 sub-portfolios of EE programs. These sub-portfolios were designed to be treated as demand-side resource option for selection by the IRP process consisting of a set of 5 Base sub-portfolios and 5 Incremental sub-portfolios.

The Base sub-portfolios were created using the assumption that the Company will be implementing the currently approved and proposed portfolio of EE programs during the IRP analysis period. For periods beyond 2018, the assumption was made that the composition and size of the future annual portfolio impacts were the same as in the 2018 portfolio. For the analysis period, the 25 year projected Base Portfolio was also divided into 5 sub-portfolios lasting 5 years each and the impacts from each of the sub-portfolios and the cost to achieve those impacts were treated as stand-alone resources available to be chosen in the IRP process.

The Incremental sub-portfolios were created using the assumption that additional participation would be obtained for the same programs that exist in the Base Portfolio, with the exception of programs that are already designed to reach the entire eligible population in the Base sub-portfolio (My Home Energy Report program) or programs where the market is expected to become fully saturated in the Base sub-portfolio (certain CFL lighting measures). During the IRP analysis period, the Incremental portfolio was divided into 5 sub-portfolios lasting 5 years each and the impacts from each of the sub-portfolios and the cost to achieve those impacts were treated as stand-alone resource available to be chosen in the IRP process.

Table 4-A below provides the potential projected MWh impacts from the EE programs assuming that all sub-portfolios (Base and Incremental) were selected. The final EE MWH impacts selected are discussed in Chapter 8.

Table 4-A: MWh LOAD IMPACTS OF EE PROGRAMS

	EE Program Load Impacts
Year	**Total MWh**
2015	132,680
2016	329,468
2017	484,671
2018	626,645
2019	768,620
2020	910,594
2021	1,052,569
2022	1,194,544
2023	1,336,518
2024	1,478,493
2025	1,620,467
2026	1,762,442
2027	1,904,416
2028	2,046,391
2029	2,188,366
2030	2,330,340
2031	2,472,315
2032	2,614,289
2033	2,756,264
2034	2,898,239
2035	3,040,213
2036	3,182,188
2037	3,324,162
2038	3,466,137
2039	3,608,111

Table 4-B provides the MW impacts from the special contracts and demand response programs. The MW impacts from the selected EE programs are included in the Load Forecasting section.

Table 4-B MW LOAD IMPACTS OF DR PROGRAMS[10]

	Demand Response Program Load Impacts			
	MW			
Year	PowerShare	Power Manager	Interruptible	Total DR
2015	393	55	184	632
2016	431	61	184	677
2017	448	61	184	694
2018	466	61	184	711
2019	478	60	184	722
2020	490	59	184	734
2021	490	59	184	734
2022	490	59	184	734
2023	490	59	184	734
2024	490	59	184	734
2025	490	59	184	734
2026	490	59	184	734
2027	490	59	184	734
2028	490	59	184	734
2029	490	59	184	734
2030	490	59	184	734
2031	490	59	184	734
2032	490	59	184	734
2033	490	59	184	734
2034	490	59	184	734
2035	490	59	184	734
2036	490	59	184	734
2037	490	59	184	734
2038	490	59	184	734
2039	490	59	184	734

[10] DR MWs from programs that are currently pending regulatory approval are not included in Table 4-B (Power Manager Water Heaters, Power Manager for Apartments, Power Manager for Business.

E. EXISTING ENERGY EFFICIENCY PROGRAMS, HISTORICAL PERFORMANCE

Duke Energy Indiana has been aggressive in the planning and implementation of energy efficiency programs. As a result of the energy efficiency efforts through the year 2014, Duke Energy Indiana has reduced summer peak demand by a projected 295 Net MW and annual energy use by 1,423 Net gigawatt-hours (GWh). These load reductions do not include the impacts of any demand response programs, including the Power Manager direct load control program, interruptible contracts, or the PowerShare® program.

The forecast of loads provided in Chapter 3 incorporates the effects of these historical impacts in the baseline forecast, subject to anticipated "roll off" into prevailing codes and standards.

F. PROGRAM SCREENING, ASSUMPTIONS, AND DATA SOURCES

EE and DR programs are evaluated using the DSMore software as a screen for IRP input.

1. DSMore

DSMore is a financial analysis tool designed to help EE and DR program planners evaluate the costs, benefits, and risks of EE programs and measures. DSMore is used to create estimates of the avoided costs (benefits) from the implementation of EE programs and measures and compare them to the costs of implementation for an assessment of the cost-effectiveness. DSMore is used to estimate the value of an EE measure at an hourly level across a wide variety of weather and energy cost conditions. This enables the user to obtain a better understanding of the risks and benefits of employing EE measures. Understanding the manner in which energy efficiency cost effectiveness varies under alternate conditions allows a more precise valuation of energy efficiency and demand response programs.

2. Cost-Effectiveness Tests

Cost-effectiveness tests compare the net present values of program costs to benefits. The programs are valued against avoided costs. The benefit/cost ratio tests indicate program cost effectiveness and projected load impacts. The criteria primarily used is the Utility Cost Test (UCT), which compares utility benefits to utility costs and does not consider other benefits such as participant savings or societal impacts.

The impacts of all programs are combined and included in IRP modeling (see Chapter 8). Further information on estimated program costs may be found in the Short-Term Implementation Plan. Table 4-D summarizes the cost-effectiveness results for the EE and DR programs as filed in Cause No. 43955 – DSM3 for 2016-18.

Table 4-D

Program	UCT	TRC	RIM	PCT(1)
Residential				
Agency Assistance Portal	1.90	3.05	0.66	>1.00
Appliance Recycling Program	1.01	1.20	0.54	>1.00
Energy Efficiency Education Program for Schools	1.50	2.12	0.77	>1.00
Residential Energy Assessments	2.15	2.64	1.00	>1.00
Multi-Family EE Products & Services	1.46	1.69	0.65	>1.00
My Home Energy Report	1.72	1.72	0.75	>1.00
Low Income Neighborhood	1.02	2.39	0.60	>1.00
Smart $aver® Residential	2.12	3.00	0.72	10.52
Low Income Weatherization	0.38	1.57	0.31	>1.00
Power Manager®	4.65	6.29	4.65	>1.00
Power Manager® for Apartments	2.21	3.35	2.21	>1.00
Non-Residential				
Power Manager® for Business	2.07	3.13	1.82	>1.00
Smart $aver® Non-Residential Custom Incentive	4.86	1.00	1.02	1.43
Smart $aver® Non-Residential Prescriptive Incentive	1.86	1.34	0.84	2.02
Small Business Energy Saver	2.68	2.00	0.90	3.28
All Programs Combined	2.56	2.24	1.13	3.39

(1) The PCT score cannot be calculated when there are no participant costs. In these instances, the program passes the PCT as indicated by the “>1.00” in the table above.

G. Integrated Volt-Var Control (IVVC)

Duke Energy is pursuing implementation of grid modernization throughout the enterprise with a vision of creating a sustainable energy future for our customers and our business by being a leader of innovative approaches that will modernize the grid.

Duke Energy Indiana is reviewing an IVVC project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Indiana distribution system. In general, the project will optimize the operation of these devices, resulting in a reduction and "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation devices and capacitors, distribution line capacitors, and distribution line voltage regulators, while integrating them into a single control system. The control system continuously monitors and operates the voltage regulators and capacitors in near real time, coordinated control to maintain the optimized "flat" voltage profile. Once the system is operating with a flat voltage profile across an entire circuit, the net result is a reduction of system loading.

The deployment of an IVVC program for Duke Energy Indiana is anticipated to take approximately seven years following project approval. This IVVC program is projected to reduce future distribution-only system peak needs by approximately 0.1% in 2018, 0.3% in 2019, 0.4% in 2020, 0.5% in 2021, 0.6% in 2022, and 0.7% in 2023 and beyond.

While the subject of grid modernization is very broad, only the supply and demand impacts of the IVVC program is included in the IRP process.

5. SUPPLY-SIDE RESOURCES

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options that Duke Energy Indiana uses to reliably and economically meet the energy needs of its customers. These options can include existing generating units, repowering options for these units, existing or potential power purchases, and new utility-owned generating units (conventional, advanced technologies, combined heat and power, and renewables). The IRP process assesses the possible supply-side resource options that would be appropriate to meet the system needs by considering their technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, operation and maintenance (O&M) cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

1. Description

The total installed net summer generation capability owned or purchased by Duke Energy Indiana is currently 7,507 MW.[11] This capacity consists of 4,765 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 285 MW of natural gas-fired combined cycle capacity, 45 MW of hydroelectric capacity, and 1,804 MW of natural gas-fired or oil-fired peaking capacity. Also included is a power purchase agreement with Benton County Wind Farm (100 MW, with 13 MW contribution to peak modeled).

The coal-fired steam capacity consists of 14 units at four stations (Gibson, Cayuga, Gallagher and Wabash River). The syngas/natural combined cycle capacity is comprised of two syngas/natural gas-fired combustion turbines and one steam turbine at the Edwardsport IGCC station. The combined cycle capacity consists of a single station comprised of three natural gas-fired combustion turbines and two steam turbines at the Noblesville Station. The hydroelectric

[11] Excluding the ownership interests of Indiana Municipal Power Agency (IMPA) (155 MW) and Wabash Valley Power Association, Inc. (WVPA) (155 MW) in Gibson Unit 5, and the ownership interest of WVPA (213 MW) in Vermillion, but including the non-jurisdictional portion of Henry County (50MW) associated with a long-term contract.

generation is a run-of-river facility comprised of three units at Markland on the Ohio River. The peaking capacity consists of seven oil-fired diesels located at the Cayuga and Wabash River stations, seven oil-fired CT units located at Connersville and Miami-Wabash, and 24 natural gas-fired CTs located at five stations (Cayuga, Henry County, Madison, Vermillion, and Wheatland). One of these natural gas-fired units has oil back-up. Duke Energy Indiana also provides steam service to one industrial customer from Cayuga, which reduces Duke Energy Indiana's net capability to serve electric load by approximately 20 MW.

The largest units are the five Gibson units at approximately 620-630 net MW each, and the two Cayuga units at approximately 500 MW each. The smallest coal-fired units on the system are the three 85 MW Wabash River units. The large variation in unit size of the coal-fired units is mainly due to vintage. The peaking units range in size from 2-3 MW oil-fired internal combustion units at Wabash River and Cayuga to 115 MW natural gas-fired CTs at Wheatland. Information concerning the existing generating units as of the date of this filing is contained in Table 5-A. This table lists the name and location of each station, unit number, type of unit, installation year, net dependable summer and winter capability (Duke Energy Indiana share), and current environmental protection measures.

The net dependable summer and winter capability (Duke Energy Indiana share) by plant is shown in Appendix F in Table F-4. A listing of the units grouped by fuel type (*i.e.*, coal, syngas, gas, oil, water and wind) is shown in Appendix F in Table F-5. Tables F-3, F-4 and F-5 are standardized templates agreed upon by the Indiana utilities involved in the IRP Investigation, docketed as Cause No. 43643. The approximate fuel storage capacity at each of the coal- and oil–fired generating stations is shown in Figure A-6 in Appendix A.

Long term purchases are shown in Figure A-7 in Appendix A. Duke Energy Indiana has contracted with Benton County Wind Farm for a 20 year wind PPA for 100 MW (13 MW capacity value modeled) expiring April 2028.

2. Availability

The unplanned outage rates of the units used for planning purposes were derived from historical Generating Availability Data System (GADS) data. Planned outages were based on the maintenance requirement projections discussed below. Generating units generally assumed to continue to operate at their present availability and efficiency (heat rate) levels. However, adjustments to present operating conditions were made for future environmental controls.

3. Maintenance Requirements

A comprehensive maintenance program is important in providing reliable, low-cost service. The general guidelines governing the major maintenance schedule are shown below. Future units will be governed by similar guidelines.

- ***Base load units 400 MW and larger:*** 6 to 12 year intervals (Cayuga 1-2, Gibson 1-5, and Edwardsport IGCC).
- ***Intermediate-duty units between 140 MW and 400 MW***: 6 to 15 year intervals (Noblesville Repowering).
- ***Limited run-time peaking and small coal units***: Condition assessments and predictive maintenance will be used to determine the need for major maintenance (Cayuga 3&4, Madison 1-8, Henry County 1-3, Wheatland 1-4, Vermillion 1-8, Connersville 1-2, Miami-Wabash 1-3&5-6, Gallagher 2&4, and Wabash River 2-6).

Maintenance is also performed during unplanned, opportunistic short duration “availability outages” outages to improve summer reliability. At appropriate times, when it is economic to do so, units may be taken out of service for generally short periods of time (*i.e.*, less than nine days) to perform maintenance activities. Generating station performance is now measured primarily by plant availability during higher price time frames. Moreover, targeted, plant-by-plant assessments have been performed annually to determine the causes of all forced outages, which enable the Company to better focus actions during maintenance and availability outages. Finally, system-wide and plant-specific contingency planning was instituted to ensure an adequate supply of labor and materials when needed, with the goal of reducing the length of any forced outages.

The general maintenance requirements for all of the existing generating units were entered into the models used to develop the IRP.

4. <u>Fuel Supply</u>

Duke Energy Indiana generates energy to serve its customers through a diverse mix of fuels consisting primarily of coal, syngas, natural gas, and fuel oil, and participates in the MISO power market, which encompasses a variety of generation sources in parts of 15 U.S. states and the Canadian province of Manitoba. The Company continues to generate a majority of its energy using coal, with usage dictated by the relative prices of coal as compared to the fuel alternatives in the economic dispatch process. The percentages of Duke Energy Indiana's generating capacity shown in Table F-5 in Appendix F by fuel type are 63% coal, 8% syngas, 26% natural gas, 2% oil, and 1% hydro.

Coal

Over 80% of Duke Energy Indiana's total energy is generated from burning or gasifying coal. In evaluating the purchase of coal, the Fuels Department considers three primary factors: (1) the reliability of supply in quantities sufficient to meet Duke Energy Indiana generating requirements, (2) the quality required to meet environmental regulations and/or manage station operational constraints, and (3) the lowest reasonable cost as compared to other purchase options. The "cost" of the coal includes the purchase price at the delivery point, transportation costs, scrubbing costs for sulfur, and the evaluated economic impacts of the coal quality on station operations.

To aid in fuel supply reliability, fuel procurement policies (*e.g.* contract versus short term ratios, inventory target levels) guide decisions on when the Fuels Department should enter the market to procure certain quantities and types of fuel. These policies are viewed in the context of economic and market forecasts and probabilistic dispatch models to collectively provide the Company with a five-year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To enhance fuel supply reliability and mitigate supply risk, Duke Energy Indiana purchases coal from multiple mines in the geographic area of our stations. Stockpiles of coal are maintained at each station to guard against short-term supply disruptions. Currently, coal supplied to the base load coal stations comes primarily from Indiana and Illinois. These states are rich in coal reserves with decades of remaining economically recoverable reserves. In 2015, over 90% of the coal supplied to base load stations are under long-term coal contracts. Prior to entering long-term commitments with coal suppliers, the Company evaluates the financial stability, performance history and overall reputation of potential suppliers. By entering into long-term commitments with suppliers, Duke Energy Indiana further protects itself from risk of insufficient coal availability while also giving suppliers the needed financial stability to allow them to make capital investments in the mines and hire the labor force. If the Company were to try to purchase significant portions of its requirements on the short-term open market, the Company likely would have severe difficulties in finding sufficient coal for purchase to meet our needs due to the inability of the mines to increase production to accommodate 10-12 million annual tons in such a short timeframe. The current Duke Energy Indiana supply portfolio includes six long-term coal supply agreements. Under these contracts, the Company buys coal at the mine. Thus, the contracts do not restrict our ability to move the coal to the various Duke Energy Indiana coal-fired generating stations as necessary to meet generation requirements. This arrangement allows for greater flexibility in meeting fluctuations in generating demand and any supply or transportation disruptions.

For low capacity factor coal stations such as Gallagher and Wabash River, a much shorter term procurement policy is used due to the continued uncertainties around future environmental regulations (*e.g.* MATS and NAAQS) and the potential for retirement of these aging units. Typically we source lower-sulfur coal for these intermediate stations on a short-term basis, typically one-year or less, from such places as Colorado, Wyoming, Indiana and West Virginia. Duke Energy Indiana fills out the remainder of its fuel needs for both base load and intermediate load stations with spot coal purchases. Spot coal purchases are used to 1) take advantage of changing market conditions that may lead to low-priced incremental tonnage, 2) test new coal supplies, and 3) supplement coal supplies during periods of increased demand for generation or during contract delivery disruptions.

Coal Price Forecast

For 2015, Duke Energy employed Energy Ventures Analysis, Inc. (EVA) to produce Duke Energy's fully integrated fuel and energy Fundamental Forecast case. Among many factors, this forecast captures the national interplay between gas and coal as well as inter-basin competition among coals, along with all logistics to move the fuels to their respective combustion points, thereby arriving at the least cost solution to meet energy needs over the long-term.

Natural Gas

The use of natural gas by Duke Energy Indiana for electric generating purposes has generally been limited to CT and CC applications. Natural gas is currently purchased on the spot market and is typically transported (delivered) using interruptible transportation contracts or as a bundled delivered product (spot natural gas plus transportation), although the company does have firm transportation contracts on the Midwestern Gas pipeline for gas delivery to Edwardsport, Vermillion, and Wheatland. The future CC fuel cost incorporates both the natural gas commodity price and firm transportation cost, and the future CT fuel cost includes the natural gas commodity price and interruptible transportation cost.

Outlook for Natural Gas

The collapse in oil prices in late 2014 started the dominos falling across the energy sector. We saw another plunge in natural gas prices back toward 2012 levels when a massive displacement of coal in the power dispatch was needed to balance the gas market. Facing a market in 2015 with lower market prices, rising OPEC production and weaker Asian demand coupled with a strong dollar, producers cut the number of drilling rigs targeting oil by 56% and gas rigs by another 34%. Yet, despite the lower prices and reduced drilling levels, the US has posted year over year monthly production gains, led by the Marcellus. The delayed production response is due in part to a large backlog of drilled and uncompleted wells and the momentum of the prior drilling programs heading into 2015. However, with a glut of gas and limited take away capacity, prices in the Marcellus have dropped well below $2/MMBtu. Thus far, the most immediate impact of the lower oil prices on the gas market appears to be another reduction in upstream drilling and well service costs. The sudden drop in demand for specialized drilling and completion equipment has reduced the cost of new wells and has driven new shale gas well ‘breakeven cost’ estimates even lower. Gas prices are expected to remain weak in the near term as there is little upward pressure available. However, significant gas demand growth is coming and with reduced drilling in place, prices are expected to move higher before stabilizing a bit around 2020.

Even with the cloud of uncertainty over the final disposition of the EPA's MATS rule and litigation of the greenhouse gas rule, the power sector is continuing the shift toward natural gas and away from coal as the primary US fuel source for power generation. The power sector has been leading this growth cycle in natural gas demand for the past several years, but there is another wave of gas demand building and this time it is in the industrial and gas export sectors. While the current drop in gas prices will benefit certain industrial gas consumers like fertilizer and DRI steel production, the drop in oil prices has changed the value proposition for natural gas liquids and recently led to the cancelation of the major Sasol gas to liquids project in Louisiana. There could be additional project delays or cancellations on the horizon, but most of the announced industrial and LNG export projects are still moving forward. The gas to oil price linkage is a complicated relationship and will have a complex impact on the gas sector, particularly if the relationship remains volatile. Whereas Asian demand growth for US LNG appears to be weakening, European interest in US supplies is growing. Likewise, energy reforms in Mexico are leading to a wave of new pipeline investments to move US gas across the Southern border which is fueling a conversion of their power sector from oil to gas. Investments in new petrochemical, fertilizer and LNG facilities are concentrated along the US Gulf coast will have implications for the direction of future flows of natural gas and the need for new pipelines, storage and new interconnection points along the interstate pipeline system. The majority of the current pipeline projects will facilitate the movement of gas out of the Northeast (Marcellus/Utica), and into the Midwest, Southeast and Gulf Coast.

Risks to the Outlook

The supply outlook for US natural gas looks solid in light of recent upward revisions to estimates by the US potential gas committee on likely reserves (+8%), and a new study suggesting that the Utica may hold more recoverable gas than the Marcellus. The primary risk to the supply picture is what happens to costs after the current tier one reserves are depleted. Producers are drilling their most productive assets today in this low price environment and still others are writing down the costs of their investments in more challenging plays. Demand is also rising rapidly as the US looks to become a major gas exporter as well as a global leader in several gas intensive industries. Demand is also continuing to rise in the power sector where the US coal industry is facing serious financial challenges and many producers are struggling just to survive. Technological improvements spurred on by the specter of sustained high market prices led to the shale revolution, and it will require new technologies to sustain the momentum under the anticipated higher demand levels in the forecast. Technology could provide the means to sustain the current low price environment, resulting in a significant downside to the forecast. Alternatively, prices could begin to climb faster if there are significantly more coal retirements and a second wave of LNG export terminals. The environmental risks to the hydraulic fracturing process appear to be somewhat limited at this point to stricter controls on wastewater treatment and deep well injection and capturing fugitive methane emissions. Water consumption remains an issue in certain states, but the industry is aggressively implementing best practices aimed at reducing consumption and recycling. If new studies establish a linkage of hydraulic fracturing to seismicity beyond the activities associated with wastewater disposal, that could lead to additional limitations at the state level and on federal lands.

Gas Price Scenario Forecasts

EVA was the primary consultant for the 2015 Duke Energy fundamental outlook. The Duke Energy Fundamental Forecast Case is differentiated from the EVA outlook as a result of several input assumption changes requested by Duke Energy. These changes include carbon pricing, higher levels of renewable energy technologies in several of the Duke Energy jurisdictional states, and generation capital and O&M cost assumptions. These changes requested by Duke Energy were limited to the power sector which impacted the demand for natural gas and, by extension, the price of gas and power at the margin.

Duke Energy directed EVA to perform the same comprehensive analysis for three separate scenarios. One scenario included a national carbon tax beginning in 2020, another modeled EPA’s proposed clean power plan assuming state by state mass caps on carbon, and a final scenario assuming no additional restrictions on carbon. All of these cases relied on EVA’s proprietary database, knowledge of the upstream US gas supply base, and their integrated fundamental modeling framework for price discovery.

Oil

Duke Energy Indiana uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Some CT peaking facilities are oil-fired. Cayuga Unit 4 uses oil as a back-up fuel. Oil supplies, purchased on an as-needed basis, are expected to be sufficient to meet needs for the foreseeable future.

5. Fuel Prices

Fuel prices for both existing and new units were developed using a combination of observable forward market prices and longer term market fundamentals. EVA performed the long term fundamentals analysis with input from Duke Energy subject matter experts. The projected fuel prices are considered by Duke Energy Indiana and EVA to be trade secrets and proprietary competitive information.

6. Condition Assessment

Duke Energy Indiana continues to implement its engineering condition assessment programs. The intent is to maintain the generating units at their current levels of efficiency and reliability when economically feasible.

The older CT units at Miami-Wabash and Connersville were assumed to retire in 2018. Each CT is tested once per year to meet MISO reliability requirements. Given the age of these turbines, if significant maintenance is required to meet the reliability requirements, the retirement decision on a specific unit could accelerate. As an example, Miami-Wabash Unit 4 was retired in 2010 following generator equipment failures.

7. Efficiency

Duke Energy Indiana evaluates the cost-effectiveness of maintenance options on various individual components of the existing generating units. If the potential maintenance options prove to be cost-justified and pass a New Source Review (NSR) screen, they are budgeted and generally undertaken during a future scheduled unit maintenance outage.

Duke Energy Indiana routinely monitors the efficiency and availability of its generating units. Based on those observations, projects that are intended to maintain long-term performance are planned, evaluated, selected, budgeted, and executed. Such routine periodic projects might include, but are not limited to, turbine-generator overhauls; condenser cleanings and condenser system repairs, such as vacuum pump and circulating water pump rebuilds; burner replacements, coal pulverizer overhauls, and combustion system tuning; secondary air heater basket material replacements; boiler tube section replacements; and pollution control equipment maintenance, such as selective catalytic reduction (SCR) catalyst replacement and flue gas desulfurization (FGD) limestone slurry pump rebuilds. In addition, Duke Energy Indiana looks for targeted projects designed to improve generating unit efficiency.

Any plans to increase fossil fuel generation efficiency must be viewed in light of regulatory requirements, specifically the NSR rules defined by the EPA. These regulatory requirements are subject to interpretation and change over the years. Within the context of such requirements, Duke Energy Indiana plans routine maintenance projects, which may maintain or increase the efficiency of its generating units.

C. EXISTING NON-UTILITY GENERATION

Some Duke Energy Indiana customers have electric production facilities for self-generation, peak shaving, or emergency back-up. Non-emergency self-generation facilities are normally of the baseload type and are generally sized for reasons other than electric demand (*e.g.*, steam or other thermal demands of industrial processes or heating). Peak shaving equipment is typically oil- or gas-fired and generally is used only to reduce the peak billing demand. Depending on whether it is operated at peak, this capacity can reduce the load otherwise required to be served by Duke Energy Indiana which, like DR programs, also reduces the need for new capacity.

D. UTILITY-OWNED COMBINED HEAT AND POWER (CHP)

CHP systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a technology, but an approach to applying technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power.

While the conventional method of producing usable heat and power separately has a typical combined efficiency of 45 percent, CHP systems can operate at levels as high as 80 percent. Duke Energy is exploring and working with potential customers with base thermal loads on a regulated CHP offer. Other benefits of CHP could include CO_2 emission reductions, T&D loss reduction, economic development potential, and improved reliability. CHP units are included as a potential generating resource in this IRP.

E. EXISTING POOLING AND BULK POWER AGREEMENTS

Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and Vectren), plus Duke Energy Ohio and Kentucky.

Duke Energy Indiana participates in the MISO energy markets. MISO ensures the safe, cost-effective delivery of electric power across all or parts of 15 states. As a Regional Transmission Organization (RTO), MISO assures consumers access to unbiased regional grid management and open access to the transmission facilities under MISO’s functional supervision. Duke Energy Indiana co-owns Gibson Unit 5 with WVPA and IMPA, and meets with them periodically to discuss planning and operation.

Duke Energy Indiana has several bulk power agreements that allow the Company to provide/purchase energy and/or capacity to/from other utilities or facilities.

- WVPA - Duke Energy Indiana has a contract to provide 70 MW of firm capacity and energy to WVPA for up to 35 years (i.e., through 2032). There are also contracts to provide 50 MW of firm capacity and energy through 2025 and 150 MW (expands to 180 MW in 2020) of firm capacity and energy through 2031.
- IMPA - Duke Energy Indiana has a contract to provide IMPA with 50 MW of firm capacity and energy through May 31, 2017 and another agreement to provide 100 MW of firm capacity and energy between June 2017 and May 2020.
- Hoosier Energy - Duke Energy Indiana has two 100 MW contracts to provide firm capacity and energy to Hoosier Energy. The period of the first contract is through December 31, 2017, and

the second is through December 31, 2023. A third contract to provide 50 MW of firm capacity and energy to Hoosier Energy is scheduled to begin on January 1, 2016, and ends on December 31, 2025.

- Henry County Station– Duke Energy Indiana has a 20-year, 50 MW contract with WVPA associated with the Henry County Station, which reduces the capacity available for Duke Energy Indiana native load customers at this station by this amount. (This 50 MW has been jurisdictionalized out of Duke Energy Indiana's retail rates).
- Benton County Wind Farm - The Company has a contract to purchase the energy produced and delivered by 100 MW of wind turbines from the Benton County Wind Energy Project (See Section G later in this chapter).
- Logansport - Effective July 1, 2009, Duke Energy Indiana purchased all of the Logansport Unit #6 capacity (approximately 8 MW) from the City of Logansport. The contract agreement is scheduled to end December 31, 2018. Logansport notified Duke Energy Indiana in summer 2011 that this unit was unavailable and it remains unavailable at this time.
- Solar Power Purchase Agreements (PPAs) – Following a formal bid solicitation and evaluation, the Company has agreed to purchase a total of 20 MW of solar power from four 5 MW installations. See Appendix E for details.
- Other - Duke Energy Indiana has both full and partial requirements contracts to serve a number of municipals in Indiana, although some of these cities elected to join IMPA, which terminated their contracts with Duke Energy Indiana.

With the exceptions of the 20 MW of six small municipal contracts, all of the wholesale load obligations are modeled as firm load throughout the study period, which assumes that these contracts will be renewed or replaced with new contracts.

Additionally, Duke Energy Indiana routinely executes energy hedge trades, which provide Duke Energy Indiana price certainty and reduce customers' exposure to energy price volatility. Further information concerning power purchase contracts may be found in the Short-Term Implementation Plan contained in Appendix E.

F. SUPPLY-SIDE RESOURCE SCREENING

In the screening analysis, a diverse range of technology choices utilizing a variety of different fuels was considered including pulverized coal (PC) units with and without carbon capture and storage (CCS), integrated gas combined cycle (IGCC) with CCS, CC, CT, CHP, and nuclear units. In addition, wind, solar, landfill gas, battery storage, and various combinations of generation and battery storage for renewable technologies were evaluated.

Technology types were screened within their own general category of baseload, peaking/intermediate, and renewable. The ultimate goal of the screening process was to pass the best alternatives from each of these three categories to the integration process. These initial screening analyses determine the most viable and cost-effective resources for further evaluation. This is necessary because of the size of the problem to be solved and computer execution time limitations of the System Optimizer capacity planning model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to, the following: Duke Energy's New Generation Project Development, Emerging Technologies, and Analytical Engineering; the EPRI Technology Assessment Guide (TAG®); and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of these. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Midwest.

Finally, every effort is made to ensure that cost and other parameters are current and include similar scope across the technologies being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's markets for commodities, construction materials, and manufactured equipment is challenging.

Technical Screening

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Indiana service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- ***Geothermal*** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.
- ***Compressed Air Energy Storage*** (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- ***Small Modular Nuclear Reactors*** (SMR) are generally defined as having capabilities of less than 300 MW. In 2012, U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." The focus of the grant is the first-of-a-kind engineering associated with NRC design certification and licensing efforts in order to demonstrate the ability to achieve NRC design certification and licensing to support SMR plant deployment on a domestic site by 2022. The grant was awarded to the Babcock & Wilcox Company (B&W), which will lead the effort in partnership with the Tennessee Valley Authority (TVA) and Bechtel Corporation. TVA has communicated with the NRC regarding TVA outlining six key assumptions for the possible licensing and construction of up to six Babcock & Wilcox (B&W) mPower design small modular reactor (SMR) modules at its Clinch River site in Roane County, Tennessee in a letter to the NRC in late 2010. It is estimated that this project may lead to the development of "plug and play" type nuclear reactor applications that are about one-third the size of current reactors. These are expected to become commercially available around 2022. NuScale, Holtec, Westinghouse, and B&W are still engaged with the NRC on pre-application activities for their SMR designs as of 10/22/14. Duke Energy will be monitoring the progress of the SMR project for potential consideration and evaluation for future resource planning.

- ***Fuel cells***, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.
- ***Poultry and swine waste digesters*** remain relatively expensive and face operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates or incentives for use of these technologies. Such projects are typically small and so would not materially impact the IRP.

Economic Screening

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor. The screening within each general class uses a spreadsheet-based screening curve model developed by Duke Energy. The model is considered to be proprietary, confidential and competitive information by Duke Energy Indiana. The screening curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors, using the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as in the Carbon Tax Scenario in the System Optimizer analysis (discussed in Chapter 8). This process is performed for each supply technology to create a family of lines. On the graph of all the lines in a general class, the lowest portions of the lines represent the least cost supply option at the corresponding capacity factor. Lines that are never lowest, or that are lowest only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and can be eliminated from further analysis.

2. <u>Screening Results</u>

In the quantitative analysis phase, the Company further evaluates those technologies from each of the three general categories screened (Base load, Peaking/Intermediate, and Renewables), which had the lowest levelized busbar cost for a given capacity factor range within each of these categories. The results of the screening within each category are shown in Appendix A.

Even though EPA's MATS and GHG New Source regulations may effectively preclude new coal-fired generation, Duke Energy Indiana has included supercritical pulverized coal (SCPC) and IGCC technologies with CCS of 800 pounds/net-MWh as options for base load analysis consistent with the proposed EPA NSPS rules. Additional detail on the expected impacts from EPA regulations for new coal-fired options is included in Chapter 6.

Baseload Technologies

Figure A-1 in Appendix A shows the screening curves (both No CO_2 and with CO_2) for the following technologies in the baseload category:

1. 723 MW Supercritical Pulverized Coal (SCPC) with CCS
2. 525 MW IGCC with CCS
3. 2 x 1,117 MW Nuclear units (AP1000)
4. 443 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
5. 895 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
6. 1,349 MW – 3x3x1 Advanced Combined Cycle (Inlet Chiller and Fired)
7. 14.5 MW – Combined Heat & Power (CHP)

Figure A-1 indicates that combined cycle generation is the least-cost base load resource. With lower gas prices, larger capacities and increased efficiency, combined cycle units have become more cost-effective at higher capacity factors in both the with CO_2 and without CO_2 screening cases. Although CHP is competitive with CC throughout the capacity range, it is site specific and requires a local steam load. The baseload curves also show that nuclear generation may be a cost effective option at high capacity factors with CO2 costs included.

Peak / Intermediate Technologies

Figure A-2 in Appendix A shows the screening curves (both No CO_2 and with CO_2) for the following technologies in the peak/intermediate category:

1. 173 MW 4-LM6000 CTs

2. 831 MW 4-7FA CTs

The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs.

Renewable Technologies

Figure A-3 in Appendix A shows the screening curves for the following technologies in the renewable category:

1) 150 MW Wind - On-Shore
2) 25 MW Solar PV
3) 25 MW Solar and 15 MWh Li-ion Battery (off-peak charging)
4) 25 MW Solar and 15 MW CT
5) 1 MW Li-ion Battery (off-peak charging)
6) 2 MW Li-ion Battery (off peak charging)

One must remember that busbar chart comparisons for wind and solar resources can be somewhat misleading because they do not contribute their full installed capacity at the time of the system peak.[12] Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis.

New hydro resources tend to be very site-specific; therefore, Duke Energy Indiana normally evaluates both pumped storage capacity and new run-of-river energy resources on a project-specific basis. Figure A-3 indicates solar is a more economical alternative than wind. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas projects are limited based on site availability. A nominal amount of landfill gas was included in IRP modeling although not shown on the screening curve. Solar and wind projects are not dispatchable and therefore less suited to

[12] For purposes of this IRP, wind resources are assumed to contribute 13% of installed capacity at the time of peak and solar resources are assumed to contribute 42% of installed capacity at the time of peak.

provide consistent peaking capacity. Aside from their technical limitations, solar and wind technologies are not currently economically competitive without State and Federal subsidies. Other energy sources are required to offset the ramping effects of solar and intermittency of wind to maintain grid stability. Fast-start/aeroderivative CTs and/or energy storage can play a role in the future as renewables are added to the system.

Energy storage solutions are becoming an increasing necessity for support of grid stability at peak demand times and for support of energy shifting and smoothing from renewable sources. Energy storage in the form of battery storage is becoming more feasible with advances in battery technology (Tesla low-cost Lithium-ion battery technology) and the reduction in battery cost; however, their uses (even within Duke Energy) have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Duke Energy has several battery storage projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. This includes projects ranging from the Notrees Battery Storage project (36 MW) in Texas, which supports a 153 MW wind farm, to the smaller 250 kW Marshall Battery Storage Project in North Carolina, which supports a 1.2 MW solar array. Additional examples include the Rankin Battery Storage Project (402 kW), the McAlpine Community Energy Storage Project (24 kW), McAlpine Substation Energy Storage Project (200 kW), all in North Carolina, and a 2 MW storage facility on Ohio’s former Beckjord Station grounds. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. These examples demonstrate a growing trend of coupling battery storage with an intermittent renewable energy source to stabilize output and increase net capacity factor.

Centralized generation will remain the backbone of the grid for Duke Energy in the long term; however, it is likely that distributed generation will begin to assume more grid responsibilities over time as technologies such as energy storage increase flexibility. Duke Energy Indiana is interested in increasing the amount of its distributed generation in the near term. Future analysis of the final CPP may increase the favorability of distributed generation.

The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be utilized for determining a long term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

3. Unit Size

The unit sizes selected for planning purposes generally are the largest technologies available today because they offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, operating and maintenance costs, emission costs, and installed $/kW cost). If a partial share of large nuclear or CC unit is selected as part of a least cost plan, joint ownership can be pursued.

4. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types such as simple-cycle CT units and CC units are relatively well known based on Duke Energy building experience, cost estimates in the TAG®, information obtained from architect and engineering (A&E) firms, and equipment vendors. The current estimated CC cost uses the information obtained from Duke Energy's recent and planned CC construction projects. The cost estimates include step-up transformers and a substation to connect with the transmission system. Because any additional transmission costs would be site-specific and because specific sites requiring additional transmission are unknown, typical values for additional transmission costs were added to the alternatives. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. Lead Time for Construction

The estimated construction lead time is three years for CTs, four for CCs, and six for coal units For nuclear units, the lead time is approximately eight years, however, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process and can increase the total project time by seven to eight years.

6. RD&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Duke Energy's research, development, and delivery (RD&D) activities enable Duke Energy Indiana to track new options including modular and dispersed generation systems (small and medium nuclear reactors), CTs, and advanced fossil technologies. Emphasis is placed on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new power generation technology to assure the Company is in the forefront of electricity supply and delivery.

Of particular interest is the expected advancements in CT/CC technology. Advances in stationary industrial CT/CC technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

Also of increasing interest is the adoption of utility owned distributed generation technologies. Generating electricity closer to load centers can increase reliability and reduce in line losses associated with central plant generation. This also adds diversity to the Indiana generation fleet. One example of this is CHP. This can be a low cost generation asset for the electric grid by also supplying low cost steam to the host. Examples of good CHP host sites include large industrials, hospitals, military, and universities. Inverter-based microgrid applications are also being explored, including both solar and energy storage. Energy storage can provide a wide range of grid benefits such as shifting energy from off-peak to peak times and can aid in the integration of renewable technologies to our generation portfolio. If placed at the right locations, storage can also provide back up to critical facilities such as Hospitals, Military Bases and Fire Stations.

7. Coordination With Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus the capacity requirement of each utility and whether the timing of the need for facilities is the same. To the extent that units that are larger than needed for Duke Energy Indiana's requirements become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

G. BENTON COUNTY WIND FARM PPA

Duke Energy Indiana has a 20-year power purchase agreement (PPA) with the Benton County Wind Farm. Duke Energy Indiana purchases the energy output from 100 MW of wind turbine capacity delivered to the designated delivery point for a period of 20 years. This was the first commercial wind farm in the state of Indiana. The facility's in service date was April 19, 2008.

A capacity credit of 13% of the installed capacity was modeled (13 MW out of the installed 100 MW) as capacity toward the reserve margin requirement.

The Company only pays for the energy it receives from Benton County Wind at a fixed price per MWh, which escalates annually. Benton County Wind receives and retains existing and future tax credits or tax benefits as the owner or operator of the wind renewable energy project. Duke Energy Indiana is entitled to ownership of all of the renewable energy certificates (RECs) and carbon credits associated with power produced by the wind turbines.

H. RENEWABLE ACTIVITIES

An extension of the GoGreen Power program was approved on July 3, 2013. The extension is for a three year term with the possibility of an automatic extension for an additional two-year period. The renewed program reduced the price for all green power kWh purchased per month to $1.00 per 100 kWh block, with a minimum purchase of two blocks. The block price was reduced again to $0.90 in early 2014. There are approximately 1306 customers on the program. Under the program, Duke Energy Indiana will purchase renewable energy in the form of renewable energy certificates. Duke Energy Indiana may self-certify RECs created from new, renewable projects of 3 MW or less located within Duke Energy Indiana's service territory.

Duke Energy Indiana has contracted to purchase 20 MWs of solar generation in the form of purchase power agreements under four agreements for 5 MWs. See Appendix E for further details.

In addition, Duke Energy Indiana is exploring potential additions of renewable energy sources, possibly located on customer sites or in areas in need of grid support. The renewable energy sources could be paired with energy storage, be part of a micro-grid, or be standalone. The Company believes that making investments in smaller, carbon-free energy sources in the near term makes sense, particularly given the increasing number of environmental regulations and related uncertainty. To the extent we are facing a carbon-constrained future, such investments will serve to support the state's carbon reduction goal, while also providing Duke Energy Indiana with valuable experience in managing and integrating renewables, storage and micro-grids with its generation portfolio.

I. <u>WABASH RIVER 2-6</u>

Analyses performed in the 2011 IRP and in Duke Energy Indiana's MATS rule Phase 2 Compliance Plan showed that retirement of Wabash River units 2-5 was more economical than retrofitting these units to comply with MATS. The assumed retirement date in the 2013 IRP was the MATS compliance date of April 16, 2015. On December 16, 2013, Duke Energy Indiana requested one year MATS extensions for units 2-6. This request was a result of transmission system reliability issues identified by MISO due to the retirements of units 2-5. MISO's study determined that unit 6 was an essential unit that must operate to support the transmission grid in the local Terre Haute area if units 2 through 5 are no longer available. It also found that a new high voltage transmission line must be constructed to resolve these transmission reliability issues and relieve unit 6 of its essential status. The construction of this line could not have been completed by the MATS compliance date. Duke Energy Indiana currently estimates that the project could be completed in 2016, hence the need for the MATS extensions. One year MATS extensions were granted for units 2-6 by IDEM on January 16, 2015. The resulting MATS compliance date for units 2-6 is April 16, 2016; this is also the revised assumed retirement date for units 2-5 in the 2015 IRP. Wabash River unit 6 continues to be evaluated for natural gas conversion and no decision been made. Duke Energy Indiana is currently investing in preliminary engineering necessary to support a conversion of Wabash River unit 6 from coal-fired to gas-fired, but is planning to further assess the economics of proceeding with conversion to natural gas under the final EPA Clean Power Plan rule.

It should also be noted that the pending retirement of Wabash River units 2 through 5 and suspension of unit 6 on April 16, 2016, created a synchronization issue with the 2015 - 2016 MISO Planning Resource Auction ("PRA"). Generators must commit their capacity for an entire year starting on June 1st and ending on May 31st of the next year. MATS driven retirements in mid-April result in an approximately 6.5 week shortage of the yearly commitment. Duke Energy Indiana requested a waiver from the MISO Tariff's requirement to offer Wabash River units 2 through 6 into the MISO annual planning auction for 2015 – 2016. The Federal Energy Regulatory Commission ("FERC") approved the waiver on February 20, 2015.

J. MARKLAND HYDRO UPGRADE

In the near term, Duke Energy Indiana intends to file a Certificate of Public Convenience and Necessity (CPCN), per Indiana Code 8-1-8.5, for a major upgrade to the Markland Hydroelectric facility. The three-unit facility is located on the Ohio River in Switzerland County, in Florence, Indiana. Total station generation capacity is 65 MW with a dispatch rating of 45 MW.

Originally entering service in 1967, key generating components at Markland Station are still utilizing the original technology from that era. Duke Energy Indiana has proposed to overhaul and upgrade each Markland unit from the ground up, replacing most components with more modern, efficient, upgraded options. The major scopes of work are as follows: replace the station runners and blades with an upgraded, more efficient design, replace the discharge rings, and draft tube transition piece, refurbish wicket gates (or replace as needed), rewind the generators, replace excitation controls and voltage regulators, replace and upgrade station controls, procure new intake and draft tube gates, and replace the main power transformer, as well as an overhaul and replacement of the general high voltage electrical systems at the station. The targeted outage windows are the fall of 2017, 2018, and 2019, one unit each year.

As a run-of-river hydro station, the generating units extract as much energy from the flow of the river as possible, within guidelines governed by the Army Corps of Engineers. This project will upgrade the performance of this facility with the latest technology in turbine runner efficiency, which will allow the Company to extract even more energy and capacity from the finite water resource. With this technology upgrade, Duke Energy Indiana expects to gain approximately 3MW of incremental design capacity output per unit, along with an expected increase of 36.7 GWh of actual annual average energy production from the station.

Table 5-A

Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Cayuga	1	Cayuga	IN	1970	ST	Coal		100.00%	505.0	500.0	FGD, EP, LNB, OFA, CT. SCR, DSI	
Cayuga	2	Cayuga	IN	1972	ST	Coal		100.00%	500.0	495.0	FGD, EP, LNB, OFA, CT, SCR, DSI	
Cayuga	3A	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3B	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3C	Cayuga	IN	1972	IC	Oil		100.00%	3.0	2.0	None	
Cayuga	3D	Cayuga	IN	1972	IC	Oil		100.00%	2.0	2.0	None	
Cayuga	4	Cayuga	IN	1993	CT	Gas	Oil	100.00%	120.0	99.0	DLN (Gas); WI (Oil)	
Connersville	1	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Connersville	2	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Edwardsport	IGCC	Knox County	IN	2013	IGCC	Syngas	Gas	100.00%	630.0	595.0	Selexol, SCR, MGB, CT	
Gallagher	2	New Albany	IN	1958	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gallagher	4	New Albany	IN	1961	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gibson	1	Owensville	IN	1976	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	2	Owensville	IN	1975	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	3	Owensville	IN	1978	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	4	Owensville	IN	1979	ST	Coal		100.00%	627.0	622.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	5	Owensville	IN	1982	ST	Coal		50.05%	312.8	310.3	FGD, SCR, SBS, EP, LNB, OFA, CL	Jointly owned with WVPA (25%) and IMPA (24.95%)
Henry County	1	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	50 MW from the plant is supplied to load other than DEI under PPA
Henry County	2	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	
Henry County	3	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	
Madison	1	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	2	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	3	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	4	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	5	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	6	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	7	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	8	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Markland	1	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	2	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	3	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	

Table 5-A: Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Miami-Wabash	1	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	2	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	3	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	5	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	6	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Noblesville	1	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	2	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	3	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	4	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	5	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Vermillion	1	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	2	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	3	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	4	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	5	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	6	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	7	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	8	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Wabash River	2	West Terre Haute	IN	1953	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	3	West Terre Haute	IN	1954	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	4	West Terre Haute	IN	1955	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	5	West Terre Haute	IN	1956	ST	Coal		100.00%	95.0	95.0	EP, LNB, OFA	
Wabash River	6	West Terre Haute	IN	1968	ST	Coal		100.00%	318.0	318.0	EP, LNB, OFA	
Wabash River	7A	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7B	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7C	West Terre Haute	IN	1967	IC	Oil		100.00%	2.1	2.1	None	
Wheatland	1	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	2	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	3	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	4	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Total									7,871.0	7,494.0		

Unit Type

ST	Steam
CT	Simple Cycle Combustion Turbine
CC	Combined Cycle Combustion Turbine
IC	Internal Combustion
HY	Hydro
IGCC	Integrated Coal Gasification Combined Cycle

Fuel Type

Coal
Gas
Syngas
Oil
Water

Environmental Controls

FGD	SO_2 Scrubber
SCR	Selective Catalytic Reduction
SBS	Sodium Bisulfite / Soda Ash Injection System
LNB	Low NO_x Burner
EP	Electrostatic Precipitator
BH	Baghouse
CT	Cooling Tower
CL	Cooling Lake
WI	Water Injection (NO_x)
OFA	Overfire Air
CO	Passive Carbon Monoxide Catalyst
DSI	Dry Sorbent Injection
MGB	Mercury Guard Carbon Bed
DLN	Dry Low NO_x Combustion System
Selexol	Acid-Gas removal technology

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6. ENVIRONMENTAL COMPLIANCE

A. INTRODUCTION

The environmental compliance planning process develops an integrated resource/compliance plan meeting future resource needs and environmental requirements in a reliable and economic manner. Compliance planning associated with existing laws and regulations is discussed in this chapter. Risks associated with anticipated and potential changes to environmental regulations are discussed in Section G.

B. CLEAN AIR ACT AMENDMENTS (CAAA) PHASE I COMPLIANCE

A detailed description of Duke Energy Indiana's CAAA Phase I compliance planning process can be found in the 1995, 1997, and 1999 IRPs.

C. CAAA PHASE II COMPLIANCE

A detailed description of Duke Energy Indiana's CAAA Phase II compliance planning process can be found in the 1995, 1997, and 1999 IRPs.

D. NO_x STATE IMPLEMENTATION PLAN CALL COMPLIANCE

A detailed description of Duke Energy Indiana's Nitrogen Oxide (NO_x) State Implementation Plan (SIP) Call compliance planning process can be found in the 1999, 2001, and 2003 IRPs.

E. CLEAN AIR INTERSTATE RULE (CAIR) AND CLEAN AIR MERCURY RULE (CAMR) - DUKE ENERGY INDIANA PHASE 1

A detailed description of Duke Energy Indiana's CAIR and CAMR Phase 1 compliance planning process and results can be found in the 2005, and 2007, and 2009 IRPs.

F. MERCURY AND AIR TOXICS STANDARDS (MATS) – DUKE ENERGY INDIANA PHASE 2 AND 3

Maximum Achievable Control Technology (MACT) standards became effective April 16, 2012 under MATS. MATS regulates Hazardous Air Pollutants (HAPs) and establishes unit-level emission limits for mercury, acid gases, and non-mercury metals (or filterable particulate matter), and sets work practice standards for organics, for coal and oil-fired electric generating units. The compliance date was April 16, 2015. Duke Energy Indiana has completed the installation of selective catalytic reduction (SCR) systems on the two units at Cayuga Station, which will aid in effective capture of mercury in the existing flue gas desulfurization systems by enhancing mercury oxidation. In addition to the SCRs, calcium bromide systems are being tested at Cayuga to help further enhance mercury oxidation. The Cayuga units are already equipped with wet scrubbers for SO_2 reduction, which also result in reduction of emissions of other acid gases regulated under MATS. Finally, systems for prevention of re-emission of mercury captured in the scrubbers have also been installed at Cayuga for both units.

Gibson Station Units 1 through 5 are all equipped with SCRs, wet scrubbers, calcium bromide systems and mercury re-emission prevention systems. Precipitator refurbishment projects for Units 3 and 4 are complete, and Unit 5 is scheduled for the fall of 2015.

The Gallagher units are well equipped for MATS rule compliance, with existing fabric filters for particulate control, as well as hydrated lime injection for SO_2 and acid gas control. Wabash River Units 2 through 5 are planned to be retired in April 2016. Evaluation continues on whether Wabash River Unit 6 will potentially be retired or converted to natural gas, but either way, it will likely cease burning coal in April 2016 due to MATS.

A detailed discussion of Duke Energy Indiana's MATS rule compliance planning process and results can be found in the 2013 IRP.

G. <u>ENVIRONMENTAL RISK/REGULATORY IMPACTS</u>

Several environmental risks/regulatory changes can affect Duke Energy Indiana in the future. The Company closely monitors these changes and develops responses when necessary.

1. <u>Ozone National Ambient Air Quality Standards (NAAQS)</u>

In March 2008, EPA reduced the 8 Hour Ozone Standard from 84 to 75 ppb. In September of 2009, EPA announced a decision to reconsider the 75 ppb standard in response to a court challenge from environmental groups, and its own belief that a lower standard was justified.

However, EPA announced in September 2011 that it would retain the 75 ppb primary standard until it is reconsidered under the next 5-year review cycle. On May 21, 2012, EPA finalized the area designations for the 75 ppb 8-hour ozone standard. There are no nonattainment areas in Duke Energy Indiana's service territory.

On October 1, 2015, EPA finalized a rule lowering the ozone standard from 75 to 70 ppb. States will have until October 1, 2016 to submit area designation recommendations to EPA. The EPA indicated that it will finalize designations by October 1, 2017, likely based on 2014-2016 ozone air quality data. The schedule for an area to attain the revised standard will depend on the severity of its nonattainment designation. Duke Energy Indiana will have a better indication of the possible implications of the lower ozone standard once area designations are finalized.

2. Particulate Matter NAAQS ($PM_{2.5}$)

On December 14, 2012, EPA finalized a rule lowering the annual $PM_{2.5}$ standard from 15 to 12 ug/m^3 and retaining the 35 ug/m^3 daily $PM_{2.5}$ standard. The EPA finalized area designations for the standard in early 2015. No areas in the Company's service territory were designated as nonattainment areas for the revised standard.

To date, neither the annual nor the daily $PM_{2.5}$ standard has directly driven emission reduction requirements at Duke Energy Indiana facilities. The reduction in SO_2 and NO_x emissions to address the $PM_{2.5}$ standards has been achieved through CAIR and CSAPR, each developed to address interstate transport. At this time, there is no indication that the revised $PM_{2.5}$ standard will result in EPA developing a new $PM_{2.5}$ interstate transport rule.

3. SO_2 NAAQS

On June 22, 2010, EPA established a 75 ppb 1-hour SO_2 NAAQS and revoked the annual and 24-hour SO_2 standards. EPA finalized initial nonattainment area designations in July 2013. The area around the Wabash River station was designated a nonattainment area. The Indiana Department of Environmental Management (IDEM) submitted a state implementation plan to EPA on October 2, 2015 that included SO_2 emission limits for

Wabash River starting January 1, 2017. Wabash River units 2-5 are planned to be retired in April 2016 in response to the EPA's MATS rule, and Wabash River unit 6 will potentially be fuel switched to natural gas or retired by April 2016, also in response to the MATS rule.

In May 2014, EPA issued a proposed Data Requirements Rule that included a proposed strategy and schedule for addressing the attainment status of areas not designated as nonattainment in July 2013. On August 21, 2015, EPA finalized that rule. The final rule requires state air agencies to characterize air quality around sources that emit 2,000 tons per year or more of SO_2, including the Gibson and Cayuga stations. State air agencies can characterize air quality by either modeling or monitoring air quality.

In June 2014, EPA requested comments on a proposed Consent Decree with the Sierra Club and the Natural Resources Defense Council related to the implementation of the 2010 75 ppb SO_2 standard. The proposed Consent Decree included provisions for addressing the attainment status of areas surrounding coal-fired power plants. The court entered the Consent Decree on March 2, 2015. Under its terms, EPA is required to sign a notice promulgating area designations by December 31, 2017 for areas where a state air agency relies on air quality modeling, or by December 31, 2020 for areas where a state air agency relies on air quality monitoring to characterize air quality.

4. <u>Cross-State Air Pollution Rule – Replacement for Clean Air Interstate Rule</u>

The EPA finalized CAIR in May 2005. CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. In December 2008, the United States District Court for the District of Columbia issued a decision remanding CAIR to the EPA, allowing CAIR to remain in effect until EPA developed a replacement regulation.

In August 2011, a replacement for CAIR was finalized as the CSAPR; however, on December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit. Numerous petitions for review of CSAPR were filed with the D.C. Circuit Court. On August 21, 2012, by a 2-1 decision, the D.C. Circuit vacated CSAPR. The Court also directed the

EPA to continue administering CAIR pending completion of a remand rulemaking to replace CSAPR with a valid rule. CAIR required additional Phase II reductions in SO_2 and NO_x emissions beginning in 2015.

The EPA filed a petition with the D.C. Circuit for en banc rehearing of the CSAPR decision, which the court denied. EPA then filed a petition with the Supreme Court asking that it review the D.C. Circuit's decision. On June 24, 2013, the Supreme Court granted EPA's petition, and on April 29, 2014, the Supreme Court reversed the D.C. Circuit's decision, finding that with CSAPR, EPA reasonably interpreted the good neighbor provision of the Clean Air Act. The case was remanded to the D.C. Circuit for further proceedings consistent with the Supreme Court's opinion. As part of those proceedings, EPA requested that the D.C. Circuit lift the CSAPR stay and direct that Phase 1 of the rule take effect on January 1, 2015. The court granted the EPA request, and Phase I of CSAPR took effect on January 1, 2015, replacing the CAIR. Phase II of CSAPR is set to take effect on January 1, 2017.

There were additional legal challenges to the CSAPR filed in 2012 but not initially addressed by the D.C. Circuit. On July 28, 2015 the Court issued its decision on those issues. That decision will have no impact on the CSAPR emission budgets for Indiana, nor on Duke Energy Indiana. The Company can already comply with CSAPR Phase I and II, so no additional controls are planned for this regulation.

5. <u>Mercury and Air Toxics Standard (MATS)</u>

EPA proposed the MACT rule in March 2011, and published on February 16, 2012 in the Federal Register the final rule known as the MATS rule. It regulates HAPs and establishes unit-level emission limits for mercury, acid gases, and non-mercury metals, and sets work practice standards for organics for coal and oil-fired steam electric generating units. Compliance with the emission limits was required by April 16, 2015. Permitting authorities have the discretion to grant up to a 1-year compliance extension, on a case-by-case basis. Duke Energy Indiana requested and was granted one-year compliance extensions for some of its affected sources for some or all of the rule requirements.

Numerous petitions for review of the final MATS rule were filed with the U.S. Court of Appeals for the D.C. circuit. In April 2014, the D.C. Circuit ruled in favor of EPA regarding all petitions. Several parties to the litigation subsequently petitioned the Supreme Court to review the D.C. Circuit's decision, and the court agreed to review the decision as it relates to EPA's failure to consider costs as part of its determination that it was appropriate and necessary to regulate HAPs from power plants. On June 29, 2015 the Supreme Court found that EPA should have considered costs as part of its determination of whether the regulation of HAPs from power plants was appropriate and necessary, and remanded the case to the D.C. Circuit for further proceedings. Despite the Supreme Court's decision, the MATS rule remains in effect pending further action by the D.C. Circuit, meaning that all affected sources must continue to meet the rule requirements except where compliance extensions have been granted. Duke Energy Indiana cannot predict the outcome of the court proceedings or how it might affect the MATS requirements.

6. <u>Clean Water Act Section 316(a) and 316(b)</u>

Protection of single fish species and aquatic communities is a primary focus of water permitting for coal, oil, gas, and nuclear power plants and industrial facilities under the Clean Water Act Section 316(a) - heated cooling water discharges, and 316(b) – entrainment through cooling water intake systems and impingement on intake screens.

All of the Company's stations that have once-through cooling are potentially affected by Section 316(a) regulation of heated cooling-water discharge; however, we do not see a significant likelihood that cooling towers would be required at any of those stations.

Federal regulations implementing Section 316(b) may necessitate cooling water system modifications to minimize impingement (pinned against cooling water intake structures) and entrainment (being drawn into cooling water systems and affected by heat, chemicals or physical stress) of aquatic organisms. The final regulation for existing facilities was signed on May 19, 2014. The rule was published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The final regulation establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters, utilizes at least 25% of the water withdrawn for cooling purposes, and has a National Pollutant Discharge Elimination System (NPDES) discharge permit.

The rule establishes one standard each for impingement and entrainment. To demonstrate impingement standard compliance, facilities must choose and implement one of these:

- Closed cycle re-circulating cooling system
- Demonstrate that maximum design through-screen velocity is less than 0.5 feet per second (fps) under all conditions
- Demonstrate the actual, measured through-screen velocity is less than 0.5 fps
- Install modified traveling water screens and optimize two-year performance
- Demonstrate a system of technologies, practices, and operational measures optimized to reduce impingement mortality relative to the impingement mortality limit
- Demonstrate that impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a 24-month contiguous period. The rule also allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

Rather than mandating a specific technology, the entrainment standard establishes a process for the state permitting agency to determine any controls necessary to reduce site-specific entrainment mortality. Facilities that withdraw more than 125 MGD are required to submit information to characterize the entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities with a NPDES permit expiring after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit expiring prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. Duke Energy Indiana expects submittals to be due in the 2018 to 2021 timeframe, and intake modification, if necessary, to be required in the 2019 to 2021 timeframe, depending on the NPDES permit renewal date and compliance schedule developed by the state permitting agency.

7. Steam Electric Effluent Limitation Guidelines

EPA signed the final revisions to the Steam Electric Effluent Limitations Guidelines (ELG) on September 30, 2015. The rule becomes effective 60-days after publication in the Federal Register. The revisions affect a station's wastewater discharge permit by establishing technology-based permit limits based on the performance of the best available technology (BAT) selected by EPA. The final rule is applicable to all steam electric generating units: coal, natural gas, nuclear, oil, combined-cycle, petroleum coke, and synthesis gas. However, the waste streams affected by the revisions are generated at coal-fired and IGCC facilities. The waste streams and BAT selected by EPA are provided below.

Waste Stream	Best Available Technology
FGD Wastewater	— Chemical precipitation plus biological — Incentive for voluntarily installing Vapor Compression Evaporation system
Fly Ash Transport Wastewater	Zero discharge (dry handling)
Bottom Ash Transport Wastewater	Zero discharge (dry handling or closed loop)
Leachate from CCR Landfills and Impoundments	Surface Impoundments
Flue Gas Mercury Control Wastewater	Zero discharge (dry handling)
Gasification Wastewater	Vapor compression evaporation

The new limitations will be incorporated into a station's NPDES permit upon renewal after the effective date of the rule. The rule requires the new limitations for all waste streams, except coal combustion residual (CCR) leachate, to apply based on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately 3 years following promulgation of rule), but no later than December 31, 2023. For CCR leachate, the limits are effective immediately upon issuance of the permit after the effective date of the rule. The date determined by the permitting authority will be dependent on the site specific-modifications necessary to comply with the rule.

8. Waters of the United States (aka Clean Water Rule)

The Clean Water Act (CWA) provides federal jurisdiction over waters defined as "the waters of the United States" (WOTUS) and are regulated by both EPA and U.S. Army Corps of Engineers (Corps). The final Clean Water Rule, which revises the definition of "waters of the United States", was signed on May 27, 2015 and published in the Federal Register on June 29, 2015 with an effective date of August 28, 2015. The regulation is not specific to the utility industry (agriculture, housing and other industries have all expressed concern over any expansion of jurisdiction). On October 9, 2015, the Sixth Circuit issued a nationwide, temporary stay of the rule while it determines whether the courts of appeal or district courts have jurisdiction over challenges filed by states and private parties. A longer stay may be requested later. While the stay is in effect, the previous definition of WOTUS will be applied. The following provides a summary of the final rule, which will go into effect if the stay is lifted.

While EPA and the Corps have attempted to provide some limits to the rule's jurisdictional scope, it is very broad and likely to expand jurisdiction to many more water features. The final rule determines which waters are under EPA and Corps jurisdiction by defining WOTUS to include eight categories; six that are automatically covered by the regulation and two that establish jurisdiction on a case-specific basis through "significant nexus" determinations. A water will be determined to have a significant nexus if any single function or combination of functions contributes significantly to the chemical, physical or biological integrity of the nearest traditionally navigable water, interstate water or territorial sea.

Jurisdiction by rule (automatically included in the regulation):

1. All waters currently used, were in the past, or may be susceptible to use in interstate or foreign commerce, including tidal waters (also called traditionally navigable waters – TWN);
2. All interstate waters, including interstate wetlands (ISW);
3. The territorial seas (TS);
4. All impoundments of waters otherwise defined as waters of the U.S.;
5. All tributaries of waters identified in 1-3 above;
6. All waters adjacent to water identified in 1-5

Case-specific significant nexus analysis:

7. Five specific types of wetlands to be analyzed in combination: (a) Prairie potholes, (b) Carolina & Delmarva bays, (c) pocosins, (d) western vernal pools in California, and (e) Texas coastal prairie wetlands.
8. For two other types of waters: (a) those within a 100-year floodplain of a traditional navigable water, interstate water or territorial sea and (b) those within 4000 feet of the high tide mark or ordinary high water mark (OHWM) of a TWN, ISW or TS, impoundment or covered tributary.

Excluded waters and features (non-jurisdictional):

— A number of exclusions in the final rule are critical to water features at our generating stations that are not currently jurisdictional. Some of these include: waste treatment systems, certain ditches, cooling ponds, artificial/constructed lakes and ponds, stormwater control facilities, wastewater recycling structures, groundwater, erosional features and water-filled depressions from construction activities.

— It should be noted that excluded water features can still serve as hydrologic connections when performing case-specific significant nexus determinations. Some exclusions may be difficult to obtain since they must have been created in “dry land” to qualify for the exclusion. Also, some exclusions may be difficult for applicants to prove (through topographic maps, historic photographs, etc.)

Once a waterbody has been classified as a WOTUS, it is then subject to numerous CWA programs, including sections 402 (wastewater discharge permitting), 404 (discharge of dredged and fill material permitting), 311 (oil spill program), 302/303 (water quality standards/total maximum daily load programs), 316(b) (cooling water intake structures) and 401 (state water quality certification).

9. Coal Combustion Residuals (CCR)

In June 2010, following the Tennessee Valley Authority's Kingston ash pond dike failure in December 2008, EPA proposed a regulation for the disposal of CCRs. CCRs include fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. On April 17, 2015 EPA published its final rule for the disposal of CCRs. The rule regulates CCRs as a non-hazardous waste under Subtitle D of the Resource Conservation Recovery Act. This is the first federal regulation of CCRs. The effective date of the rule was October 19, 2015, starting with the requirement to comply with the operating requirements.

The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs if they are located at a power plant actively generating electricity, regardless of fuel source being used. In addition to surface impoundments that are actively receiving CCRs, the rule applies to CCRs surface impoundments no longer receiving CCRs if they contain CCRs and liquids and are located at a power plant that is currently producing electricity. These impoundments are defined as inactive impoundments. The rule does not apply to inactive landfills. The rule will result in the closure of most existing surface impoundments used to store or dispose of CCRs and treat non-CCR wastewaters. The closure of surface impoundments will lead to dry handling of fly ash and bottom ash and the need for additional landfill capacity. It will also result in a need for alternative wastewater treatment for the non-CCR wastewaters in smaller lined ponds. The regulatory deadlines that could trigger the closure of surface impoundments include non-compliance with structural integrity standards (April 2017), exceedance of ground water protection standards (April 2018), or failure to demonstrate compliance with location restrictions (April 2019). Duke Energy Indiana anticipates soon filing a proceeding with the Commission in which it sets forth its CCR compliance plan.

10. Greenhouse Gas Regulation

On August 3, 2015, EPA signed final CO_2 emission limit guidelines for existing fossil-fuel power plants, known as the "Clean Power Plan" (CPP). The CPP does not impose any regulatory requirements on affected power plants. Instead, each state is to develop a plan for how it will implement the CPP, or the EPA will impose a federal plan on sources in states that fail to submit an approvable plan. Either a final state plan or final federal plan will contain the regulatory requirements that will apply to the Company's affected sources.

Under the CPP schedule, states have until September 6, 2016 to submit a complete plan or an initial plan with an extension request. States receiving an extension must submit a final plan by September 6, 2018. EPA plans to take up to a year to approve or disapprove state plans.

If a state chooses not to submit a plan or submits a plan to EPA that is not approved, EPA plans to impose a federal plan on the state. On August 3, 2015, EPA issued a proposed federal plan for public comment. Comments are due 90 days after the proposed rule is published in the Federal Register. The emission reduction requirements and implementation schedule in the proposed federal plan are the same as those contained in the final CPP.

The final CPP establishes 2030 as the year when final CO_2 emission reductions are to be achieved. EPA also established a 2022-2029 interim performance period consisting of three interim steps of 2022-2024, 2025-2027, and 2028-2029, with each period having unique emission reduction targets that are intended to produce an emission reduction glide path to 2030. Therefore, under the final CPP, emission reduction requirements are to begin in 2022.

Duke Energy Indiana does not know what CPP regulatory requirements may ultimately apply to its affected sources. The final CPP is expected to be challenged in court by numerous parties, including many states. It is also expected that the court will be asked to stay the implementation of the CPP until the legal proceedings are complete.

On August 3, 2015, EPA also finalized a rule that establishes CO_2 emission standards for new, modified, and reconstructed fossil-fuel power plants. The requirements for new plants would apply to any plants constructed after January 8, 2014 (the date the rule was proposed). Requirements for any existing units that might be modified and reconstructed are effective June 18, 2014 (the date that rule was proposed). This final rule will prevent Duke Energy Indiana from developing any new coal-fired power plants that are not equipped with carbon capture and storage technology.

H. ENVIRONMENTAL COMPLIANCE PLAN

The current modeling analysis primarily focused on evaluation of alternatives to comply with the CCR, ELG, and 316(b) rule requirements. For CCR and ELG compliance, conversion to dry ash handling, waste water treatment, and landfill construction options were considered. For 316(b) compliance, based on site-specific considerations, standard mesh and fish friendly screens and fish return systems were assumed. The Engineering Screening Model was used to provide the cost of these technologies to the IRP models.

In summary, for purposes of this IRP, the suite of non-carbon related future environmental regulations and general requirements modeled included:

- CCR Rule, and ELG revisions
    - Dry ash management conversion costs
    - Waste water treatment addition/upgrade costs
    - Landfill construction costs
- 316(b) Intake Structure Rule
    - Aquatic impingement and entrainment studies
    - Intake structure and traveling screen upgrade costs
    - Cooling tower installations were assumed to be mandated for coastal and estuarial units, but this assumption only impacted the development of fundamental forecast inputs as none of Duke Energy Indiana’s assets meets these criteria
    - Also for fundamental forecast development purposes only, the compliance timeframe for 316(b) ranged from 2020 in the No Carbon Regulation Scenario and 2016 in the Carbon Regulation Scenarios. This range did not impact the units’ specific IRP modeling as the compliance timeframes were based off of each facility’s NPDES permit renewal schedule per the proposed rule.

- National Ambient Air Quality Standards (NAAQS) for Ozone and SO_2
  - Increased risk for additional NO_x and SO_2 reductions
  - Increased risk for site-specific control requirements
  - Given that Cayuga and Gibson are fully scrubbed with SCRs, and that the Wabash River units will either be retired or converted to natural gas, the NAAQS assumptions mainly impacted future modeling of Gallagher, which was either required to install SNCR or assumed to retire due to a requirement to install SCR and/or FGD, or to CCR and/or ELG requirements. Except in the No Carbon Regulation Scenario, Cayuga and Gibson were assumed to install relatively low cost scrubber additives for enhanced SO_2 control, and Gibson units were modeled with SCR upgrades for increased NO_x removal, all in the 2020 timeframe.

The balance of all of the assumptions for the compliance analysis were reviewed and updated where necessary to coincide with the other assumptions used for the development of this IRP.

1. Compliance Planning Process

For this analysis, Duke Energy Indiana generally utilized the same three-stage analytical modeling process as in other past compliance planning activities, involving an external vendor's (for 2015, EVA) national modeling tools and Duke Energy Indiana's internal Engineering Screening Model. EVA used their national modeling tools to model the current, pending, and proposed rules. As in the past, from these modeling runs Duke Energy Indiana was provided forecasted emission allowance prices, power prices, and fuel prices. EVA provided the fundamental forecast information for the No Carbon Regulation, Carbon Tax, and P-CPP Scenarios.

2. Engineering Screening Model

Historically, Duke Energy Indiana's in-house Engineering Environmental Compliance Planning and Screening Model (Engineering Screening Model) has been used to screen down a large number of air-emission control alternatives to the most economic emission reduction options. As some generating units have already been committed to retirement and others are already well controlled or undergoing construction of additional controls, the number of remaining viable air-emission control alternatives has dwindled. As a result, no specific screening activity was performed for this IRP. However, the model's functionality was still used to organize modeling information, and provide the necessary modeling characteristic data for emission control alternatives to the System Optimizer and Planning and Risk models (discussed in Chapter 8).

The Engineering Screening Model incorporates the operating characteristics of the Duke Energy Indiana units (net MW, heat rates, emission rates, emission control equipment removal rates, availabilities, variable operating and maintenance expenses, etc.), and market information (energy, emission allowance, and fuel prices), calculates the dispatch costs of the units, and dispatches them independently against the energy price curve. The model calculates generation, emissions, operating margin, and, ultimately, free cash flow with the inclusion of capital costs.

The Engineering Screening Model also contains costs and operating characteristics of emission control equipment. This includes wet and dry flue gas desulfurization equipment (FGD or scrubber) and dry sorbent injection for SO_2 removal; selective and non-selective catalytic reduction (SCR and SNCR) and low NO_x burners (LNB) for NOx removal; baghouses, activated carbon injection (ACI), mercury re-emission chemical, and calcium bromide fuel additive for mercury removal; and various fuel switching options with related capital costs (such as a switch to lower sulfur content coal with required electrostatic precipitator upgrades). The model also appropriately treats emission reduction co-benefits, such as increased mercury removal with the combination of SCR and FGD. The Engineering Screening Model also contains similar characteristic information for water and waste management modeling, such as dry bottom ash conversions and waste water treatment systems.

The Engineering Screening Model was used to support this IRP by organizing modeling information and providing the necessary modeling characteristic data for emission control alternatives to the System Optimizer and Planning and Risk models. The model is considered proprietary confidential and competitive information by Duke Energy Indiana.

New Technologies

Investigating new emission control technologies was discussed in the 2005, 2007, 2009, 2011, and 2013 IRPs. Duke Energy Indiana continues to investigate alternative emission control options that may be operationally, environmentally, and/or economically more advantageous than traditional or demonstrated technologies. Recently, the most pertinent options include dry ash handling and refined waste water treatment technologies. In addition, Duke Energy Indiana continues to evaluate the possible conversion of existing coal-fired boilers to natural gas firing as a means of retaining the capacity value of a unit while achieving significant emission reductions.

Capital Cost Estimates

High-level cost estimates have been developed for the modeled compliance requirements, such as dry ash management conversion, wastewater treatment, and the other such projects noted above. For units and project options that have not had detailed studies performed, costs have been estimated using best engineering judgment of equipment and installation requirements, typically based on industry information. This includes reviewing technological aspects, trends in the cost of construction, and construction retrofit difficulty.

3. **System Optimizer / Planning and Risk Results**

The modeled emission control alternatives associated with CCR, ELG, 316(b), and other regulations passed to the System Optimizer and Planning and Risk models from the Engineering Screening Model were analyzed in the integration step of this IRP in conjunction with the energy efficiency and supply-side alternatives. This is discussed in detail in Chapter 8.

I. EMISSION ALLOWANCE MANAGEMENT

Figure 6-A shows the base number of SO_2 allowances allotted by the US EPA for affected units on the Duke Energy Indiana system for the CSAPR 2015 through 2017 control periods. Figures 6-B and 6-C show the base number of Seasonal and Annual NO_x allowances, respectively, allotted by the US EPA for affected units on the Duke Energy Indiana system for the CSAPR 2015 through 2017 control periods.

The emission allowance markets can impact compliance strategies. The projected allowance market price is a basis against which the costs of compliance options are compared to determine whether the options are economic (*i.e.*, a “market-based” compliance planning process). Even with the reinstatement of the CSAPR, significant additional emission reductions are expected due to the MATS rule responses including new control installations and unit retirements. This causes low projected emission allowance prices for SO_2 and NO_x, typically below the variable cost of control. Therefore, these markets are not playing a significant role in the environmental compliance strategy at this time.

Duke Energy Indiana has maintained an interdepartmental group to perform SO_2 and NO_x emission allowance management. Duke Energy Indiana manages emissions risk by utilizing a mixture of purchasing or selling allowances, installing equipment and, when applicable, purchasing power. The most economic decision is dependent upon the current and forecasted market price of allowances, the cost and lead-time to install control equipment, and the current and forecasted market price of power. These factors will be reviewed as the markets change and the most economic emission compliance strategy will be employed.

Figure 6-A

SO_2 ALLOWANCES (TONS) ALLOCATED TO DUKE INDIANA UNITS

Station	Unit	Percent Ownership	2015	2016	2017
Cayuga	1	100	7,205	7,289	4,084
Cayuga	2	100	7,105	7,187	4,027
Edwardsport	6-1	100	1	1	1
Edwardsport	7-1	100	245	248	139
Edwardsport	7-2	100	209	212	119
Edwardsport	8-1	100	253	256	143
Gallagher	2	100	1,672	1,691	948
Gallagher	4	100	1,601	1,619	907
Gibson	1	100	10,046	10,163	5,694
Gibson	2	100	9,922	10,038	5,624
Gibson	3	100	10,731	10,856	6,082
Gibson	4	100	9,178	9,178	5,615
Gibson	5	50.05	4,261	4,310	2,415
Wabash River	2	100	1,325	1,341	751
Wabash River	3	100	1,282	1,297	727
Wabash River	4	100	1,481	1,498	840
Wabash River	5	100	1,359	1,374	770
Wabash River	6	100	5,041	5,099	2,857

Figure 6-B

SEASONAL NO_x ALLOWANCES (TONS) ALLOCATED TO DUKE INDIANA UNITS

Station	Unit	Percent Ownership	2015	2016	2017
Cayuga	1	100	1,136	1,136	1,119
Cayuga	2	100	1,080	1,080	1,063
Edwardsport	6-1	100	1	1	1
Edwardsport	7-1	100	32	32	32
Edwardsport	7-2	100	27	27	26
Edwardsport	8-1	100	35	35	35
Gallagher	2	100	270	270	266
Gallagher	4	100	268	268	264
Gibson	1	100	1,600	1,600	1,576
Gibson	2	100	1,532	1,532	1,509
Gibson	3	100	1,632	1,632	1,608
Gibson	4	100	1,526	1,526	1,503
Gibson	5	50.05	656	656	646
Henry County	1	100	10	10	10
Henry County	2	100	10	10	10
Henry County	3	100	11	11	11
Noblesville Repowering	1-3	100	128	128	128
Vermillion	1	62.50	1	1	1
Vermillion	2	62.50	1	1	1
Vermillion	3	62.50	3	3	3
Vermillion	4	62.50	1	1	1
Vermillion	5	62.50	2	2	2
Vermillion	6	62.50	2	2	2
Vermillion	7	62.50	1	1	1
Vermillion	8	62.50	3	3	3
Wabash River	2	100	189	189	186
Wabash River	3	100	186	186	184
Wabash River	4	100	227	227	224
Wabash River	5	100	199	199	196
Wabash River	6	100	821	821	808
Wheatland	1	100	9	9	9
Wheatland	2	100	7	7	7
Wheatland	3	100	7	7	7
Wheatland	4	100	7	7	7

Figure 6-C

ANNUAL NO_x ALLOWANCES (TONS) ALLOCATED TO DUKE INDIANA UNITS

Station	Unit	Percent Ownership	2015	2016	2017
Cayuga	1	100	2,666	2,731	2,700
Cayuga	2	100	2,628	2,693	2,663
Edwardsport	6-1	100	1	1	1
Edwardsport	7-1	100	91	93	92
Edwardsport	7-2	100	77	79	78
Edwardsport	8-1	100	93	96	95
Gallagher	2	100	579	594	587
Gallagher	4	100	592	607	600
Gibson	1	100	3,717	3,808	3,765
Gibson	2	100	3,671	3,761	3,719
Gibson	3	100	3,970	4,068	4,022
Gibson	4	100	3,665	3,755	3,713
Gibson	5	50.05	1,576	1,615	1,597
Henry County	1	100	16	16	16
Henry County	2	100	16	16	16
Henry County	3	100	17	17	17
Noblesville Rep	1-3	100	239	245	243
Vermillion	1	62.50	3	3	3
Vermillion	2	62.50	3	3	3
Vermillion	3	62.50	3	3	3
Vermillion	4	62.50	3	3	3
Vermillion	5	62.50	3	3	3
Vermillion	6	62.50	3	3	3
Vermillion	7	62.50	3	3	3
Vermillion	8	62.50	3	3	3
Wabash River	2	100	490	502	497
Wabash River	3	100	474	486	481
Wabash River	4	100	548	561	555
Wabash River	5	100	503	515	509
Wabash River	6	100	1,865	1,911	1,889
Wheatland	1	100	12	12	12
Wheatland	2	100	11	11	11
Wheatland	3	100	9	9	9
Wheatland	4	100	10	10	10

7. ELECTRIC TRANSMISSION FORECAST

All transmission and distribution information is located in Appendix G.

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8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. INTRODUCTION

Once the screening processes for demand-side, supply-side, and environmental compliance resources reduced the options to a manageable number, the next step was to integrate these options into optimized resource portfolios for consideration. This chapter will describe the integration process, the scenario and sensitivity analyses, the creation of the 2015 IRP, selection of the preferred resource plan and its general implementation in the short-term.

B. RESOURCE INTEGRATION PROCESS

The goal of the integration process was to take all of the pre-screened EE, supply-side, and environmental compliance options to develop an integrated resource plan using a consistent method of evaluation. The tools used were the ABB System Optimizer (SO) model and the ABB Planning and Risk (PaR) model.

Model Descriptions

System Optimizer

SO is an economic optimization model used to develop integrated resource plans while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional units (*e.g.*, CTs, CCs, coal units, *etc.*), renewable resources (*e.g.*, wind, solar), and EE resources. SO uses a linear programming optimization procedure to select the most economic expansion plan based on Present Value Revenue Requirements (PVRR). The model calculates the cost and reliability effects of modifying the load with demand-side management programs or adding supply-side resources to the system.

Planning and Risk

PaR is a detailed production costing model used to simulate the operation of the electric production facilities of an electric utility. Key inputs include generating unit, fuel, load, transaction, EE, emissions allowance cost, and utility-specific system operating data. These inputs, along with its complex algorithms, make PaR a powerful tool for projecting utility electric production facility operating costs.

Identify and Screen Resource Options for Future Consideration

The IRP process evaluates EE and supply-side options to meet customer energy and capacity needs. EE options are based on input from internal subject-matter experts and cost-effectiveness screening (see Chapter 4). Supply-side options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable). The Company compared capacity options by service-type (baseload, peaking, or renewable), and the most cost-effective options were selected for inclusion in the portfolio analysis phase (see Chapter 5).

Over the 20 year planning period, a 200 MW capacity addition to the Duke Energy Indiana system translates to a 3% increase in reserve margin. Therefore, some of the generic supply-side options were modeled in blocks smaller than either the optimal economic or the commercially available sizes of these units. For example, the CC and nuclear units were modeled in blocks of 448 MW and 280 MW, respectively. Actual units utilizing these technologies are normally much larger.

Using comparably sized units allows the model to make choices based more on economics than unit sizes. Supply-side screening typically showed that the largest unit sizes available for any given technology type were the most cost-effective, due to economies of scale. If smaller units were required, the capital costs on a $/kW basis would be much higher than the cost estimates used in this analysis. Duke Energy Indiana could take advantage of the economies of scale from a larger unit by joint ownership with another utility, or by signing a power purchase agreement (PPA) from a facility.

There is not currently an Indiana or federal REPS, although the final CPP rule includes incentives for early renewables installations. However, to assess the impact on long-term resource needs, the Company believes it is prudent to plan for a REPS, so all scenarios except No Carbon Regulation include a REPS. Based on the results of the screening curve analysis and support from the renewable strategy and compliance group, the renewables made available to the model were Wind, Solar, and small-scale/landfill-gas Biomass.

Based on the results of the screening analysis, the following technologies in Table 8-A were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

Table 8-A Technologies Considered

Technology	Cost Basis (Nominal MW)	Modeled in System Optimizer (Nominal MW)	% Peak Contribution
Nuclear	2,240 (2 units)	280	100%
Simple Cycle CT	831 (4 units)	208	100%
Combined Cycle CC	785 Unfired 110 Duct fired	393 Unfired 55 Duct fired	100%
Cogeneration (Gas)	14.5	14.5	100%
Wind	150	50	13%
Solar	25	10	42%
Bio-methane	5	2	100%

Projected impacts from both Core and Core Plus EE programs were included. These EE resources reduce the need for new generation resources.

Demand Response programs contain customer-specific contract curtailment options, Power Manager (residential direct load control), and PowerShare® (for non-residential customers). The DR programs were modeled in four discrete groupings:

Power Manager – Direct Load Control

Interruptible – Special Contracts

PowerShare® – Demand Response

PowerShare® – Behind The Meter Generation

Any generic resources selected by the model represent “placeholders” for the type of capacity needed on the system. The peaking, intermediate, or base load needs can be met by purchases from the market, cogeneration, repowering, or other capacity that may be economical at the time decisions are made to acquire new capacity. Decisions concerning coordinating the construction and operation of new units with other utilities or entities can also be made at the proper time.

The SO integration analysis covered 26 year period 2015-2040 to account for end effects. Production cost modeling in PaR covered 21 years (2015-2035).

C. QUANTITATIVE ANALYSIS RESULTS

Define Scenarios

Scenario analysis was included to increase the robustness of the planning process. The initial stakeholder meeting included a discussion of the underlying assumptions and driving forces that define a scenario. Based on that discussion, seven scenarios were developed.

Once the scenarios were specified, an outside consultant modeled the core scenarios using an internally consistent methodology to capture secondary and tertiary effects caused by changes in key variables. For example, in carbon tax scenarios, the higher operating costs of carbon-emitting generation causes it to dispatch less frequently. The consequence of lower fossil fuels consumption is lower demand that results in lower prices for those fuels.

Many of the assumptions for each scenario represent anticipated environmental requirements consistent with the theme of that scenario. As these environmental rules are formalized, they will be incorporated into future analysis.

While these scenarios do not cover all possible futures, they cover a reasonable range of futures. As more information is learned, it will be incorporated into future IRPs.

Scenarios

No Carbon Regulation: Features no carbon regulation or REPS.

Carbon Tax: features a carbon tax starting at $17/ton in 2020 and includes a 5% REPS; load growth is slightly lower than in the No Carbon Regulation scenario.

Proposed Clean Power Plan Rule: modeled after the proposed Clean Power Plan with a 20% CO_2 reduction for Indiana.

Delayed Carbon Regulation: Carbon regulation by carbon tax delayed until 2025.

Repealed Carbon Regulation: Carbon regulation by tax delayed until repealed in 2025.

Climate Change: Based on the Carbon Tax scenario, the Climate Change scenario features extreme weather every five years. This is modeled by higher summer temperatures and lower winter temperatures that mimic some of the extreme weather that Indiana has experienced over the past several years.

Increased Customer Choice: Features an additional 1% of rooftop solar per year beginning in 2020 and higher levels of energy efficiency.

Develop portfolios

The nine portfolios are summarized below and in Table 8-B and Figure 8-E:

Optimized Resource Portfolios

No Carbon Regulation Portfolio:

- Assumes retirement of Wabash River units 2-6 in 2016 and of the Miami-Wabash and Connersville CTs in 2018.
- Most of the resource additions are CTs
- Assumes a significant amount of energy purchased from the market

Carbon Tax Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in the 2030s
- Resource additions are primarily renewables and CTs
- Assumes a significant amount of energy purchased from the market

Proposed Clean Power Plan (P-CPP) Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in 2020
- Resource additions are primarily renewables and CT generation
- Assumes a significant amount of energy is purchased from the market

Combined Cycle Resource Portfolios

No Carbon Regulation Portfolio with additional CC

- Assumes retirement of Wabash River units 2-6 in 2016 and of the Miami-Wabash and Connersville CTs in 2018.
- Resource additions are primarily CCs and a few CHP projects
- CC generation lessens the amount of energy purchased from the market

Carbon Tax Portfolio with additional CC

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in the 2030s
- Resource additions are primarily CCs and renewables
- CC generation lessens the amount of energy purchased from the market

Proposed Clean Power Plan Portfolio with additional CC

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in 2020
- Resource additions are primarily CCs and renewables
- CC generation lessens the amount of energy purchased from the market

Stakeholder Inspired Resource Portfolios

Stakeholder Distributed Generation Portfolio

- Developed by stakeholders in IRP stakeholder meeting
- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, both Cayuga units, and Gibson units 1-3 & 5
- Resource additions include CTs and CCs with significant additions of CHP, battery storage and renewables

Stakeholder Green Utility Portfolio

- Developed by stakeholders in IRP stakeholder meeting
- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, both Cayuga units, and Gibson units 1 & 5
- Resource additions include CT and CC generation as well as significant additions (although less than the Stakeholder Distributed Generation Portfolio) of CHP and renewables

High Renewables Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in the 2030s
- Resource additions are significantly higher levels of renewables and CTs
- Assumes a significant amount of energy purchased from the market

NOTE REGARDING EE BUNDLES AS A SUBSET OF OVERALL EE

In this IRP, EE was packaged into discrete bundles to be modeled for economic selection in SO. It is important to recognize that bundles are not the complete picture of EE. Below are some graphical representations of different sources of EE by portfolio. The EE in Table 8-B is the incremental contribution to load in each 5 year period.

Figure 8-A: No Carbon Tax and No Carbon Tax with Additional CC

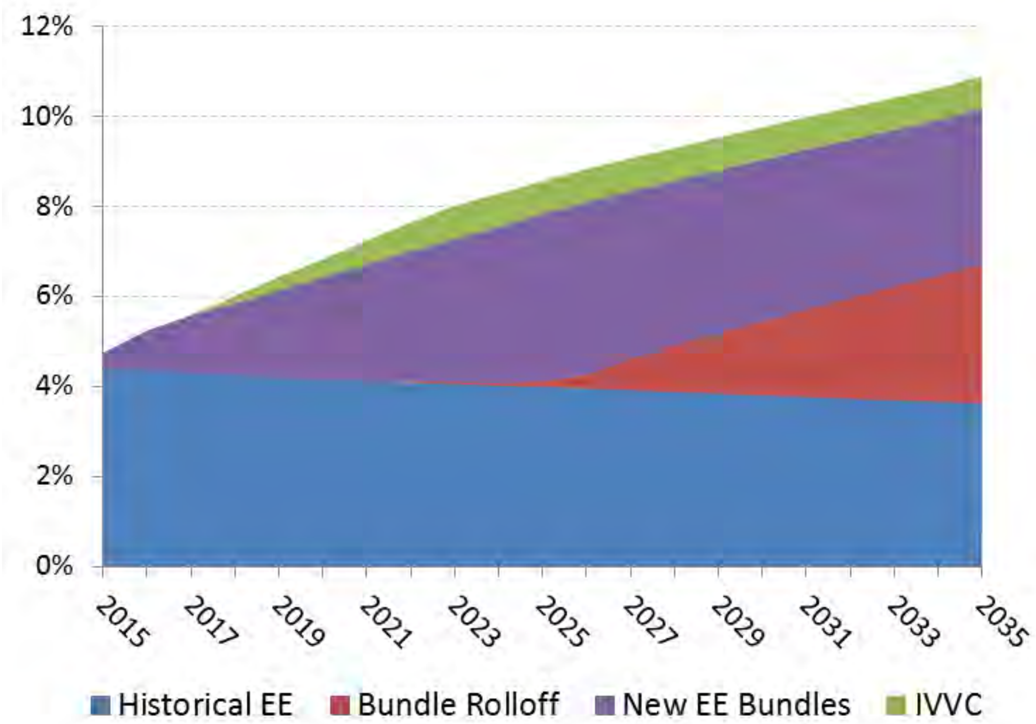


Figure 8-B: Carbon Tax, P-CPP, Carbon Tax with Additional CC, P-CPP with Additional CC & High Renewables Portfolios

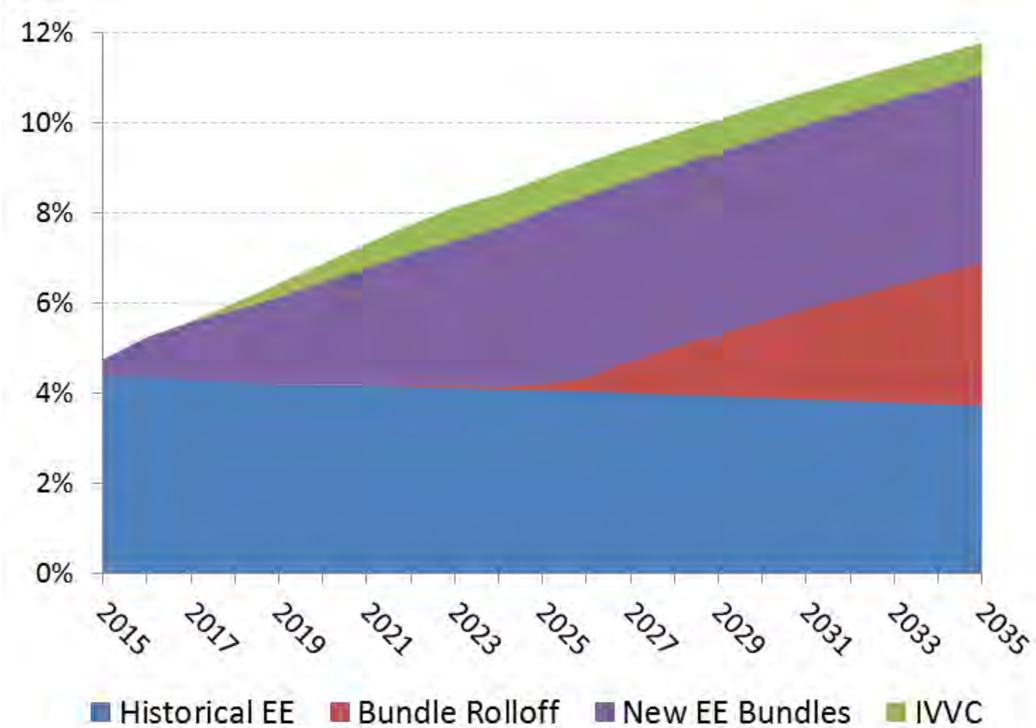


Figure 8-C: Stakeholder Distributed Generation Portfolio

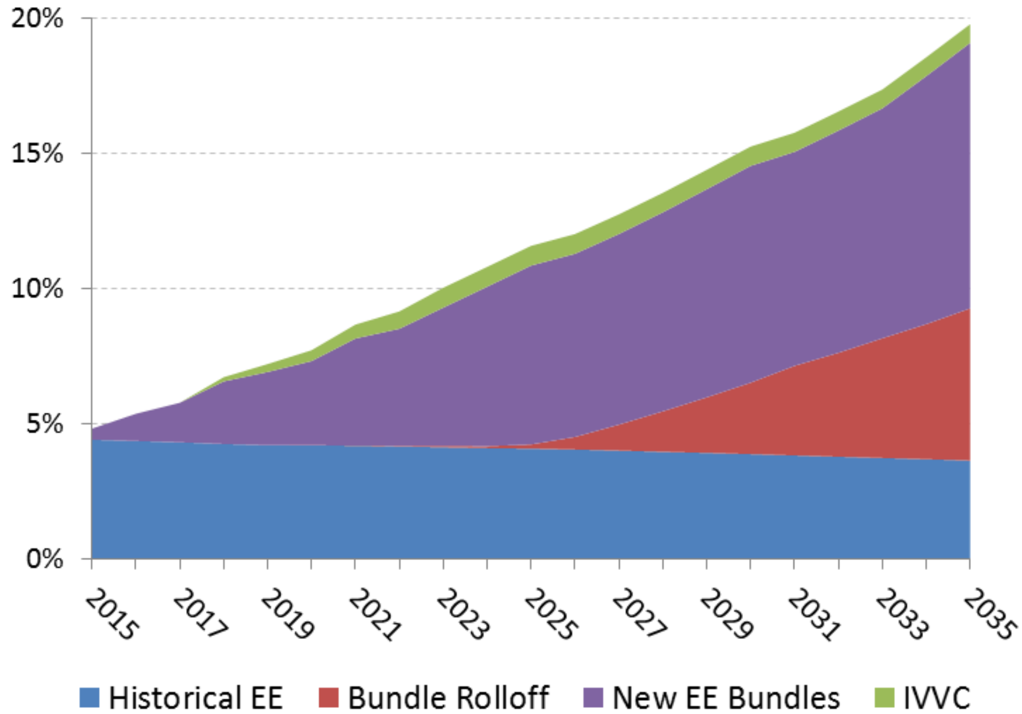


Figure 8-D: Stakeholder Green Utility Portfolio

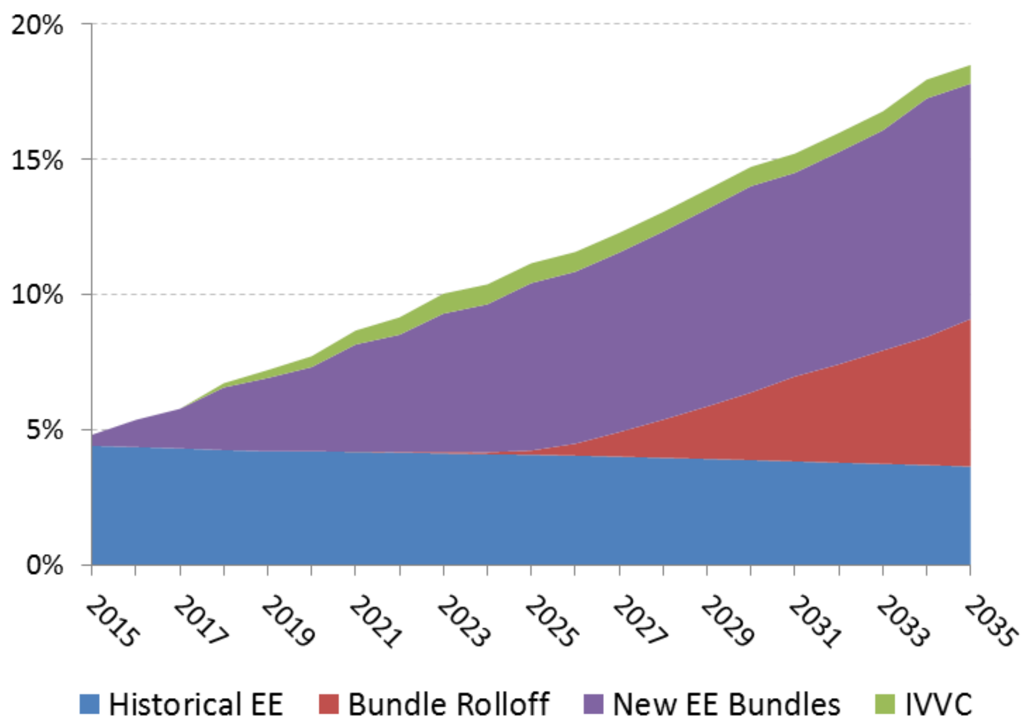


Table 8-B: Summary of Portfolios

NO CARBON REGULATION PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832	208	208	208	208
CHP	44	29	15		
CC					
EE & IVVC	244 / 3.1%	124 / 1.9%	105 / 3.2%	11 / 3.2%	4 / 3.1%
Solar					
Wind					
Biomass					

RETIREMENTS					
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			

CARBON TAX PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	416			208
CHP	15	15			
CC	448				448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	10	140	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

PROPOSED CLEAN POWER PLAN PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	208		208	208
CHP	44	29	15		
CC	448	448			
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	20	130	120	
Wind	450		300	100	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

NO CARBON REGULATION PORTFOLIO WITH ADDITIONAL CC

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	416			208	208
CHP	44	29	15		
CC	448	448			
EE & IVVC	244 / 3.1%	124 / 1.9%	105 / 3.2%	11 / 3.2%	4 / 3.1%
Solar					
Wind					
Biomass					

RETIREMENTS					
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			

CARBON TAX PORTFOLIO WITH ADDITIONAL CC

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	15	15			
CC	896	448			448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

PROPOSED CLEAN POWER PLAN PORTFOLIO WITH ADDITIONAL CC

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	44	29	15		
CC	896	896			
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		300	100	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

STAKEHOLDER DISTRIBUTED GENERATION PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832		208		624
CHP	667	160	290	15	203
CC	1,344		896		448
EE & IVVC	725 / 8.8%	171 / 2.5%	239 / 5.7%	134 / 7.1%	181 / 8.8%
Nuclear	140				140
Battery	370		180	90	100
Solar	2,480	670	970	420	420
Wind	2,050	450	800	550	250
Biomass	353	106	162	60	25

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4	Gib5 Cay1,2 Gib1		Gib2,3
MW	(4,283)	(1,114)	(1,909)		(1,260)

STAKEHOLDER GREEN UTILITY PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832	208	624		
CHP	261	29	73	73	87
CC	1,344		896		448
EE & IVVC	635 / 7.8%	171 / 2.5%	209 / 5.3%	134 / 6.7%	121 / 7.8%
Solar	930	40	380	300	210
Wind	800		250	300	250
Biomass	14	4	4	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4	Gib5 Cay1,2		Gib1
MW	(3,023)	(1,114)	(1,279)		(630)

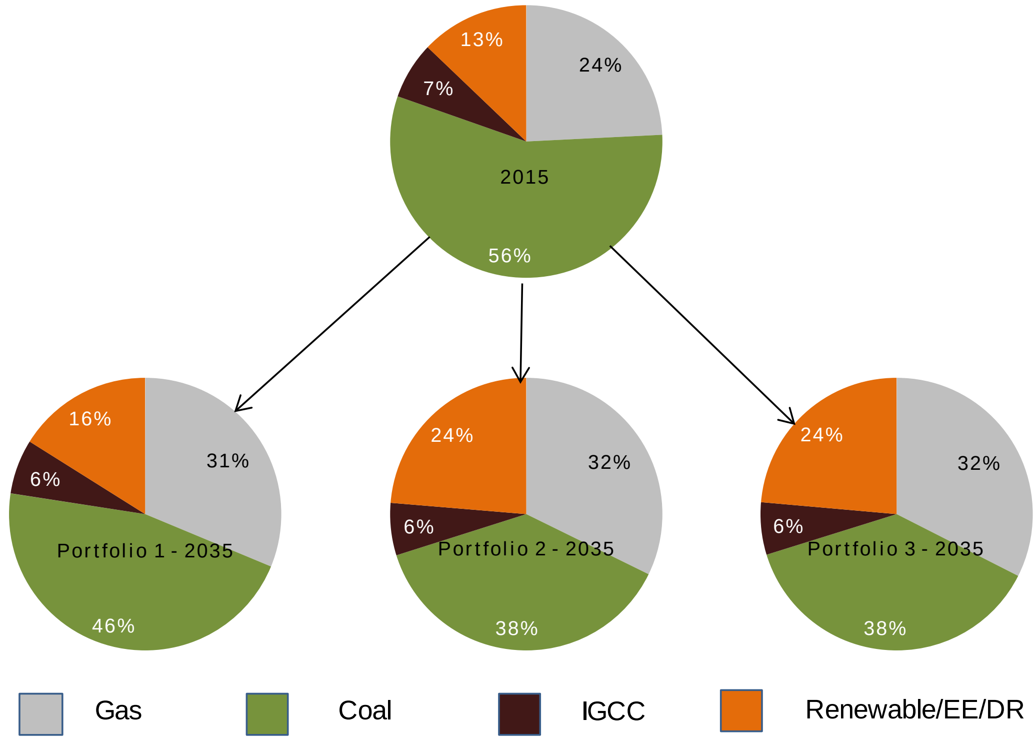
HIGH RENEWABLES PORTFOLIO

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	416		208	
CHP	29	15	15		
CC	448				448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	1,010	20	130	260	600
Wind	2,300		300	500	1,500
Biomass	14	2	8	4	

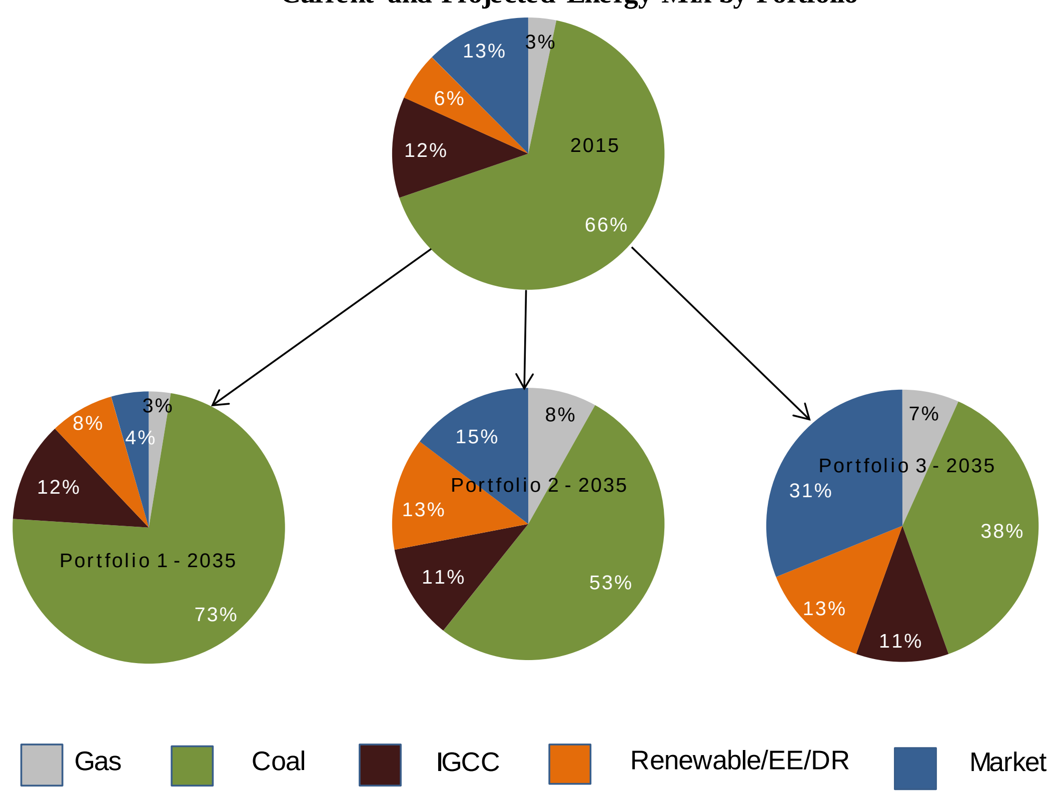
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

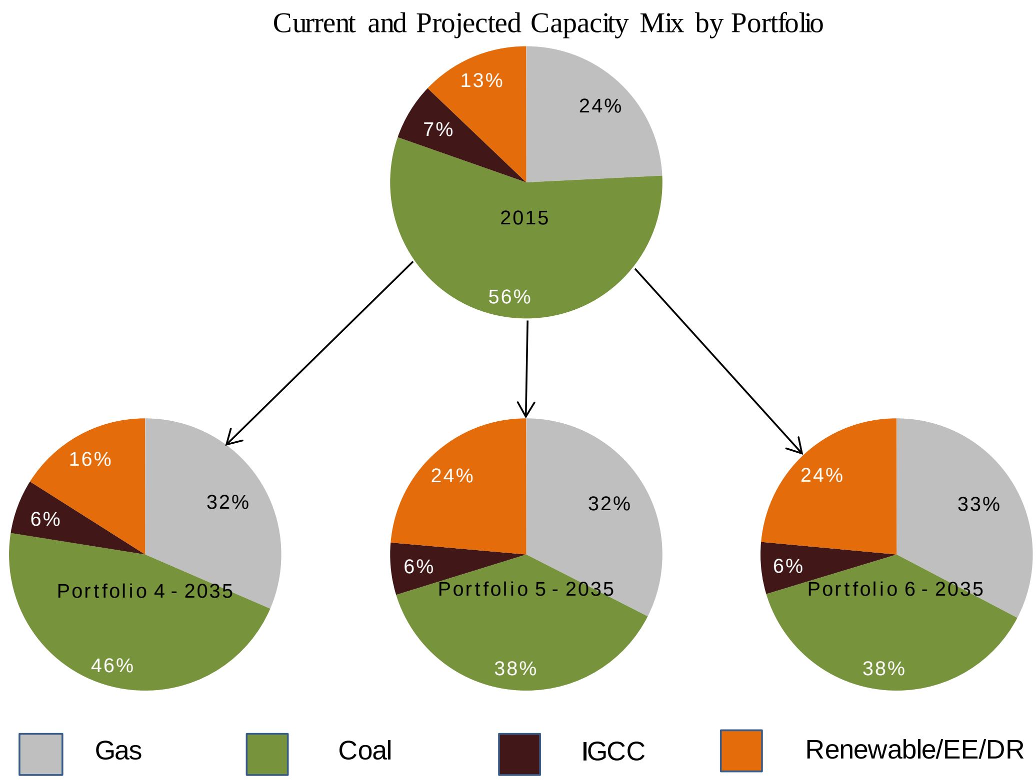
Figure 8-E Generation Mix 2015 and 2035

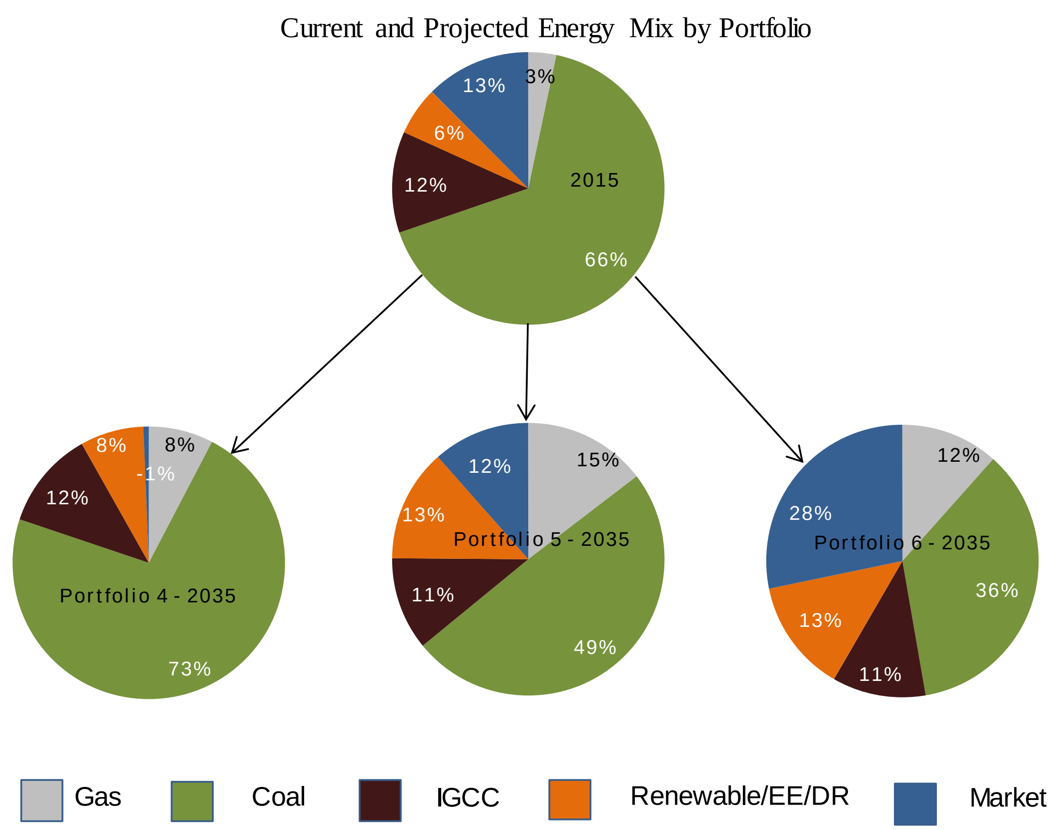
Current and Projected Capacity Mix by Portfolio



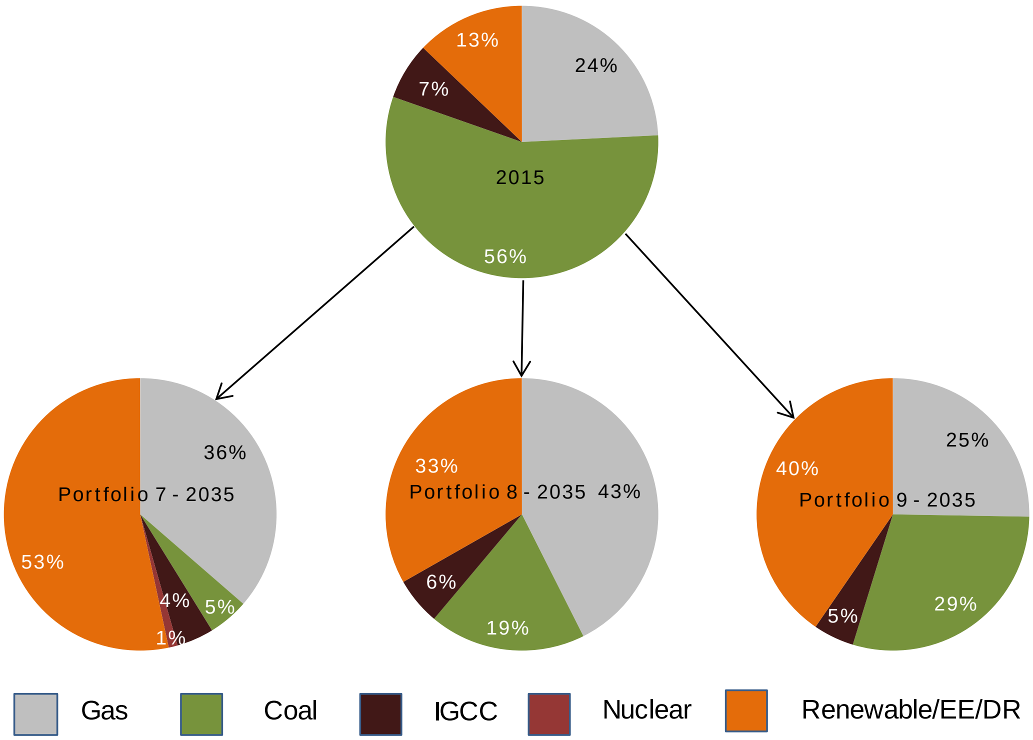
Current and Projected Energy Mix by Portfolio



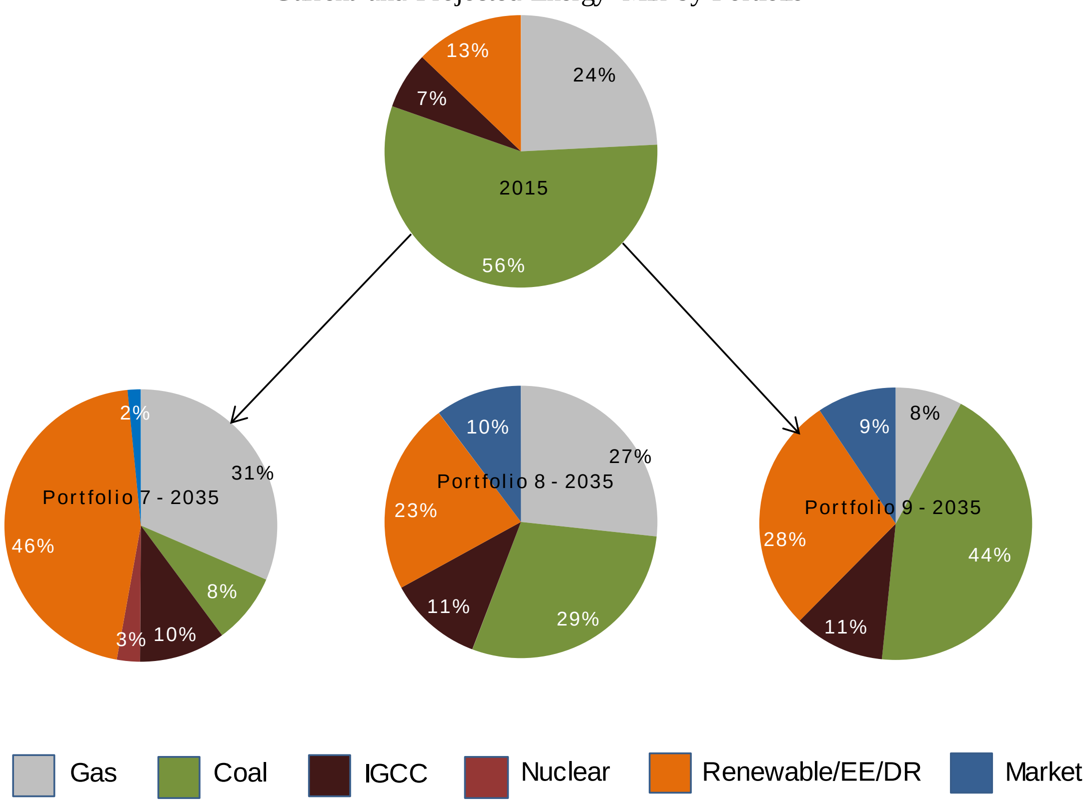

Current and Projected Capacity Mix by Portfolio
2015
24%
56%
7%
13%
Portfolio 4 - 2035
32%
46%
6%
16%
Portfolio 5 - 2035
32%
38%
6%
24%
Portfolio 6 - 2035
33%
38%
6%
24%
Gas
Coal
IGCC
Renewable/EE/DR


Current and Projected Energy Mix by Portfolio
2015
3%
66%
12%
6%
13%
Portfolio 4 - 2035
8%
73%
12%
8%
-1%
Portfolio 5 - 2035
15%
49%
11%
13%
12%
Portfolio 6 - 2035
12%
36%
11%
13%
28%
Gas
Coal
IGCC
Renewable/EE/DR
Market

Current and Projected Capacity Mix by Portfolio



Current and Projected Energy Mix by Portfolio



Portfolio Analysis

Scenario Analysis

The robustness of the planning process was enhanced by the analysis of a broad range of internally consistent future scenarios. This informed the effort to develop a robust portfolio that minimizes the PVRR.

The scenarios create a framework for the evaluation of each portfolio. For example, questions such as "How would the No Carbon Tax portfolio perform in a Carbon Tax world?" or "Which portfolio is most costly in each scenario?" are useful for deciding on the which portfolio to select for the IRP.

Sensitivity Analysis

Sensitivities provide a secondary level of analysis that addresses the responsiveness of a portfolio to changes in key variables. Scenario analysis represents a more realistic view of how a given portfolio performs under a variety of assumptions since each variable does not change completely independently of other key variables. Making statements that portfolio A is better than portfolio B because it has lower costs if gas prices increase $2/MMBtu is not a fair claim since there would be secondary effects on the dispatch of gas generation, the market prices of power, and overall demand for natural gas. What can be fairly stated is that portfolio A is less sensitive than Portfolio B to increases in natural gas prices and thus has less risk with respect to gas prices. The sensitivity analysis focused on assessing the responsiveness and risk impact of the portfolios to changes in key variables and that was used to supplement the scenario analysis is the selection of the portfolio for the IRP.

Analysis Results

The optimized portfolios were developed using SO, and the CC portfolios were developed by replacing CTs with CCs in the optimized portfolios. The Stakeholder Inspired portfolios were either explicitly developed by stakeholders or strongly influenced by comments heard at the stakeholder meetings as was the case in the High Renewables Portfolio.

The next level of analysis included detailed production modeling PaR. All nine portfolios were modeled in all seven scenarios using PaR. In Table 8-D, the seven scenarios are shown in rows and the nine portfolios in columns. The body of the table shows the PVRRs of all of the combinations of scenarios and portfolios. For example, The PVRR cost (20-year MM$) of the No Carbon Tax Portfolio in the No Carbon Tax scenario is $20,297. For each scenario, color coding indicates the three least cost (green), three highest cost (red), and three medium cost (yellow) portfolios.

Table 8-D: Portfolio PVRRs in Each Scenario

		PORTFOLIOS								
		No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
SCENARIOS	No CO2 Tax	20,297	20,655	20,891	20,379	20,677	20,931	27,465	22,623	21,219
	CO2 Tax	27,549	27,186	27,209	27,617	27,243	27,334	31,559	28,131	27,611
	CPP	23,699	23,173	22,960	23,419	22,977	22,645	26,864	23,397	23,715
	Delayed CO2 Reg	25,443	25,513	25,606	25,667	25,569	25,662	30,292	26,586	25,901
	Repealed CO2 Reg	22,136	22,092	22,335	22,236	22,137	22,401	28,732	24,183	22,683
	Inc Cust Choice	30,882	30,505	30,524	31,009	30,561	30,642	34,799	31,316	30,937
	Climate Chg	28,060	27,752	27,800	28,052	27,760	27,758	31,840	28,575	28,082

It is instructive to look at the cost of each portfolio in a given scenario, particularly those that were not optimal for that scenario. This is beneficial for measuring portfolio robustness over a range of potential future outcomes. Below are some observations of the scenario analyses.

No Carbon Regulation: This scenario rewards low capital cost portfolios. Resources with lower environmental impacts were not selected due to higher cost

Carbon Tax: Portfolios with a combination of renewables and CCs excel

P-CPP: Portfolios with a combination of renewables and CCs excel

Delayed Carbon Regulation: low cost portfolios prevail with a delay in carbon regulation

Repealed Carbon Regulation: low cost portfolios prevail with repeal of carbon regulation

Increased Customer Choice: the most expensive scenario due to the high amount of solar assumed; portfolios with a combination of renewables and CC generation excel

Climate Change: portfolios with CCs tend to be lower cost

Portfolio Performance by Scenario Probability (PVRR)

Portfolios were evaluate under a range of probabilities for each scenario. Simply averaging the portfolio columns in Table 8-D is of limited value since it would imply that each scenario is equally likely. Rather than guessing the probability of each scenario, combinations of the presence and timing of carbon regulation were modeled between 10% and 70% to evaluate:

- When is each portfolio most often among the lower cost portfolios?
- When is each portfolio most often among the higher cost portfolios?

Table 8-E: Portfolio PVRRs in Each Scenario (MM$)

SCENARIO PROBABILITIES				PORTFOLIOS								
No CO2 Tax	Delayed CO2 Reg	Repealed CO2 Reg	CO2 Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
25%	25%	25%	25%	23,856	23,862	24,010	23,975	23,906	24,082	29,512	25,381	24,353
40%	20%	20%	20%	23,144	23,220	23,386	23,256	23,260	23,452	29,103	24,829	23,727
20%	20%	20%	40%	24,595	24,526	24,650	24,703	24,573	24,732	29,922	25,931	25,005
55%	15%	15%	15%	22,433	22,579	22,762	22,537	22,614	22,821	28,693	24,278	23,100
15%	15%	15%	55%	25,333	25,191	25,289	25,432	25,241	25,383	30,331	26,481	25,656
70%	10%	10%	10%	21,721	21,938	22,138	21,818	21,969	22,191	28,284	23,726	22,473
10%	10%	10%	70%	26,072	25,856	25,929	26,160	25,908	26,033	30,740	27,031	26,308

Looking at the nine portfolios from this perspective gives insight into the relative costs of each portfolio in an uncertain future but also helps explain under what conditions a portfolio is the least cost option. Key observations:

1) The No CO_2 Regulation Optimized & the CO_2 Optimized portfolios are most frequently the lowest cost
2) Portfolios high in renewables are higher cost across the range of probabilities

Portfolio Performance by Scenario Probability Assumptions (Market Purchases)

In this perspective, an assessment of market exposure is made by looking at the average annual percentage of market purchases for each portfolio. Portfolios shaded green have the lowest levels of market purchases and are deemed to have the lowest market risk, and those shaded red have the highest levels of market purchases and are deemed to have the greatest market risk. Yellow-shaded portfolios have medium levels of market purchases and risks.

1) Portfolios with CTs rely most heavily on market purchases

2) In portfolios with CCs, higher capacity factor generation replaced market purchases
3) In portfolios with renewables, lower capacity factor generation replace purchases

Table 8-F: Portfolio Market Purchase in Each Scenario (% of Load)

SCENARIO PROBABILITIES				PORTFOLIOS								
No CO2 Tax	Delayed CO2 Reg	Repealed CO2 Reg	CO2 Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
25%	25%	25%	25%	11.4%	11.9%	11.2%	9.6%	10.1%	9.6%	8.0%	12.3%	10.6%
40%	20%	20%	20%	11.0%	11.4%	10.8%	9.1%	9.5%	9.2%	7.8%	12.2%	10.1%
20%	20%	20%	40%	11.8%	12.3%	11.7%	10.0%	10.5%	10.1%	8.2%	12.5%	11.0%
55%	15%	15%	15%	10.5%	10.9%	10.4%	8.6%	9.0%	8.7%	7.6%	12.0%	9.6%
15%	15%	15%	55%	12.2%	12.7%	12.1%	10.5%	10.9%	10.5%	8.4%	12.6%	11.4%
70%	10%	10%	10%	10.1%	10.5%	10.0%	8.1%	8.5%	8.2%	7.4%	11.9%	9.1%
10%	10%	10%	70%	12.6%	13.1%	12.5%	11.0%	11.3%	10.9%	8.6%	12.8%	11.9%

Portfolio Performance by Scenario Probability (CO_2 Reduction)

The costs of carbon emissions were explicitly included in the PVRR analyses in Tables 8-D and 8-E. In Table 8-G, the resulting change in carbon emissions is shown for each portfolio under varying probability assumptions on carbon regulation. Key observations:

1) Portfolios with higher levels of renewables show the largest decrease in CO2 emissions, but this comes with higher costs as seen in Tables 8-D and 8-E
2) Portfolios with CCs excel with greater CO_2 reduction
3) Portfolios with CTs provide the least amount of CO_2 reduction

Table 8-G: Portfolio CO_2 Change in Each Scenario (2016 vs. 2035 emissions)

SCENARIO PROBABILITIES				PORTFOLIOS								
No CO2 Tax	Delayed CO2 Reg	Repealed CO2 Reg	CO2 Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
25%	25%	25%	25%	6.5%	0.9%	-1.3%	2.4%	-1.9%	-4.0%	-43.5%	-23.2%	-12.8%
40%	20%	20%	20%	7.8%	0.8%	-1.1%	3.6%	-2.0%	-3.8%	-45.7%	-24.2%	-13.1%
20%	20%	20%	40%	5.5%	-0.3%	-2.2%	1.0%	-3.4%	-5.3%	-46.5%	-25.3%	-15.2%
55%	15%	15%	15%	9.2%	0.7%	-0.9%	4.8%	-2.1%	-3.7%	-48.0%	-25.2%	-13.4%
15%	15%	15%	55%	4.5%	-1.4%	-3.1%	-0.4%	-5.0%	-6.7%	-49.6%	-27.4%	-17.6%
70%	10%	10%	10%	10.5%	0.6%	-0.6%	6.1%	-2.3%	-3.5%	-50.3%	-26.1%	-13.6%
10%	10%	10%	70%	3.6%	-2.6%	-4.0%	-1.8%	-6.5%	-8.0%	-52.7%	-29.5%	-20.0%

Sensitivity Analysis

While scenario analysis evaluates portfolios at a more macro level, sensitivity analysis was used to evaluate each portfolio's response to changes in a number of key variables. Sensitivities analysis is more a measure of risk than an indicator of a possible outcome.

NATURAL GAS PRICES

Since natural gas is becoming an increasingly important fuel for electric generation in the Midwest, understanding how each portfolio responds to changes in natural gas prices is an important consideration. Since Duke Energy Indiana's fleet interacts with the market through both fuel and power prices, correlated power prices were assumed in conjunction with natural gas price changes. The natural gas price sensitivity was conducted by increasing and decreasing prices by 30%. The precise amount of the price change is not of primary importance but needs to be plausible and large enough to cause a change in generation mix.

Table 8-F: Natural Gas Price Sensitivity

	PORTFOLIOS								
No Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Gas Prices	1.0%	1.6%	2.2%	1.3%	1.9%	2.5%	1.4%	3.4%	1.1%
Lower Gas Prices	-2.1%	-2.8%	-3.6%	-2.8%	-3.4%	-4.3%	-2.9%	-5.0%	-2.3%
AVERAGE	-0.53%	-0.58%	-0.70%	-0.76%	-0.78%	-0.93%	-0.74%	-0.79%	-0.57%

Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Gas Prices	0.6%	1.0%	1.6%	1.0%	1.4%	1.9%	1.2%	2.6%	0.7%
Lower Gas Prices	-2.6%	-3.1%	-3.8%	-3.5%	-3.8%	-4.6%	-3.1%	-4.7%	-2.8%
AVERAGE	-1.02%	-1.00%	-1.10%	-1.24%	-1.20%	-1.36%	-0.93%	-1.04%	-1.06%

Observations

1) Most portfolios show an increase in costs of 1-2% with higher gas prices
2) Portfolios with CCs reap the greatest benefit from lower gas prices

PRICES FOR NATURAL GAS, COAL & POWER

To assess the responsiveness of each of the portfolios to changes in the overall level of market prices, a more broadly based fuel and power sensitivity was evaluated. Like natural gas price, the market price sensitivity was +/-30%.

Table 8-G: Gas, Coal, and Power Sensitivity

	PORTFOLIOS								
No Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Market Prices	10.9%	10.6%	10.7%	10.8%	10.5%	10.6%	5.0%	10.1%	9.5%
Lower Market Prices	-12.7%	-12.3%	-12.4%	-12.6%	-12.2%	-12.3%	-6.4%	-11.6%	-11.2%
AVERAGE	-0.91%	-0.85%	-0.84%	-0.90%	-0.84%	-0.84%	-0.69%	-0.79%	-0.83%

Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Market Prices	7.0%	7.4%	7.6%	7.2%	7.5%	7.7%	4.1%	7.4%	6.8%
Lower Market Prices	-8.7%	-9.1%	-9.4%	-9.0%	-9.4%	-9.6%	-5.7%	-9.0%	-8.5%
AVERAGE	-0.83%	-0.82%	-0.86%	-0.91%	-0.92%	-0.96%	-0.76%	-0.82%	-0.84%

Observations

1) Most portfolios show similar average sensitivity to changes in market prices
2) Portfolios with greater amounts of renewables show less sensitivity to prices

CHP PROJECTS

CHP has the potential to be an efficient source of electricity and steam generation. Since the Company has limited experience with CHP and each project is unique and subject to a range of costs and contracting complexities, the number of possible projects was limited to three. As a sensitivity, this amount was doubled to six and the model shows that in most portfolios six CHP projects are selected.

Table 8-H: CHP Sensitivity

No Carbon Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	Stakeholder Green Utility	High Renewables
Base Case (MW)	44	29	44	44	29	44	29
Increased CHP (MW)	87	87	87	87	87	87	87

Carbon Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	Stakeholder Green Utility	High Renewables
Base Case (MW)	44	15	44	44	15	44	29
Increased CHP (MW)	87	87	87	87	87	87	73

Observations

1) Cost is not the limiting factor when it comes to CHP
2) The Company is increasing efforts to develop cost-effective CHP projects

HIGHER CARBON TAX

In addition to the CO_2 Tax and P-CPP scenarios, a higher CO2 Tax sensitivity was evaluated to determine the impact of increasing levels of carbon regulation on each portfolio. Unlike previous sensitivities, this was only done in the carbon tax scenario since a higher carbon tax in a no carbon tax scenario has no impact. The table below shows the increase in PVRR costs and the additional reduction in CO_2 emissions.

Table 8-I: Carbon Tax Sensitivity

Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR Change	24.8%	24.7%	23.6%	23.5%	23.4%	22.2%	12.2%	19.6%	22.9%
Additional CO2 Reduction	-7.3%	-8.3%	-8.4%	-9.3%	-10.3%	-10.1%	-5.6%	-10.2%	-9.2%

Observations

1) Portfolios with higher levels of renewables and CCs are lower cost
2) Portfolios with CCs appear to be better able to reduce CO_2 emissions

ENERGY EFFICIENCY ADOPTION

Modeling energy efficiency as a resource is challenging for a number of reasons, such as the relationship between adoption rate and cost. Generally speaking, as greater incentives are offered, adoption increases, but that relationship is not well understood. In this sensitivity, the cost effectiveness for EE was varied +/-20% by varying the $/MWh cost of each EE bundle. This sensitivity can serve as a proxy for higher or lower customer adoption of utility sponsored EE programs for a given program cost or, more explicitly, as a cost sensitivity for utility-sponsored EE programs.

Table 8-J: Energy Efficiency Sensitivity

No Carbon Tax		No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	High Renewables
Lower EE $/MWh	MWh	26%	27%	27%	26%	27%	22%	16%
	PVRR	-0.6%	-0.2%	-0.9%	-0.5%	0.0%	-0.6%	-1.1%
Higher EE $/MWh	MWh	-38%	-20%	-20%	-38%	-20%	-20%	-20%
	PVRR	0.1%	0.8%	0.0%	0.1%	0.9%	-0.2%	0.3%

Carbon Tax		No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	High Renewables
Lower EE $/MWh	MWh	26%	27%	22%	26%	27%	22%	16%
	PVRR	-1.2%	-0.2%	-0.6%	-1.3%	-0.1%	-0.6%	-0.9%
Higher EE $/MWh	MWh	-24%	-20%	-21%	-39%	-20%	-21%	-20%
	PVRR	-0.3%	0.8%	0.3%	-0.4%	0.7%	0.2%	0.2%

Observations

1) Cost-effectiveness significantly impacts economic selection of EE programs across all portfolios
2) Incentives may raise adoption rates and associated MWh reductions, but the additional cost impacts cost-effectiveness of the EE measure
3) Customer behavior may not align with economic incentives further complicating efforts to accurately model EE as a supply-side resource

Sensitivity Conclusions

The sensitivity analyses suggest several conclusions and inform the selection of the preferred portfolio:

- Portfolios with more balance between CC and coal generation able respond better to changes in gas prices
- Portfolios with higher levels of renewables have higher fixed and total costs, but are better able to withstand changes in variable costs such as market prices and carbon taxes
- CHP is cost effective in all portfolios if transactions can be made at generic costs
- Adoption rates (customer behavior) are a key variable for EE programs

Explicit sensitivities not performed and rationale

Stakeholders suggested additional sensitivities that were considered but not evaluated:

- Load forecast: load variation was indirectly addressed by the different load assumptions in the various scenarios
- Roll back EE opt-out: speculative and difficult to specify
- Energy storage: screened out due to high cost and shorter useful life; technology has niche applications
- Deregulation: difficult to specify without numerous speculative assumptions
- Transmission costs: difficult to incorporate transmission costs without siting specifics potentially at the MISO footprint level

Risk Management & Decision Making

The objective of the IRP is to produce a robust portfolio that meets the load obligation while minimizing the PVRR, subject to laws and regulations, reliability and adequacy requirements, and operationally feasibility.

The IRP is a 20 year plan updated every two years. As decisions are made in the near term, additional analysis will be conducted using the best available information. The strategic flexibility of planning for the long term and then evaluating near term decisions provides context to the overall execution of a resource portfolio.

In terms of selecting a plan, cost under a range of probability assumptions is an important consideration as is the performance of each portfolio under a range of sensitivities. Additionally, the difference between the portfolios in the next 5-7 years is particularly important due to the number of environmental regulations that should be clarified in this time period. Once the regulations have been finalized, a more informed decision can be made for future resources.

Resource Plan Selection

The Optimized Carbon Tax Portfolio with additional Combined Cycle Capacity is the preferred portfolio for the Duke Energy Indiana’s 2015 IRP because of the following reasons:

- Cost competitive relative to other portfolios across the range of scenario probabilities
- Below average levels of market purchases
- Relatively favorable response to changing gas prices
- No significant shortcomings in the other sensitivities
- Flexible in the near term and positioned well for future carbon regulation

See Tables 8-K through 8-M for additional details.

Short Term

Over the next five years, the Plan retires Wabash River 2-5, and Duke Energy Indiana’s small oil CTs. Additionally, the plan calls for the retirement of Wabash River 6 as well as Gallagher 2 and 4. It is important to remember that this is the modeling output at this particular snapshot in time and not a specific decision by the Company. For example, developing regulation on carbon and waste water could result in gas conversion for Wabash River 6 and a different retirement date for the Gallagher units. A very important consideration, possibly more so today than ever, is to maintain options for the fleet to respond to future uncertainties. While the modeling performed certainly provides useful information to the Company for its future decision-making, Duke Energy Indiana will continue to review its resource options as new information becomes available – all with an eye towards making the best resource decisions possible for customers based on the best available information at the time those decisions must be made.

A significant benefit of the preferred portfolio is that in the next five to seven years, it is similar to Optimized No Carbon and High Renewables Portfolios. This gives the portfolio the flexibility to pivot towards either of these depending upon how regulatory uncertainty is resolved.

Long Term

The retirement of older coal and oil fired CT capacity sets the stage to respond to emerging environmental regulations. Future decisions to retire or control units will be made at the appropriate time using the best available information available then. As part of the overall utility planning process and for the next IRP, the planning process will be updated with then current information.

Table 8-K: Integrated Resource Plan

DUKE ENERGY INDIANA INTEGRATED RESOURCE PLAN PORTFOLIO AND RECOMMENDED PLAN (2015-2035)						
Year	Retirements	Additions	Renewables (Nameplate MW) [1]			Notable, Near-term Environmental Control Upgrades [2]
			Wind	Solar	Biomass	
2015						
2016	Wabash River 2-6 (668 MW)			20		
2017				20		Ash handling/Landfill upgrades: Cayuga 1-2 & Gibson 1-5
2018	Connersville 1&2 CT (86 MW) Mi-Wabash 1-3,5-6 CT (80 MW)					
2019	Gallagher 2 & 4 (280 MW)					
2020		CC 448 MW Cogen 15MW		10	2	
2021				10	2	
2022			50	20		
2023			50	30	2	
2024			50	30	2	
2025				30		
2026			50	20	2	
2027			50	30		
2028			100	30	2	
2029			50	30	2	
2030				10		
2031	Gibson 5 (310 MW)	CC 448 MW				
2032						
2033		CT 208 MW				
2034						
2035			50			
Total MW	1424	1119	450	290	14	

1: Wind and solar MW represent nameplate capacity.
2: Additional likely or potential control requirements include additives for mercury control, water treatment and intake structure modifications in the 2016 -2023 time frame.

Table 8-L IRP Plan Emission Control Equipment Installation Dates

	SO2		NO_x		Water		CCR
Unit	**FGD Refurb**	**DBA**	**SCR[1]**	**SNCR**	**Intake Mods**	**Water Treatment**	**Ash Handling/ Landfill**
Cayuga 1					2020	2020	2017
Cayuga 2					2020	2020	2017
Gallagher 2							
Gallagher 4							
Gibson 1		2020	2021 - 2023			2020	2017
Gibson 2		2020				2020	2017
Gibson 3		2020				2020	2017
Gibson 4		2020				2020	2017
Gibson 5		2020				2020	2017

Note 1: Gibson 1-5 existing SCR upgrades required

Table 8-M: Load, Capacity and Reserves Table

Summer Projections of Load, Capacity, and Reserves for Duke Energy Indiana 2015 IRP

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast																					
1 DEI System Peak	6,259	6,401	6,535	6,613	6,662	6,705	6,732	6,769	6,805	6,836	6,881	6,916	6,960	6,992	7,035	7,075	7,137	7,193	7,246	7,288	7,330
Reductions to Load Forecast																					
2 New Conservation Programs[a]	(9)	(31)	(56)	(83)	(110)	(134)	(159)	(162)	(183)	(195)	(210)	(223)	(228)	(228)	(232)	(235)	(238)	(241)	(244)	(248)	(250)
3 Demand Response Programs	(632)	(677)	(696)	(720)	(735)	(751)	(756)	(761)	(766)	(772)	(777)	(782)	(787)	(792)	(797)	(802)	(808)	(813)	(818)	(823)	(828)
4 Adjusted Duke System Peak	**5,618**	**5,693**	**5,783**	**5,810**	**5,817**	**5,820**	**5,818**	**5,846**	**5,857**	**5,869**	**5,894**	**5,911**	**5,945**	**5,972**	**6,007**	**6,038**	**6,092**	**6,140**	**6,184**	**6,218**	**6,252**
Cumulative System Capacity																					
5 Generating Capacity	7,387	7,387	6,719	6,719	6,553	6,273	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	5,957	5,957	5,957	5,957
6 Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Derates	0	0	0	0	0	(6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Capacity Retirements	0	(668)	0	(166)	(280)	0	0	0	0	0	0	0	0	0	0	0	(310)	0	0	0	0
9 Cumulative Generating Capacity	7,387	6,719	6,719	6,553	6,273	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	5,957	5,957	5,957	5,957	5,957
Purchase Contracts																					
10 Cumulative Purchase Contracts	13	21	21	21	21	21	21	19	19	19	19	19	19	6	6	6	6	6	6	6	6
11 Behind the Meter Generation	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
12 Cumulative Future Resource Additions																					
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking/Intermediate	0	0	0	0	0	448	448	448	448	448	448	448	448	448	448	448	896	896	1,104	1,104	1,104
Renewables	0	8	17	17	17	23	29	36	53	70	78	92	107	130	147	150	150	150	150	150	157
PPA & Cogen	0	0	0	0	300	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
13 Cumulative Production Capacity	**7,418**	**6,767**	**6,775**	**6,609**	**6,629**	**6,792**	**6,798**	**6,802**	**6,819**	**6,836**	**6,844**	**6,858**	**6,873**	**6,884**	**6,900**	**6,903**	**7,041**	**7,041**	**7,249**	**7,249**	**7,256**
Reserves																					
14 Generating Reserves	1,800	1,074	993	799	812	972	981	956	962	967	950	947	928	912	894	865	950	902	1,065	1,032	1,004
15 % Reserve Margin	**32.0%**	**18.9%**	**17.2%**	**13.8%**	**14.0%**	**16.7%**	**16.9%**	**16.4%**	**16.4%**	**16.5%**	**16.1%**	**16.0%**	**15.6%**	**15.3%**	**14.9%**	**14.3%**	**15.6%**	**14.7%**	**17.2%**	**16.6%**	**16.1%**
16 % Capacity Margin	24.3%	15.9%	14.7%	12.1%	12.3%	14.3%	14.4%	14.1%	14.1%	14.1%	13.9%	13.8%	13.5%	13.2%	13.0%	12.5%	13.5%	12.8%	14.7%	14.2%	13.8%

[a] Not already included in load forecast. This value is coincident with the net peak load, so it may not be the peak value for the year.

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The Duke Energy Indiana
2015 Integrated Resource Plan

November 1, 2015

Appendix A:
Supply Side Screening Curves/
Resource Data

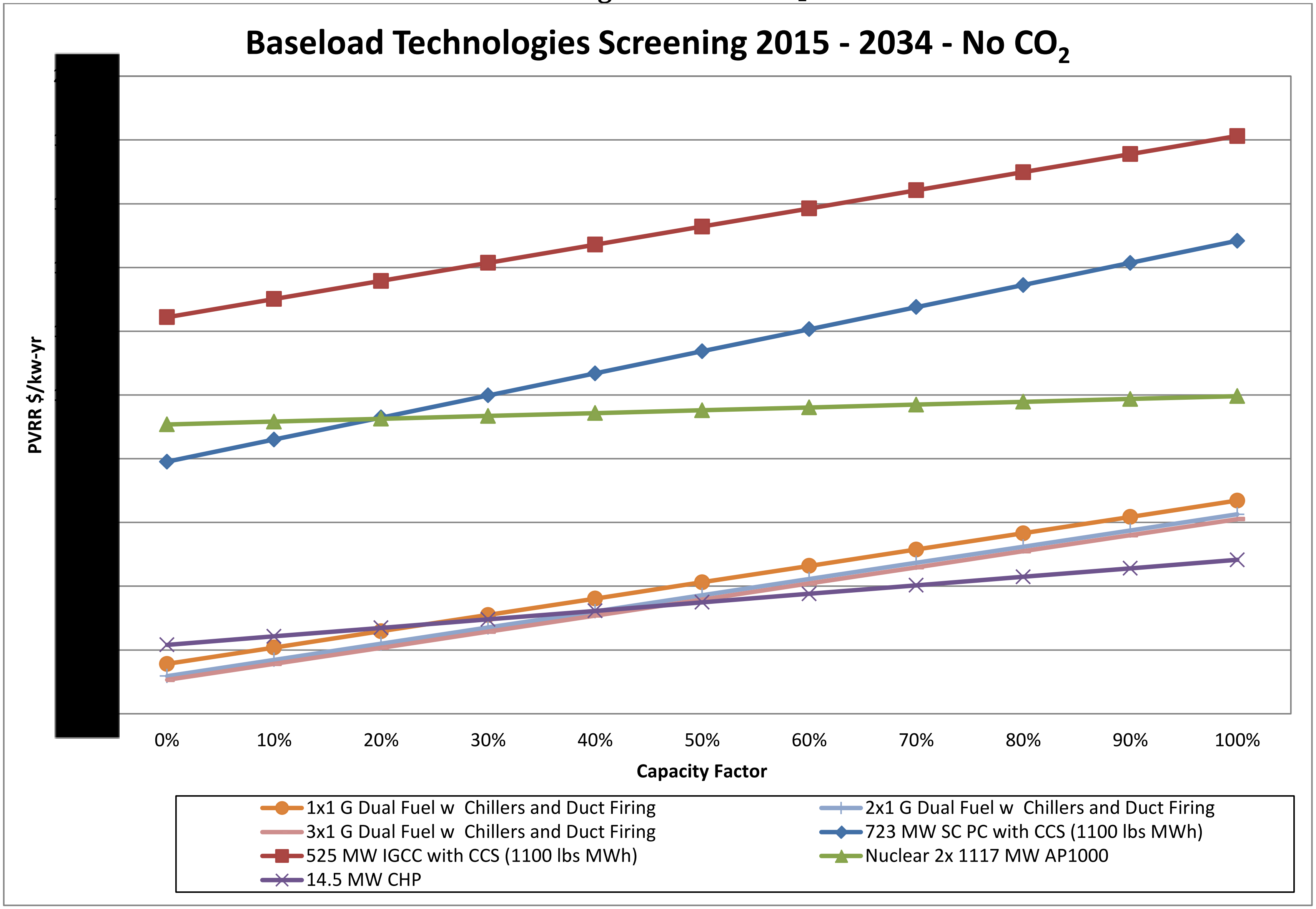
APPENDIX A – Table of Contents

1. Supply-Side Screening Curves

The following pages contain the screening curves and associated data discussed in Chapter 5 of this filing.

Duke Energy Indiana and its consultants consider cost estimates to be confidential and competitive information. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders. Please contact Beth Herriman at (317) 838-1254 for more information.

Figure A-1 No CO_2



INFORMATION REDACTED

Figure A-1 With CO_2

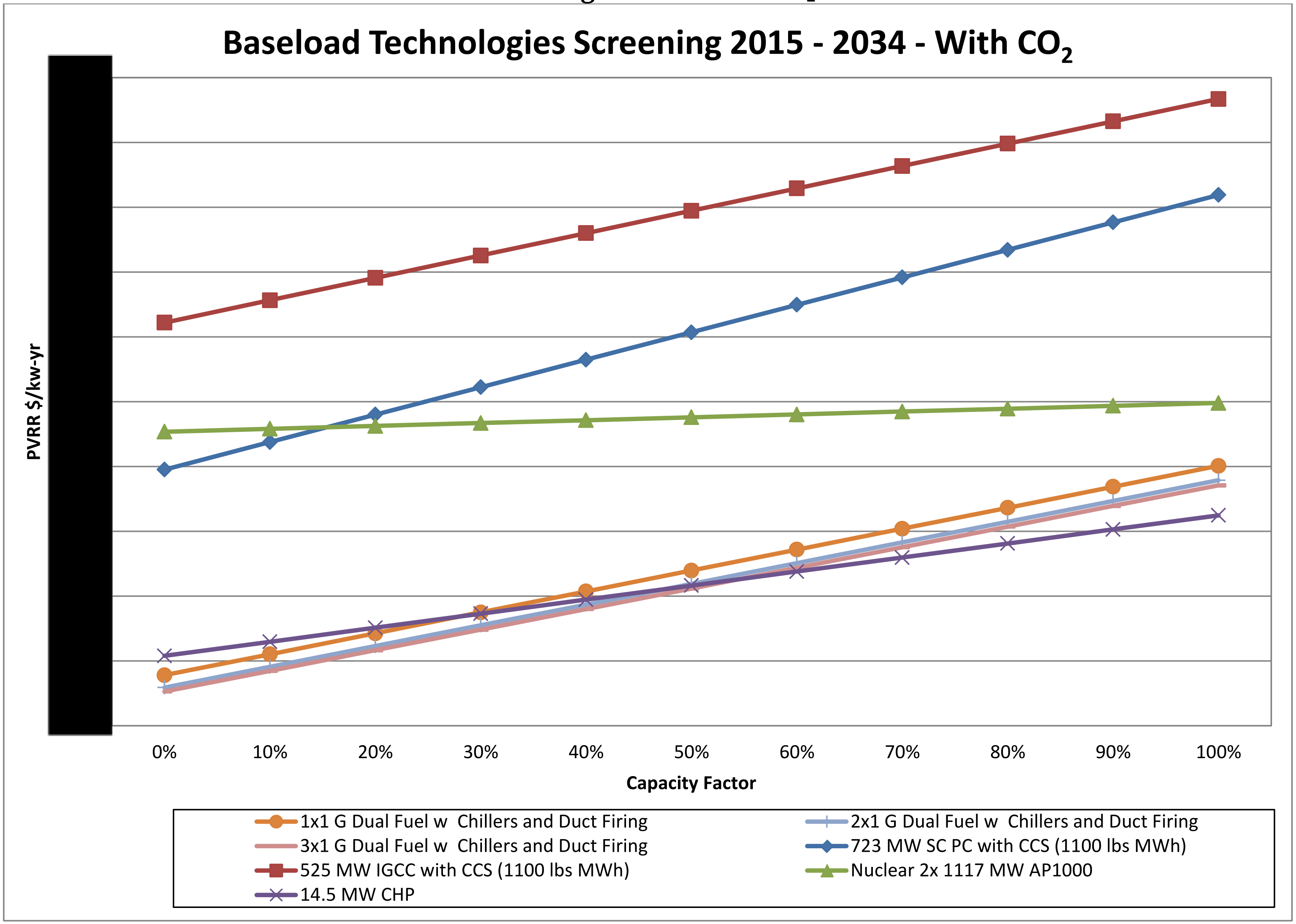


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Figure A-2 No CO_2

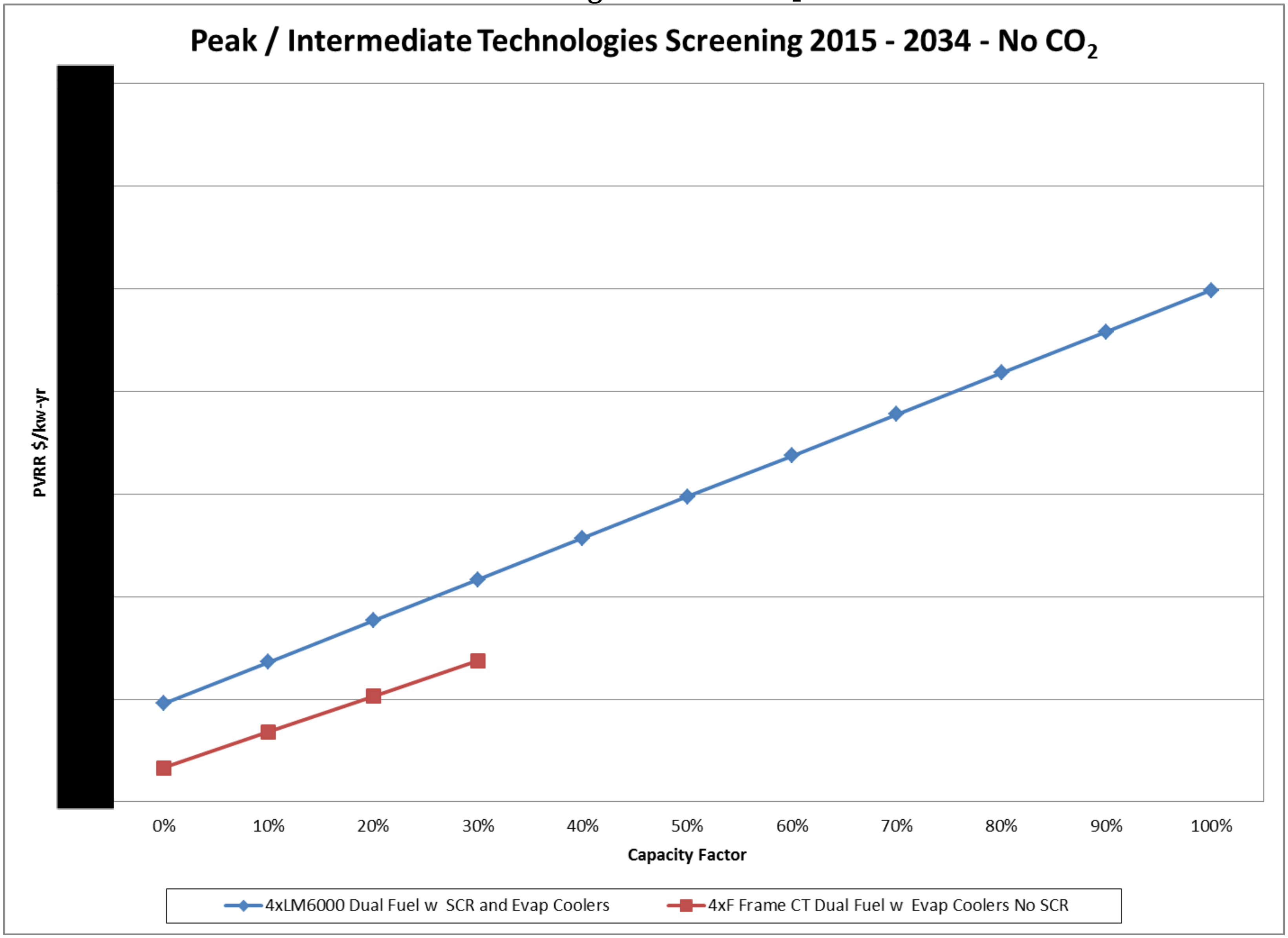

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Figure A-2 With CO_2

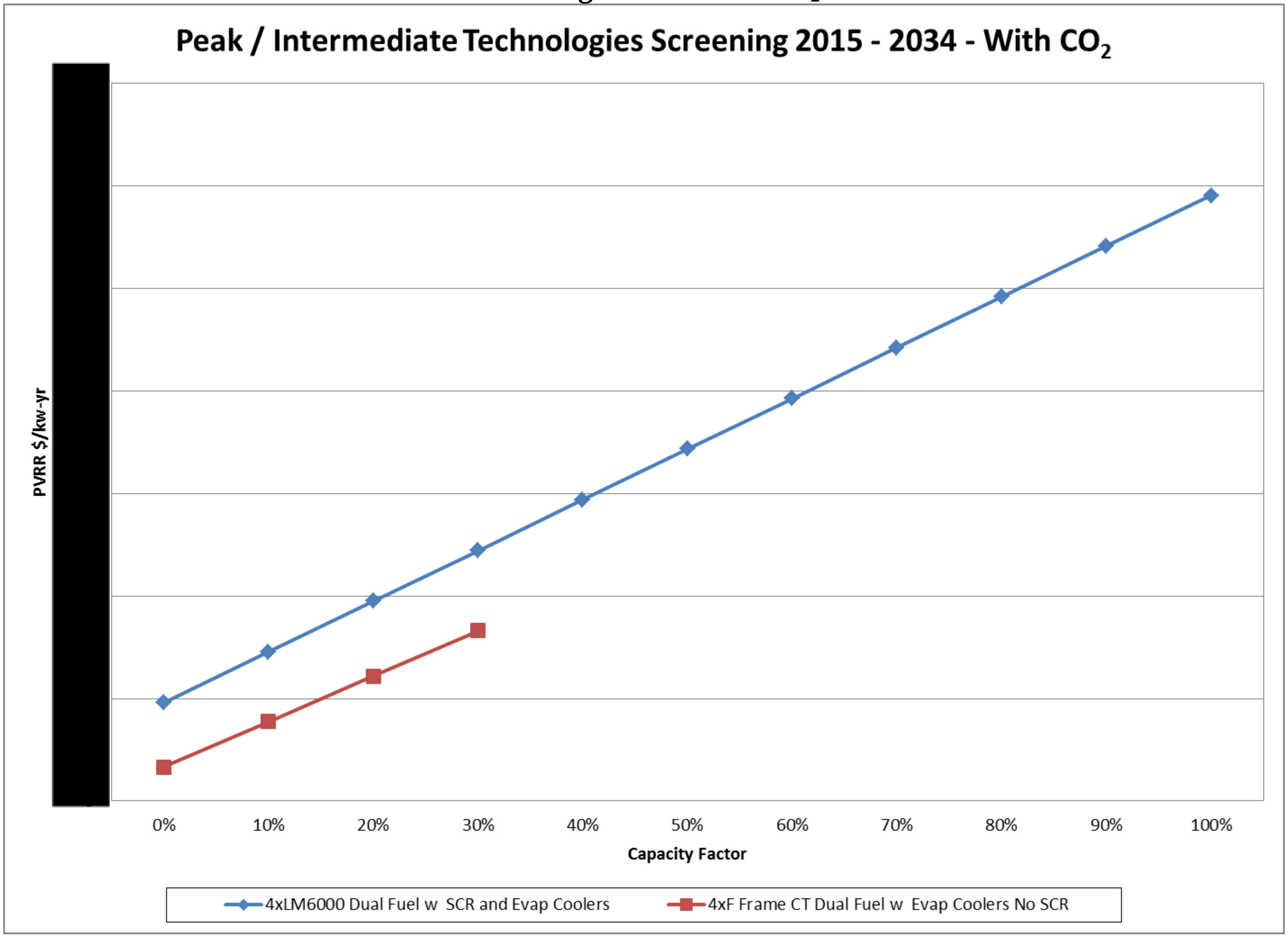

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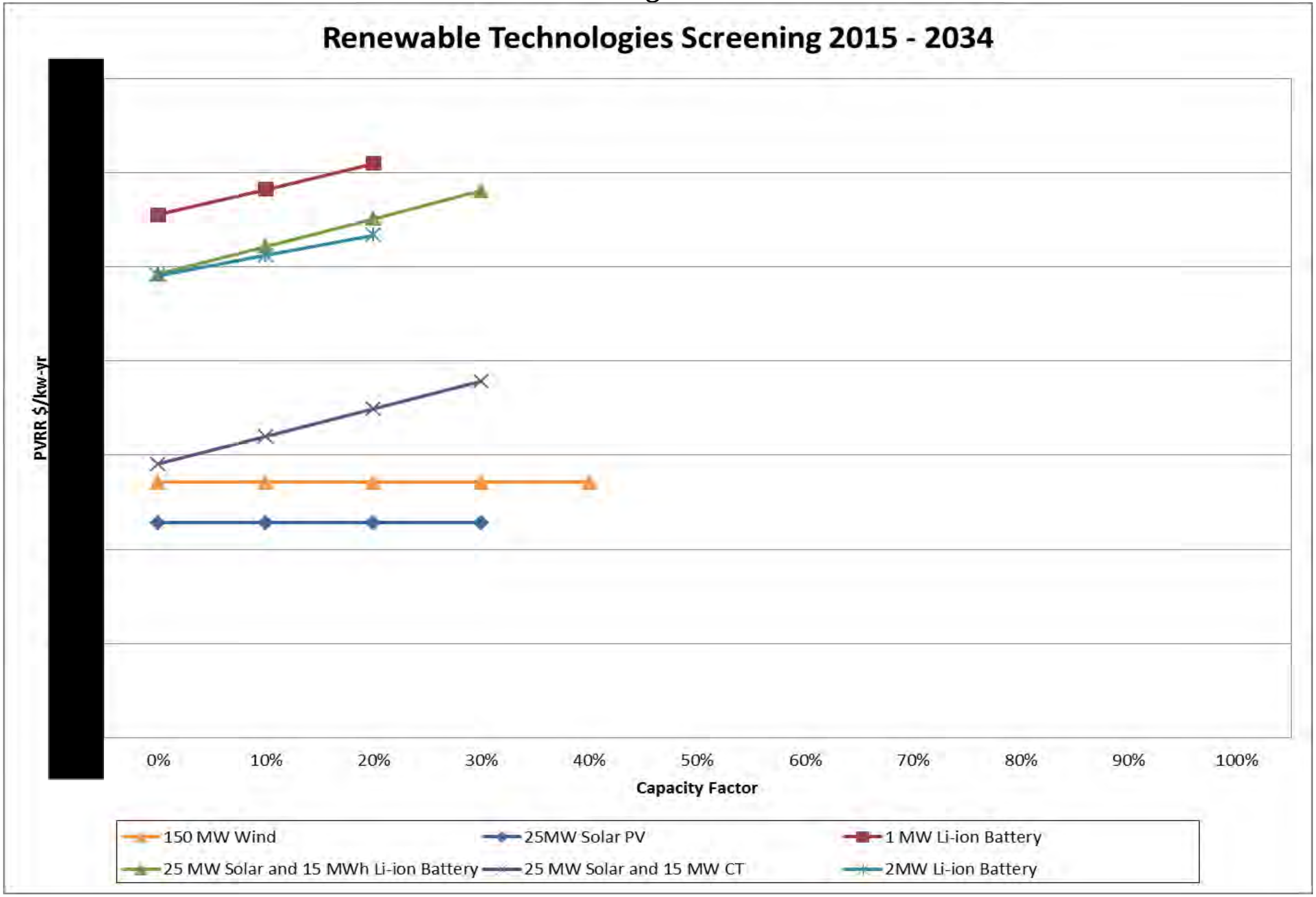
Figure A-3



CONFIDENTIAL INFORMATION
REDACTED

Figure A-4 (No CO_2)
Supply Side Technology Information – No CO_2

Discount Rate	[redacted]
Coal Price Escalation Rate	
Gas Price Escalation Rate	
EA Price Escalation Rate	
FOM and VOM Escalation Rate (%)	

Confidential business information

		Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K	Plant L	Plant M	Plant N	Plant O
Technology Description		4xLM6000 Dual Fuel w SCR and Evap Coolers	4xF Frame CT Dual Fuel w Evap Coolers No SCR	1x1 G Dual Fuel w Chillers and Duct Firing	2x1 G Dual Fuel w Chillers and Duct Firing	3x1 G Dual Fuel w Chillers and Duct Firing	723 MW SC PC with CCS (1100 lbs MWh)	525 MW IGCC with CCS (1100 lbs MWh)	150 MW Wind	25MW Solar PV	1 MW Li-ion Battery	25 MW Solar and 15 MWh Li-ion Battery	Nuclear 2x 1117 MW AP1000	25 MW Solar and 15 MW CT	14.5 MW CHP	2MW Li-ion Battery
Book Life/Tax Life	Years	[redacted]														
Nominal Unit Size at 100% Load	MW															
Total Plant Cost for Screening (2015 completion date)	$/kW															
Total Plant Cost for Screening (incl AFUDC-2015 completion date)	$/kW															
Total Plant Cost for Screening (incl AFUDC-2015 completion date)	MM$															
Average Annual Heat Rate	Btu/kWh															
VOM in 2015$	$/MWh															
FOM in 2015$	$/kW-yr															
Equivalent Planned Outage Rate	%															
Equivalent Unplanned Outage Rate	%															
Equivalent Availability	%															
NO_x Emission Rate	Lbm/MMBtu															
SO_2 Emission Rate	Lbm/MMbtu															
Hg Emission Rate	Lbm/Tbtu															
CO_2 Emission Rate	Lbm/MMBtu															

Note:
The values shown above are relative for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit size, seasonal deratings, specific site requirements, and equipment vendor competition.

CONFIDENTIAL INFORMATION REDACTED

Figure A-4 (With CO_2)
Supply Side Technology Information – With CO_2

Discount Rate	[redacted]
Coal Price Escalation Rate	
Gas Price Escalation Rate	
EA Price Escalation Rate	
FOM and VOM Escalation Rate (%)	
Confidential business information	

		Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K	Plant L	Plant M	Plant N	Plant O
Technology Description		4xLM6000 Dual Fuel w SCR and Evap Coolers	4xF Frame CT Dual Fuel w Evap Coolers No SCR	1x1 G Dual Fuel w Chillers and Duct Firing	2x1 G Dual Fuel w Chillers and Duct Firing	3x1 G Dual Fuel w Chillers and Duct Firing	723 MW SC PC with CCS (1100 lbs MWh)	525 MW IGCC with CCS (1100 lbs MWh)	150 MW Wind	25MW Solar PV	1 MW Li-ion Battery	25 MW Solar and 15 MWh Li-ion Battery	Nuclear 2x 1117 MW AP1000	25 MW Solar and 15 MW CT	14.5 MW CHP	2MW Li-ion Battery
Book Life/Tax Life	Years	[redacted]														
Nominal Unit Size at 100% Load	MW															
Total Plant Cost for Screening (2015 completion date)	$/kW															
Total Plant Cost for Screening (incl AFUDC-2015 completion date)	$/kW															
Total Plant Cost for Screening (incl AFUDC-2015 completion date)	MM$															
Average Annual Heat Rate	Btu/kWh															
VOM in 2015$	$/MWh															
FOM in 2015$	$/kW-yr															
Equivalent Planned Outage Rate	%															
Equivalent Unplanned Outage Rate	%															
Equivalent Availability	%															
NO_x Emission Rate	Lbm/MMBtu															
SO_2 Emission Rate	Lbm/MMbtu															
Hg Emission Rate	Lbm/Tbtu															
CO_2 Emission Rate	Lbm/MMBtu															

Note:
The values shown above are relative for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit size, seasonal deratings, specific site requirements, and equipment vendor competition.

CONFIDENTIAL INFORMATION
REDACTED

2. Fuel and O&M Costs

The fuel costs and annual fixed and variable O&M costs for each unit (both existing and new) in the IRP are voluminous. Duke Energy Indiana also considers them to be trade secrets and confidential and competitive information. They will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

3. Air and Waste Emissions, Water Consumption and Discharge

The table on the following page represents the total air emissions projections for Duke Energy Indiana's existing and planned units for this IRP. This table contains total system tons of NO_x, SO_x and CO_2 emissions for the selected case in this IRP. Solid waste disposal and hazardous waste and subsequent disposal costs are included in the analysis, but the model does not quantify these waste streams in its output. Please contact Beth Herriman at (317) 838-1254 for more information.

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Figure A-5 (System)

Air Emissions and Water Usage - System

					Water	
	CO_2	NOx	SO_2	Mercury	Consumed	Discharged
	[redacted]					
2015	[redacted]					
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					
2034	[redacted]					
2035	28,245	6	11	116	15,651	211,096

CONFIDENTIAL INFORMATION
REDACTED

Figure A-5 (New CCs)

Air Emissions and Water Usage - New CCs

	CO_2 kTons	NOx kTons	SO_2 kTons	Mercury Pounds	Water Consumed Mgal	Water Discharged Mgal
2015	[redacted]					
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						

CONFIDENTIAL INFORMATION REDACTED

Figure A-5 (New CT)

Air Emissions and Water Usage - New CT

	CO_2 kTons	NOx kTons	SO_2 kTons	Mercury Pounds	Water Consumed Mgal	Water Discharged Mgal
2015	[redacted]					
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						

Figure A-6

Approximate Fuel Storage Capacity

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)
Cayuga	900,000	302,555
Connersville	--	514,800
Edwardsport IGCC	400,000	
Gallagher	245,000	130,000
Gibson	3,285,000 w/two piles	520,000
Miami-Wabash	--	766,600
Noblesville	--	45,300
Wabash River	350,000	346,550

Figure A-7
Duke Energy Indiana
Summary of Long Term Power Purchase Agreements

Supplier	Type	Expiration Date	Summer MW	Winter MW	Notes
Benton County Wind Farm	Wind PPA	April-2028	9	9	8.9% capacity value used in 2013 IRP
City of Logansport	Unit Peaking	December-2018	8	8	Effective July 1, 2009, Duke Energy Indiana purchased all Logansport Unit #6 capacity from the City of Logansport. In summer 2011, the City notified Duke Energy Indiana that this unit was unavailable until further notice.

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The Duke Energy Indiana 2015 Integrated Resource Plan

November 1, 2015

Appendix B: Electric Load Forecast

APPENDIX B – Table of Contents

1. Load Forecast Dataset

The Load Forecast Dataset to develop this IRP is voluminous in nature. This data will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

2. 2014 Hourly Load Data

The 2014 hourly load data for the Duke Energy Indiana system is contained on the following pages.

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
1/1/2014	3,466	3,372	3,252	3,277	3,298	3,363	3,565	3,845	3,822	3,923	3,903	3,840
1/1/2014	3,763	3,735	3,704	3,731	3,779	4,169	4,300	4,293	4,306	4,187	4,046	3,554
1/2/2014	3,417	3,408	3,370	3,398	3,550	3,959	4,419	4,604	4,633	4,727	4,832	4,828
1/2/2014	4,874	4,938	4,739	4,775	4,972	5,178	5,314	5,303	5,231	5,064	4,900	4,564
1/3/2014	4,493	4,506	4,310	4,321	4,627	4,855	5,318	5,387	5,443	5,391	5,264	5,138
1/3/2014	5,018	4,962	4,880	4,844	4,806	4,991	5,191	5,158	5,145	5,056	4,914	4,752
1/4/2014	4,213	4,152	4,126	4,077	4,103	4,153	4,539	4,795	4,802	4,811	4,713	4,657
1/4/2014	4,497	4,395	4,262	4,209	4,266	4,384	4,541	4,513	4,447	4,357	4,127	3,954
1/5/2014	3,835	3,727	3,658	3,470	3,421	3,580	3,873	4,008	4,133	4,146	4,298	4,325
1/5/2014	4,378	4,389	4,413	4,331	4,435	4,553	4,702	4,671	4,641	4,652	4,676	4,659
1/6/2014	4,664	4,665	4,667	4,936	5,126	5,240	5,167	5,348	5,406	5,483	5,501	5,584
1/6/2014	5,580	5,580	5,569	5,594	5,710	5,923	6,038	5,995	5,925	5,736	5,654	5,507
1/7/2014	5,245	5,166	5,123	5,150	5,166	5,500	5,590	5,750	5,794	5,751	5,683	5,591
1/7/2014	5,522	5,474	5,458	5,450	5,443	5,582	5,724	5,626	5,466	5,341	5,165	5,022
1/8/2014	4,918	4,901	4,867	4,883	4,893	5,031	5,187	5,309	5,299	5,220	5,218	5,100
1/8/2014	5,049	4,995	4,900	4,862	4,855	5,000	5,144	5,164	5,046	4,905	4,706	4,582
1/9/2014	4,311	4,256	4,238	4,223	4,249	4,571	4,782	4,983	4,965	4,968	4,928	4,851
1/9/2014	4,807	4,842	4,774	4,742	4,732	4,866	4,964	4,997	4,918	4,792	4,619	4,352
1/10/2014	4,036	3,875	3,751	3,709	3,917	4,357	4,584	4,703	4,756	4,753	4,760	4,629
1/10/2014	4,626	4,642	4,339	4,288	4,292	4,615	4,678	4,596	4,475	4,416	3,858	3,623
1/11/2014	3,339	3,213	3,228	3,145	3,218	3,252	3,432	3,685	3,797	4,045	4,131	4,205
1/11/2014	4,243	4,222	4,214	4,217	4,246	4,493	4,626	4,557	4,528	4,247	3,927	3,657
1/12/2014	3,386	3,344	3,290	3,278	3,273	3,364	3,440	3,683	3,884	4,003	4,019	3,918
1/12/2014	3,849	3,717	3,699	3,652	3,761	4,152	4,372	4,402	4,421	4,067	3,814	3,618
1/13/2014	3,312	3,229	3,171	3,204	3,321	3,535	4,182	4,565	4,550	4,525	4,555	4,308
1/13/2014	4,305	4,260	4,205	4,147	4,176	4,237	4,597	4,548	4,449	4,115	3,916	3,617
1/14/2014	3,504	3,510	3,523	3,530	3,624	4,077	4,668	4,899	4,874	4,785	4,691	4,545
1/14/2014	4,506	4,302	4,271	4,223	4,281	4,653	4,788	4,802	4,755	4,657	4,180	4,027
1/15/2014	3,843	3,626	3,681	3,791	3,870	4,052	4,815	5,042	5,072	5,053	5,031	5,022
1/15/2014	4,932	4,745	4,748	4,737	4,800	5,086	5,183	5,204	5,226	5,060	4,644	4,301
1/16/2014	4,131	4,091	4,072	4,061	4,147	4,518	4,981	5,137	5,089	5,088	5,101	5,052
1/16/2014	5,022	4,958	4,845	4,816	4,789	4,911	5,092	5,032	4,976	4,809	4,542	4,225
1/17/2014	4,006	3,849	3,784	3,842	3,939	4,486	4,848	5,088	5,090	5,147	5,142	5,073
1/17/2014	5,080	5,112	5,054	4,873	5,067	5,167	5,371	5,390	5,289	4,866	4,320	4,109
1/18/2014	4,228	4,020	3,924	3,906	3,909	4,002	4,307	4,681	4,708	4,701	4,635	4,618
1/18/2014	4,414	4,397	4,317	4,340	4,315	4,570	4,700	4,607	4,534	4,389	3,922	3,744
1/19/2014	3,651	3,445	3,462	3,423	3,482	3,556	3,636	4,000	4,025	4,325	4,391	4,341
1/19/2014	4,235	4,130	3,812	3,789	3,771	4,099	4,397	4,369	4,265	4,215	4,076	3,600
1/20/2014	3,414	3,308	3,291	3,313	3,328	3,935	4,161	4,373	4,572	4,586	4,651	4,622
1/20/2014	4,538	4,458	4,389	4,382	4,409	4,551	4,767	4,774	4,740	4,599	4,320	4,024
1/21/2014	4,112	3,939	3,946	4,022	4,198	4,664	5,057	5,276	5,366	5,394	5,353	5,296
1/21/2014	5,239	5,218	5,108	5,131	5,074	5,221	5,480	5,525	5,515	5,534	5,338	5,226
1/22/2014	5,166	5,192	5,166	5,221	5,309	5,494	5,689	5,794	5,757	5,692	5,642	5,537
1/22/2014	5,481	5,449	5,357	5,302	5,279	5,389	5,535	5,586	5,531	5,448	5,338	5,181
1/23/2014	5,104	5,073	5,103	5,176	5,305	5,468	5,690	5,873	5,901	5,795	5,712	5,606
1/23/2014	5,521	5,522	5,440	5,406	5,440	5,600	5,852	5,950	5,968	5,835	5,655	5,521
1/24/2014	5,432	5,359	5,324	5,379	5,466	5,632	5,861	6,018	6,034	5,891	5,750	5,616
1/24/2014	5,540	5,503	5,373	5,355	5,311	5,420	5,540	5,559	5,518	5,413	5,189	5,042
1/25/2014	4,895	4,779	4,715	4,739	4,761	4,777	4,833	4,847	4,939	4,957	4,876	4,827
1/25/2014	4,701	4,652	4,666	4,622	4,697	4,860	5,122	5,176	5,134	5,086	4,955	4,801
1/26/2014	4,775	4,679	4,636	4,597	4,666	4,673	4,775	4,864	4,930	4,967	4,922	4,812
1/26/2014	4,683	4,564	4,426	4,291	4,318	4,442	4,638	4,663	4,615	4,438	4,339	4,267
1/27/2014	4,288	4,298	4,379	4,622	4,809	5,055	5,315	5,535	5,615	5,559	5,472	5,376
1/27/2014	5,310	5,282	5,215	5,196	5,221	5,436	5,734	5,802	5,819	5,742	5,517	5,437
1/28/2014	5,392	5,342	5,335	5,310	5,401	5,558	5,757	5,935	5,948	5,881	5,734	5,575
1/28/2014	5,474	5,349	5,260	5,175	5,162	5,306	5,586	5,722	5,700	5,605	5,450	5,362
1/29/2014	5,309	5,239	5,207	5,230	5,266	5,431	5,714	5,816	5,743	5,588	5,408	5,243
1/29/2014	5,120	5,075	4,977	4,896	4,803	4,921	5,207	5,411	5,405	5,256	5,131	5,014
1/30/2014	4,906	4,826	4,861	4,869	4,879	5,153	5,454	5,631	5,548	5,457	5,400	5,308
1/30/2014	5,204	5,168	5,084	5,004	4,914	4,978	5,112	5,078	5,019	4,910	4,673	4,533
1/31/2014	4,431	4,291	4,231	4,243	4,293	4,456	4,738	4,854	4,898	4,875	4,865	4,806
1/31/2014	4,781	4,714	4,651	4,645	4,615	4,631	4,743	4,704	4,669	4,649	4,487	4,108

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
2/1/2014	4,171	4,081	3,808	3,549	3,525	3,637	4,195	4,357	4,426	4,473	4,519	4,506
2/1/2014	4,488	4,405	4,084	3,987	4,082	4,328	4,446	4,410	4,364	4,290	4,160	3,825
2/2/2014	3,780	3,694	3,646	3,280	3,263	3,519	3,914	4,108	4,277	4,346	4,465	4,460
2/2/2014	4,489	4,178	4,206	4,177	4,191	4,566	4,676	4,666	4,645	4,540	4,257	3,932
2/3/2014	4,159	3,936	3,895	3,883	4,315	4,646	5,078	5,250	5,254	5,190	5,102	4,968
2/3/2014	4,866	4,749	4,669	4,610	4,618	4,734	4,998	5,110	5,126	4,989	4,875	4,682
2/4/2014	4,579	4,529	4,546	4,567	4,613	4,801	5,101	5,326	5,266	5,206	5,159	5,123
2/4/2014	5,072	5,038	5,072	5,067	5,046	5,129	5,302	5,295	5,174	4,982	4,844	4,566
2/5/2014	4,479	4,332	4,074	4,131	4,208	4,542	4,726	4,865	4,924	5,008	5,087	5,037
2/5/2014	4,973	4,949	4,894	4,885	4,940	5,035	5,209	5,231	5,184	5,018	4,867	4,656
2/6/2014	4,319	4,279	4,239	4,297	4,497	4,743	5,080	5,317	5,362	5,346	5,284	5,186
2/6/2014	5,098	5,033	5,002	4,982	5,018	5,168	5,427	5,516	5,542	5,443	5,334	5,270
2/7/2014	5,210	5,157	5,141	5,153	5,281	5,484	5,750	5,964	5,955	5,803	5,619	5,468
2/7/2014	5,359	5,274	5,132	4,988	5,018	5,079	5,292	5,388	5,432	5,353	5,184	5,063
2/8/2014	4,950	4,868	4,799	4,793	4,837	4,878	4,975	5,082	5,161	5,176	5,165	5,067
2/8/2014	4,919	4,838	4,760	4,739	4,762	4,813	4,941	4,936	4,872	4,735	4,585	4,246
2/9/2014	4,105	4,003	3,957	3,915	3,945	4,039	4,138	4,320	4,424	4,555	4,593	4,513
2/9/2014	4,529	4,476	4,449	4,453	4,565	4,732	4,963	5,005	5,006	4,912	4,788	4,704
2/10/2014	4,652	4,630	4,607	4,711	4,871	5,111	5,473	5,692	5,649	5,607	5,465	5,300
2/10/2014	5,182	5,099	5,069	5,010	5,002	5,113	5,400	5,545	5,592	5,512	5,331	5,219
2/11/2014	5,156	5,084	5,123	5,170	5,329	5,470	5,791	5,996	5,948	5,738	5,568	5,384
2/11/2014	5,238	5,141	5,006	4,962	4,948	5,042	5,296	5,410	5,469	5,390	5,290	5,161
2/12/2014	5,118	5,091	5,101	5,132	5,233	5,326	5,649	5,800	5,705	5,526	5,309	5,082
2/12/2014	4,956	4,857	4,740	4,677	4,668	4,799	4,943	5,151	5,184	5,067	4,950	4,756
2/13/2014	4,697	4,635	4,686	4,655	4,810	5,041	5,397	5,573	5,458	5,251	5,081	4,879
2/13/2014	4,790	4,703	4,615	4,544	4,596	4,636	4,736	4,864	4,891	4,812	4,644	4,452
2/14/2014	4,385	4,286	4,291	4,322	4,439	4,644	5,013	5,191	5,104	5,122	5,114	5,088
2/14/2014	5,017	4,939	4,903	4,839	4,830	4,861	4,993	5,060	5,038	4,981	4,773	4,546
2/15/2014	4,561	4,401	4,463	4,440	4,508	4,660	4,793	4,942	5,022	4,998	4,887	4,692
2/15/2014	4,582	4,473	4,386	4,439	4,541	4,610	4,759	4,831	4,763	4,584	4,525	4,385
2/16/2014	4,316	4,155	4,066	4,142	4,149	3,989	4,264	4,376	4,447	4,539	4,520	4,509
2/16/2014	4,435	4,362	4,235	4,182	4,313	4,458	4,682	4,830	4,798	4,663	4,560	4,444
2/17/2014	4,214	4,157	4,131	4,164	4,227	4,623	4,915	5,095	5,187	5,164	5,045	5,008
2/17/2014	4,962	4,974	4,985	4,746	4,679	4,963	5,057	5,056	5,028	4,873	4,622	4,471
2/18/2014	4,043	3,881	3,730	3,741	3,925	4,282	4,631	4,832	4,798	4,621	4,548	4,461
2/18/2014	4,411	4,345	4,222	4,200	4,145	4,184	4,454	4,620	4,608	4,405	4,241	4,084
2/19/2014	3,550	3,391	3,365	3,297	3,363	3,668	4,467	4,634	4,492	4,432	4,373	4,288
2/19/2014	4,225	4,196	4,080	3,832	4,054	4,123	4,322	4,451	4,430	4,407	4,037	3,578
2/20/2014	3,599	3,415	3,379	3,296	3,421	3,847	4,448	4,661	4,550	4,554	4,532	4,470
2/20/2014	4,427	4,352	4,350	4,289	4,217	4,276	4,370	4,396	4,243	4,176	3,822	3,674
2/21/2014	3,256	3,178	3,094	3,206	3,316	3,636	4,379	4,652	4,676	4,645	4,670	4,603
2/21/2014	4,577	4,509	4,407	4,290	4,226	4,190	4,355	4,512	4,509	4,431	4,277	3,765
2/22/2014	3,771	3,632	3,442	3,239	3,260	3,425	3,999	4,215	4,254	4,243	4,200	4,073
2/22/2014	4,029	3,899	3,626	3,566	3,581	3,851	3,977	4,051	4,087	4,063	3,770	3,602
2/23/2014	3,470	3,496	3,403	3,235	3,408	3,376	3,770	4,024	4,159	4,242	4,282	4,297
2/23/2014	4,284	4,217	4,197	3,944	3,911	4,219	4,371	4,608	4,621	4,509	4,406	4,107
2/24/2014	4,238	4,205	4,183	4,200	4,363	4,534	4,933	5,143	5,093	5,069	4,961	4,874
2/24/2014	4,827	4,678	4,705	4,618	4,651	4,722	4,877	5,003	4,975	4,846	4,623	4,416
2/25/2014	4,323	4,297	4,254	4,222	4,316	4,549	4,888	5,087	5,044	4,959	4,926	4,891
2/25/2014	4,863	4,850	4,780	4,759	4,798	4,904	5,049	5,126	5,108	5,001	4,874	4,722
2/26/2014	4,668	4,616	4,654	4,706	4,810	4,983	5,354	5,526	5,425	5,319	5,220	5,066
2/26/2014	5,001	4,925	4,837	4,754	4,671	4,774	5,070	5,288	5,320	5,209	5,009	4,860
2/27/2014	4,794	4,723	4,694	4,697	4,762	4,928	5,281	5,439	5,393	5,275	5,259	5,157
2/27/2014	5,130	5,052	4,967	4,875	4,808	4,866	5,085	5,294	5,351	5,276	5,155	5,009
2/28/2014	4,950	4,897	4,906	4,920	4,990	5,209	5,493	5,574	5,467	5,386	5,233	5,033
2/28/2014	4,881	4,768	4,692	4,493	4,455	4,441	4,593	4,714	4,745	4,680	4,482	4,347

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
3/1/2014	4,135	3,892	3,754	3,737	3,736	3,804	4,161	4,266	4,375	4,431	4,444	4,352
3/1/2014	4,180	4,125	4,030	4,003	4,067	4,156	4,205	4,348	4,341	4,304	4,183	4,026
3/2/2014	3,944	3,915	3,938	3,879	3,937	4,082	4,163	4,309	4,474	4,638	4,696	4,669
3/2/2014	4,626	4,636	4,623	4,592	4,703	4,801	4,970	5,064	4,995	4,918	4,770	4,698
3/3/2014	4,654	4,581	4,564	4,645	4,773	4,979	5,276	5,428	5,424	5,358	5,249	5,112
3/3/2014	4,997	4,973	4,897	4,836	4,815	4,866	5,057	5,318	5,162	5,052	4,897	4,686
3/4/2014	4,727	4,737	4,682	4,653	4,751	4,877	5,171	5,288	5,199	5,020	4,893	4,747
3/4/2014	4,671	4,563	4,513	4,425	4,393	4,450	4,632	4,856	4,865	4,751	4,582	4,474
3/5/2014	4,424	4,399	4,400	4,425	4,530	4,743	5,109	5,192	5,068	4,960	4,833	4,735
3/5/2014	4,700	4,668	4,616	4,592	4,570	4,674	4,868	5,002	5,022	4,937	4,759	4,520
3/6/2014	4,472	4,421	4,409	4,439	4,467	4,681	5,069	5,175	5,101	4,994	4,867	4,771
3/6/2014	4,647	4,560	4,432	4,291	4,168	4,213	4,363	4,646	4,646	4,602	4,474	4,266
3/7/2014	4,142	3,708	3,723	3,810	3,919	4,559	4,847	4,978	4,818	4,696	4,565	4,457
3/7/2014	4,361	4,261	4,204	4,069	4,020	3,992	4,025	4,160	4,230	4,170	4,053	3,907
3/8/2014	3,216	3,183	3,175	3,122	3,201	3,288	3,880	4,028	4,116	4,072	4,153	4,096
3/8/2014	3,981	3,720	3,469	3,505	3,512	3,578	3,991	4,156	4,138	4,044	3,952	3,379
3/9/2014	3,340	3,308	3,326	3,307	3,404	3,517	3,687	3,797	3,925	4,024	3,973	3,878
3/9/2014	3,412	3,348	3,229	3,226	3,252	3,282	3,851	4,067	4,005	3,914	3,804	3,357
3/10/2014	3,334	3,209	3,235	3,263	3,422	3,910	4,266	4,254	4,396	4,455	4,299	4,271
3/10/2014	4,198	3,872	3,814	3,649	3,688	3,936	3,944	4,158	3,984	3,830	3,530	3,175
3/11/2014	3,168	3,073	2,970	3,007	3,198	3,872	4,407	4,372	4,281	4,245	4,198	4,155
3/11/2014	4,085	4,014	3,979	3,908	3,909	3,861	3,958	4,151	4,013	3,793	3,368	2,958
3/12/2014	2,792	2,850	2,840	2,939	3,122	3,923	4,226	4,338	4,410	4,506	4,491	4,540
3/12/2014	4,582	4,550	4,500	4,481	4,569	4,630	4,724	4,865	4,840	4,661	4,304	4,146
3/13/2014	4,324	4,348	4,368	4,452	4,658	5,066	5,240	5,214	5,044	4,914	4,805	4,714
3/13/2014	4,632	4,586	4,503	4,471	4,442	4,449	4,544	4,714	4,652	4,472	4,273	4,171
3/14/2014	3,901	3,806	3,710	3,777	4,051	4,565	4,730	4,639	4,598	4,528	4,426	4,327
3/14/2014	4,266	4,177	4,058	3,926	3,965	3,963	3,989	4,080	4,046	3,922	3,739	3,495
3/15/2014	3,585	3,073	3,004	3,008	3,110	3,339	3,525	4,092	4,096	4,057	4,004	3,889
3/15/2014	3,823	3,719	3,601	3,519	3,550	3,573	3,642	3,826	3,815	3,715	3,623	3,398
3/16/2014	3,314	3,047	3,047	3,113	3,216	3,356	3,968	4,069	4,233	4,278	4,325	4,342
3/16/2014	4,317	4,211	4,279	4,337	4,358	4,401	4,438	4,636	4,530	4,418	4,092	4,086
3/17/2014	4,197	3,978	4,010	4,118	4,472	4,877	5,067	5,037	5,030	5,024	4,943	4,816
3/17/2014	4,688	4,526	4,442	4,334	4,282	4,248	4,342	4,510	4,435	4,340	4,128	4,053
3/18/2014	4,028	4,056	4,045	4,132	4,294	4,653	4,873	4,834	4,750	4,649	4,535	4,510
3/18/2014	4,388	4,331	4,208	4,138	4,090	4,090	4,160	4,296	4,264	4,017	3,847	3,822
3/19/2014	3,090	3,025	2,989	3,127	3,427	4,144	4,400	4,368	4,316	4,361	4,363	4,313
3/19/2014	4,298	4,200	4,174	4,153	4,249	4,267	4,403	4,438	4,381	4,219	4,031	3,605
3/20/2014	3,358	3,229	3,250	3,359	3,571	4,405	4,600	4,551	4,462	4,372	4,259	4,199
3/20/2014	3,939	3,862	3,770	3,777	3,739	3,731	3,826	4,256	4,205	3,956	3,530	3,381
3/21/2014	3,275	3,247	3,197	3,332	3,461	4,268	4,469	4,411	4,361	4,329	4,196	4,143
3/21/2014	4,041	3,975	3,878	3,836	3,785	3,774	3,786	3,919	3,877	3,531	3,102	2,950
3/22/2014	2,800	2,830	2,741	2,760	2,912	3,039	3,319	3,664	3,988	4,001	4,007	3,953
3/22/2014	3,866	3,809	3,741	3,700	3,723	3,727	3,743	3,959	3,871	3,822	3,675	3,230
3/23/2014	3,329	3,063	3,043	3,064	3,150	3,310	3,667	3,973	4,065	4,085	4,047	4,046
3/23/2014	3,980	3,943	3,656	3,651	3,652	3,655	3,993	4,230	4,263	4,190	4,080	3,810
3/24/2014	3,986	3,986	4,071	4,172	4,413	4,655	4,874	4,862	4,876	4,801	4,661	4,533
3/24/2014	4,496	4,442	4,296	4,281	4,271	4,299	4,381	4,538	4,551	4,391	4,205	4,099
3/25/2014	4,054	4,005	3,995	4,159	4,331	4,649	4,838	4,845	4,838	4,875	4,803	4,786
3/25/2014	4,701	4,605	4,608	4,642	4,641	4,643	4,723	4,814	4,728	4,567	4,474	4,412
3/26/2014	4,280	4,315	4,341	4,412	4,563	4,916	5,016	4,920	4,771	4,650	4,525	4,433
3/26/2014	4,409	4,333	4,264	4,095	4,168	4,106	4,215	4,538	4,432	4,309	4,115	4,057
3/27/2014	3,778	3,657	3,661	3,703	3,931	4,472	4,676	4,659	4,683	4,691	4,714	4,655
3/27/2014	4,649	4,496	4,402	4,353	4,362	4,362	4,352	4,452	4,313	4,130	3,694	3,565
3/28/2014	3,355	3,248	3,167	3,196	3,579	4,050	4,245	4,269	4,243	4,338	4,354	4,261
3/28/2014	4,224	4,170	4,064	4,029	3,947	3,929	3,921	4,062	3,789	3,521	3,187	3,044
3/29/2014	2,965	2,888	2,880	2,893	2,982	3,111	3,296	3,825	3,930	4,029	3,970	3,980
3/29/2014	3,763	3,747	3,686	3,695	3,685	3,672	3,898	3,934	3,861	3,730	3,392	3,133
3/30/2014	3,039	2,993	3,053	3,069	3,160	3,400	3,503	3,814	3,777	3,587	3,634	3,568
3/30/2014	3,314	3,212	3,163	3,157	3,167	3,127	3,402	3,509	3,598	3,276	3,034	2,985
3/31/2014	2,891	2,891	2,900	3,004	3,167	4,002	4,223	4,162	4,189	4,157	4,232	4,239
3/31/2014	4,177	4,114	4,029	3,960	3,897	3,919	4,011	4,143	4,090	3,830	3,627	3,158

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
4/1/2014	2,858	2,796	2,785	2,828	3,279	3,710	3,861	3,873	3,916	3,934	3,898	3,908
4/1/2014	3,944	3,893	3,850	3,797	3,762	3,752	3,779	3,921	3,864	3,532	2,989	2,934
4/2/2014	2,867	2,825	2,810	2,866	3,094	3,871	4,092	4,133	4,171	4,172	4,138	4,100
4/2/2014	4,050	4,030	4,057	4,093	4,045	4,113	4,096	4,192	4,151	3,990	3,427	3,218
4/3/2014	3,022	2,983	2,956	3,023	3,268	3,995	4,199	4,300	4,318	4,321	4,380	4,376
4/3/2014	4,314	4,262	4,189	4,079	4,073	4,113	4,191	4,245	4,128	3,960	3,317	3,177
4/4/2014	2,981	2,893	2,921	2,966	3,145	4,124	4,344	4,332	4,404	4,486	4,416	4,460
4/4/2014	4,424	4,490	4,495	4,465	4,439	4,428	4,455	4,561	4,528	4,181	3,546	3,451
4/5/2014	3,345	3,308	3,151	3,243	3,360	3,445	3,797	4,043	4,133	4,116	4,031	3,922
4/5/2014	3,859	3,777	3,517	3,449	3,406	3,399	3,622	3,734	3,799	3,586	3,486	3,188
4/6/2014	3,063	3,081	3,021	3,045	3,094	3,356	3,681	3,886	3,895	3,825	3,820	3,789
4/6/2014	3,741	3,640	3,388	3,378	3,390	3,633	3,689	3,826	3,857	3,720	3,285	2,950
4/7/2014	2,842	2,874	2,888	2,988	3,323	4,100	4,325	4,310	4,220	4,315	4,362	4,455
4/7/2014	4,440	4,379	4,346	4,350	4,369	4,384	4,423	4,432	4,351	4,133	3,933	3,490
4/8/2014	3,268	3,190	3,194	3,236	3,450	4,294	4,447	4,390	4,373	4,366	4,316	4,286
4/8/2014	4,169	4,145	4,088	4,060	3,989	4,040	4,030	4,175	4,161	3,917	3,570	3,308
4/9/2014	3,082	3,064	3,091	3,172	3,501	4,206	4,354	4,304	4,260	4,148	4,137	4,100
4/9/2014	4,072	4,019	3,957	3,877	3,823	3,753	3,796	4,054	3,988	3,759	3,283	3,194
4/10/2014	2,992	2,901	2,923	2,977	3,192	4,033	4,099	4,090	4,090	4,088	4,021	4,002
4/10/2014	3,964	3,950	3,890	3,835	3,836	3,838	3,936	4,071	4,051	3,692	3,264	3,045
4/11/2014	2,846	2,676	2,696	2,844	3,047	3,766	3,954	4,031	4,082	4,075	4,050	4,107
4/11/2014	4,075	3,998	3,924	3,777	3,732	3,676	3,665	3,737	3,774	3,552	3,200	2,984
4/12/2014	2,949	2,798	2,695	2,749	2,790	3,005	3,390	3,512	3,754	3,821	3,749	3,755
4/12/2014	3,712	3,456	3,479	3,468	3,495	3,479	3,661	3,695	3,714	3,538	2,899	2,763
4/13/2014	2,640	2,601	2,555	2,517	2,586	2,616	2,745	3,268	3,455	3,553	3,586	3,640
4/13/2014	3,432	3,387	3,385	3,409	3,485	3,576	3,808	3,935	3,939	3,658	3,053	3,012
4/14/2014	2,729	2,707	2,721	2,791	3,094	3,763	4,071	4,042	4,123	4,159	4,188	4,152
4/14/2014	4,211	4,167	4,107	4,078	4,121	4,119	4,259	4,293	4,248	4,046	3,671	3,507
4/15/2014	3,426	3,315	3,312	3,485	3,877	4,345	4,506	4,595	4,552	4,553	4,592	4,589
4/15/2014	4,536	4,391	4,400	4,334	4,368	4,338	4,363	4,522	4,558	4,360	4,212	3,794
4/16/2014	3,719	3,697	3,686	3,737	4,088	4,563	4,590	4,576	4,473	4,394	4,303	4,243
4/16/2014	4,209	4,119	4,042	4,046	4,079	4,060	4,103	4,257	4,300	4,121	3,781	3,456
4/17/2014	3,401	3,285	3,253	3,265	3,768	4,288	4,381	4,363	4,322	4,271	4,254	4,190
4/17/2014	4,172	4,139	4,035	4,014	3,958	3,932	3,908	4,007	3,953	3,604	3,180	2,992
4/18/2014	2,745	2,684	2,731	2,808	3,005	3,706	3,949	3,953	3,940	3,943	3,916	3,884
4/18/2014	3,870	3,795	3,754	3,680	3,672	3,640	3,530	3,550	3,596	3,365	2,987	2,754
4/19/2014	2,681	2,640	2,592	2,566	2,638	2,836	3,050	3,563	3,639	3,612	3,672	3,600
4/19/2014	3,609	3,359	3,182	3,135	3,146	3,204	3,481	3,588	3,621	3,077	2,781	2,614
4/20/2014	2,519	2,524	2,498	2,467	2,558	2,696	2,839	3,162	3,442	3,431	3,413	3,453
4/20/2014	3,086	2,923	2,897	2,924	3,106	3,120	3,426	3,654	3,695	3,503	2,878	2,698
4/21/2014	2,622	2,582	2,574	2,592	2,917	3,682	3,861	3,980	3,982	4,157	4,147	4,124
4/21/2014	4,192	4,195	4,118	4,108	4,084	4,060	4,087	4,198	4,004	3,845	3,229	3,080
4/22/2014	2,850	2,791	2,747	2,820	3,031	3,738	3,923	3,891	4,031	3,979	4,009	3,990
4/22/2014	3,989	4,007	3,888	3,800	3,950	3,934	3,925	4,000	4,039	3,749	3,240	3,091
4/23/2014	2,844	2,826	2,791	2,908	3,213	3,957	4,084	4,061	4,043	4,018	3,979	3,940
4/23/2014	3,899	3,845	3,890	3,851	3,888	3,802	3,884	3,979	3,988	3,802	3,223	3,097
4/24/2014	2,874	2,823	2,827	2,842	3,081	3,829	4,088	4,094	4,111	4,128	4,084	4,118
4/24/2014	4,138	4,103	4,029	4,010	3,976	3,955	3,887	4,067	4,078	3,704	3,263	3,093
4/25/2014	2,861	2,799	2,748	2,797	2,915	3,776	3,914	3,980	4,086	4,093	4,084	4,093
4/25/2014	4,060	4,030	3,968	3,870	3,860	3,807	3,796	3,809	3,865	3,551	3,116	2,866
4/26/2014	2,806	2,630	2,672	2,652	2,751	2,893	3,074	3,366	3,641	3,685	3,703	3,547
4/26/2014	3,313	3,309	3,316	3,326	3,353	3,294	3,219	3,624	3,666	3,201	2,909	2,674
4/27/2014	2,629	2,611	2,590	2,595	2,602	2,705	2,873	3,118	3,218	3,337	3,430	3,462
4/27/2014	3,443	3,483	3,475	3,527	3,529	3,519	3,580	3,821	3,831	3,447	2,937	2,828
4/28/2014	2,740	2,706	2,699	2,766	2,945	3,592	4,002	4,054	4,163	4,164	4,166	4,249
4/28/2014	4,220	4,222	4,151	4,101	4,058	4,053	4,061	4,122	4,045	3,862	3,395	3,027
4/29/2014	2,852	2,813	2,802	2,828	2,944	3,764	3,975	4,030	4,111	4,172	4,217	4,203
4/29/2014	4,249	4,184	4,148	4,074	4,049	3,955	4,028	4,017	3,984	3,781	3,234	2,955
4/30/2014	2,801	2,846	2,780	2,797	3,026	3,696	3,892	3,922	3,940	3,998	3,969	3,984
4/30/2014	3,989	3,967	3,909	3,869	3,841	3,877	3,872	3,931	3,943	3,802	3,290	3,117

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
5/1/2014	2,993	2,920	2,915	2,964	3,224	3,912	4,092	4,079	4,117	4,139	4,184	4,188
5/1/2014	4,151	4,135	4,055	4,046	4,029	4,068	4,099	4,118	4,132	3,949	3,577	3,255
5/2/2014	3,058	2,971	2,940	3,011	3,282	3,958	4,106	4,115	4,160	4,151	4,107	4,119
5/2/2014	4,099	4,077	3,950	3,950	3,917	3,881	3,829	3,889	3,948	3,778	3,481	3,119
5/3/2014	3,072	2,800	2,824	2,870	2,879	3,120	3,202	3,460	3,753	3,780	3,718	3,726
5/3/2014	3,635	3,178	3,216	3,188	3,163	3,186	3,392	3,580	3,647	3,162	2,936	2,811
5/4/2014	2,646	2,607	2,602	2,565	2,585	2,774	2,859	2,992	3,441	3,478	3,502	3,467
5/4/2014	3,516	3,191	3,122	3,209	3,453	3,669	3,685	3,746	3,834	3,433	3,083	2,908
5/5/2014	2,749	2,590	2,657	2,754	3,065	3,819	4,018	4,100	4,119	4,182	4,153	4,153
5/5/2014	4,203	4,179	4,145	4,117	4,100	4,035	4,033	4,087	4,051	3,863	3,417	3,085
5/6/2014	2,936	2,818	2,795	2,844	3,149	3,810	3,948	4,003	4,082	4,092	4,128	4,187
5/6/2014	4,217	4,185	4,166	4,189	4,159	4,172	4,112	4,091	4,194	3,936	3,521	3,170
5/7/2014	3,005	2,812	2,863	2,837	3,121	3,806	3,907	4,007	4,118	4,204	4,242	4,302
5/7/2014	4,365	4,424	4,448	4,445	4,482	4,455	4,399	4,458	4,439	4,236	3,745	3,342
5/8/2014	3,173	3,031	2,952	3,002	3,161	3,823	4,107	4,271	4,405	4,560	4,679	4,714
5/8/2014	4,837	4,873	4,872	4,963	4,911	4,851	4,725	4,739	4,768	4,467	4,010	3,609
5/9/2014	3,311	3,166	3,124	3,089	3,227	3,822	4,164	4,260	4,363	4,349	4,386	4,419
5/9/2014	4,351	4,462	4,470	4,460	4,400	4,302	4,232	4,196	4,217	4,052	3,615	3,250
5/10/2014	3,005	2,866	2,724	2,696	2,748	2,876	3,045	3,445	3,769	3,861	3,914	3,936
5/10/2014	3,944	3,992	3,989	3,877	4,030	3,960	3,971	3,843	3,963	3,765	3,142	2,955
5/11/2014	2,762	2,659	2,620	2,506	2,548	2,698	2,806	3,322	3,560	3,719	3,828	3,903
5/11/2014	4,009	4,025	4,091	4,245	4,271	4,296	4,251	4,305	4,256	4,032	3,402	3,149
5/12/2014	3,000	2,956	2,862	2,955	3,088	3,662	4,060	4,222	4,415	4,571	4,734	4,849
5/12/2014	4,918	4,957	4,929	4,865	4,814	4,768	4,731	4,638	4,660	4,328	3,914	3,438
5/13/2014	3,212	3,122	3,054	3,057	3,169	3,788	4,187	4,302	4,513	4,673	4,769	4,871
5/13/2014	4,888	4,790	4,728	4,714	4,675	4,521	4,469	4,407	4,266	4,062	3,609	3,129
5/14/2014	2,934	2,798	2,765	2,832	2,962	3,719	3,809	3,902	3,953	3,994	4,001	4,022
5/14/2014	4,018	3,974	3,946	3,911	3,930	3,944	4,071	4,100	3,958	3,585	3,160	2,987
5/15/2014	2,852	2,843	2,798	2,841	2,962	3,708	3,902	3,979	4,010	4,088	4,090	4,030
5/15/2014	4,069	4,045	3,957	3,801	3,752	3,715	3,698	3,931	4,025	3,723	3,262	3,088
5/16/2014	3,022	2,939	2,968	2,994	3,197	3,599	4,057	4,192	4,184	4,172	4,149	4,122
5/16/2014	4,063	4,077	4,039	3,641	3,596	3,553	3,539	3,933	3,986	3,724	3,395	3,217
5/17/2014	3,065	2,898	2,893	2,826	2,906	3,078	3,233	3,525	3,806	3,835	3,821	3,790
5/17/2014	3,606	3,526	3,476	3,485	3,450	3,385	3,289	3,524	3,654	3,445	3,033	2,890
5/18/2014	2,843	2,783	2,762	2,768	2,831	2,877	2,934	3,083	3,350	3,406	3,360	3,382
5/18/2014	3,412	3,396	3,369	3,392	3,444	3,637	3,634	3,628	3,770	3,489	3,036	2,842
5/19/2014	2,757	2,694	2,633	2,791	3,003	3,756	3,998	4,120	4,184	4,169	4,232	4,248
5/19/2014	4,254	4,232	4,191	4,156	4,115	4,069	4,018	4,111	4,125	3,829	3,213	3,024
5/20/2014	2,965	2,847	2,819	2,852	3,045	3,791	4,006	4,103	4,163	4,289	4,288	4,377
5/20/2014	4,559	4,610	4,614	4,600	4,599	4,560	4,518	4,577	4,589	4,356	3,743	3,485
5/21/2014	3,003	2,887	2,840	2,834	2,929	3,306	3,786	3,921	4,061	4,191	4,277	4,400
5/21/2014	4,520	4,611	4,599	4,588	4,561	4,477	4,414	4,363	4,287	3,945	3,361	3,145
5/22/2014	3,249	3,102	3,042	3,042	3,208	3,712	4,124	4,310	4,447	4,608	4,647	4,717
5/22/2014	4,807	4,789	4,759	4,795	4,777	4,676	4,614	4,494	4,518	4,271	3,627	3,326
5/23/2014	3,031	2,952	2,894	2,933	3,038	3,260	3,878	4,049	4,161	4,290	4,288	4,387
5/23/2014	4,497	4,455	4,481	4,515	4,480	4,412	4,324	4,225	4,143	3,941	3,329	3,063
5/24/2014	2,781	2,745	2,633	2,644	2,618	2,617	2,782	3,053	3,403	3,566	3,821	3,875
5/24/2014	3,950	3,977	3,974	4,037	4,098	4,032	3,960	3,901	3,886	3,422	3,110	2,739
5/25/2014	2,658	2,600	2,576	2,533	2,561	2,596	2,654	2,898	3,072	3,283	3,544	3,882
5/25/2014	3,899	3,959	4,014	4,095	4,107	4,152	4,052	3,940	3,948	3,782	3,178	2,981
5/26/2014	2,752	2,625	2,573	2,554	2,533	2,559	2,652	2,899	3,160	3,704	4,046	4,259
5/26/2014	4,384	4,530	4,643	4,684	4,702	4,708	4,680	4,591	4,613	4,327	3,656	3,490
5/27/2014	3,296	3,148	3,013	3,046	3,217	3,831	4,260	4,439	4,637	4,816	4,978	5,245
5/27/2014	5,341	5,363	5,392	5,380	5,339	5,273	5,159	5,067	5,030	4,760	4,425	3,754
5/28/2014	3,467	3,245	3,163	3,138	3,224	3,763	4,113	4,280	4,501	4,658	4,817	4,967
5/28/2014	5,093	5,150	5,181	5,230	5,182	5,068	4,952	4,871	4,793	4,535	4,067	3,563
5/29/2014	3,323	3,120	3,034	3,056	3,194	3,577	4,093	4,393	4,535	4,698	4,823	4,969
5/29/2014	5,013	5,139	5,142	5,124	5,111	5,060	5,020	4,908	4,859	4,639	4,163	3,625
5/30/2014	3,334	3,139	3,065	3,042	3,174	3,408	4,014	4,302	4,494	4,682	4,802	4,943
5/30/2014	5,049	5,080	5,109	5,207	5,106	5,065	4,929	4,717	4,709	4,482	3,708	3,381
5/31/2014	3,152	3,066	2,843	2,865	2,896	2,845	3,043	3,399	4,077	4,300	4,420	4,531
5/31/2014	4,568	4,674	4,758	4,820	4,864	4,821	4,760	4,601	4,544	4,301	3,543	3,194

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
6/1/2014	2,988	2,814	2,726	2,644	2,654	2,658	2,769	3,000	3,300	3,738	4,343	4,564
6/1/2014	4,701	4,859	4,985	5,104	5,098	5,012	4,881	4,735	4,645	4,492	3,831	3,584
6/2/2014	3,280	3,210	3,119	3,130	3,342	3,592	4,260	4,469	4,748	4,864	4,963	5,053
6/2/2014	5,083	5,068	5,072	5,027	4,983	4,901	4,870	4,781	4,699	4,507	4,057	3,612
6/3/2014	3,381	3,183	3,121	3,163	3,348	3,593	4,219	4,393	4,547	4,981	5,166	5,303
6/3/2014	5,361	5,497	5,550	5,536	5,515	5,435	5,368	5,259	5,064	4,841	4,349	3,797
6/4/2014	3,582	3,218	3,168	3,177	3,362	3,539	3,897	4,208	4,309	4,575	4,619	4,718
6/4/2014	4,853	4,892	5,004	4,971	5,007	4,834	4,684	4,643	4,581	4,294	3,723	3,417
6/5/2014	3,190	2,974	2,901	2,904	3,023	3,306	3,761	3,963	4,205	4,489	4,544	4,671
6/5/2014	4,748	4,870	4,911	4,910	4,920	4,881	4,766	4,635	4,591	4,267	3,694	3,342
6/6/2014	3,182	2,921	2,909	2,909	2,988	3,139	3,494	3,672	4,039	4,562	4,680	4,722
6/6/2014	4,885	4,945	4,994	5,061	5,055	4,985	4,891	4,370	4,275	4,063	3,636	3,337
6/7/2014	3,168	2,909	2,784	2,771	2,798	2,832	2,979	3,222	3,785	4,169	4,332	4,438
6/7/2014	4,578	4,622	4,701	4,750	4,697	4,641	4,517	4,450	4,409	3,806	3,514	3,356
6/8/2014	3,015	2,859	2,739	2,708	2,705	2,722	2,840	2,928	3,091	3,248	3,723	3,784
6/8/2014	3,806	3,948	4,136	4,201	4,211	4,184	4,146	4,119	4,216	3,757	3,440	3,257
6/9/2014	3,087	2,836	2,774	2,801	2,959	3,251	3,484	3,699	4,003	4,427	4,627	4,700
6/9/2014	4,761	4,763	4,835	4,823	4,820	4,815	4,656	4,631	4,597	4,060	3,688	3,440
6/10/2014	3,172	2,927	2,929	2,980	3,093	3,270	3,558	3,725	3,812	4,406	4,474	4,585
6/10/2014	4,647	4,656	4,679	4,622	4,606	4,597	4,540	4,551	4,562	3,998	3,733	3,449
6/11/2014	3,260	3,025	3,018	3,017	3,067	3,240	3,510	3,888	4,165	4,433	4,546	4,631
6/11/2014	4,721	4,749	4,793	4,813	4,791	4,754	4,704	4,577	4,553	4,384	3,745	3,474
6/12/2014	3,291	3,012	2,985	2,914	3,053	3,315	3,536	3,934	4,228	4,587	4,614	4,749
6/12/2014	4,873	4,914	4,987	5,016	5,054	5,021	4,938	4,814	4,805	4,231	3,904	3,604
6/13/2014	3,406	3,117	3,042	2,982	3,053	3,230	3,365	3,616	3,789	4,077	4,514	4,586
6/13/2014	4,652	4,672	4,696	4,667	4,639	4,618	4,110	3,968	3,881	3,736	3,449	3,227
6/14/2014	2,997	2,765	2,720	2,697	2,716	2,746	2,878	3,019	3,218	3,476	3,771	3,757
6/14/2014	3,821	3,865	3,957	4,256	4,273	4,066	3,788	3,707	3,646	3,530	3,192	3,040
6/15/2014	2,859	2,657	2,520	2,547	2,582	2,558	2,691	2,839	3,036	3,186	3,729	3,933
6/15/2014	4,054	4,189	4,537	4,715	4,809	4,815	4,666	4,484	4,528	4,436	3,898	3,541
6/16/2014	3,401	3,145	3,094	3,113	3,221	3,475	4,131	4,407	4,634	4,961	5,213	5,373
6/16/2014	5,569	5,650	5,703	5,739	5,820	5,715	5,682	5,523	5,453	5,216	4,426	4,079
6/17/2014	3,904	3,576	3,478	3,363	3,450	3,602	4,277	4,497	4,885	5,269	5,474	5,584
6/17/2014	5,727	5,968	6,009	6,042	5,980	5,996	5,856	5,706	5,598	5,364	4,866	4,312
6/18/2014	3,995	3,710	3,614	3,489	3,604	3,733	4,357	4,647	4,898	5,340	5,522	5,691
6/18/2014	5,774	5,871	5,940	5,874	5,748	5,508	5,410	5,294	5,275	5,011	4,697	4,035
6/19/2014	3,761	3,505	3,394	3,371	3,492	3,667	4,130	4,430	4,825	5,261	5,478	5,639
6/19/2014	5,800	5,865	5,917	5,815	5,717	5,583	5,397	5,281	5,194	4,955	4,452	3,945
6/20/2014	3,709	3,467	3,322	3,282	3,430	3,616	3,876	4,314	4,549	5,042	5,243	5,420
6/20/2014	5,515	5,540	5,503	5,465	5,384	5,297	5,209	5,116	4,897	4,725	4,236	3,866
6/21/2014	3,487	3,360	3,089	3,024	2,982	3,145	3,184	3,519	3,855	4,235	4,740	4,966
6/21/2014	5,090	5,135	5,273	5,377	5,208	5,189	5,067	4,860	4,690	4,338	3,939	3,683
6/22/2014	3,424	3,155	3,085	3,047	2,999	2,964	3,088	3,348	3,668	4,002	4,334	4,740
6/22/2014	4,893	5,065	5,130	5,215	5,261	5,398	5,352	5,222	5,101	4,729	4,141	3,835
6/23/2014	3,587	3,293	3,223	3,253	3,380	3,646	3,914	4,491	4,937	5,391	5,612	5,834
6/23/2014	6,000	6,039	5,982	5,887	5,646	5,462	5,284	5,160	5,104	4,875	4,190	3,884
6/24/2014	3,680	3,392	3,274	3,313	3,448	3,690	3,913	4,317	4,482	4,977	5,126	5,320
6/24/2014	5,339	5,353	5,280	5,164	5,153	5,047	4,976	4,951	4,905	4,581	4,044	3,738
6/25/2014	3,615	3,485	3,201	3,176	3,422	3,574	3,742	3,986	4,417	4,954	5,144	5,308
6/25/2014	5,437	5,458	5,560	5,598	5,633	5,555	5,451	5,358	5,243	4,898	4,240	3,895
6/26/2014	3,698	3,426	3,200	3,238	3,426	3,606	3,833	4,110	4,560	4,889	5,216	5,429
6/26/2014	5,612	5,697	5,789	5,776	5,692	5,614	5,509	5,373	5,000	4,755	4,214	3,881
6/27/2014	3,613	3,502	3,254	3,164	3,308	3,448	3,698	4,158	4,655	5,088	5,315	5,501
6/27/2014	5,611	5,689	5,690	5,684	5,590	5,389	5,190	5,062	4,979	4,833	4,168	3,888
6/28/2014	3,558	3,432	3,091	3,055	3,057	3,090	3,269	3,509	3,750	4,429	4,576	4,701
6/28/2014	4,656	4,807	4,882	4,967	5,028	4,960	4,880	4,763	4,639	4,512	3,910	3,666
6/29/2014	3,472	3,166	3,012	2,968	2,927	2,934	3,003	3,307	3,497	3,863	4,375	4,570
6/29/2014	4,679	4,766	4,825	4,875	4,957	4,973	4,910	4,784	4,658	4,537	3,921	3,657
6/30/2014	3,339	3,019	3,025	3,016	3,126	3,324	3,736	4,052	4,261	4,604	4,661	4,727
6/30/2014	4,779	4,850	5,077	5,207	5,399	5,391	5,326	5,178	5,169	4,923	4,593	4,034

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
7/1/2014	3,760	3,489	3,261	3,267	3,396	3,597	4,135	4,419	4,692	4,946	5,142	5,266
7/1/2014	5,452	5,596	5,633	5,714	5,661	5,564	5,392	5,173	4,997	4,744	4,404	3,733
7/2/2014	3,461	3,376	3,269	3,151	3,305	3,457	3,570	4,037	4,465	4,627	4,827	4,929
7/2/2014	5,077	5,106	5,066	4,972	4,972	4,955	4,792	4,602	4,516	4,328	3,590	3,326
7/3/2014	3,135	2,946	2,866	2,874	3,042	3,201	3,324	3,523	3,836	4,161	4,224	4,252
7/3/2014	4,288	4,324	4,382	4,363	4,300	4,192	4,154	3,796	3,555	3,406	3,115	2,896
7/4/2014	2,726	2,548	2,453	2,422	2,421	2,380	2,427	2,645	2,807	2,959	3,059	3,348
7/4/2014	3,608	3,639	3,759	3,870	3,917	3,885	3,758	3,369	3,231	2,955	2,862	2,713
7/5/2014	2,569	2,407	2,333	2,332	2,338	2,333	2,465	2,639	2,835	3,167	3,502	3,624
7/5/2014	3,780	3,885	4,032	4,128	4,162	4,147	4,021	3,605	3,495	3,227	3,020	2,832
7/6/2014	2,697	2,521	2,478	2,442	2,452	2,449	2,488	2,719	2,883	3,097	3,532	3,961
7/6/2014	4,117	4,262	4,395	4,508	4,629	4,703	4,633	4,607	4,553	4,401	3,705	3,458
7/7/2014	3,309	3,211	3,085	3,130	3,330	3,501	3,888	4,330	4,538	4,689	4,845	5,009
7/7/2014	5,014	5,127	5,226	5,133	5,110	4,987	4,854	4,764	4,646	4,503	3,923	3,658
7/8/2014	3,364	3,266	3,258	3,189	3,357	3,622	3,854	4,384	4,552	4,692	4,901	5,029
7/8/2014	5,084	5,128	5,191	5,188	5,255	5,194	5,102	4,965	4,831	4,580	3,909	3,573
7/9/2014	3,322	3,184	3,014	3,049	3,222	3,349	3,441	3,851	4,108	4,533	4,720	4,860
7/9/2014	4,992	5,035	5,028	5,056	5,123	5,107	4,985	4,812	4,765	4,317	3,812	3,449
7/10/2014	3,274	3,165	3,028	3,013	3,194	3,303	3,491	3,825	4,236	4,439	4,568	4,690
7/10/2014	4,869	5,007	5,085	5,070	5,116	5,049	4,935	4,814	4,691	4,492	3,739	3,414
7/11/2014	3,216	3,047	2,959	2,912	3,151	3,257	3,361	3,730	4,192	4,474	4,666	4,810
7/11/2014	4,917	5,003	4,994	5,095	5,140	5,036	5,030	4,867	4,768	4,538	3,848	3,564
7/12/2014	3,340	3,210	3,068	3,023	3,005	3,070	3,228	3,363	3,843	4,266	4,427	4,523
7/12/2014	4,533	4,558	4,603	4,702	4,717	4,739	4,656	4,613	4,563	4,268	3,854	3,554
7/13/2014	3,362	3,228	3,127	3,083	3,159	3,132	3,303	3,516	3,787	4,219	4,634	4,848
7/13/2014	4,975	5,064	5,160	5,188	5,253	5,160	5,046	4,987	4,874	4,668	3,990	3,660
7/14/2014	3,464	3,327	3,238	3,207	3,441	3,630	3,988	4,339	4,595	4,826	4,980	5,219
7/14/2014	5,338	5,422	5,513	5,362	5,138	4,962	4,783	4,648	4,522	4,384	3,686	3,398
7/15/2014	3,227	3,136	3,037	3,023	3,126	3,201	3,572	3,762	3,968	4,295	4,346	4,454
7/15/2014	4,470	4,512	4,405	4,384	4,440	4,275	4,182	4,084	4,109	3,696	3,338	3,070
7/16/2014	2,705	2,698	2,610	2,603	2,785	2,938	3,081	3,205	3,545	3,858	3,894	3,879
7/16/2014	4,042	4,037	3,998	4,001	4,029	4,013	3,746	3,680	3,660	3,382	3,084	2,873
7/17/2014	2,705	2,616	2,575	2,527	2,728	2,841	2,937	3,125	3,614	3,763	3,829	3,925
7/17/2014	3,996	4,039	4,161	4,191	4,185	4,138	4,042	3,926	3,891	3,785	3,222	3,001
7/18/2014	2,884	2,609	2,649	2,669	2,692	2,954	3,067	3,364	3,524	3,696	3,978	4,094
7/18/2014	4,141	4,172	4,143	4,178	4,135	4,040	3,914	3,631	3,627	3,488	3,071	2,813
7/19/2014	2,560	2,476	2,543	2,535	2,576	2,635	2,773	2,894	3,064	3,361	3,644	3,710
7/19/2014	3,709	3,783	3,858	3,883	3,885	3,907	3,811	3,625	3,636	3,323	3,060	2,835
7/20/2014	2,662	2,589	2,523	2,472	2,463	2,505	2,576	2,726	2,988	3,183	3,708	3,875
7/20/2014	3,988	4,117	4,232	4,302	4,395	4,429	4,353	4,274	4,145	3,971	3,320	3,145
7/21/2014	2,923	2,857	2,679	2,731	2,907	3,143	3,418	3,853	4,301	4,635	4,897	5,095
7/21/2014	5,231	5,320	5,433	5,484	5,494	5,503	5,404	5,257	5,121	4,832	4,243	3,633
7/22/2014	3,247	3,146	3,064	2,957	3,112	3,326	3,830	4,024	4,363	4,943	5,107	5,391
7/22/2014	5,576	5,651	5,825	5,893	5,843	5,807	5,708	5,503	5,429	5,127	4,488	3,778
7/23/2014	3,628	3,433	3,366	3,313	3,392	3,595	3,808	3,917	4,204	4,266	4,597	4,662
7/23/2014	4,728	4,897	4,921	4,949	4,940	4,771	4,731	4,287	4,261	4,105	3,453	3,138
7/24/2014	2,969	2,878	2,727	2,797	3,010	3,140	3,320	3,454	3,557	4,109	4,242	4,330
7/24/2014	4,722	4,752	4,766	4,784	4,720	4,674	4,275	4,149	3,879	3,531	3,174	2,996
7/25/2014	2,837	2,740	2,618	2,710	2,861	3,061	3,165	3,492	3,620	3,977	4,099	4,186
7/25/2014	4,307	4,343	4,281	4,218	4,135	4,125	4,063	4,017	3,823	3,512	3,230	3,072
7/26/2014	2,910	2,765	2,726	2,714	2,718	2,842	2,870	3,058	3,428	3,758	4,017	4,269
7/26/2014	4,360	4,498	4,560	4,606	4,603	4,541	4,412	4,391	4,302	4,030	3,610	3,232
7/27/2014	3,064	2,947	2,824	2,749	2,761	2,807	2,860	3,069	3,235	3,529	3,901	4,013
7/27/2014	4,180	4,345	4,510	4,631	4,707	4,654	4,521	4,298	4,216	4,014	3,499	3,077
7/28/2014	2,893	2,782	2,690	2,710	2,888	3,185	3,462	3,591	3,925	4,063	4,111	4,191
7/28/2014	4,248	4,284	4,240	4,262	4,250	4,191	4,083	3,890	3,839	3,685	3,084	2,901
7/29/2014	2,911	2,818	2,812	2,795	2,909	3,153	3,262	3,444	3,717	4,006	4,174	4,306
7/29/2014	4,425	4,459	4,498	4,518	4,500	4,491	4,440	4,315	4,312	3,847	3,432	3,205
7/30/2014	2,995	2,909	2,855	2,857	2,865	3,175	3,255	3,375	3,567	3,906	4,262	4,434
7/30/2014	4,554	4,637	4,658	4,680	4,749	4,717	4,673	4,547	4,255	3,881	3,547	3,353
7/31/2014	3,127	3,010	2,983	2,929	3,034	3,368	3,488	3,658	4,006	4,133	4,607	4,802
7/31/2014	4,959	5,012	5,127	5,168	5,151	5,122	4,920	4,600	4,500	4,241	3,722	3,439

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
8/1/2014	3,200	2,954	2,883	2,873	3,013	3,289	3,397	3,802	4,042	4,560	4,759	4,905
8/1/2014	4,956	5,068	5,071	5,059	5,024	4,872	4,734	4,547	4,485	4,068	3,751	3,356
8/2/2014	3,172	2,990	2,889	2,878	2,889	2,969	2,918	3,137	3,522	3,705	4,169	4,370
8/2/2014	4,494	4,583	4,716	4,804	4,746	4,760	4,644	4,485	4,392	4,240	3,533	3,275
8/3/2014	3,065	2,885	2,810	2,725	2,721	2,760	2,798	3,057	3,420	3,656	4,094	4,369
8/3/2014	4,561	4,685	4,772	4,806	4,870	4,951	4,866	4,647	4,610	4,368	3,800	3,342
8/4/2014	3,135	2,989	2,962	2,921	3,121	3,389	3,578	3,972	4,457	4,677	4,901	5,118
8/4/2014	5,282	5,369	5,442	5,420	5,377	5,280	5,246	5,114	4,983	4,645	4,260	3,638
8/5/2014	3,387	3,074	3,078	3,117	3,338	3,576	3,772	3,922	4,376	4,578	4,750	4,840
8/5/2014	4,944	5,005	5,086	5,126	5,161	5,101	4,976	4,919	4,845	4,547	4,201	3,659
8/6/2014	3,403	3,300	3,241	3,222	3,325	3,566	3,881	4,020	4,468	4,686	4,714	4,863
8/6/2014	5,030	5,107	5,170	5,122	5,128	5,113	5,026	4,909	4,847	4,568	3,998	3,567
8/7/2014	3,378	3,259	3,164	3,168	3,300	3,484	3,684	3,833	4,003	4,396	4,511	4,592
8/7/2014	4,736	4,776	4,802	4,804	4,786	4,685	4,640	4,618	4,595	4,315	3,781	3,354
8/8/2014	3,268	3,124	2,975	3,004	3,218	3,491	3,791	3,945	4,284	4,385	4,413	4,548
8/8/2014	4,641	4,680	4,688	4,689	4,595	4,554	4,482	4,401	4,406	3,993	3,550	3,272
8/9/2014	3,139	2,924	2,803	2,850	2,858	2,882	3,013	3,177	3,550	3,755	4,132	4,243
8/9/2014	4,338	4,427	4,455	4,522	4,550	4,574	4,510	4,438	4,447	4,093	3,612	3,322
8/10/2014	3,136	3,078	2,909	2,846	2,825	2,879	2,952	3,203	3,538	3,698	4,135	4,390
8/10/2014	4,566	4,602	4,733	4,780	4,809	4,781	4,750	4,714	4,688	4,377	3,737	3,355
8/11/2014	3,201	3,115	3,056	3,139	3,238	3,574	3,881	4,082	4,240	4,555	4,733	4,906
8/11/2014	4,989	5,040	4,991	5,178	5,217	5,198	5,098	4,997	4,882	4,608	4,040	3,568
8/12/2014	3,366	3,276	3,147	3,145	3,353	3,541	3,864	3,887	4,054	4,367	4,454	4,561
8/12/2014	4,584	4,563	4,586	4,516	4,504	4,493	4,396	4,328	4,306	4,026	3,382	3,177
8/13/2014	3,038	2,900	2,880	2,898	3,061	3,392	3,424	3,679	4,060	4,230	4,340	4,423
8/13/2014	4,556	4,590	4,683	4,794	4,878	4,937	4,868	4,741	4,673	4,368	3,803	3,372
8/14/2014	3,163	3,085	3,027	3,028	3,154	3,552	3,667	3,877	4,261	4,496	4,706	4,870
8/14/2014	4,946	5,076	5,092	5,049	5,066	5,016	4,842	4,687	4,536	4,147	3,437	3,160
8/15/2014	2,979	2,919	2,892	2,875	2,961	3,356	3,474	3,535	4,001	4,105	4,265	4,379
8/15/2014	4,469	4,545	4,634	4,605	4,569	4,489	4,292	4,130	4,081	3,857	3,295	3,106
8/16/2014	2,937	2,908	2,760	2,742	2,780	2,823	2,995	3,168	3,651	3,795	3,854	4,016
8/16/2014	4,104	4,159	4,167	4,245	4,218	4,193	4,171	4,138	4,190	3,959	3,452	3,131
8/17/2014	3,009	2,860	2,797	2,705	2,783	2,846	2,892	3,091	3,405	3,749	3,848	3,941
8/17/2014	4,084	4,247	4,318	4,399	4,472	4,426	4,454	4,431	4,423	4,082	3,603	3,307
8/18/2014	3,195	3,128	3,012	3,008	3,253	3,608	3,946	4,035	4,468	4,646	4,833	5,023
8/18/2014	5,163	5,257	5,356	5,409	5,433	5,407	5,295	5,229	5,087	4,698	4,081	3,605
8/19/2014	3,460	3,316	3,233	3,178	3,352	3,848	4,018	4,369	4,560	4,846	5,146	5,311
8/19/2014	5,484	5,523	5,612	5,632	5,480	5,416	5,381	5,249	5,141	4,719	4,145	3,841
8/20/2014	3,661	3,388	3,282	3,263	3,408	3,840	3,898	4,234	4,467	4,739	4,981	5,184
8/20/2014	5,287	5,249	5,217	5,180	5,124	5,137	5,160	5,060	4,977	4,577	3,993	3,789
8/21/2014	3,417	3,317	3,259	3,249	3,418	3,931	4,287	4,356	4,587	4,802	4,913	5,045
8/21/2014	5,210	5,358	5,591	5,660	5,687	5,701	5,597	5,515	5,437	4,944	4,590	4,066
8/22/2014	3,639	3,575	3,496	3,514	3,628	4,036	4,278	4,577	4,672	4,840	4,979	5,139
8/22/2014	5,308	5,415	5,453	5,528	5,545	5,478	5,318	5,230	5,069	4,750	4,375	3,915
8/23/2014	3,625	3,363	3,200	3,166	3,212	3,372	3,421	3,787	4,325	4,626	4,892	5,067
8/23/2014	5,267	5,317	5,385	5,367	5,188	4,951	4,783	4,678	4,542	4,323	4,043	3,650
8/24/2014	3,335	3,221	3,048	2,989	2,935	3,049	3,092	3,426	3,912	4,176	4,443	4,705
8/24/2014	4,915	5,079	5,223	5,279	5,372	5,389	5,297	5,220	5,062	4,723	4,420	3,933
8/25/2014	3,632	3,502	3,417	3,362	3,527	4,031	4,214	4,619	4,940	5,242	5,504	5,724
8/25/2014	5,888	6,038	6,096	6,111	6,096	5,974	5,770	5,666	5,440	4,995	4,474	3,973
8/26/2014	3,643	3,529	3,400	3,423	3,548	4,034	4,194	4,531	4,733	5,106	5,308	5,546
8/26/2014	5,812	5,965	6,006	5,877	5,703	5,577	5,404	5,346	5,125	4,833	4,413	3,850
8/27/2014	3,557	3,443	3,315	3,322	3,445	3,906	4,066	4,411	4,672	4,974	5,216	5,454
8/27/2014	5,628	5,758	5,837	5,852	5,849	5,755	5,639	5,531	5,393	4,920	4,533	3,961
8/28/2014	3,577	3,369	3,220	3,240	3,468	3,926	4,068	4,322	4,502	4,747	4,973	5,134
8/28/2014	5,363	5,515	5,545	5,682	5,661	5,627	5,446	5,371	5,225	4,766	4,145	3,896
8/29/2014	3,508	3,344	3,260	3,220	3,351	3,801	3,982	4,318	4,539	4,711	4,897	5,083
8/29/2014	5,242	5,376	5,487	5,619	5,558	5,417	5,267	5,135	4,995	4,742	4,112	3,736
8/30/2014	3,362	3,202	3,128	2,985	3,017	3,126	3,247	3,520	3,993	4,222	4,376	4,487
8/30/2014	4,545	4,663	4,688	4,740	4,722	4,589	4,470	4,454	4,397	4,156	3,658	3,414
8/31/2014	3,135	2,956	2,904	2,857	2,853	2,915	2,996	3,225	3,562	3,808	3,967	4,134
8/31/2014	4,080	4,564	4,664	4,791	4,818	4,838	4,699	4,636	4,490	4,327	3,743	3,319

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
9/1/2014	3,167	3,068	3,040	2,992	3,037	3,125	3,127	3,297	3,934	4,267	4,546	4,695
9/1/2014	4,821	4,903	4,902	4,990	4,989	4,988	4,889	4,880	4,787	4,452	3,975	3,658
9/2/2014	3,301	3,278	3,234	3,224	3,357	3,861	4,158	4,475	4,592	4,716	4,822	4,897
9/2/2014	4,946	4,966	5,043	5,125	5,160	5,138	4,966	4,930	4,762	4,442	3,880	3,533
9/3/2014	3,238	3,164	3,055	3,037	3,269	3,923	4,024	4,124	4,379	4,664	4,850	5,034
9/3/2014	5,203	5,311	5,378	5,391	5,408	5,329	5,265	5,172	4,986	4,619	4,017	3,694
9/4/2014	3,371	3,244	3,054	3,070	3,340	3,996	4,171	4,348	4,573	4,962	5,179	5,364
9/4/2014	5,561	5,685	5,814	5,823	5,748	5,681	5,638	5,451	5,330	4,998	4,348	4,037
9/5/2014	3,659	3,524	3,422	3,412	3,598	4,142	4,569	4,751	4,963	5,197	5,461	5,728
9/5/2014	5,871	6,049	6,110	6,130	5,966	5,843	5,685	5,640	5,368	5,038	4,307	3,918
9/6/2014	3,545	3,381	3,286	3,230	3,186	3,293	3,373	3,660	3,951	4,044	4,104	4,157
9/6/2014	4,154	4,173	4,149	4,120	4,152	4,102	3,964	4,025	3,934	3,721	3,213	2,933
9/7/2014	2,720	2,569	2,543	2,471	2,527	2,567	2,587	2,798	3,322	3,435	3,623	3,757
9/7/2014	3,908	4,013	4,097	4,201	4,270	4,247	4,148	4,115	4,044	3,825	3,166	2,973
9/8/2014	2,800	2,770	2,748	2,742	2,791	3,275	3,614	3,773	4,046	4,291	4,342	4,469
9/8/2014	4,563	4,624	4,689	4,743	4,790	4,768	4,638	4,626	4,438	4,093	3,373	3,099
9/9/2014	2,903	2,793	2,743	2,777	2,891	3,531	3,773	4,074	4,276	4,432	4,444	4,548
9/9/2014	4,717	4,764	4,837	4,856	4,805	4,790	4,727	4,785	4,610	4,376	3,796	3,577
9/10/2014	3,132	3,004	2,994	2,966	3,200	3,669	3,902	4,219	4,420	4,481	4,527	4,609
9/10/2014	4,714	4,759	4,842	4,916	4,950	4,913	4,891	4,979	4,793	4,528	3,973	3,646
9/11/2014	3,291	3,037	2,957	2,963	3,135	3,539	3,767	4,079	4,175	4,232	4,229	4,221
9/11/2014	4,219	4,168	4,157	4,075	4,029	4,063	4,081	4,097	4,028	3,756	3,286	2,934
9/12/2014	2,831	2,793	2,772	2,803	2,935	3,434	3,643	3,933	4,028	4,091	4,120	4,124
9/12/2014	4,113	4,098	4,029	4,014	3,964	3,933	3,905	4,019	3,855	3,740	3,119	2,915
9/13/2014	2,811	2,752	2,619	2,633	2,761	2,834	3,095	3,184	3,547	3,666	3,763	3,719
9/13/2014	3,755	3,735	3,678	3,647	3,663	3,649	3,638	3,743	3,629	3,443	2,855	2,738
9/14/2014	2,554	2,459	2,485	2,475	2,478	2,619	2,672	2,791	3,289	3,341	3,483	3,578
9/14/2014	3,563	3,539	3,564	3,711	3,740	3,823	3,815	3,956	3,818	3,579	2,941	2,794
9/15/2014	2,647	2,593	2,581	2,601	2,791	3,445	3,696	3,986	4,063	4,142	4,224	4,153
9/15/2014	4,184	4,195	4,148	4,117	4,080	4,128	4,172	4,233	4,064	3,845	3,349	2,977
9/16/2014	2,917	2,784	2,750	2,778	2,968	3,533	3,974	4,066	4,115	4,178	4,179	4,196
9/16/2014	4,210	4,178	4,159	4,126	4,089	4,097	4,060	4,144	4,097	3,810	3,332	3,138
9/17/2014	2,825	2,828	2,708	2,705	2,919	3,408	3,840	3,890	3,927	4,009	4,025	4,043
9/17/2014	4,065	4,067	4,093	4,093	4,080	4,051	4,049	4,212	4,124	3,834	3,324	2,945
9/18/2014	2,718	2,697	2,741	2,699	2,915	3,443	3,902	4,018	4,000	4,108	4,178	4,253
9/18/2014	4,267	4,311	4,332	4,290	4,286	4,161	4,093	4,193	4,091	3,873	3,214	2,976
9/19/2014	2,748	2,716	2,701	2,682	2,936	3,459	3,908	3,990	4,083	4,127	4,110	4,128
9/19/2014	4,186	4,188	4,277	4,209	4,148	4,046	3,977	4,006	3,955	3,510	3,135	2,913
9/20/2014	2,807	2,756	2,636	2,610	2,663	2,833	3,310	3,392	3,476	3,632	3,749	3,811
9/20/2014	3,895	3,929	4,056	4,109	4,146	4,094	4,103	4,134	4,031	3,802	3,239	3,120
9/21/2014	3,144	2,878	2,780	2,783	2,725	2,915	3,192	3,217	3,599	3,746	3,943	3,987
9/21/2014	3,938	3,998	4,028	3,981	3,976	3,929	3,870	3,999	3,840	3,530	3,075	2,881
9/22/2014	2,667	2,603	2,575	2,633	2,821	3,603	3,848	3,936	3,980	4,101	4,079	4,177
9/22/2014	4,173	4,173	4,218	4,180	4,151	4,169	4,100	4,206	4,026	3,783	3,166	2,952
9/23/2014	2,866	2,676	2,715	2,750	2,935	3,646	3,848	3,900	4,033	4,097	4,101	4,107
9/23/2014	4,225	4,231	4,215	4,231	4,234	4,221	4,221	4,261	4,111	3,552	3,128	2,917
9/24/2014	2,764	2,709	2,697	2,781	2,974	3,672	3,817	3,871	3,933	3,996	4,035	4,087
9/24/2014	4,153	4,197	4,258	4,294	4,246	4,259	4,261	4,276	4,110	3,611	3,392	3,014
9/25/2014	2,815	2,656	2,646	2,669	2,864	3,596	3,856	3,936	3,997	4,175	4,166	4,245
9/25/2014	4,318	4,383	4,409	4,486	4,444	4,423	4,318	4,379	4,255	3,748	3,473	3,030
9/26/2014	2,827	2,765	2,744	2,703	2,930	3,645	3,847	3,952	4,075	4,194	4,291	4,377
9/26/2014	4,458	4,582	4,614	4,651	4,604	4,532	4,374	4,372	4,092	3,683	3,430	3,043
9/27/2014	2,860	2,824	2,733	2,685	2,717	2,841	3,079	3,340	3,589	3,688	3,802	3,888
9/27/2014	4,021	4,129	4,233	4,245	4,217	4,184	4,124	4,084	3,879	3,531	3,322	2,919
9/28/2014	2,742	2,605	2,520	2,532	2,546	2,663	2,755	3,006	3,455	3,635	3,781	3,972
9/28/2014	4,039	4,095	4,234	4,363	4,479	4,474	4,406	4,361	4,175	3,651	3,374	3,015
9/29/2014	2,812	2,766	2,665	2,713	2,877	3,684	3,889	3,948	4,108	4,278	4,367	4,476
9/29/2014	4,599	4,633	4,681	4,739	4,733	4,687	4,603	4,595	4,336	3,818	3,529	3,141
9/30/2014	2,924	2,847	2,843	2,822	3,089	3,723	3,951	4,061	4,135	4,184	4,282	4,336
9/30/2014	4,364	4,423	4,434	4,484	4,514	4,463	4,426	4,502	4,278	3,786	3,348	3,062

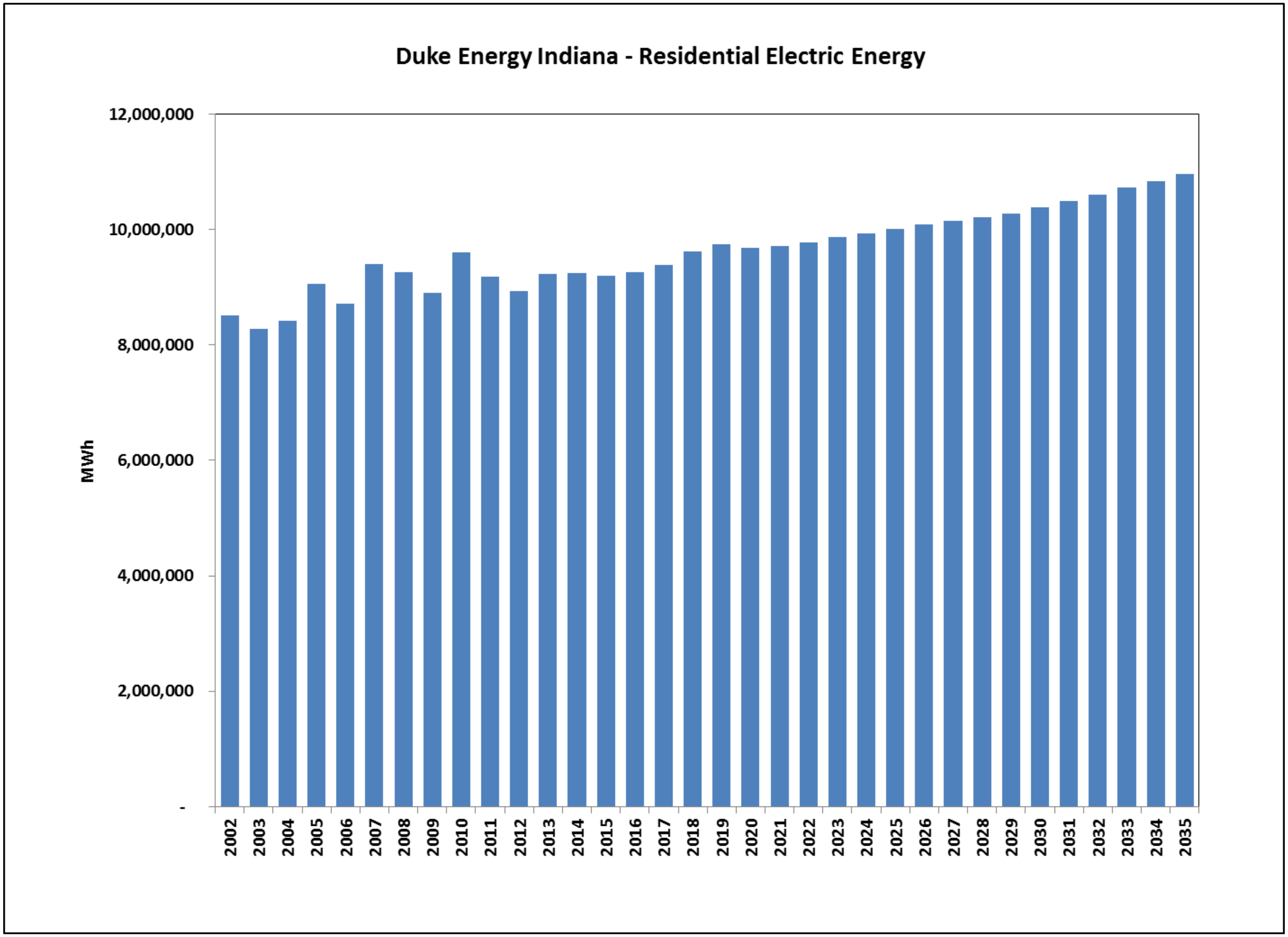
Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
10/1/2014	2,935	2,840	2,746	2,740	2,985	3,671	3,906	3,925	4,082	4,123	4,214	4,235
10/1/2014	4,382	4,466	4,506	4,547	4,497	4,440	4,504	4,482	4,268	3,828	3,389	3,116
10/2/2014	2,962	2,876	2,805	2,830	3,000	3,683	3,914	4,007	4,081	4,175	4,222	4,325
10/2/2014	4,432	4,523	4,670	4,647	4,597	4,596	4,697	4,721	4,583	4,251	3,752	3,312
10/3/2014	3,178	3,062	2,997	2,987	3,208	3,943	4,237	4,307	4,311	4,358	4,356	4,319
10/3/2014	4,272	4,244	4,113	4,092	4,026	3,948	3,953	3,975	3,766	3,376	3,020	2,859
10/4/2014	2,781	2,708	2,693	2,652	2,750	3,032	3,209	3,570	3,672	3,741	3,699	3,730
10/4/2014	3,751	3,713	3,640	3,608	3,624	3,640	3,749	3,788	3,695	3,431	3,215	2,898
10/5/2014	2,721	2,658	2,632	2,646	2,638	2,889	3,081	3,226	3,562	3,597	3,576	3,585
10/5/2014	3,482	3,468	3,459	3,487	3,581	3,607	3,773	3,788	3,723	3,328	3,143	2,799
10/6/2014	2,617	2,628	2,617	2,717	2,949	3,635	3,941	4,047	4,057	4,080	4,097	4,085
10/6/2014	4,071	4,051	3,989	3,943	3,898	3,966	3,988	4,093	3,982	3,587	3,344	2,970
10/7/2014	2,878	2,800	2,817	2,810	3,172	3,690	3,998	4,048	4,165	4,155	4,162	4,219
10/7/2014	4,212	4,131	4,085	4,057	4,048	4,010	4,153	4,190	4,018	3,845	3,320	3,118
10/8/2014	2,897	2,806	2,800	2,856	3,206	3,787	3,997	4,105	4,120	4,163	4,157	4,136
10/8/2014	4,167	4,186	4,142	4,109	4,034	4,034	4,111	4,140	4,017	3,771	3,313	3,064
10/9/2014	2,860	2,806	2,767	2,887	3,047	3,753	4,046	4,093	4,168	4,190	4,212	4,185
10/9/2014	4,163	4,166	4,122	4,050	4,049	4,080	4,222	4,212	4,080	3,857	3,389	3,041
10/10/2014	2,925	2,812	2,762	2,823	2,980	3,714	4,012	4,054	4,168	4,182	4,175	4,187
10/10/2014	4,164	4,145	4,091	4,021	4,022	4,003	4,083	4,099	3,997	3,624	3,423	3,065
10/11/2014	3,033	2,818	2,829	2,842	2,906	3,220	3,420	3,719	3,833	3,916	3,862	3,784
10/11/2014	3,721	3,687	3,674	3,647	3,606	3,662	3,821	3,837	3,738	3,285	3,169	3,009
10/12/2014	2,895	2,765	2,733	2,758	2,781	2,857	3,108	3,258	3,497	3,509	3,517	3,551
10/12/2014	3,557	3,473	3,457	3,466	3,531	3,602	3,816	3,811	3,716	3,551	3,189	2,993
10/13/2014	2,787	2,614	2,643	2,740	2,949	3,674	3,987	4,139	4,218	4,229	4,299	4,334
10/13/2014	4,399	4,345	4,302	4,281	4,264	4,268	4,382	4,351	4,244	3,930	3,479	3,057
10/14/2014	2,990	2,920	2,791	2,872	3,202	3,665	4,002	4,149	4,210	4,250	4,241	4,264
10/14/2014	4,277	4,222	4,223	4,148	4,110	4,104	4,159	4,228	4,094	3,637	3,390	2,985
10/15/2014	2,899	2,786	2,728	2,755	3,112	3,684	3,882	3,987	4,041	4,096	4,077	4,074
10/15/2014	4,067	4,075	4,111	4,054	4,115	4,072	4,235	4,231	4,105	3,667	3,415	3,079
10/16/2014	2,947	2,873	2,827	2,887	3,184	3,729	3,906	4,085	4,145	4,116	4,119	4,202
10/16/2014	4,189	4,196	4,147	4,043	4,070	4,080	4,213	4,207	4,069	3,681	3,440	3,063
10/17/2014	2,963	2,846	2,856	2,927	3,179	3,731	3,970	4,030	4,098	4,107	4,126	4,164
10/17/2014	4,105	4,071	3,980	3,966	3,953	3,991	4,079	4,022	3,933	3,526	3,279	2,912
10/18/2014	2,833	2,770	2,662	2,678	2,765	3,020	3,188	3,358	3,713	3,822	3,851	3,806
10/18/2014	3,789	3,792	3,743	3,759	3,797	3,773	3,862	3,881	3,721	3,380	3,163	2,951
10/19/2014	2,750	2,630	2,635	2,634	2,663	2,784	3,132	3,246	3,539	3,654	3,601	3,610
10/19/2014	3,505	3,415	3,409	3,417	3,493	3,586	3,855	3,867	3,731	3,349	3,161	2,856
10/20/2014	2,803	2,759	2,795	2,880	3,028	3,715	4,041	4,132	4,212	4,218	4,174	4,225
10/20/2014	4,208	4,221	4,167	4,108	3,980	4,016	4,131	4,143	4,011	3,546	3,192	3,035
10/21/2014	2,911	2,849	2,844	2,915	3,189	3,750	4,060	4,060	4,155	4,191	4,175	4,179
10/21/2014	4,114	4,104	4,081	4,062	4,030	4,096	4,228	4,247	4,065	3,942	3,431	3,145
10/22/2014	2,991	2,954	2,858	2,967	3,369	3,968	4,206	4,296	4,305	4,295	4,182	4,215
10/22/2014	4,189	4,161	4,078	4,095	4,072	4,053	4,188	4,183	4,052	3,902	3,489	3,184
10/23/2014	3,057	2,955	2,931	3,102	3,502	4,063	4,367	4,220	4,274	4,237	4,226	4,229
10/23/2014	4,184	4,136	4,051	4,032	4,023	4,090	4,224	4,191	4,068	3,652	3,403	3,113
10/24/2014	2,914	2,857	2,859	2,925	3,108	3,799	4,075	4,177	4,217	4,204	4,143	4,132
10/24/2014	4,056	4,005	3,976	3,958	3,974	3,951	4,028	4,035	3,942	3,522	3,267	2,955
10/25/2014	2,772	2,669	2,682	2,734	2,712	2,924	3,285	3,661	3,756	3,767	3,798	3,767
10/25/2014	3,746	3,713	3,732	3,752	3,738	3,685	3,789	3,787	3,675	3,258	3,043	2,620
10/26/2014	2,478	2,471	2,456	2,421	2,477	2,559	2,922	3,063	3,381	3,433	3,510	3,503
10/26/2014	3,494	3,464	3,451	3,495	3,572	3,600	3,763	3,793	3,627	3,241	3,001	2,648
10/27/2014	2,577	2,507	2,506	2,512	2,767	3,535	3,874	3,941	3,986	4,044	4,078	4,100
10/27/2014	4,147	4,153	4,123	4,071	4,055	4,077	4,178	4,110	3,967	3,693	3,202	2,855
10/28/2014	2,679	2,617	2,576	2,611	2,843	3,562	3,853	3,977	3,963	3,980	3,937	3,963
10/28/2014	3,966	3,930	3,881	3,813	3,745	3,838	4,010	3,968	3,826	3,367	3,103	2,753
10/29/2014	2,610	2,563	2,563	2,610	2,786	3,562	3,898	3,968	4,012	4,059	4,034	4,021
10/29/2014	3,994	3,981	3,943	3,898	3,949	4,019	4,125	4,131	4,009	3,597	3,228	2,968
10/30/2014	2,756	2,765	2,773	2,839	3,055	3,887	4,197	4,277	4,232	4,180	4,094	4,084
10/30/2014	4,036	3,995	3,924	3,861	3,881	3,967	4,094	4,056	3,954	3,580	3,309	2,985
10/31/2014	2,781	2,740	2,687	2,780	3,031	3,774	4,071	4,134	4,162	4,197	4,174	4,184
10/31/2014	4,234	4,194	4,194	4,178	4,197	4,179	4,276	4,280	4,183	3,848	3,526	3,335

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
11/1/2014	3,145	3,101	3,082	3,096	3,223	3,544	3,950	4,072	4,118	4,172	4,093	4,004
11/1/2014	3,866	3,801	3,729	3,660	3,693	3,842	4,014	4,050	3,984	3,656	3,473	3,166
11/2/2014	3,186	3,097	3,087	3,112	3,147	3,453	3,709	4,047	4,138	4,039	3,950	3,816
11/2/2014	3,869	3,755	3,716	3,635	3,773	3,797	4,021	4,114	4,076	3,930	3,351	3,198
11/3/2014	3,042	2,964	2,898	2,903	3,101	3,698	4,119	4,295	4,312	4,313	4,282	4,215
11/3/2014	4,234	4,194	4,150	4,049	4,052	4,130	4,285	4,233	4,149	4,010	3,583	3,241
11/4/2014	3,026	2,939	2,889	2,919	2,958	3,548	3,809	4,004	4,029	4,038	4,019	4,039
11/4/2014	4,062	4,060	4,007	3,995	4,010	4,129	4,166	4,190	4,123	3,938	3,559	3,170
11/5/2014	3,211	3,077	3,010	3,004	3,218	3,773	4,075	4,275	4,287	4,332	4,336	4,222
11/5/2014	4,143	4,173	4,160	4,128	4,046	4,137	4,270	4,343	4,290	4,131	3,744	3,387
11/6/2014	3,089	2,991	2,999	2,938	3,160	3,683	4,089	4,257	4,254	4,273	4,367	4,336
11/6/2014	4,392	4,384	4,380	4,373	4,398	4,452	4,533	4,527	4,408	4,281	3,885	3,553
11/7/2014	3,629	3,469	3,435	3,407	3,507	4,039	4,357	4,472	4,435	4,474	4,386	4,312
11/7/2014	4,250	4,161	4,136	4,025	4,030	4,122	4,264	4,242	4,191	4,154	3,809	3,618
11/8/2014	3,377	3,271	3,167	3,184	3,267	3,499	3,643	3,919	4,015	4,033	4,029	4,000
11/8/2014	3,757	3,696	3,723	3,693	3,714	4,056	4,104	4,028	4,021	3,705	3,602	3,269
11/9/2014	3,255	3,218	3,208	3,192	3,238	3,285	3,565	3,663	3,676	3,902	3,882	3,784
11/9/2014	3,539	3,488	3,465	3,460	3,507	3,867	4,043	4,040	3,970	3,684	3,534	3,246
11/10/2014	3,142	3,064	2,983	2,916	3,143	3,530	4,159	4,354	4,326	4,277	4,217	4,198
11/10/2014	4,162	4,132	4,099	4,067	4,010	4,110	4,288	4,243	4,226	4,053	3,847	3,451
11/11/2014	3,221	3,074	2,945	2,999	3,124	3,331	3,978	4,141	4,065	4,148	4,160	4,157
11/11/2014	4,158	4,174	4,201	3,989	4,201	4,313	4,452	4,463	4,409	4,271	3,893	3,606
11/12/2014	3,457	3,380	3,164	3,207	3,344	3,704	4,386	4,482	4,465	4,490	4,466	4,433
11/12/2014	4,419	4,394	4,401	4,426	4,499	4,675	4,814	4,759	4,739	4,617	4,198	4,027
11/13/2014	3,738	3,675	3,665	3,617	3,725	4,310	4,639	4,844	4,866	4,841	4,834	4,830
11/13/2014	4,825	4,803	4,762	4,764	4,760	4,864	4,971	4,925	4,866	4,779	4,574	4,206
11/14/2014	3,960	3,929	3,947	3,941	4,023	4,397	4,915	5,086	5,002	4,899	4,785	4,715
11/14/2014	4,657	4,595	4,521	4,487	4,499	4,632	4,689	4,743	4,745	4,675	4,542	4,216
11/15/2014	3,972	3,929	3,966	3,937	3,966	4,191	4,554	4,659	4,680	4,656	4,564	4,473
11/15/2014	4,374	4,249	4,181	4,127	4,192	4,353	4,437	4,428	4,400	4,287	3,965	3,793
11/16/2014	3,517	3,483	3,397	3,331	3,357	3,395	3,940	4,048	4,136	4,235	4,196	4,213
11/16/2014	4,228	4,234	4,213	4,217	4,290	4,488	4,519	4,514	4,458	4,340	4,050	3,858
11/17/2014	3,520	3,461	3,489	3,453	3,576	4,252	4,628	4,819	4,894	4,901	4,814	4,812
11/17/2014	4,863	4,863	4,915	4,910	4,967	5,169	5,277	5,286	5,243	5,118	4,967	4,432
11/18/2014	4,528	4,472	4,478	4,486	4,585	4,731	5,294	5,388	5,271	5,174	5,093	5,008
11/18/2014	5,009	4,990	4,982	4,978	5,044	5,200	5,306	5,248	5,170	5,094	4,882	4,565
11/19/2014	4,429	4,409	4,424	4,459	4,505	4,888	5,179	5,307	5,198	5,091	5,053	4,955
11/19/2014	4,834	4,819	4,755	4,755	4,843	4,929	4,957	5,042	4,970	4,838	4,602	4,484
11/20/2014	4,208	4,165	4,137	4,149	4,200	4,450	4,982	5,139	5,087	4,963	4,913	4,835
11/20/2014	4,822	4,797	4,539	4,531	4,618	4,786	4,924	4,936	4,925	4,855	4,746	4,409
11/21/2014	4,286	4,211	4,182	4,224	4,312	4,514	5,090	5,303	5,253	5,122	5,005	4,873
11/21/2014	4,766	4,651	4,323	4,282	4,462	4,617	4,766	4,811	4,749	4,647	4,461	4,038
11/22/2014	3,734	3,666	3,587	3,548	3,546	3,602	3,949	4,259	4,282	4,364	4,356	4,297
11/22/2014	4,062	3,933	3,800	3,730	3,762	4,094	4,104	4,056	3,987	3,617	3,340	3,142
11/23/2014	3,072	2,942	2,898	2,916	2,920	3,001	3,233	3,350	3,559	3,700	3,728	3,752
11/23/2014	3,547	3,557	3,591	3,623	3,711	4,129	4,144	4,090	3,992	3,880	3,310	3,128
11/24/2014	3,044	2,955	2,938	2,934	2,994	3,258	4,008	4,227	4,244	4,327	4,397	4,406
11/24/2014	4,523	4,547	4,552	4,530	4,558	4,707	4,704	4,688	4,605	4,412	3,913	3,696
11/25/2014	3,478	3,370	3,352	3,390	3,477	3,919	4,528	4,739	4,762	4,767	4,777	4,735
11/25/2014	4,736	4,699	4,646	4,607	4,594	4,754	4,867	4,809	4,796	4,663	4,246	3,931
11/26/2014	3,654	3,503	3,535	3,555	3,672	4,310	4,569	4,671	4,703	4,730	4,691	4,616
11/26/2014	4,488	4,445	4,345	4,394	4,379	4,582	4,676	4,662	4,597	4,488	4,142	3,670
11/27/2014	3,579	3,311	3,228	3,188	3,248	3,352	3,520	4,034	4,205	4,360	4,398	4,372
11/27/2014	4,133	3,925	3,515	3,473	3,612	4,122	4,190	4,182	4,197	4,175	3,844	3,508
11/28/2014	3,428	3,276	3,312	3,274	3,444	3,630	3,774	4,261	4,381	4,433	4,437	4,463
11/28/2014	4,301	4,180	3,752	3,790	4,167	4,342	4,436	4,320	4,250	4,179	3,721	3,386
11/29/2014	3,301	3,173	3,157	3,137	3,151	3,221	3,418	3,968	4,065	4,156	4,111	4,064
11/29/2014	3,951	3,875	3,505	3,500	3,667	3,983	3,967	3,902	3,883	3,556	3,264	2,945
11/30/2014	2,852	2,662	2,638	2,590	2,608	2,711	2,775	2,948	3,284	3,556	3,613	3,680
11/30/2014	3,699	3,328	3,296	3,246	3,547	3,920	4,002	4,013	3,967	3,702	3,318	3,018

Dt	Hr 01 & 13	Hr 02 & 14	Hr 03 & 15	Hr 04 & 16	Hr 05 & 17	Hr 06 & 18	Hr 07 & 19	Hr 08 & 20	Hr 09 & 21	Hr 10 & 22	Hr 11 & 23	Hr 12 & 24
12/1/2014	2,927	2,907	2,901	2,884	2,989	3,546	4,192	4,524	4,661	4,677	4,715	4,756
12/1/2014	4,792	4,779	4,682	4,641	4,580	4,852	5,031	5,030	5,017	4,900	4,289	4,123
12/2/2014	3,834	3,770	3,667	3,629	3,691	4,168	4,702	5,017	4,993	4,974	4,999	4,954
12/2/2014	4,931	4,868	4,830	4,820	4,845	5,008	5,020	4,993	4,939	4,784	4,396	3,961
12/3/2014	3,632	3,573	3,516	3,495	3,588	3,694	4,462	4,723	4,758	4,739	4,697	4,583
12/3/2014	4,514	4,430	4,179	4,172	4,350	4,566	4,723	4,737	4,695	4,636	4,323	3,836
12/4/2014	3,618	3,558	3,566	3,596	3,680	3,820	4,626	4,877	4,899	4,838	4,898	4,813
12/4/2014	4,762	4,595	4,611	4,605	4,730	4,878	4,942	4,917	4,859	4,772	4,152	3,923
12/5/2014	3,648	3,491	3,497	3,457	3,526	3,786	4,551	4,693	4,670	4,741	4,780	4,640
12/5/2014	4,628	4,578	4,388	4,311	4,468	4,666	4,553	4,546	4,480	4,391	3,878	3,505
12/6/2014	3,353	3,208	3,151	3,052	3,177	3,189	3,367	3,603	4,255	4,379	4,432	4,445
12/6/2014	4,249	4,009	3,968	3,959	4,345	4,450	4,481	4,454	4,249	3,770	3,667	3,475
12/7/2014	3,358	3,319	3,318	3,291	3,323	3,369	3,572	3,783	3,874	4,181	4,126	4,091
12/7/2014	3,840	3,844	3,773	3,782	4,030	4,489	4,632	4,602	4,585	4,436	3,857	3,666
12/8/2014	3,412	3,206	3,236	3,301	3,434	3,704	4,467	4,793	4,810	4,834	4,752	4,645
12/8/2014	4,641	4,650	4,581	4,445	4,561	4,751	4,828	4,768	4,651	4,572	4,140	3,683
12/9/2014	3,390	3,272	3,332	3,323	3,344	3,735	4,492	4,718	4,767	4,778	4,818	4,786
12/9/2014	4,636	4,583	4,360	4,290	4,562	4,806	4,901	4,815	4,815	4,528	4,046	3,745
12/10/2014	3,581	3,437	3,424	3,352	3,509	3,802	4,490	4,685	4,654	4,645	4,638	4,590
12/10/2014	4,460	4,440	4,394	4,413	4,625	4,792	4,920	4,876	4,862	4,775	4,208	3,914
12/11/2014	3,696	3,539	3,454	3,488	3,586	3,937	4,645	4,915	4,868	4,765	4,746	4,528
12/11/2014	4,497	4,409	4,156	4,116	4,338	4,697	4,898	4,905	4,899	4,680	4,218	3,943
12/12/2014	3,801	3,697	3,660	3,661	3,815	4,033	4,835	5,132	4,985	4,932	4,691	4,587
12/12/2014	4,478	4,476	4,236	4,155	4,419	4,742	4,767	4,727	4,665	4,407	4,011	3,721
12/13/2014	3,540	3,384	3,329	3,323	3,284	3,347	3,539	4,019	4,182	4,220	4,219	4,152
12/13/2014	3,801	3,752	3,628	3,582	3,656	4,173	4,186	4,063	3,997	3,695	3,434	3,201
12/14/2014	2,982	2,869	2,878	2,856	2,849	2,936	3,003	3,186	3,400	3,678	3,706	3,671
12/14/2014	3,409	3,347	3,284	3,324	3,644	4,141	4,292	4,256	4,072	3,855	3,376	3,148
12/15/2014	3,021	2,959	2,913	2,940	3,097	3,306	3,984	4,420	4,506	4,505	4,380	4,393
12/15/2014	4,367	4,350	4,095	4,119	4,349	4,606	4,735	4,629	4,609	4,311	3,694	3,453
12/16/2014	3,194	3,058	3,031	3,051	3,133	3,345	4,143	4,440	4,437	4,496	4,415	4,368
12/16/2014	4,377	4,428	4,175	4,092	4,488	4,770	4,888	4,881	4,801	4,566	4,053	3,823
12/17/2014	3,608	3,504	3,470	3,471	3,559	3,799	4,607	4,807	4,816	4,836	4,838	4,778
12/17/2014	4,667	4,659	4,437	4,494	4,717	5,055	5,107	5,124	5,081	4,936	4,396	4,054
12/18/2014	3,840	3,742	3,703	3,680	3,788	4,015	4,739	4,995	4,950	4,968	4,961	4,822
12/18/2014	4,802	4,746	4,456	4,460	4,696	4,972	5,086	5,037	5,021	4,911	4,309	4,033
12/19/2014	3,887	3,792	3,746	3,783	3,874	4,195	4,871	5,088	5,018	5,019	4,966	4,852
12/19/2014	4,850	4,667	4,387	4,238	4,568	4,885	4,869	4,814	4,774	4,608	4,222	3,868
12/20/2014	3,631	3,531	3,503	3,479	3,507	3,606	3,842	4,379	4,589	4,615	4,630	4,618
12/20/2014	4,171	4,077	4,085	4,010	4,029	4,545	4,615	4,577	4,550	4,181	3,954	3,762
12/21/2014	3,640	3,540	3,498	3,511	3,461	3,562	3,745	4,077	4,397	4,395	4,294	3,963
12/21/2014	3,852	3,654	3,600	3,643	3,764	4,379	4,559	4,557	4,364	4,325	3,879	3,743
12/22/2014	3,523	3,505	3,466	3,472	3,502	3,758	4,461	4,630	4,711	4,653	4,771	4,681
12/22/2014	4,499	4,478	4,159	4,101	4,303	4,589	4,655	4,572	4,536	4,420	3,848	3,569
12/23/2014	3,271	3,173	3,133	3,069	2,999	3,145	3,858	4,092	4,192	4,082	4,064	4,058
12/23/2014	3,976	3,775	3,714	3,651	3,860	4,125	4,182	4,181	4,093	3,820	3,344	3,084
12/24/2014	2,782	2,722	2,677	2,619	2,668	2,676	2,849	2,982	3,298	3,449	3,454	3,453
12/24/2014	3,222	3,212	3,163	3,143	3,150	3,512	3,554	3,440	3,398	3,112	2,969	2,862
12/25/2014	2,752	2,683	2,626	2,614	2,654	2,679	2,781	2,969	3,055	3,336	3,364	3,171
12/25/2014	3,025	2,913	2,823	2,735	2,733	3,057	3,299	3,317	3,137	2,991	2,845	2,744
12/26/2014	2,663	2,611	2,611	2,634	2,679	2,815	3,025	3,203	3,435	3,423	3,378	3,416
12/26/2014	3,163	3,055	3,038	2,986	3,010	3,503	3,654	3,605	3,558	3,156	3,031	2,909
12/27/2014	2,696	2,628	2,595	2,567	2,632	2,632	2,730	3,131	3,186	3,361	3,463	3,477
12/27/2014	3,213	3,144	3,032	3,010	3,097	3,499	3,526	3,521	3,518	3,278	3,031	2,977
12/28/2014	2,805	2,790	2,826	2,712	2,773	2,899	3,020	3,132	3,430	3,595	3,557	3,673
12/28/2014	3,514	3,456	3,423	3,451	3,519	4,163	4,154	4,128	4,030	3,876	3,575	3,463
12/29/2014	3,371	3,276	3,264	3,264	3,347	3,525	4,128	4,449	4,502	4,559	4,579	4,416
12/29/2014	4,198	4,077	4,048	3,942	4,027	4,418	4,624	4,584	4,603	4,495	3,879	3,691
12/30/2014	3,309	3,287	3,220	3,230	3,299	3,488	4,003	4,360	4,451	4,441	4,470	4,409
12/30/2014	4,184	4,169	4,105	4,092	4,115	4,563	4,701	4,758	4,695	4,429	4,124	3,944
12/31/2014	3,621	3,575	3,576	3,544	3,625	3,727	3,939	4,273	4,362	4,175	4,123	4,062
12/31/2014	3,949	3,863	3,748	3,709	3,693	4,262	4,424	4,336	4,054	3,837	3,733	3,649

3. Duke Energy Indiana Long-Term Electric Forecast

The following pages pertain to customer demand for electric energy within the Duke Energy Indiana service territory.


Duke Energy Indiana - Residential Electric Energy
MWh
12,000,000
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8,000,000
6,000,000
4,000,000
2,000,000
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2002
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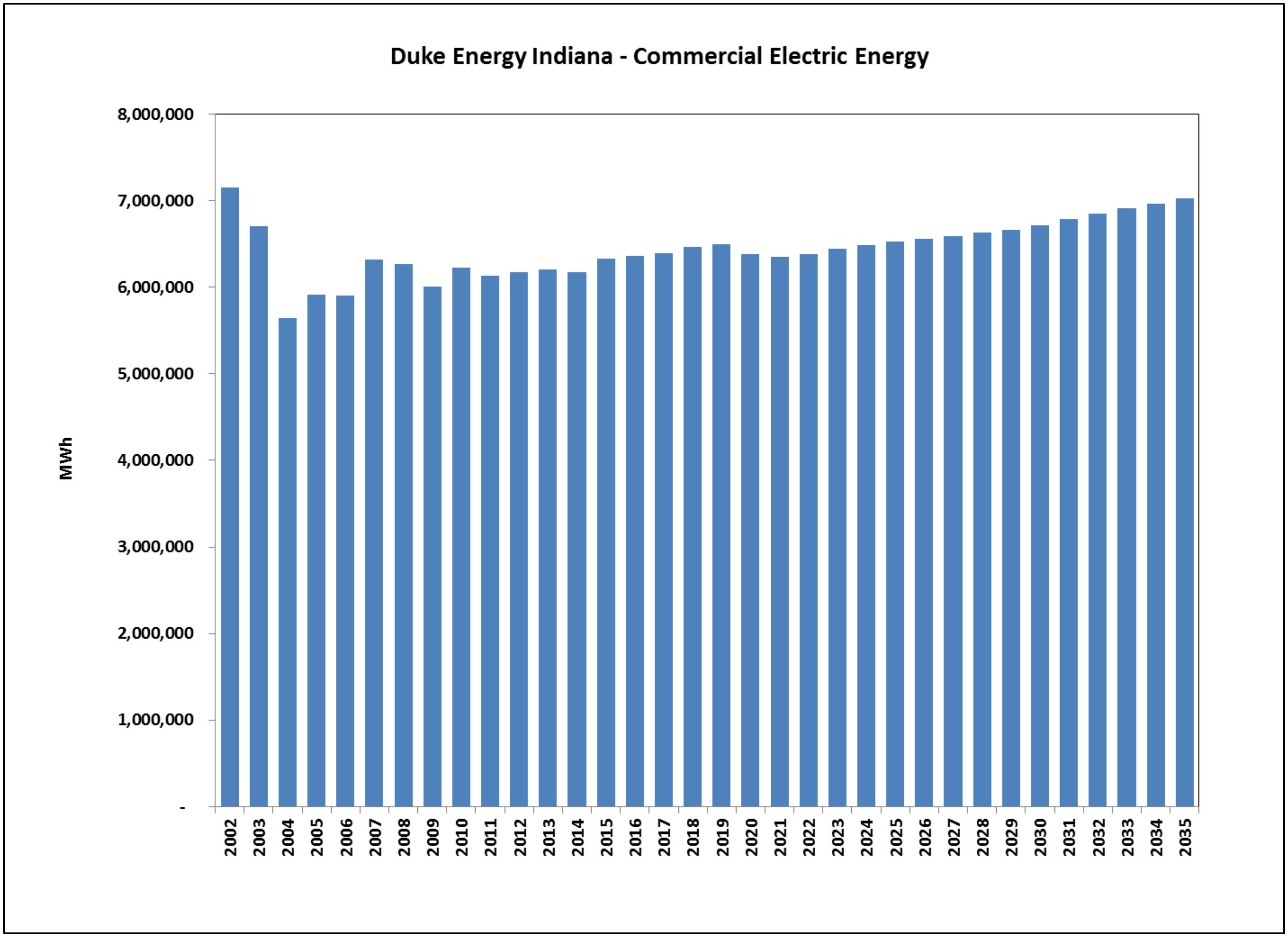
Duke Energy Indiana - Commercial Electric Energy
MWh
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
-
2002
2003
2004
2005
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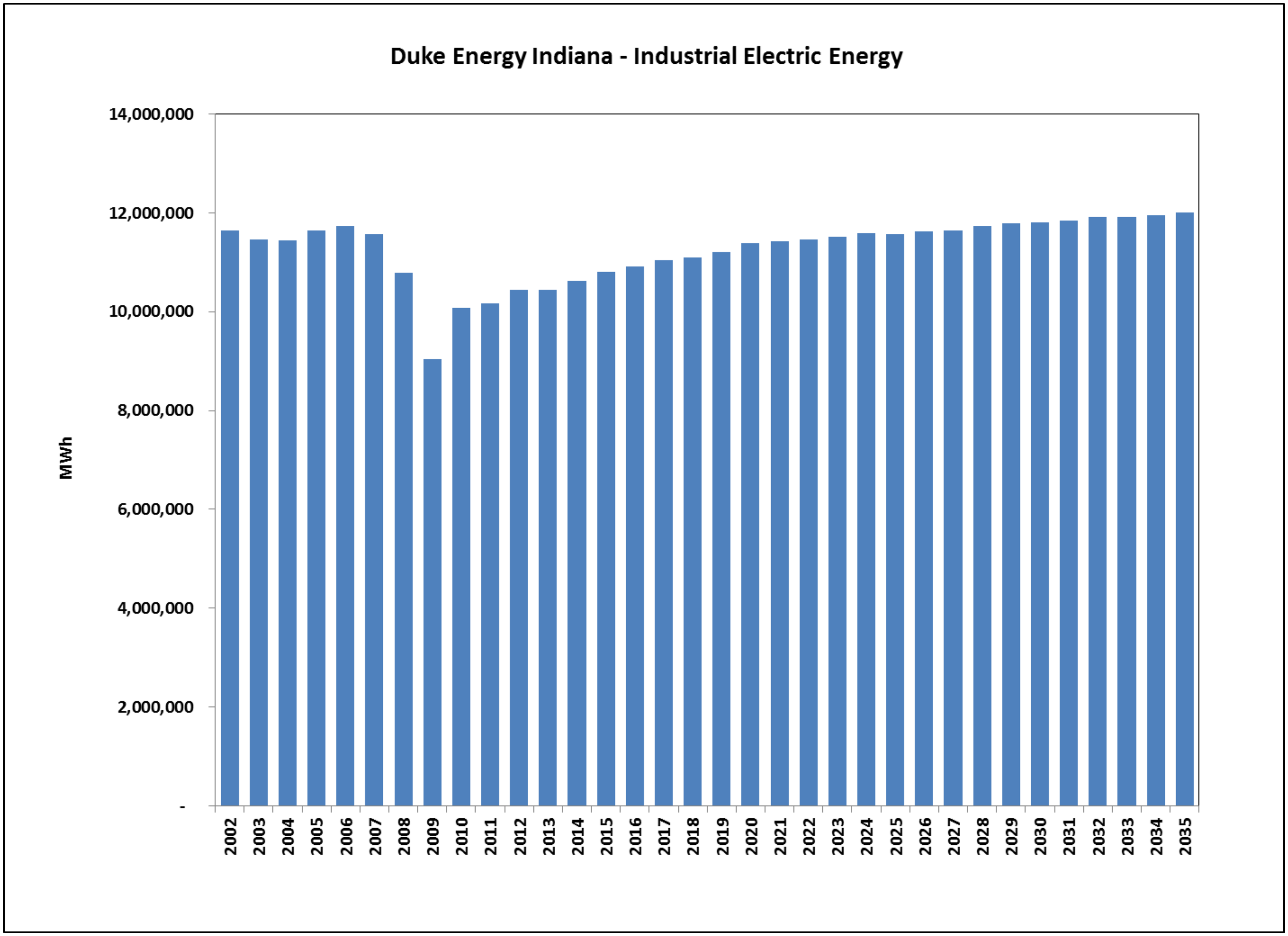
197


Duke Energy Indiana - Industrial Electric Energy
MWh
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
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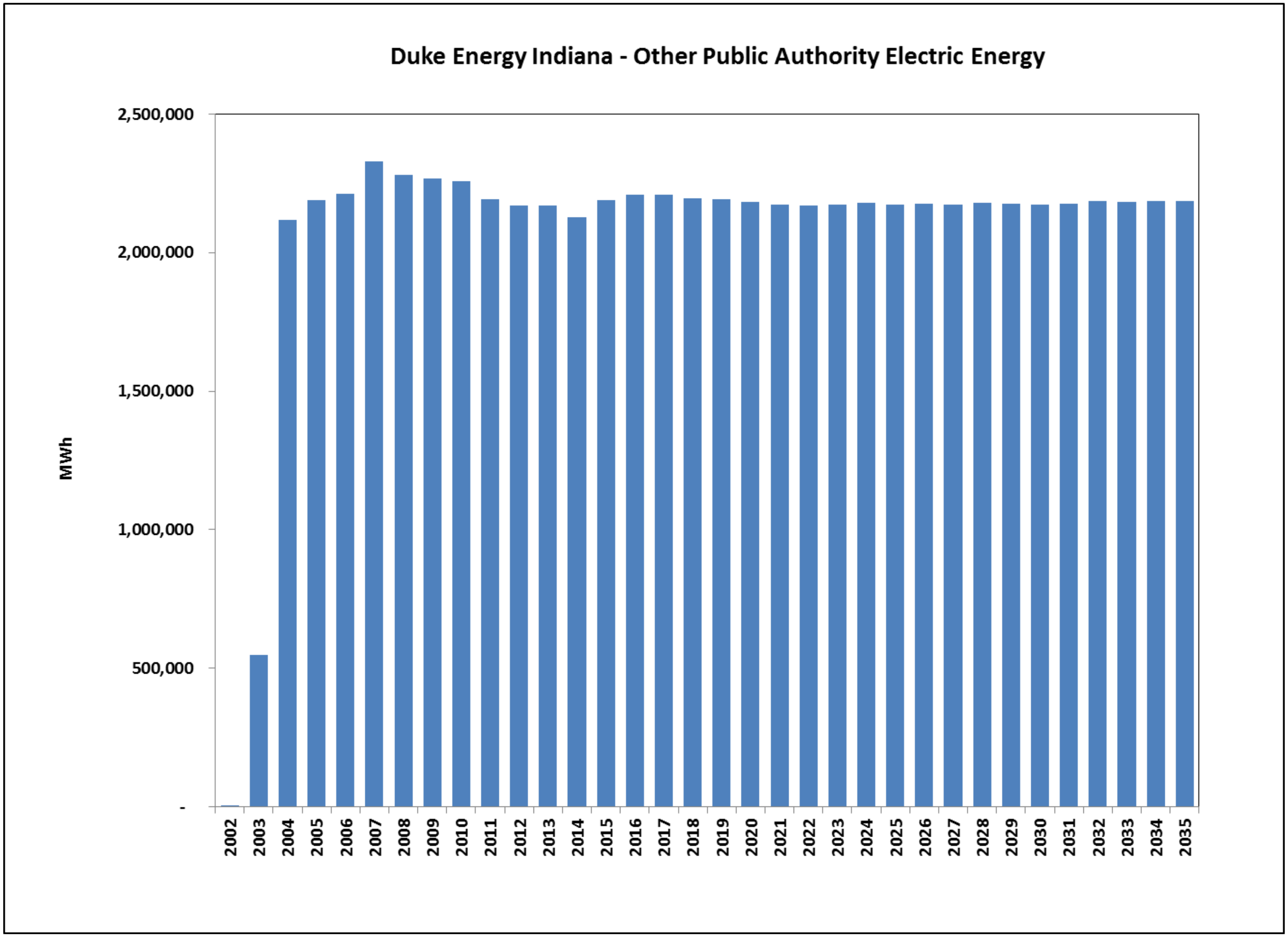
198


Duke Energy Indiana - Other Public Authority Electric Energy
MWh
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
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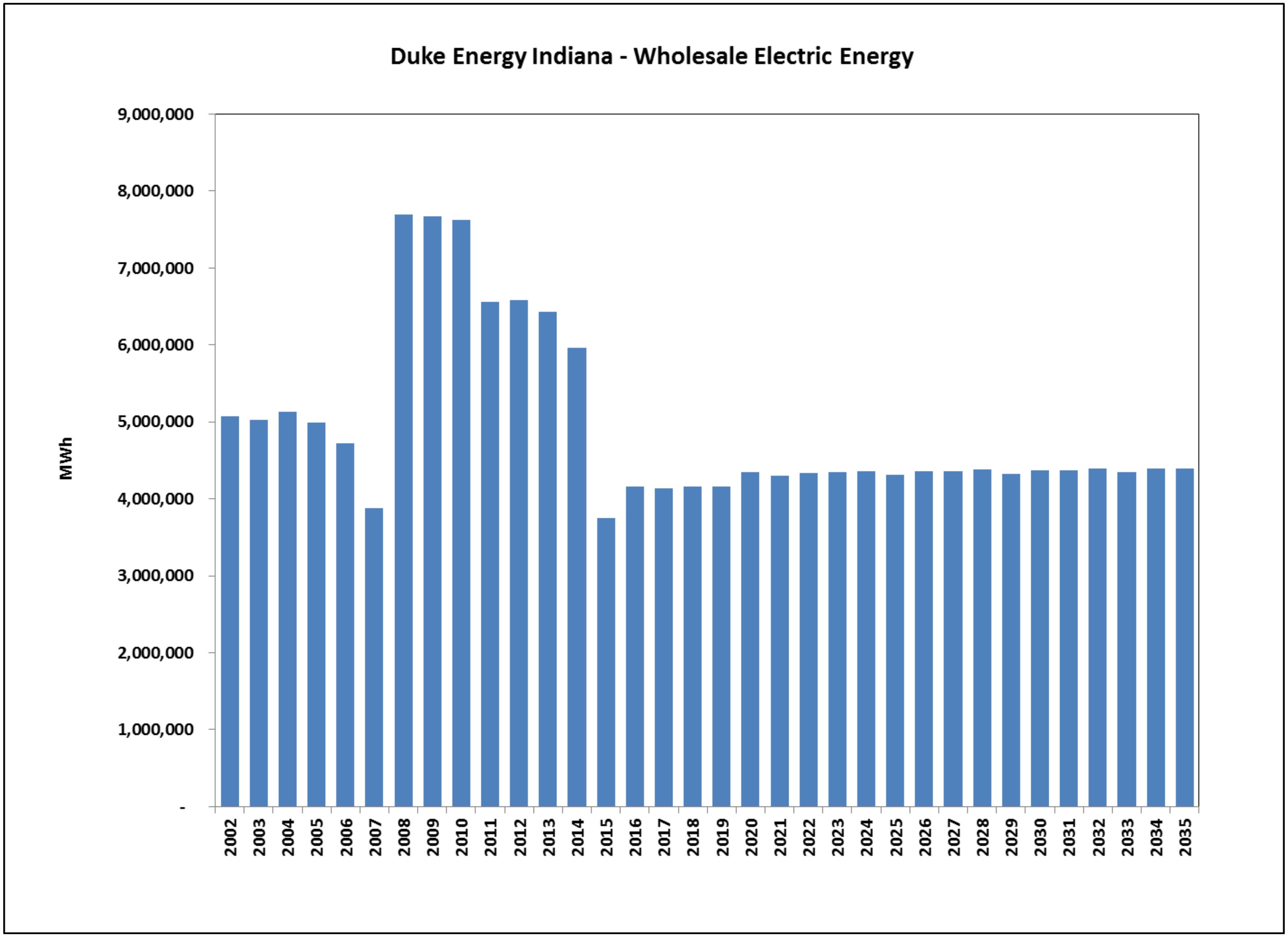
Duke Energy Indiana - Wholesale Electric Energy
MWh
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
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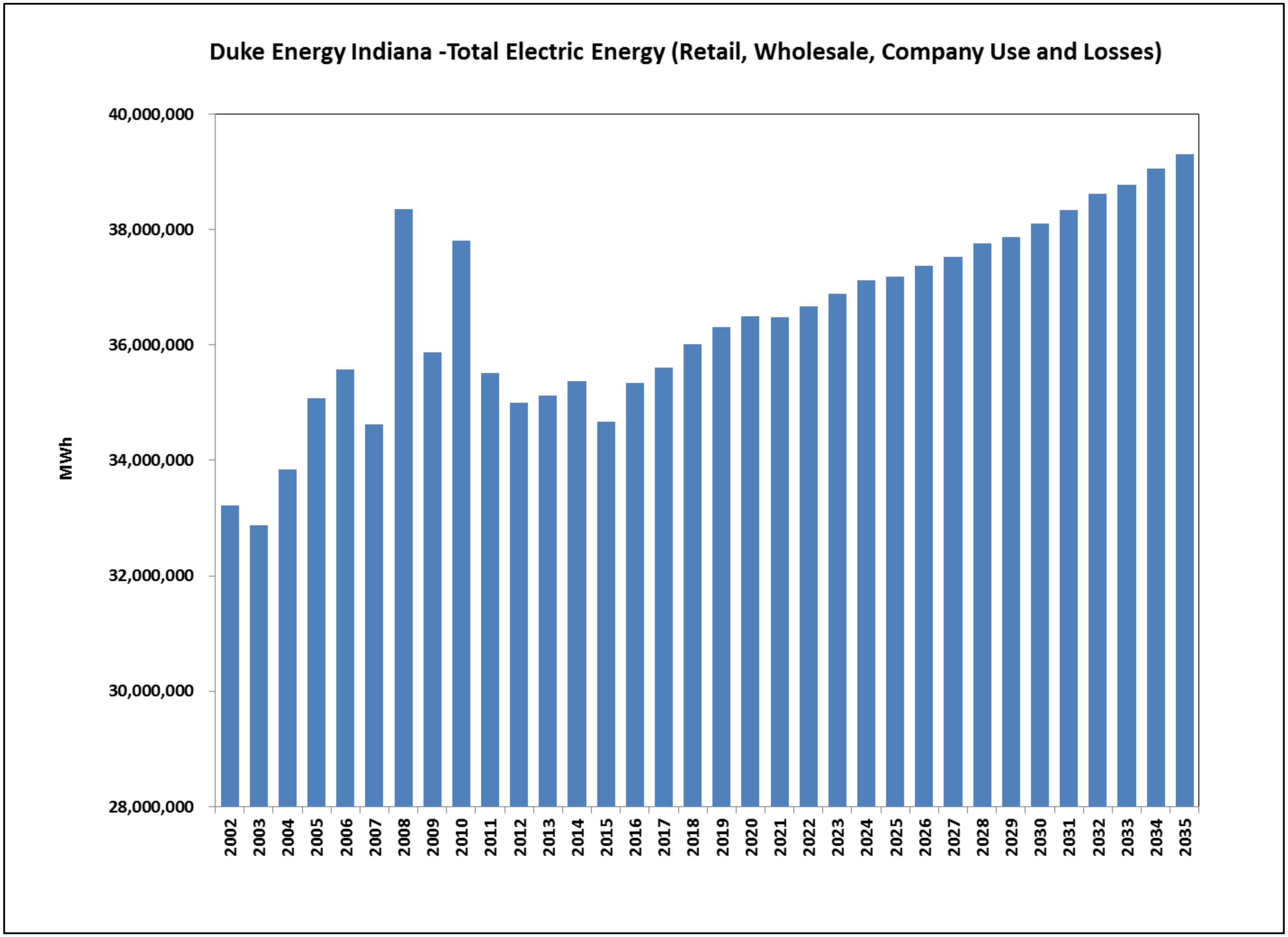
Duke Energy Indiana -Total Electric Energy (Retail, Wholesale, Company Use and Losses)
MWh
40,000,000
38,000,000
36,000,000
34,000,000
32,000,000
30,000,000
28,000,000
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
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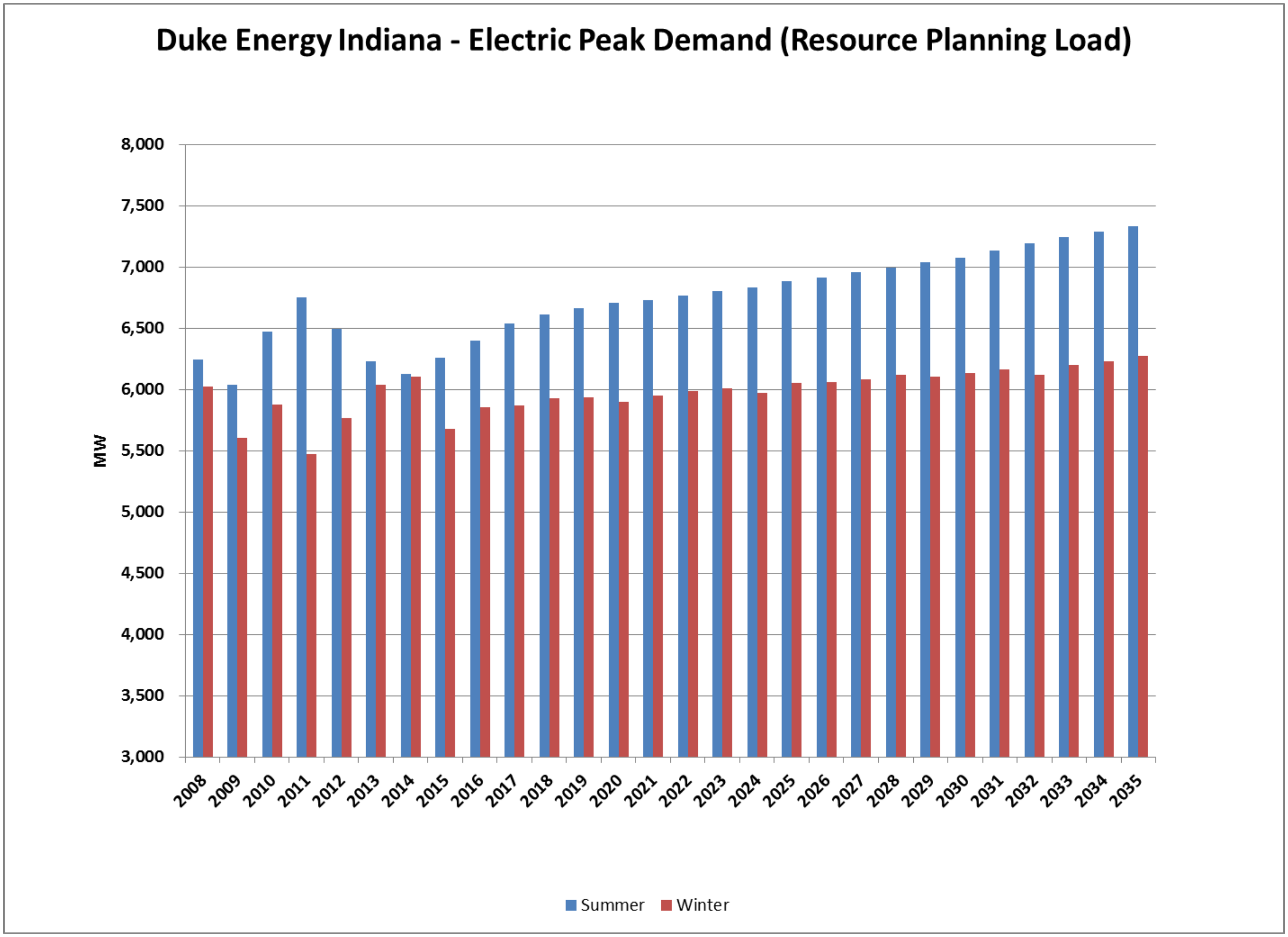
2033
2034
2035


Duke Energy Indiana - Electric Peak Demand (Resource Planning Load)
MW
8,000
7,500
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
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2020
2021
2022
2023
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2026
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2030
2031
2032
2033
2034
2035
Summer
Winter

DUKE ENERGY INDIANA
ELECTRIC CUSTOMERS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O. P. A.	STREET LIGHTING	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
2008	673,412	89,544	2,842	9,586	1,261	776,646		13,762
2009	672,740	89,410	2,814	9,862	1,319	776,144	(501)	13,232
2010	677,998	89,554	2,790	10,119	1,358	781,819	5,675	14,173
2011	678,931	89,493	2,754	10,302	1,399	782,878	1,059	13,524
2012	683,335	89,861	2,734	10,259	1,433	787,621	4,742	13,084
2013	688,302	89,973	2,726	1,473	10,282	792,756	5,135	13,413
2014	693,006	90,117	2,708	10,235	1,514	797,579	4,823	13,340
2015	696,215	90,115	2,700	10,272	1,567	800,870	3,291	13,224
2016	699,011	90,137	2,692	10,318	1,596	803,754	2,884	13,253
2017	704,302	90,276	2,682	10,363	1,626	809,247	5,493	13,324
2018	709,512	90,430	2,672	10,402	1,654	814,670	5,423	13,559
2019	712,870	90,531	2,662	10,433	1,682	818,178	3,508	13,678
2020	715,906	90,627	2,653	10,460	1,708	821,354	3,176	13,520
2021	718,562	90,712	2,644	10,482	1,734	824,133	2,779	13,524
2022	721,206	90,798	2,635	10,502	1,758	826,898	2,765	13,566
2023	724,329	90,901	2,627	10,521	1,781	830,158	3,260	13,620
2024	727,582	91,008	2,620	10,538	1,803	833,550	3,392	13,651
2025	730,819	91,115	2,612	10,553	1,824	836,923	3,373	13,705
2026	733,986	91,220	2,606	10,567	1,844	840,223	3,299	13,734
2027	736,868	91,315	2,599	10,579	1,864	843,225	3,003	13,778
2028	739,759	91,411	2,593	10,590	1,883	846,237	3,011	13,812
2029	742,758	91,510	2,587	10,601	1,901	849,357	3,121	13,838
2030	745,920	91,615	2,581	10,612	1,919	852,646	3,289	13,919
2031	749,035	91,718	2,576	10,621	1,936	855,886	3,239	14,018
2032	751,963	91,815	2,570	10,630	1,953	858,932	3,046	14,091
2033	754,949	91,914	2,565	10,639	1,969	862,036	3,104	14,212
2034	757,696	92,005	2,560	10,647	1,984	864,892	2,856	14,314
2035	760,145	92,086	2,555	10,653	1,999	867,440	2,548	14,421
GROWTH RATE								
2013-2018	0.6%	0.1%	-0.4%	121.3%	-16.8%	0.6%		0.2%
2013-2023	0.5%	0.1%	-0.4%	61.4%	-8.3%	0.5%		0.2%
2013-2033	0.5%	0.1%	-0.3%	31.1%	-4.0%	0.4%		0.3%

NOTE: 2015 FIGURES REPRESENT TWELVE MONTHS FORECAST

4. Schedule for End-Use Surveys

In the residential sector, Duke Energy Indiana is currently on a three-year schedule for conducting end-use surveys. The most recent survey was conducted during 2013. The results of that survey were incorporated into the Company's 2013 and subsequent forecasts.

In the commercial sector, the last survey was conducted in 1991. There has been no formal survey work conducted in the industrial sector, due to the nature of the sector itself. The industrial sector is a heterogeneous mix of distinct operations. Even customers within the same NAICS can exhibit significant differences in processes and energy use patterns. For this reason, a formal on-site census is the preferred method for gathering useful end-use information. Currently, Duke Energy Indiana has no plans to conduct a formal industrial end-use census. This may also be modified according to the information needs of the Duke Energy Indiana forecasting department and other departments.

5. Evaluation of Previous 10 Years of Forecasts

Tables are attached showing actual versus forecast for the previous ten years.

In general, the methodology, equations, and types of data used have remained consistent over the years. In addition, the IURC has passed judgment on the reasonableness of the forecast and the methodology several times. Finally, the State Utility Forecasting Group (SUFG), though using models quite distinct from Duke Energy Indiana's, has historically produced forecasts that are similar to Duke Energy Indiana's.

Duke Energy Indiana Sales Forecasts - Comparison to Actuals in Thousands of Megawatthours

	Actual	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005											
Residential	9,063	8,755									
Commercial	5,912	5,768									
Industrial	11,646	11,561									
Other	2,243	2,172									
Sales for Resale	4,997	4,772									
Total Sales	33,861	33,028									
2006											
Residential	8,719	8,940	9,069								
Commercial	5,903	5,935	5,847								
Industrial	11,727	11,712	11,954								
Other	2,266	2,247	2,259								
Sales for Resale	4,724	4,621	3,064								
Total Sales	33,339	33,455	32,193								
2007											
Residential	9,396	9,128	9,212	9,046							
Commercial	6,318	5,992	5,923	6,007							
Industrial	11,572	11,753	11,933	11,580							
Other	2,383	2,262	2,281	2,255							
Sales for Resale	3,881	2,962	1,548	7,690							
Total Sales	33,550	30,899	30,899	30,899							
2008											
Residential	9,267	9,294	9,322	9,162	9,092						
Commercial	6,263	6,053	6,006	6,077	6,277						
Industrial	10,792	11,793	11,952	11,486	11,411						
Other	2,335	2,275	2,307	2,273	2,402						
Sales for Resale	7,701	1,860	427	7,320	7,673						
Total Sales	36,358	30,015	30,015	30,015	30,015						
2009											
Residential	8,901	9,449	9,436	9,326	9,140	9,021					
Commercial	6,008	6,131	6,107	6,162	6,301	6,178					
Industrial	9,032	11,847	12,007	11,533	11,391	9,496					
Other	2,323	2,300	2,340	2,300	2,421	2,315					
Sales for Resale	7,675	1,880	433	7,327	7,695	7,597					
Total Sales	33,939	31,606	30,324	36,648	36,948	34,607					
2010											
Residential	9,609	9,615	9,546	9,482	9,244	8,863	9,094				
Commercial	6,229	6,204	6,204	6,253	6,362	6,156	5,974				
Industrial	10,082	11,900	12,050	11,654	11,400	9,824	9,236				
Other	2,310	2,324	2,371	2,332	2,431	2,291	2,352				
Sales for Resale	7,631	1,903	439	7,335	7,623	7,665	7,506				
Total Sales	35,861	31,946	30,610	37,056	37,059	34,799	34,162				
2011											
Residential	9,316	9,794	9,681	9,644	9,362	8,893	8,960	9,097			
Commercial	6,156	6,297	6,309	6,358	6,425	6,278	6,010	6,139			
Industrial	10,237	11,957	12,133	11,795	11,511	9,973	9,136	10,193			
Other	2,203	2,357	2,406	2,369	2,448	2,238	2,301	2,225			
Sales for Resale	5,370	1,924	446	7,343	7,585	7,675	7,486	7,081			
Total Sales	33,282	32,329	30,975	37,509	37,332	35,057	33,893	34,735			
2012											
Residential	8,867	9,979	9,832	9,803	9,279	8,958	8,943	9,098	8,945		
Commercial	6,152	6,402	6,433	6,469	6,449	6,401	6,171	6,268	6,010		
Industrial	10,411	12,018	12,245	11,948	11,571	10,016	9,147	10,244	10,358		
Other	2,162	2,394	2,448	2,408	2,458	2,210	2,289	2,286	2,138		
Sales for Resale	5,796	1,949	454	7,351	7,579	7,676	7,493	7,095	4,396		
Total Sales	33,389	32,741	31,412	37,979	37,336	35,261	34,043	34,991	31,847		
2013											
Residential	9,170	10,162	9,977	9,951	9,151	8,750	8,754	9,119	8,966	8,808	
Commercial	6,192	6,501	6,547	6,573	6,450	6,407	6,305	6,440	6,182	6,015	
Industrial	10,389	12,079	12,363	12,098	11,632	9,963	9,168	10,284	10,399	10,506	
Other	2,161	2,429	2,488	2,445	2,435	2,153	2,290	2,435	2,286	2,203	
Sales for Resale	6,431	1,973	461	7,359	7,570	7,664	7,488	7,096	4,397	6,471	
Total Sales	34,343	33,144	31,836	38,426	37,238	34,937	34,004	35,375	32,231	34,003	
2014											
Residential	9,245	10,337	10,120	10,085	9,036	8,771	8,781	9,169	9,016	8,824	9,088
Commercial	6,170	6,597	6,661	6,675	6,459	6,338	6,312	6,559	6,300	6,113	6,248
Industrial	10,629	12,148	12,492	12,256	11,731	9,870	9,227	10,288	10,402	10,648	10,523
Other	2,127	2,463	2,527	2,481	2,421	2,082	2,272	2,477	2,329	2,244	2,274
Sales for Resale	5,967	1,998	468	7,366	7,563	7,658	7,482	7,102	4,403	6,478	5,999
Total Sales	34,138	33,544	32,268	38,863	37,211	34,718	34,074	35,595	32,450	34,306	34,131

Forecasts reflect weather-normal sales while actual is not weather-normalized.

Duke Energy Indiana Summer Peak Forecasts - Comparison to Actual in Megawatts

	Actual	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005	6539	6719									
2006	6702	6835	6688								
2007	6705	6332	6171	6897							
2008	6213	6384	6218	6923	6998						
2009	6037	6442	6285	6995	7026	6759					
2010	6476	6502	6346	7082	7059	6797	6658				
2011	6749	6569	6424	7179	7145	6867	6634	6604			
2012	6494	6641	6517	7278	7230	6926	6711	6710	6549		
2013	6229	6711	6608	7373	7294	6956	6811	6834	6610	6516	
2014	6130	6781	6700	7467	7374	6966	6885	6936	6679	6609	6698

Duke Energy Indiana Winter Peak Forecasts - Comparison to Actual in Megawatts

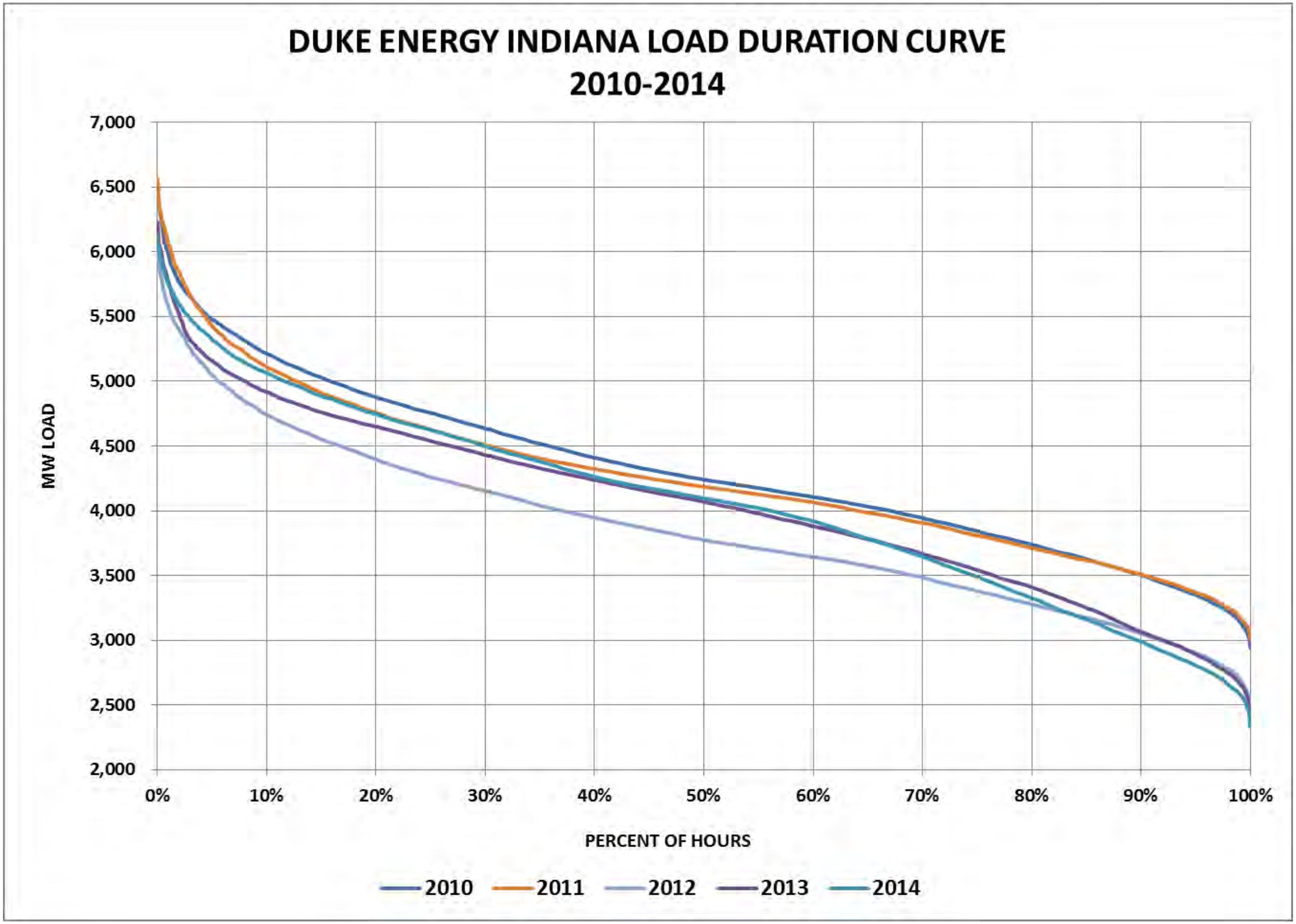
	Actual	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005-06	5617	5885									
2006-07	5762	5944	5691								
2007-08	5996	5530	5330	6043							
2008-09	5920	5584	5375	6096	6153						
2009-10	5602	5645	5418	6157	6199	6154					
2010-11	5878	5709	5472	6226	6262	6202	5920				
2011-12	5603	5773	5535	6296	6307	6243	5971	5988			
2012-13	5763	5835	5597	6361	6353	6216	6039	5993	6131		
2013-14	6038	5897	5659	6425	6412	6176	6092	6178	6189	6189	
2014-15	5729	5960	5719	6329	6319	5897	5821	5774	6233	6233	6004

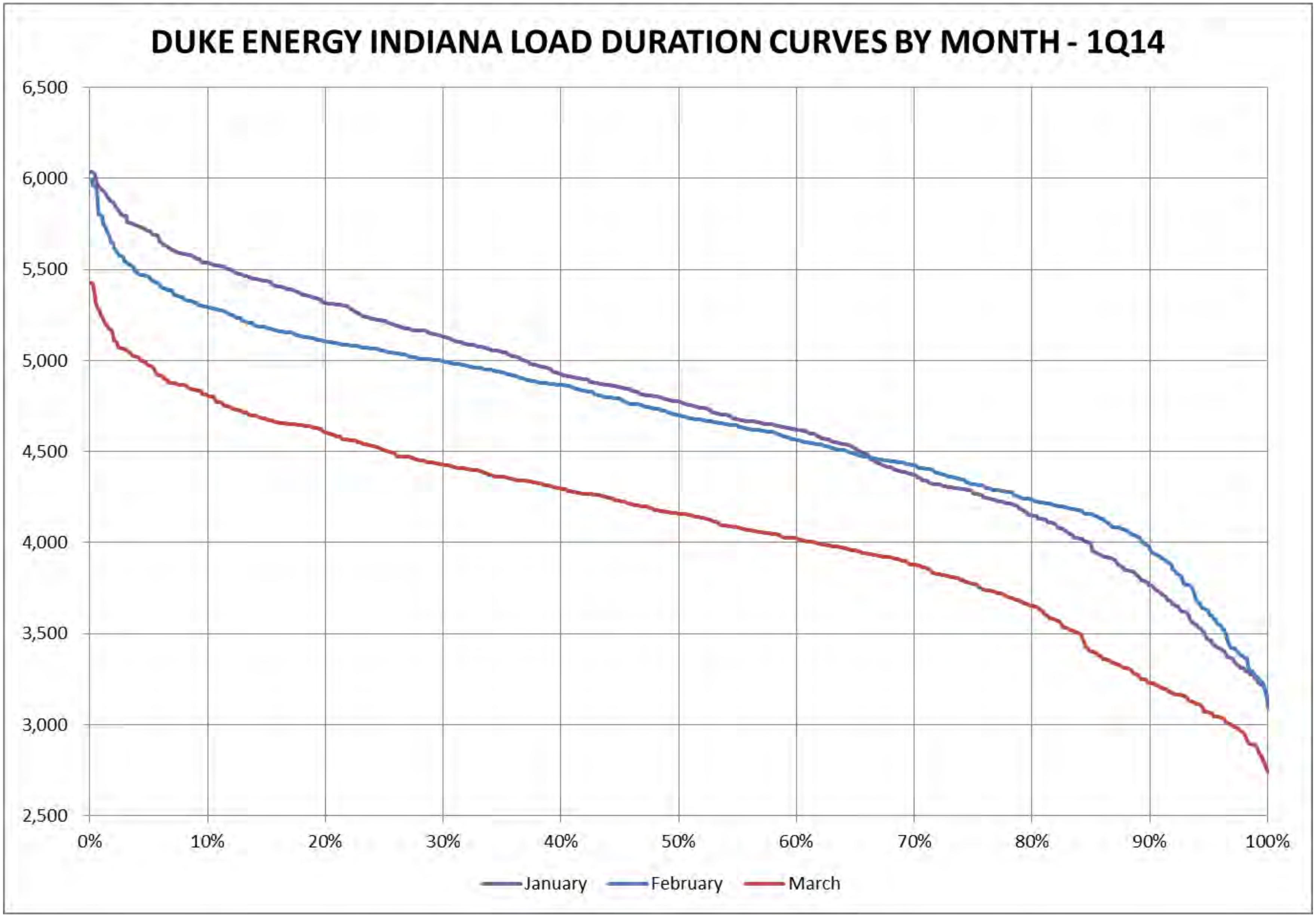
Forecasts reflect weather-normal peaks before the impact of demand resonse.
History reflects actual peaks after the impacto of demand resonse.

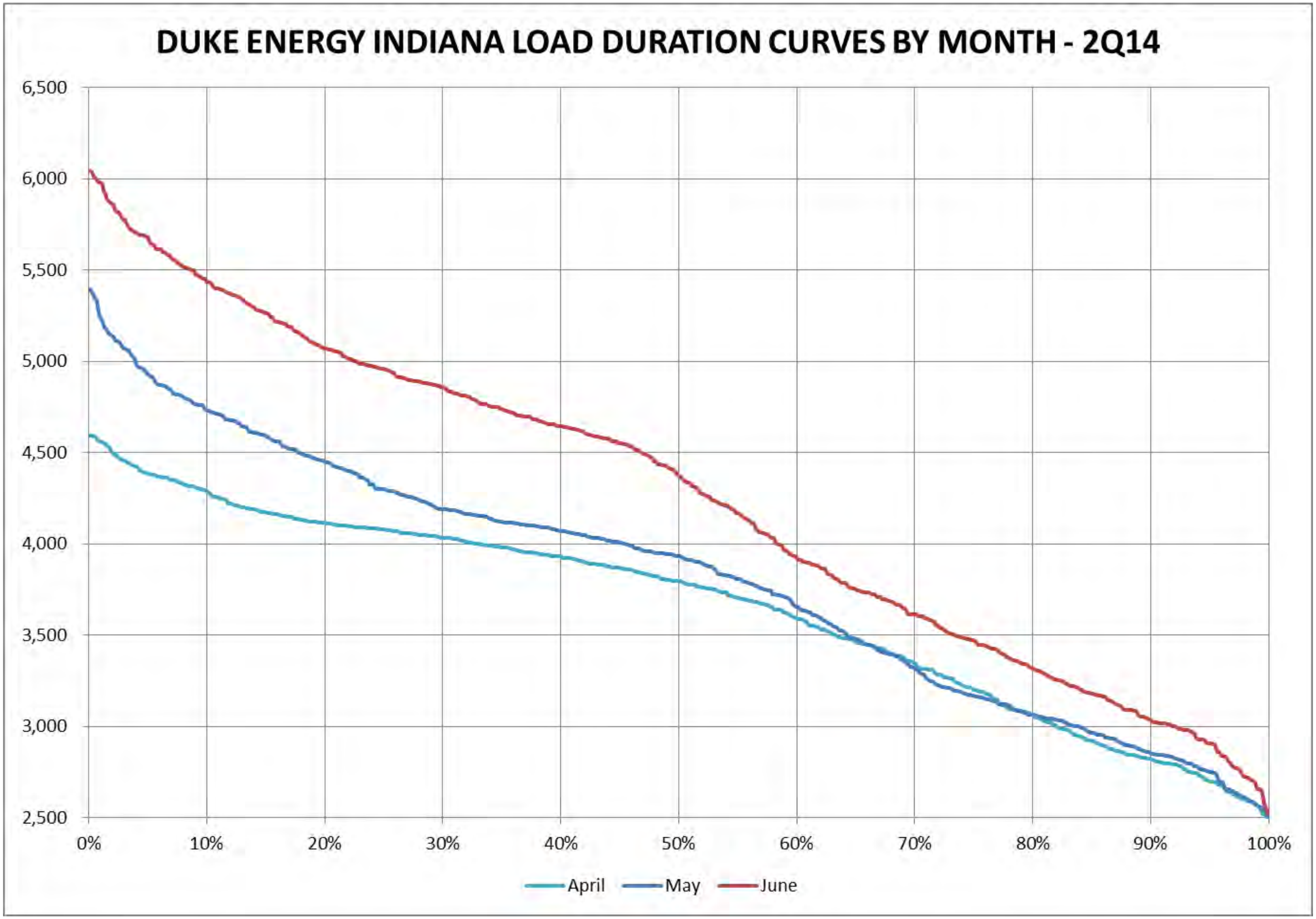
6. Load Shapes

Graphical representations of load duration curves annually for 2010-2014 and monthly for 2014 follow.

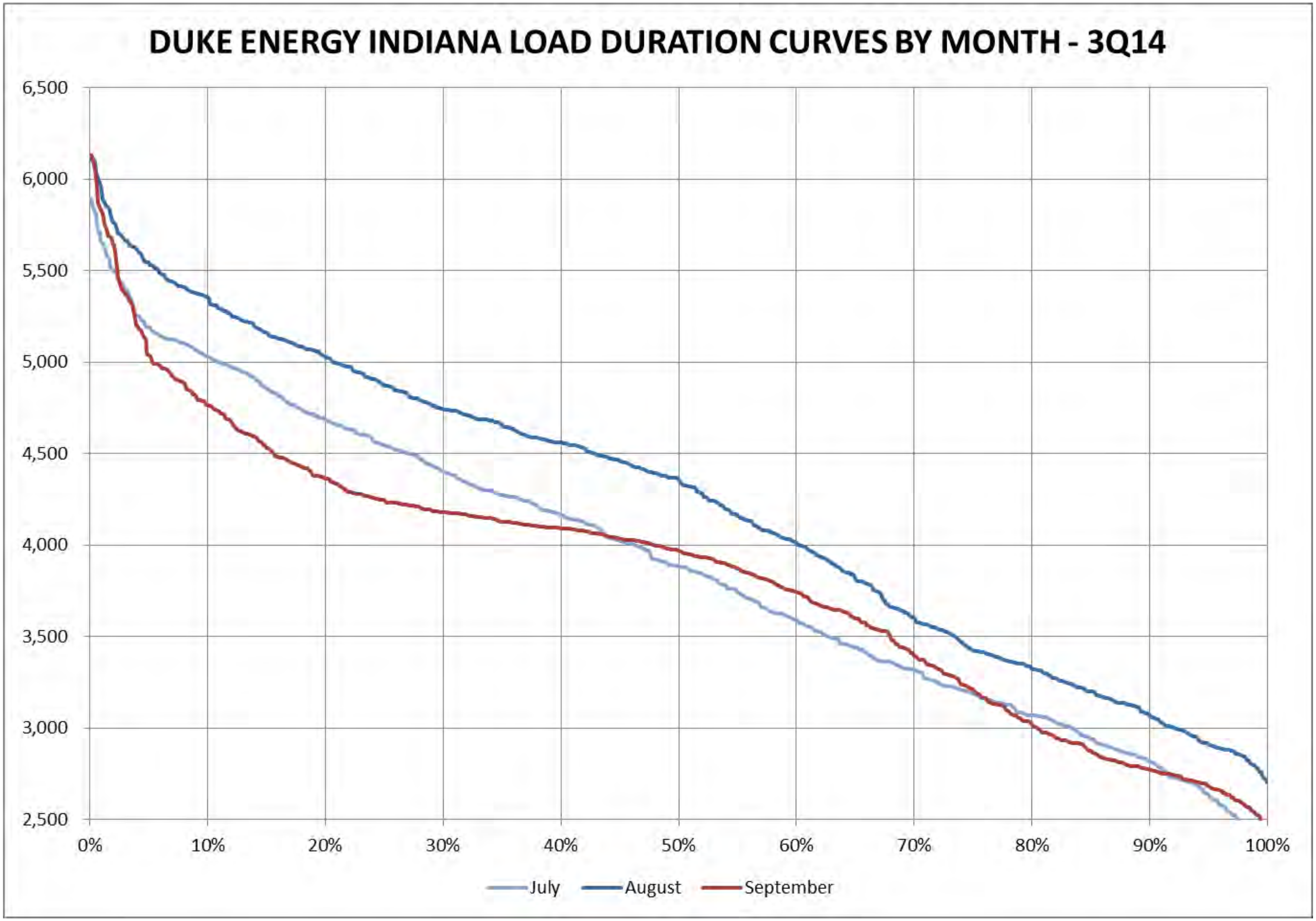
Summer and winter peak day load shapes for 2010-2014 follow. Typical summer and winter weekday and weekend shapes are also attached. For the forecast period, no significant trends or changes from the historic load shapes are expected.


DUKE ENERGY INDIANA LOAD DURATION CURVE
2010-2014
MW LOAD
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS
2010
2011
2012
2013
2014

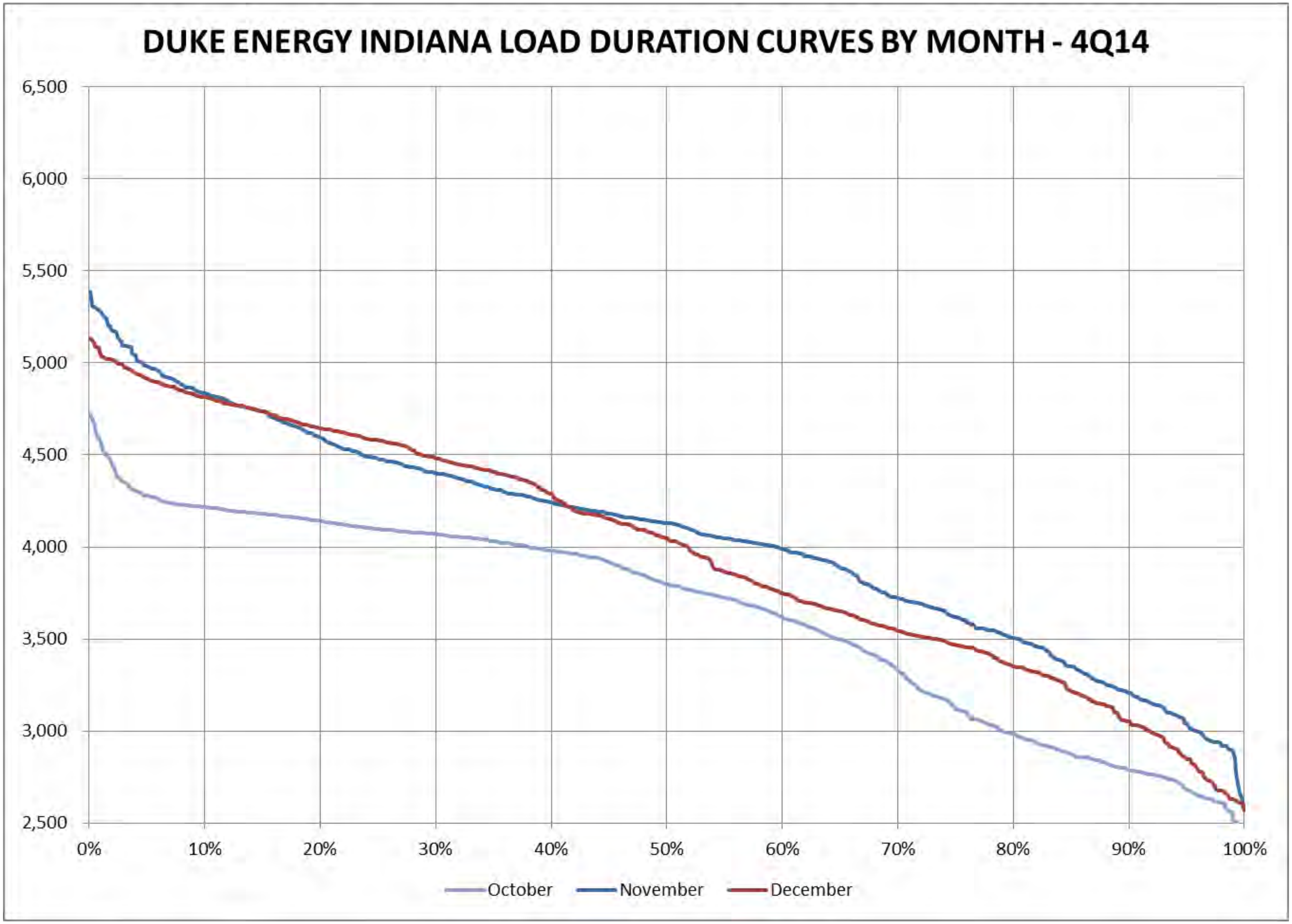

DUKE ENERGY INDIANA LOAD DURATION CURVES BY MONTH - 1Q14
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
January
February
March

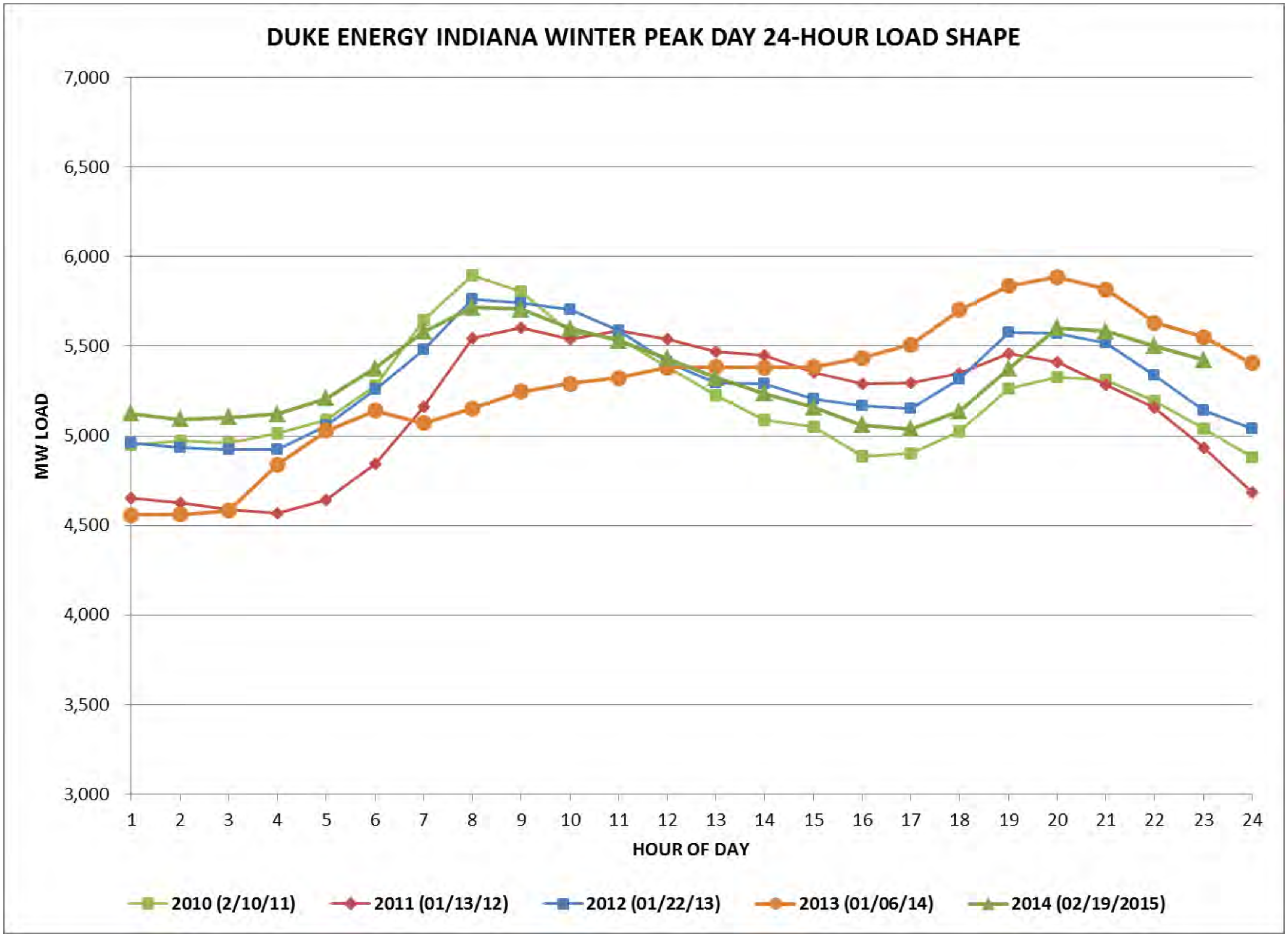

DUKE ENERGY INDIANA LOAD DURATION CURVES BY MONTH - 2Q14
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
April
May
June

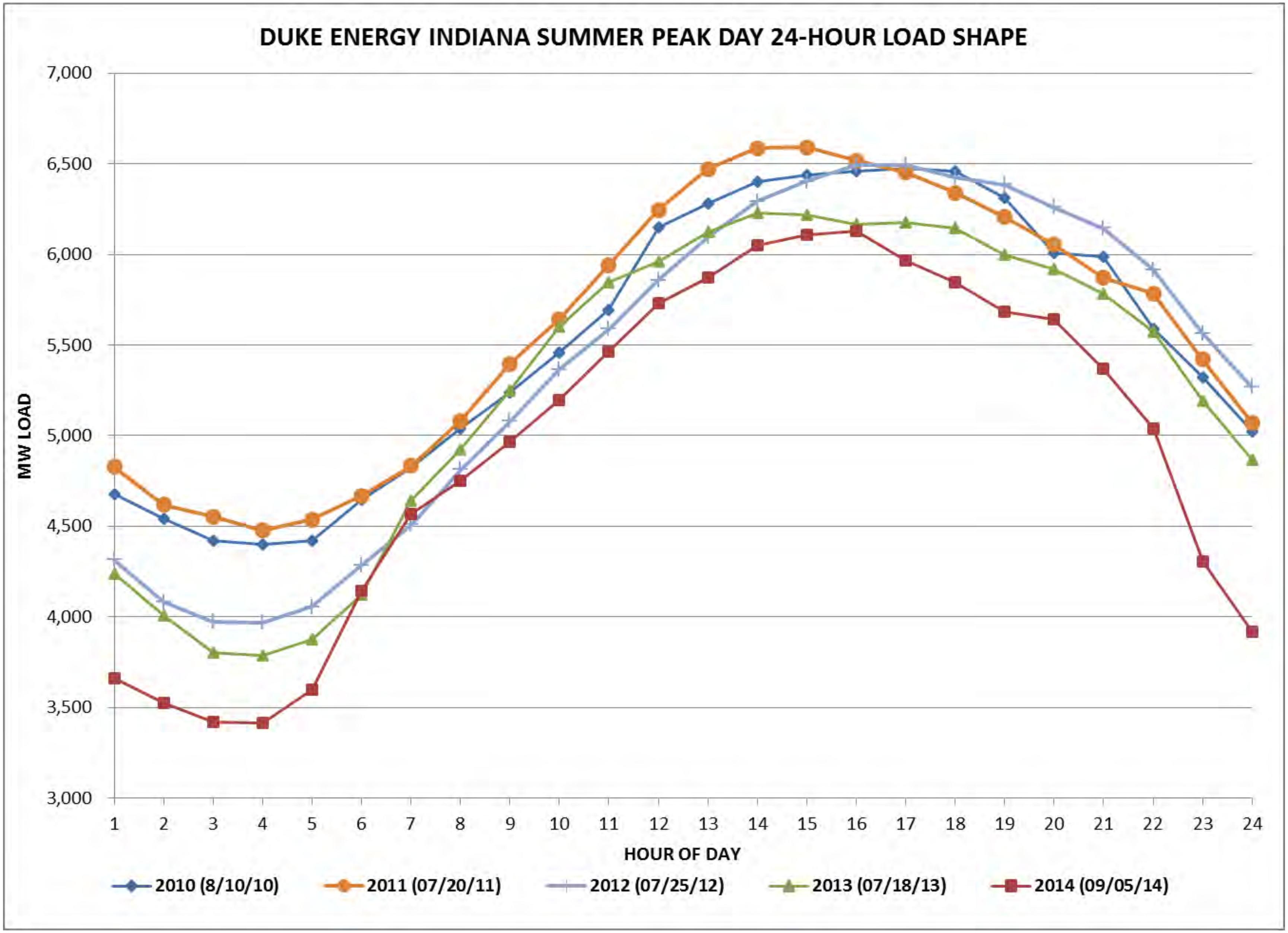
211

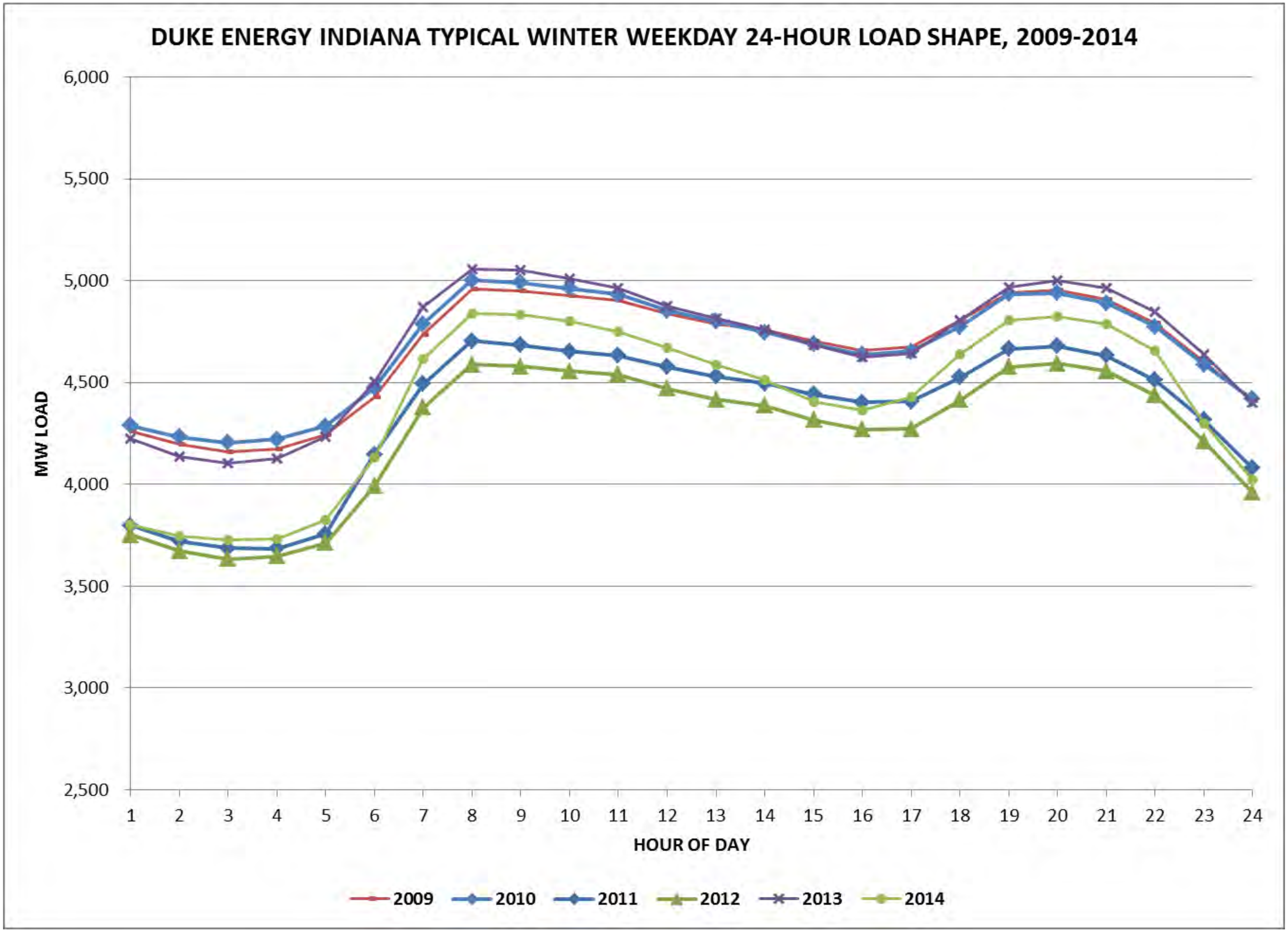

DUKE ENERGY INDIANA LOAD DURATION CURVES BY MONTH - 3Q14
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
July
August
September

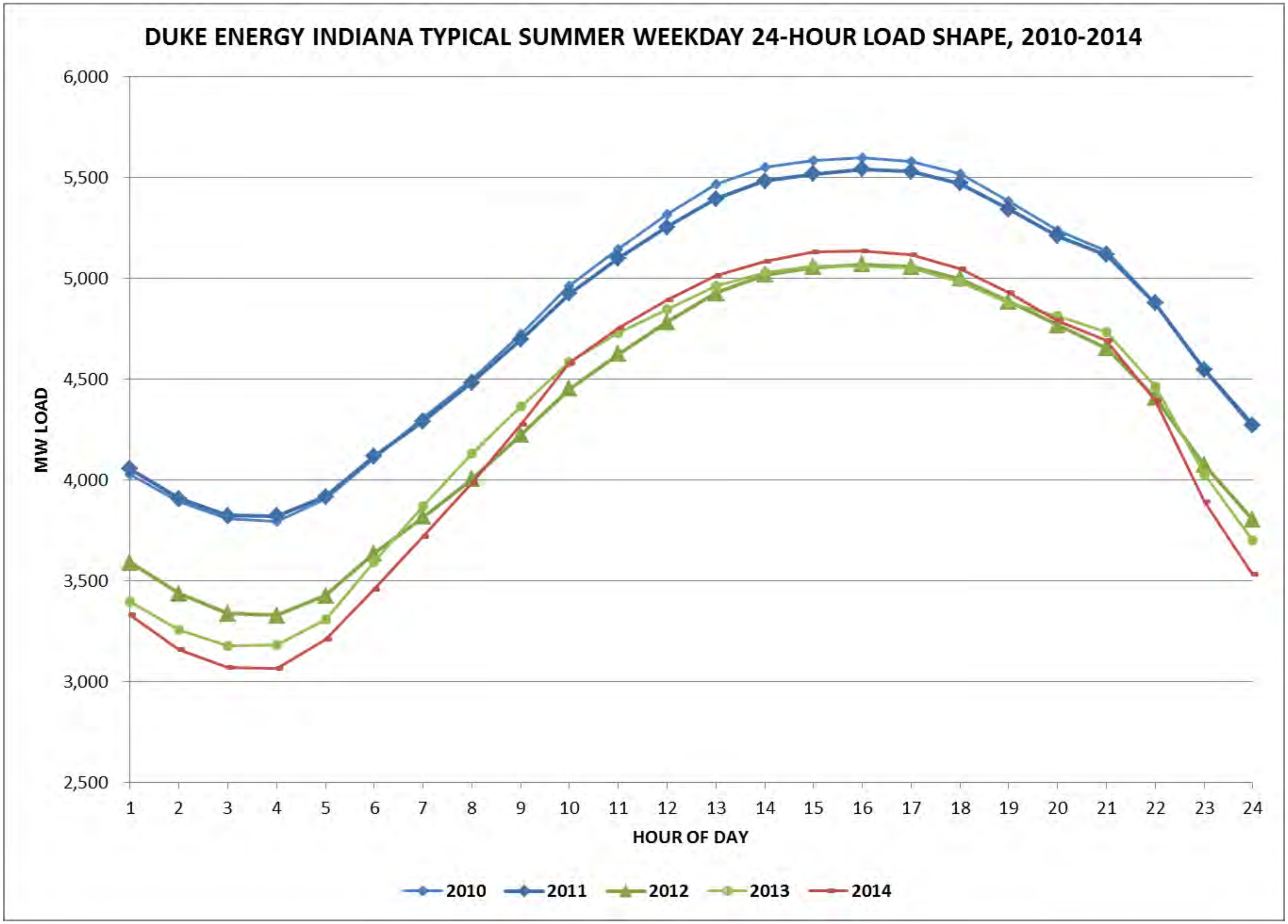
212

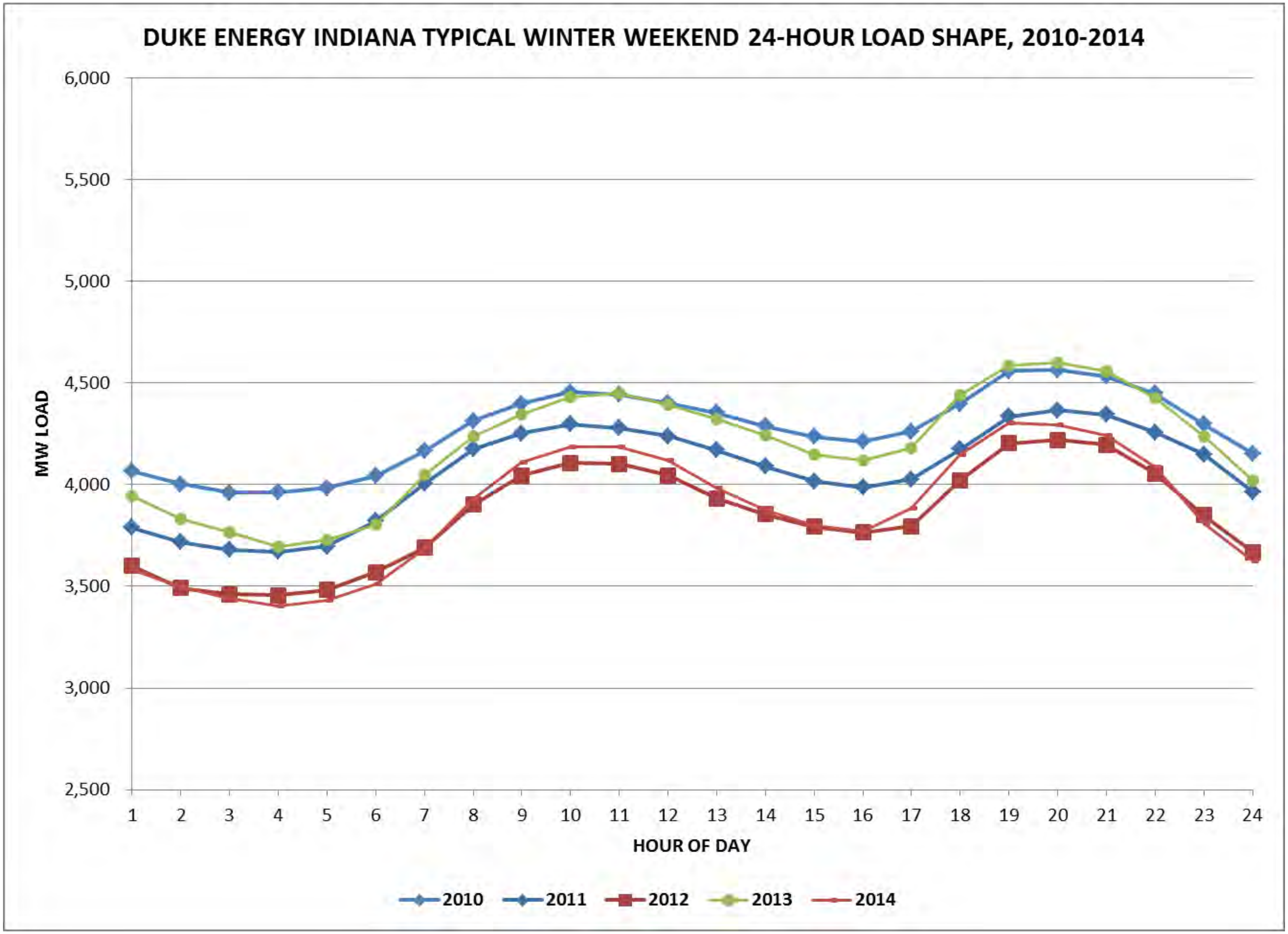

DUKE ENERGY INDIANA LOAD DURATION CURVES BY MONTH - 4Q14
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
October
November
December


DUKE ENERGY INDIANA WINTER PEAK DAY 24-HOUR LOAD SHAPE
MW LOAD
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2010 (2/10/11)
2011 (01/13/12)
2012 (01/22/13)
2013 (01/06/14)
2014 (02/19/2015)

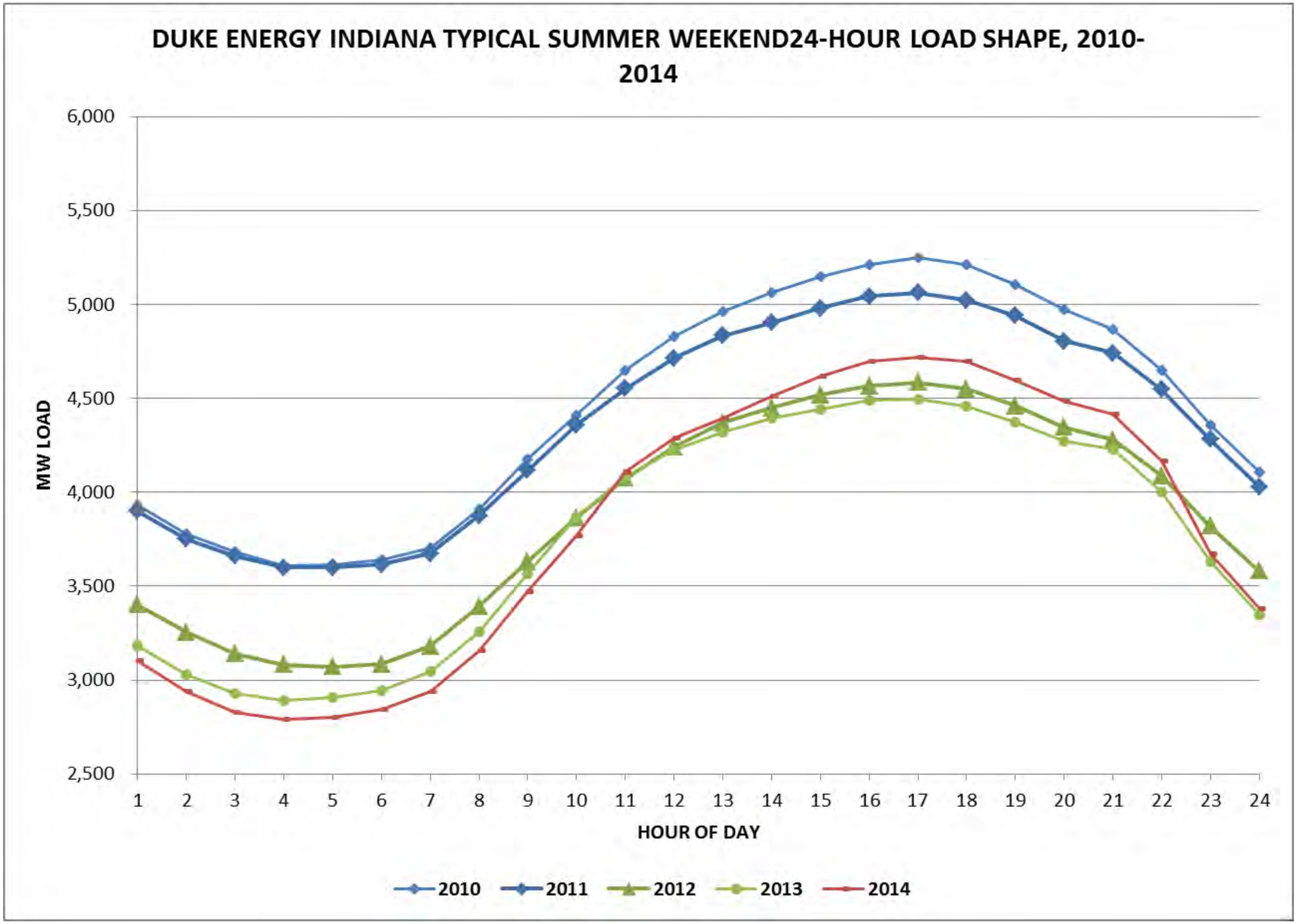

DUKE ENERGY INDIANA SUMMER PEAK DAY 24-HOUR LOAD SHAPE
MW LOAD
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2010 (8/10/10)
2011 (07/20/11)
2012 (07/25/12)
2013 (07/18/13)
2014 (09/05/14)


DUKE ENERGY INDIANA TYPICAL WINTER WEEKDAY 24-HOUR LOAD SHAPE, 2009-2014
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2009
2010
2011
2012
2013
2014


DUKE ENERGY INDIANA TYPICAL SUMMER WEEKDAY 24-HOUR LOAD SHAPE, 2010-2014
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY
2010
2011
2012
2013
2014


DUKE ENERGY INDIANA TYPICAL WINTER WEEKEND 24-HOUR LOAD SHAPE, 2010-2014
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY
2010
2011
2012
2013
2014

218


DUKE ENERGY INDIANA TYPICAL SUMMER WEEKEND24-HOUR LOAD SHAPE, 2010-2014
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY
2010
2011
2012
2013
2014

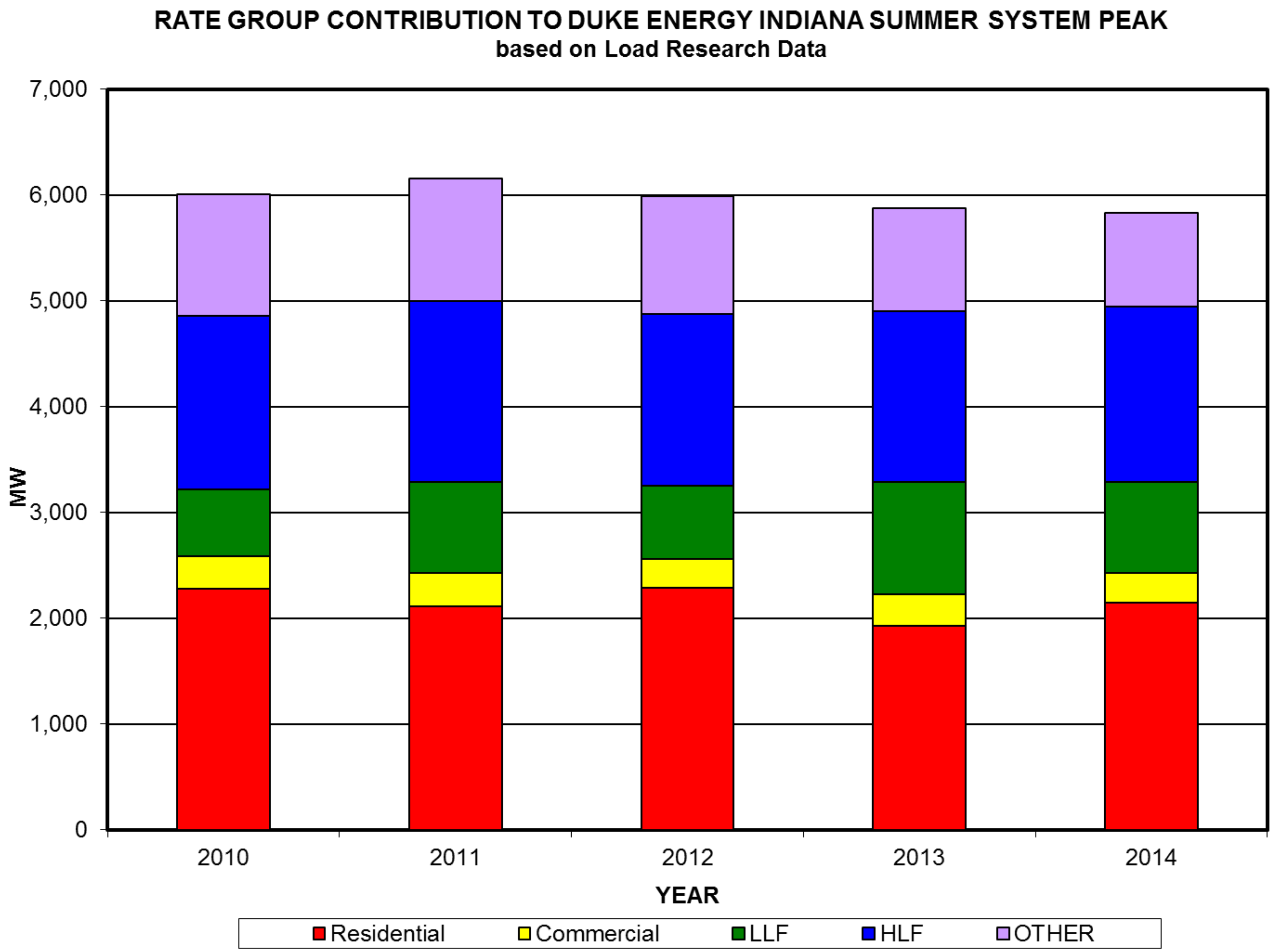
7. Disaggregated Load Shapes

The graphs showing Rate Group Contribution to Duke Energy Indiana System Peaks for the years 2010 through 2014 are attached.

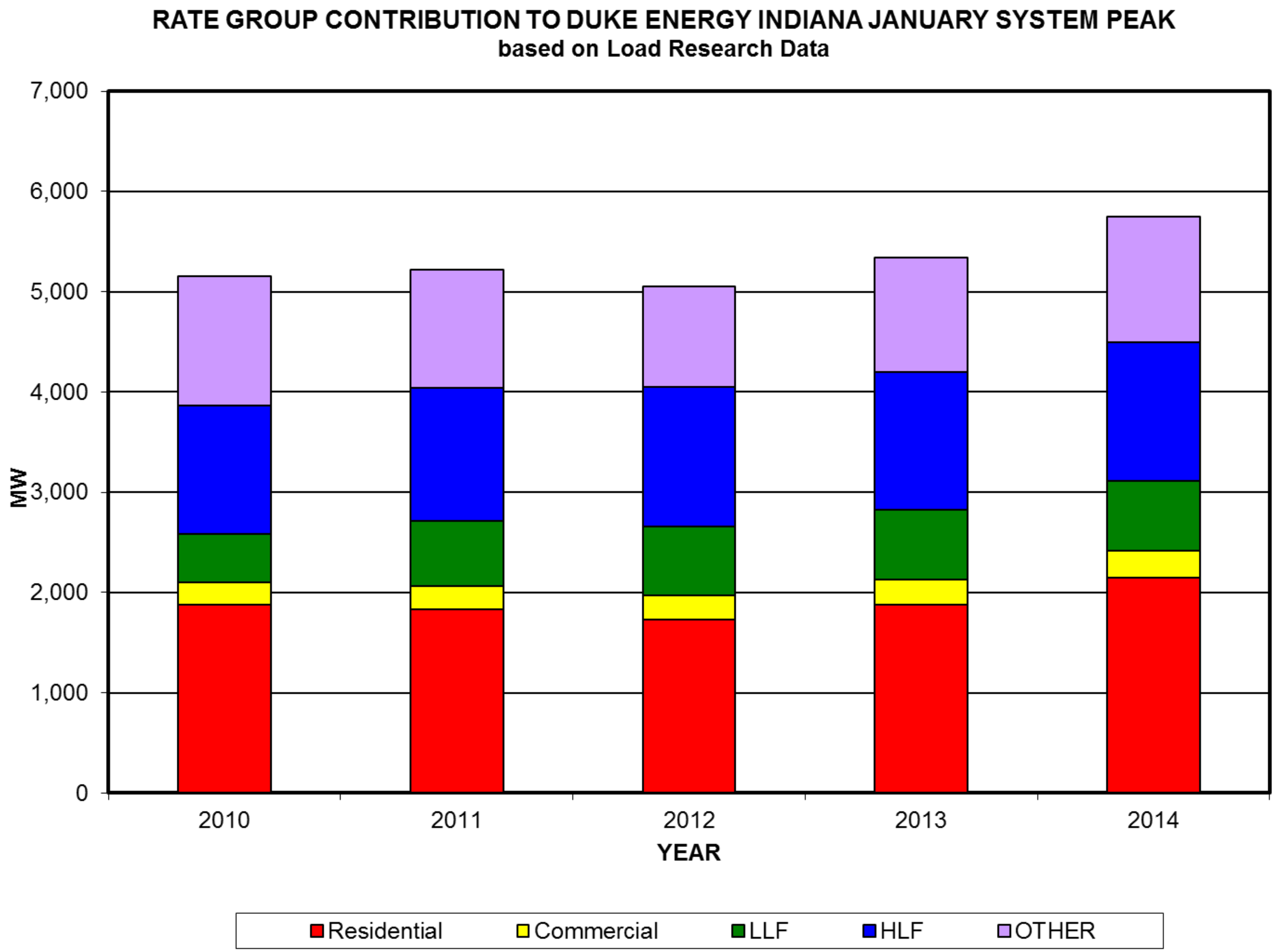
Differences in peak from those reported elsewhere arise from:

- A different method for determining the hour of peak,
- Differences in how wholesale contracts including backstands are counted, and
- Demand Response.

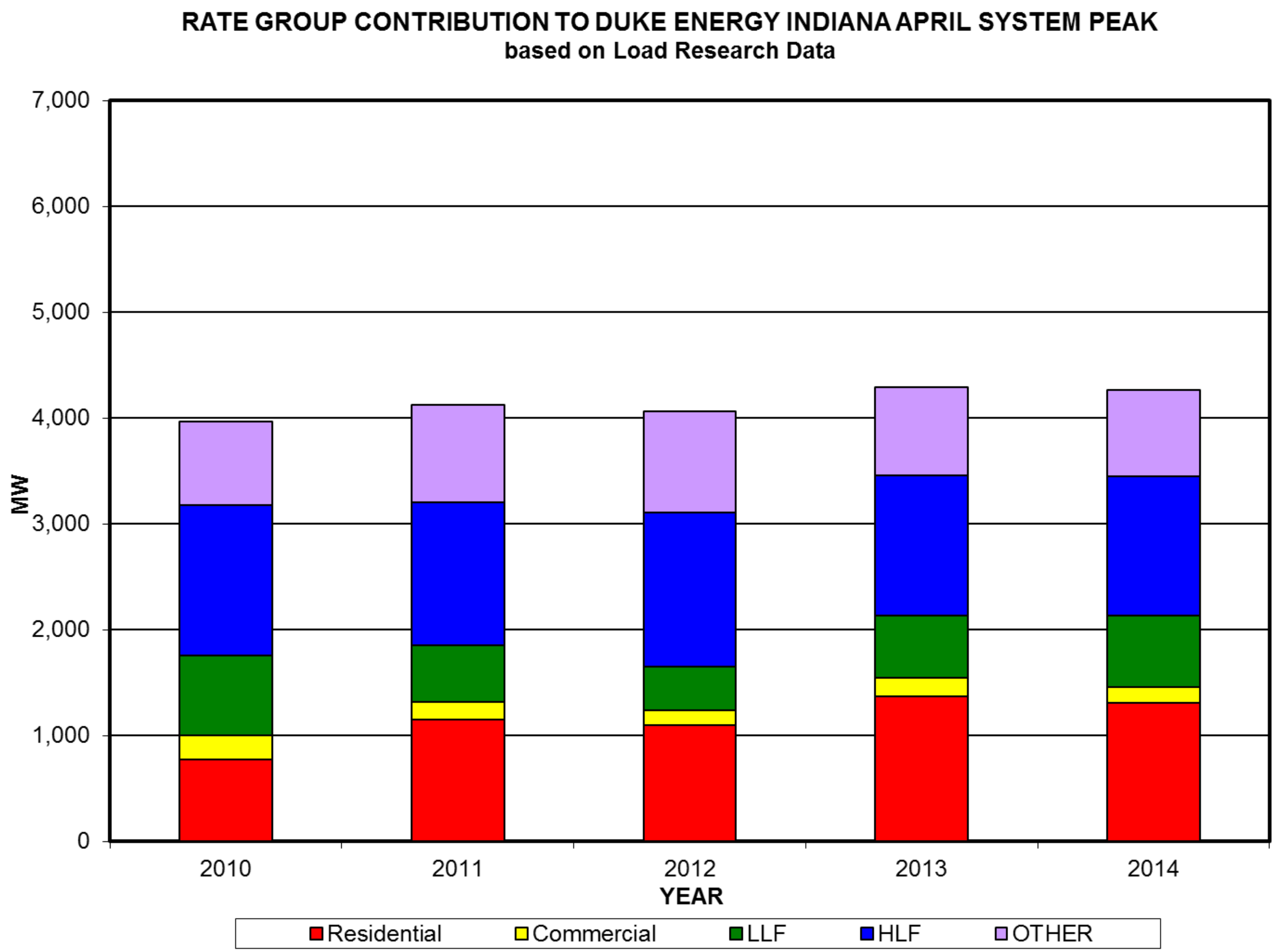
220

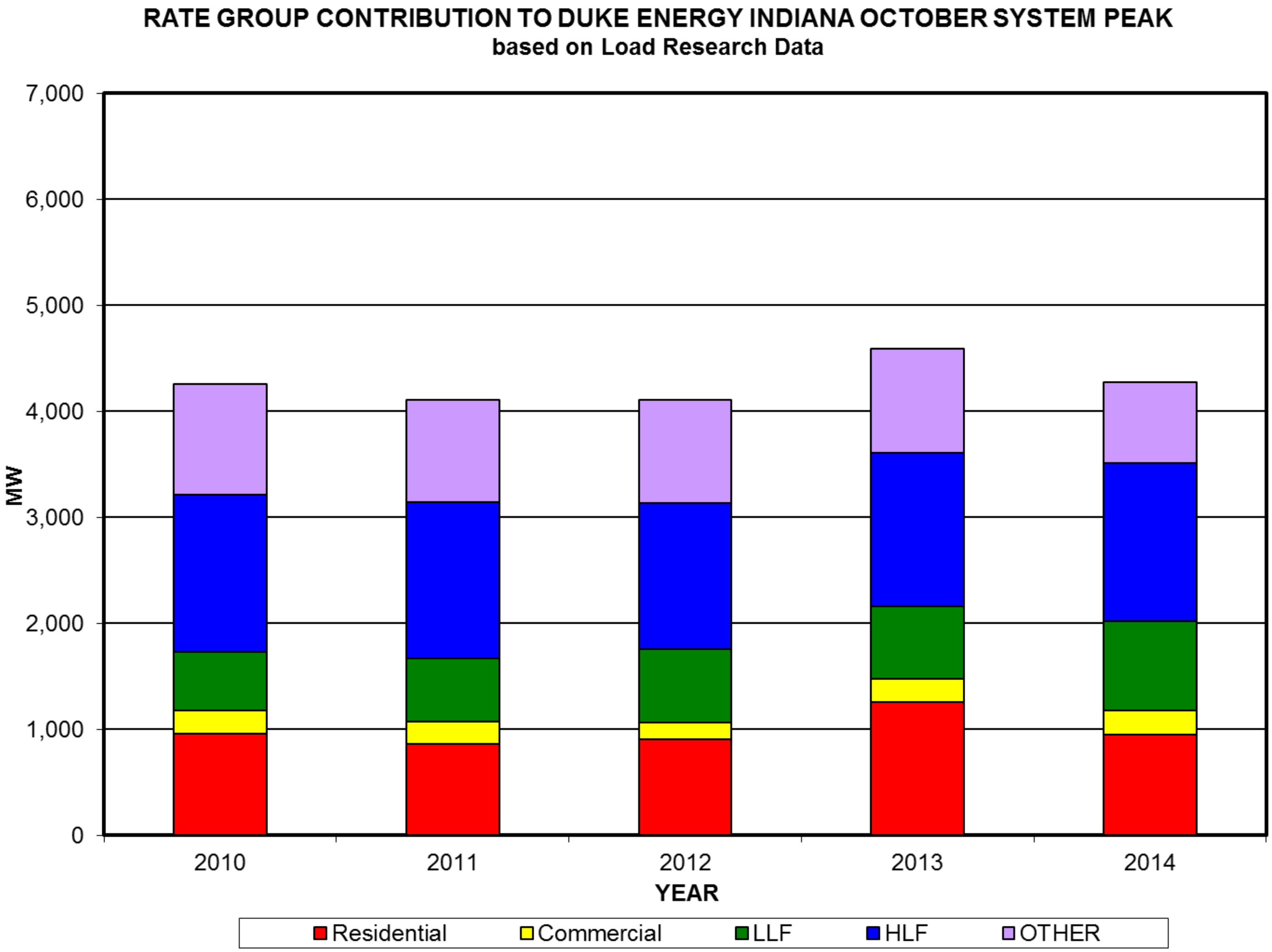

RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA SUMMER SYSTEM PEAK
based on Load Research Data
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
MW
2010
2011
2012
2013
2014
YEAR
Residential
Commercial
LLF
HLF
OTHER

221


RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA JANUARY SYSTEM PEAK
based on Load Research Data
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
MW
2010
2011
2012
2013
2014
YEAR
Residential
Commercial
LLF
HLF
OTHER

222


RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA APRIL SYSTEM PEAK
based on Load Research Data
MW
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2010
2011
2012
2013
2014
YEAR
Residential
Commercial
LLF
HLF
OTHER


RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA OCTOBER SYSTEM PEAK
based on Load Research Data
MW
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2010
2011
2012
2013
2014
YEAR
Residential
Commercial
LLF
HLF
OTHER

8. Weather-Normalized Peaks

DUKE ENERGY INDIANA
ACTUAL AND WEATHER NORMALIZED PEAKS (MW)

	SUMMER			WINTER	
YEAR	ACTUAL	WEATHER NORMALIZED		ACTUAL	WEATHER NORMALIZED
2001	6,101	6,224	2001-02	5,098	5,247
2002	6,250	6,397	2002-03	5,595	5,488
2003	6,269	6,564	2003-04	5,568	5,597
2004	6,136	6,409	2004-05	5,701	5,873
2005	6,766	6,692	2005-06	5,617	5,775
2006	6,702	6,739	2006-07	5,933	6,023
2007	6,866	6,804	2007-08	5,996	6,195
2008	6,243	6,493	2008-09	6,023	5,954
2009	6,037	6,194	2009-10	5,602	5,985
2010	6,476	6,491	2010-11	5,878	6,067
2011	6,749	6,490	2011-12	5,475	5,152
2012	6,494	6,510	2012-13	5,769	5,273
2013	6,229	6,461	2013-14	6,034	6,544
2014	6,130	6,508	2014-15	5,718	5,805

Note: Actual peak loads have been increased to include past impacts from demand response programs.
Note: Winter 2014-2015 peak based on preliminary data

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Appendix C: Energy Efficiency

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1. Avoided Cost for EE Screening

The avoided costs used in screening the EE and DR programs were based on information in the New Portfolio Program filing (Cause No. 43955 – DSM3) made with the Commission. The Company considers this information to be a trade secret and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

2. Duke Energy Indiana EE Program Data

EE and DR Program data is voluminous, and will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours. Please contact Beth Herriman at (317) 838-1254 for more information.

The table below provides projections of Gross MWh savings and program expenditures for the EE Programs for 2016-18. Please note that a filing requesting approval of a three year portfolio covering 2016-18 has been submitted in Cause 43955 DSM3 and the projections listed below for 2016-18 are subject to change pending final approval.

	Gross KWh @ Generation(1)	Gross KWh @ Generation(1)	Gross KWh @ Generation(1)	Program Expenditures(2)	Program Expenditures(2)	Program Expenditures(2)
Energy Efficiency Program Name	**Projected 2016**	**Projected 2017**	**Projected 2018**	**Projected 2016**	**Projected 2017**	**Projected 2018**
Residential						
Agency Assistance Portal	1,056,518	1,048,558	1,048,558	$ 184,475	$ 125,135	$ 126,918
Appliance Recycling Program	707,573	707,573	707,573	$ 164,662	$ 128,834	$ 151,309
Energy Efficiency Education Program for Schools	1,730,583	2,019,013	2,019,013	$ 651,084	$ 735,076	$ 764,330
Low Income Neighborhood	1,429,189	1,429,189	1,429,189	$ 689,642	$ 680,084	$ 739,613
Low Income Weatherization	741,056	741,056	741,056	$ 1,799,912	$ 1,803,960	$ 1,804,551
Multi-Family EE Products & Services	343,904	390,329	386,191	$ 94,989	$ 201,467	$ 101,510
My Home Energy Report	77,000,181	78,139,903	78,139,903	$ 3,376,867	$ 3,374,813	$ 3,396,708
Residential Energy Assessments	1,916,550	2,107,445	2,318,612	$ 843,763	$ 878,451	$ 932,386
Smart $aver® Residential	65,435,842	56,074,899	41,569,057	$ 9,238,655	$ 8,332,477	$ 6,536,661
Non-Residential						
Power Manager® for Business (3)	71,881	651,535	920,627	$ 112,551	$ 59,559	$ 76,808
Small Business Energy Saver	14,753,198	20,490,552	20,490,552	$ 3,420,558	$ 4,769,201	$ 4,699,526
Smart $aver® Non-Residential Custom Incentive	13,671,044	15,311,569	16,077,148	$ 1,959,510	$ 2,121,992	$ 2,222,489
Smart $aver® Non-Residential Prescriptive Incentive	27,459,780	28,653,674	29,808,602	$ 8,045,312	$ 8,113,473	$ 8,260,234
Total	**206,317,298**	**207,765,295**	**195,656,080**	**$ 30,581,980**	**$ 31,324,522**	**$ 29,813,043**

(1) MyHER KWh represents annual capability
(2) Program Expenditures include M&V costs
(3) KWh and Program Expenditures includes only EE portion of program

3. Benefit/Cost Test Components and Equations

BENEFIT/COST TEST MATRIX					
Benefits:	Participant Test	Utility Test	Ratepayer Impact Test	Total Resource Test	Societal Test
Customer Electric Bill Decrease	X				
Customer Non-electric Bill Decrease	X				
Customer O&M a nd Other Cost Decrease	X			X	X
Customer Income Tax Decrease	X			X	
Customer Investment Decrease	X			X	X
Customer Rebates Received	X				
Utility Revenue Increase			X		
Utility Electric Production Cost Decrease		X	X	X	X
Utility Generation Capacity Credit		X	X	X	X
Utility Transmission Capacity Credit		X	X	X	X
Utility Distribution Capacity Credit		X	X	X	X
Utility Administrative Cost Decrease		X	X	X	X
Utility Cap. Administrative Cost Decrease		X	X	X	X
Non-electric Acquisition Cost Decrease				X	X
Utility Sales Tax Cost Decrease		X	X	X	
Costs:					
Customer Electric Bill Increase	X				
Customer Non-electric Bill Increase	X			X	
Customer O&M and Other Cost Increase	X			X	X
Customer Income Tax Increase	X			X	
Customer Capital Investment Increase	X			X	X
Utility Revenue Decrease			X		
Utility Electric Production Cost Increase		X	X	X	X
Utility Generation Capacity Debit		X	X	X	X
Utility Transmission Capacity Debit		X	X	X	X
Utility Distribution Capacity Debit		X	X	X	X
Utility Rebates Paid		X	X		
Utility Administrative Cost Increase		X	X	X	X
Utility Cap. Administrative Cost Increase		X	X	X	X
Non-electric Acquisition Cost Increase				X	X
Utility Sales Tax Cost Increase		X	X	X	

Benefit/Cost Ratio = Total Benefits/Total Costs

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Appendix D: Financial Discussion Information

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CONFIDENTIAL INFORMATION REDACTED

1. NO_x and SO_2 Allowance Price Forecasts

The following Figure D-1 contains the NO_x and SO_2 allowance price forecasts used in the development of this IRP. These forecasts are trade secrets and are proprietary to EVA and Duke Energy Indiana. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders. Please contact Beth Herriman at (317) 838-1254 for more information.

Figure D-1

NOx and SO_2 Price Forecasts Nominal $/Ton		
Year	Annual NO_x	Annual SO_2
2015	[redacted]	
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		

Note: Seasonal NO_x allowance prices are assumed to be the same as the annual value.

2. Annual Avoided Cost

The annual avoided costs for the plan in this IRP are based on the market price forecast. Energy Ventures Analysis considers this forecast to be a trade secret and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

3. CO_2 Allowance Price Forecasts

Figure D-2 contains the CO_2 allowance price forecast used in the development of this IRP.

Figure D-2

CO_2 Price Forecasts Nominal $/Ton	
Year	Annual CO_2
2015	0
2016	0
2017	0
2018	0
2019	0
2020	17
2021	19
2022	21
2023	22
2024	24
2025	26
2026	28
2027	31
2028	33
2029	36
2030	39
2031	43
2032	46
2033	50
2034	53
2035	57

4. IRP PVRR

The 2015 Present Value Revenue Requirement (PVRR) obtained from the Planning and Risk (PaR) output for the selected plan is $31.6 billion or $0.067/kWh on a 25 year basis, and $19.8billion or $0.055/kWh on a 15 year basis. The following table shows the details.

TIME PERIOD	25 YEAR		15 YEAR	
	PVRR (B$)	% OF COSTS	PVRR (B$)	% OF COSTS
CAPITAL	$2.1	6.7%	$1.1	5.6%
PRODUCTION	$21.4	67.9%	$14.9	75.1%
CO2	$8.0	25.4%	$3.8	19.3%
TOTAL	$31.6	100%	$19.8	100%
$/kwh	$0.067		$0.055	

The modeling in PaR does not include the existing rate base (generation, transmission, or distribution). In addition, with the inclusion of estimates of both spot market purchases from, and sales to, the MISO market within the PaR modeling, Present Value Average Rate figures would not accurately reflect projected customer rates, so they have been omitted.

The effective after-tax discount rate used was 6.92%.

5. Impact of a Planned Addition on Rates

Information concerning the impact of each individual planned resource addition by itself is not available because an IRP, by definition, is an integrated combination of resources which together provide energy services in a reliable, efficient, and economic manner while factoring in environmental considerations.

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Appendix E:
Short-Term Implementation Plan

PREFACE

This section contains Duke Energy Indiana's plan for implementing supply-side resources and energy efficiency program resources over the next several years. The supply-side resources are forecast for the period 2016 through 2020.

ADDITIONS (MW)	2016	2017	2018	2019	2020
CT	0	0	0	0	0
Cogen	0	0	0	0	14.5
CC	0	0	0	0	448
PPA	0	0	0	300	-300
EE & IVVC	22	25	28	26	23
WR6 NG Conv	0	0	0	0	0
Solar	20	20	0	0	10
Wind	0	0	0	0	0
Biomass	0	0	0	0	2

RETIREMENTS

Unit	WR2-6		Oil CTs	Gal 2,4	
MW	-668	0	-166	-280	0

There is an additional layer to the analysis when specific resource decisions are made which involves an updated analysis that includes then current information. This is done to ensure that tactical decisions are made based on the best available data.

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SHORT-TERM IMPLEMENTATION PLAN

1. Supply-Side

Planned Purchases

Year	Company	Purchase Type	MW(1)
2015-2020	Benton County	Wind	100 (2)
2016-2020	Pastime	Solar	5 (3)
	McDonald	Solar	5 (3)
	Sullivan	Solar	5 (3)
	Geres	Solar	5 (3)

NOTES: (1) Rounded to the nearest full MW
(2) 13 MW assumed capacity value at the time of summer peak
(3) 2 MW assumed capacity value at the time of summer peak

Additionally, Duke Energy Indiana routinely executes energy hedge trades which provide Duke Energy Indiana price certainty and reduce customers' exposure to energy price volatilities.

Distributed Solar

Duke Energy Indiana intends to pursue opportunities to partner with its customers to install smaller-scale renewable energy projects throughout its system, and to possibly pair those renewable resources with storage and micro-grid technology. Duke Energy Indiana's preferred resource plan includes 20 MW of solar coming online in 2017 as a placeholder for a Company-owned solar project to be constructed and in-service by the end of 2016. The Company is currently working with several customers on projects in this approximate size and intends to present these projects to the Commission for its consideration.

Markland Hydro

Duke Energy Indiana intends to file in the near term for a Certificate of Public Convenience and Necessity (CPCN), per Indiana Code 8-1-8.5, for a major upgrade to the Markland

Hydroelectric facility. The Company intends to overhaul and upgrade each Markland unit from the ground up, replacing most components with more modern, efficient, upgraded options. The targeted outage windows are the fall of 2017, 2018, and 2019, one unit each year. This project will upgrade performance with the latest technology in turbine runner efficiency, allowing the extraction of more energy and capacity from the finite water resource. With this technology upgrade, Duke Energy Indiana expects to gain approximately 3MW/unit and 36.7 GWh from the station.

2. Environmental Compliance

MATS Compliance

Project Description

Duke Energy Indiana has completed installation of mercury re-emission prevention chemical addition systems and SCRs on Cayuga Units 1 and 2, as well as calcium bromide addition systems and mercury re-emission prevention chemical addition systems at Gibson. The precipitators refurbishments associated with Gibson Units 3, 4 and 5 are all expected to be completed by the fall of 2015. Filterable particulate matter and mercury CEMS, and mercury sorbent traps have all been installed per plan. In conjunction with this plan, MATS compliance extensions of one year (until April 16, 2016) have been granted for Cayuga, Gibson and Wabash River stations. Remaining short term actions include completion of initial MATS compliance demonstrations, the execution of the Wabash River Units 2-5 retirement in April of 2016, and determination of the Wabash River Unit 6 retire versus natural gas conversion decision.

Duke Energy Indiana CCR Rule Compliance

Project Description

Duke Energy Indiana has an ongoing detailed study of the Coal Combustion Residuals rule in order to determine applicability and develop a plan for compliance. Compliance with the CCR Rule will require taking appropriate measures to close existing ash ponds/basins. To support continued operation, each site will likely require installation of new retention ponds; dry bottom ash handling systems; ground water monitoring systems; fugitive dust controls;

run-on and run-off controls for landfills and inflow design flood control systems for impoundments, among other projects.

Other preliminary activities required to be completed prior to the installation of the above systems in the short term include: structural integrity evaluations; conducting engineering and/or environmental studies to determine if "Location Restrictions" are met; assessment of liner requirements; installation and evaluation of groundwater monitoring networks at impoundments and landfills and development of closure plans.

Anticipated Time Frame and Estimated Costs

Given the magnitude of the projects and the short time frame for compliance, planning assumptions for CCR began with the issuance of the proposed rule. EPA published the final CCR Rule on April 17, 2015. Duke Energy Indiana is evaluating the final rule and developing an appropriate compliance plan. The Company anticipates filing a proceeding with the Commission detailing its proposed CCR compliance plan, possibly by the end of 2015. The following are the current best cost estimates (excluding closure of ash ponds), subject to ongoing plan refinement.

	Estimated Capital Costs, 2015 IRP
2016	$128 million
2017	$33 million
2018	$0.3 million

Also see Chapter 6 for information related to environmental compliance planning.

3. Energy Efficiency

For 2015, the EE program portfolio reflects the implementation of a portfolio of programs approved in Cause 43955 – DSM2 . For periods 2016-18 the portfolio reflects the programs that were filed for approval in Cause 43955 – DSM3.

EE Programs Historically Offered By Duke Energy Indiana

Duke Energy Indiana has a long history EE programs. EE programs help reduce system demand during times of peak load and reduce energy consumption during peak and off-peak hours. The programs fall into two categories: traditional EE programs and demand response programs. Demand response programs include customer-specific contract curtailment options, the Power Manager (residential or commercial direct load control) program, and the PowerShare® program (for non-residential customers). Implementing cost-effective energy efficiency and demand response programs helps reduce overall long-term supply costs. Duke Energy Indiana's energy efficiency programs are primarily selected for implementation based upon their appeal to Duke Energy Indiana customers and cost-effectiveness; however, there may be programs, such as a low income program, that are chosen for implementation due to desirability from an educational and/or societal perspective.

Since 1991, Duke Energy Indiana has offered a variety of energy efficiency programs that create significant savings to customers. These programs have been approved through a variety of Commission Orders and will continue to be offered until replaced or modified as necessary due to mandates by the Commission or requests for Commission approval.

Current Programs

Duke Energy Indiana intends to continue to be a leader in EE by offering programs administered by the Company as submitted for approval in Cause No 43955 – DSM3.

General Objective

Through the portfolio of programs submitted for approval in Cause No. 43955 – DSM3, Duke Energy Indiana expects to reduce energy and demand through the implementation of a broad set of EE programs. These programs will be available for both residential and non-residential customers and include both energy efficiency and demand response programs.

Criteria for Measuring Progress

Evaluation, Measurement, and Verification (EM&V) studies will be undertaken to measure the impacts achieved from the implementation of the proposed programs. The EM&V will be conducted by an independent contractor employed by Duke Energy Indiana with oversight from the Indiana Oversight Board. The timetable the EM&V analyses will depend upon the timing of the deployment of these programs. A proposed schedule of EM&V Analysis was submitted in Cause No. 43955 – DSM3.

Program Descriptions

The details of the current and proposed Programs are included in Chapter 4, Section E.

Table E-1 Projected Program Expenditures (STIP-1)

	Program Costs & Overhead		
	2016	2017	2018
Portfolio			
Residential			
Energy Efficiency			
Agency Assistance Portal	$ 110,475	$ 115,135	$ 116,918
Appliance Recycling Program	$ 122,662	$ 123,834	$ 124,809
Energy Efficiency Education Program for Schools	$ 601,084	$ 705,076	$ 714,330
Low Income Neighborhood	$ 604,642	$ 630,084	$ 654,613
Low Income Weatherization	$ 1,739,115	$ 1,743,163	$ 1,743,754
Multi-Family EE Products & Services	$ 81,989	$ 84,467	$ 91,510
My Home Energy Report	$ 3,314,284	$ 3,322,000	$ 3,323,125
Residential Energy Assessments	$ 777,046	$ 848,799	$ 926,455
Smart $aver® Residential	$ 8,994,569	$ 8,132,371	$ 6,365,124
Energy Efficiency Total	**$ 16,345,866**	**$ 15,704,929**	**$ 14,060,638**
Demand Response			
Power Manager®	$ 2,046,494	$ 2,022,455	$ 1,925,741
Power Manager® for Apartments	$ 118,109	$ 273,237	$ 353,707
Demand Response Total	**$ 2,164,603**	**$ 2,295,692**	**$ 2,279,448**
Non-Residential			
Energy Efficiency			
Power Manager® for Business	$ 112,551	$ 59,559	$ 76,808
Small Business Energy Saver	$ 3,410,799	$ 4,635,032	$ 4,650,736
Smart $aver® Non-Residential Custom Incentive	$ 1,719,510	$ 1,881,992	$ 1,982,489
Smart $aver® Non-Residential Prescriptive Incentive	$ 7,530,312	$ 7,598,473	$ 7,745,234
Energy Efficiency Total	**$ 12,773,172**	**$ 14,175,056**	**$ 14,455,267**
Demand Response			
Power Manager® for Business	$ 500,607	$ 412,898	$ 708,787
Demand Response Total	**$ 500,607**	**$ 412,898**	**$ 708,787**

4. Transmission and Distribution

The transmission and distribution information is located in Appendix G of this report.

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Appendix F: Standardized Templates

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Table F
Supply vs Demand Balance

DUKE ENERGY INDIANA
SUPPLY VS. DEMAND BALANCE
(Summer Capacity and Loads)

YEAR	Owned Capacity[a] (MW)	Incremental Purchases (MW)	Incremental Capacity Additions (MW)	Incremental Capacity Retirements/ Derates (MW)	Incremental Behind The Meter Generation (MW)	Total Capacity (MW)	Peak Load (MW)	Conservation[b] (MW)	Demand Response (MW)	Net Load (MW)	Reserve Margin (%)	NOTES
2015	7387	13	0	0	18	7418	6259	-9	-632	5618	32.0	
2016	7418	8	8	-668	0	6767	6401	-31	-677	5693	18.9	Wabash River 2-6 retirement, Renewable PPAs
2017	6767	0	8	0	0	6775	6535	-56	-696	5783	17.2	Renewable
2018	6775	0	0	-166	0	6609	6613	-83	-720	5810	13.8	Connersville and Miami Wabash retirement
2019	6609	0	300	-280	0	6629	6662	-110	-735	5817	14.0	Gallagher 2 and 4 retirement, 1 year PPA
2020	6629	0	169	-6	0	6792	6705	-134	-751	5820	16.7	Environmental Controls, PPA Expiration, New CC, Renewable, Cogen
2021	6792	0	6	0	0	6798	6732	-159	-756	5818	16.9	Renewable
2022	6798	-3	7	0	0	6802	6769	-162	-761	5846	16.4	Renewable
2023	6802	0	17	0	0	6819	6805	-183	-766	5857	16.4	Renewable
2024	6819	0	17	0	0	6836	6836	-195	-772	5869	16.5	Renewable
2025	6836	0	8	0	0	6844	6881	-210	-777	5894	16.1	Renewable
2026	6844	0	14	0	0	6858	6916	-223	-782	5911	16.0	Renewable
2027	6858	0	15	0	0	6873	6960	-228	-787	5945	15.6	Renewable
2028	6873	-13	23	0	0	6884	6992	-228	-792	5972	15.3	Renewable
2029	6884	0	17	0	0	6900	7035	-232	-797	6007	14.9	Renewable
2030	6900	0	3	0	0	6903	7075	-235	-802	6038	14.3	Renewable
2031	6903	0	448	-310	0	7041	7137	-238	-808	6092	15.6	Gibson 5 retirement, New CC
2032	7041	0	0	0	0	7041	7193	-241	-813	6140	14.7	
2033	7041	0	208	0	0	7249	7246	-244	-818	6184	17.2	New CT
2034	7249	0	0	0	0	7249	7288	-248	-823	6218	16.6	
2035	7249	0	7	0	0	7256	7330	-250	-828	6252	16.1	Renewable

Notes:

[a] 20MW derate to serve steam to Premier Boxboard has been deducted

[b] Not already included in load forecast. This value is coincident with the net peak load, so it may not be the peak value for the year.

Table F-2
Duke Energy Indiana
Peak and Energy Forecasts (a)

	Summer Peak MW	Winter Peak (b) MW	Annual Peak MW	Annual Energy MWH	Load Factor (%)
2015	6,259	5,678	6,259	34,707,807	63.3%
2016	6,401	5,857	6,401	35,459,919	63.1%
2017	6,535	5,873	6,535	35,807,398	62.5%
2018	6,613	5,926	6,613	36,292,623	62.6%
2019	6,662	5,932	6,662	36,662,980	62.8%
2020	6,705	5,899	6,705	36,925,513	62.7%
2021	6,732	5,954	6,732	36,975,888	62.7%
2022	6,769	5,987	6,769	37,223,250	62.8%
2023	6,805	6,009	6,805	37,476,558	62.9%
2024	6,836	5,974	6,836	37,745,789	62.9%
2025	6,881	6,053	6,881	37,838,690	62.8%
2026	6,916	6,060	6,916	38,040,414	62.8%
2027	6,960	6,085	6,960	38,202,915	62.7%
2028	6,992	6,116	6,992	38,449,718	62.6%
2029	7,035	6,108	7,035	38,555,788	62.6%
2030	7,075	6,134	7,075	38,783,804	62.6%
2031	7,137	6,164	7,137	39,023,233	62.4%
2032	7,193	6,123	7,193	39,301,704	62.2%
2033	7,246	6,202	7,246	39,468,990	62.2%
2034	7,288	6,228	7,288	39,747,313	62.3%
2035	7,330	6,274	7,330	39,989,642	62.3%
CAGR	0.8%	0.5%	0.8%	0.7%	

(a) Figures reflect the impact of historical energy efficiency, represent peak demand before demand response, and numbers are weather normal.

(b) Winter load reference is to peak loads which occur in the following winter

Table F-3: Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Cayuga	1	Cayuga	IN	1970	ST	Coal		100.00%	505.0	500.0	FGD, EP, LNB, OFA, CT, SCR, DSI	
Cayuga	2	Cayuga	IN	1972	ST	Coal		100.00%	500.0	495.0	FGD, EP, LNB, OFA, CT, SCR, DSI	
Cayuga	3A	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3B	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3C	Cayuga	IN	1972	IC	Oil		100.00%	3.0	2.0	None	
Cayuga	3D	Cayuga	IN	1972	IC	Oil		100.00%	2.0	2.0	None	
Cayuga	4	Cayuga	IN	1993	CT	Gas	Oil	100.00%	120.0	99.0	DLN (Gas); WI (Oil)	
Connersville	1	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Connersville	2	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Edwardsport	IGCC	Knox County	IN	2013	IGCC	Syngas	Gas	100.00%	630.0	595.0	Selexol, SCR, MGB, CT	
Gallagher	2	New Albany	IN	1958	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gallagher	4	New Albany	IN	1961	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gibson	1	Owensville	IN	1976	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	2	Owensville	IN	1975	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	3	Owensville	IN	1978	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	4	Owensville	IN	1979	ST	Coal		100.00%	627.0	622.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	5	Owensville	IN	1982	ST	Coal		50.05%	312.8	310.3	FGD, SCR, SBS, EP, LNB, OFA, CL	Jointly owned with WVPA (25%) and IMPA (24.95%)
Henry County	1	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	50 MW from the plant is
Henry County	2	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	supplied to load other than DEI
Henry County	3	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	under PPA
Madison	1	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	2	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	3	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	4	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	5	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	6	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	7	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	8	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Markland	1	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	2	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	3	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	

[1] Edwardsport IGCC capacity ratings are preliminary pending ongoing program performance testing. The summer capacity reflects evaporative coolers in service.

Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Miami-Wabash	1	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	2	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	3	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	5	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	6	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Noblesville	1	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	2	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	3	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	4	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	5	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Vermillion	1	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	2	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	3	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	4	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	5	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	6	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	7	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	8	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Wabash River	2	West Terre Haute	IN	1953	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	3	West Terre Haute	IN	1954	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	4	West Terre Haute	IN	1955	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	5	West Terre Haute	IN	1956	ST	Coal		100.00%	95.0	95.0	EP, LNB, OFA	
Wabash River	6	West Terre Haute	IN	1968	ST	Coal		100.00%	318.0	318.0	EP, LNB, OFA	
Wabash River	7A	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7B	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7C	West Terre Haute	IN	1967	IC	Oil		100.00%	2.1	2.1	None	
Wheatland	1	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	2	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	3	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	4	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Total									7,871.0	7,494.0		

Unit Type

ST	Steam
CT	Simple Cycle Combustion Turbine
CC	Combined Cycle Combustion Turbine
IC	Internal Combustion
HY	Hydro
IGCC	Integrated Coal Gasification Combined Cycle

Fuel Type

Coal
Gas
Syngas
Oil
Water

Environmental Controls

FGD	SO_2 Scrubber
SCR	Selective Catalytic Reduction
SBS	Sodium Bisulfite / Soda Ash Injection System
LNB	Low NO_x Burner
EP	Electrostatic Precipitator
BH	Baghouse
CT	Cooling Tower
CL	Cooling Lake
WI	Water Injection (NO_x)
OFA	Overfire Air
CO	Passive Carbon Monoxide Catalyst
DSI	Dry Sorbent Injection
MGB	Mercury Guard Carbon Bed
DLN	Dry Low NO_x Combustion System
Selexol	Acid-Gas removal technology

Table F-4
Duke Energy Indiana
Summary of Existing Electric Generating Facilities by Plant

	Winter (MW)	Summer (MW)
Cayuga	1,136	1,104
Connersville	98	86
Edwardsport	630	595
Gallagher	280	280
Gibson	2,844.8	2,822.3
Henry County	129	129
Madison	704	576
Markland	45	45
Miami-Wabash	85	80
Noblesville	310.1	285.2
Vermillion	444.8	355.2
Wabash River	676.3	676.3
Wheatland	488	460
Grand Total	**7,871.0**	**7,494.0**

Table F-5
Duke Energy Indiana
Summary of Existing Electric Generating Facilities by Fuel

	Winter (MW)	Summer (MW)	Winter % of Total Capacity	Summer % of Total Capacity
Coal	**4,797.8**	**4,765.3**	**61.0%**	**63.6%**
Cayuga	1,005.0	995.0		
Gallagher	280.0	280.0		
Gibson	2,844.8	2,822.3		
Wabash River	668.0	668.0		
Syngas	**630.0**	**595.0**	**8.0%**	**7.9%**
Edwardsport	630.0	595.0		
Gas	**2,195.9**	**1,904.4**	**27.9%**	**25.4%**
Cayuga	120.0	99.0		
Henry County	129.0	129.0		
Madison	704.0	576.0		
Noblesville	310.1	285.2		
Vermillion	444.8	355.2		
Wheatland	488.0	460.0		
Oil	**202.3**	**184.3**	**2.5%**	**2.5%**
Cayuga	11.0	10.0		
Connersville	98.0	86.0		
Miami-Wabash	85.0	80.0		
Wabash River	8.3	8.3		
Water	**45.0**	**45.0**	**0.6%**	**0.6%**
Markland	45.0	45.0		
Grand Total	**7,871.0**	**7,494.0**		

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The Duke Energy Indiana
2015 Integrated Resource Plan

November 1, 2015

Appendix G:
Transmission Planning and Forecast

PREFACE

References to the combined transmission systems of Duke Energy Ohio and Duke Energy Kentucky are called Duke Energy Ohio. References to the combined transmission systems of Duke Energy Indiana and Duke Energy Ohio are called Duke Energy Midwest. The Figures associated with each chapter or section of this appendix are located at the end of that chapter or section.

APPENDIX G - Table of Contents

1. TRANSMISSION EXECUTIVE SUMMARY

A. System Description

The Duke Energy Midwest bulk transmission system is comprised of the 345 kilovolt (kV), and 138 kV systems of Duke Energy Ohio and the 345 kV, 230 kV, and 138 kV systems of Duke Energy Indiana. The transmission system serves primarily to deliver bulk power into and/or across Duke Energy Midwest's service area. This bulk power is distributed to numerous substations that supply lower voltage sub-transmission systems and distribution circuits, or directly to large customer loads. Because of the numerous interconnections Duke Energy Midwest has with neighboring local balancing areas, the Duke Energy Midwest transmission system increases electric system reliability and decreases costs to customer by permitting the exchange of power and energy with other utilities on an emergency or economic basis.

As of December 2014, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 850 circuit miles of 345 kV lines, 775 of 230 kV, and 1439 of 138 kV. Duke Energy Indiana, Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Association (WVPA) own the Joint Transmission System (JTS) in Indiana. The three co-owners have rights to use the JTS. Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and Vectren) plus Duke Energy Ohio.

Portions of the Duke Energy Ohio 345 kV system are jointly owned with Columbus Southern Power (CSP) and/or Dayton Power & Light (DP&L). As of December, 2014, the system of Duke Energy Ohio and its subsidiary companies consisted of approximately 403 circuit miles of 345 kV lines (including Duke Energy Ohio's share of jointly-owned transmission) and 726 circuit miles of 138 kV lines. Duke Energy Ohio is directly connected to five local balancing authorities (American Electric Power, Dayton Power and Light, East Kentucky Power

Cooperative, Louisville Gas and Electric Energy, Ohio Valley Electric Cooperative) plus Duke Energy Indiana.

B. Electric Transmission Forecast

As a member of MISO, Duke Energy Indiana participates in the MISO planning processes, and is subject to MISO overview and coordination mechanisms. All of Duke Energy Indiana's transmission facilities, including those transmission facilities owned by WVPA and IMPA but operated and maintained by Duke Energy Indiana, are included in these MISO planning processes. Additional coordination occurs through a variety of mechanisms, including Reliability*First* Corporation (RFC) and joint meetings with the other entities held as necessary.

2. ELECTRIC TRANSMISSION FORECAST

A. General Description

The Duke Energy Midwest bulk transmission system is comprised of 138 kV, 230 kV, and 345 kV systems. The 345 kV system distributes power from Duke Energy Midwest's large generating units, and interconnects the Duke Energy Midwest system with other systems. These interconnections enable the transmission of power between systems from jointly owned generating units and they provide capacity for economy and emergency power transfers. The 345 kV system is connected to the 138 kV and 230 kV systems through large transformers at a number of substations across the system. These 138 kV and 230 kV systems distribute power received through the transformers and from several smaller generating units, which are connected directly at these voltage levels. This power is distributed to substations, which supply lower voltage sub-transmission systems and distribution circuits, or directly to a number of large customer loads.

B. Transmission and Distribution Planning Process

Transmission and distribution (T&D) planning is a complex process which requires the evaluation of numerous factors to provide meaningful insights into the performance of the system. Duke Energy Midwest's distribution system planners gather information concerning actual distribution substation transformer and line loadings. The loading trend for each transformer is examined, and a projection of future transformer bank loading is made based on the historic load growth combined with the distribution planners' knowledge of load additions within the area. The load growth in a distribution planning area tends to be somewhat more uncertain and difficult to predict than the load forecasts made for Duke Energy Midwest as a whole.

Customers' decisions can dramatically impact the location and timing of future distribution capacity, and system improvement projects. Because of this uncertainty, distribution development plans are under continual review to make sure proposed projects remain appropriate for the area's needs.

T&D planning generally depends on the specific location of the loads, therefore the effects of co-generation capacity on T&D planning is location-specific. To the extent that fewer new T&D resources are required to serve these customers or the local areas in which they reside, Duke Energy Midwest's T&D planning will reflect this change.

Adding new distribution substation capacity to an area typically takes 18 to 24 months. Factors related to the future customer load, such as local knowledge of growth potential based on zoning, highway access and surrounding development, can help forecast ultimate distribution system needs.

Transmission system planners utilize the historical distribution substation transformer bank loading and trends, combined with the Duke Energy Midwest load forecast and resource plan and firm service schedules, to develop models of the transmission system. These models are used to simulate the transmission system performance under a range of credible conditions to ensure that expected performance meets both North American Electric Reliability Corporation (NERC) and Duke Energy Indiana planning criteria. Should these simulations indicate that a violation of the planning criteria occurs, more detailed studies are conducted to determine the severity of the problem and possible measures to alleviate it.

Duke Energy Indiana's planning criteria are filed under the FERC Form 715 Part 4. The Company adheres to any applicable NERC and RFC Reliability Standards, and to its own detailed planning criteria, which are shown in the following paragraphs. Violations of these criteria would require expansion of transmission system and/or new or revised operating procedures. Acceptance of operating procedures is based on engineering judgment with the consideration of the probability of violation weighed against its consequences and other factors.

Voltage

Bus voltages are screened using the Transmission System Voltage Limits below. These Limits specify minimum and maximum voltage levels during both normal and contingency conditions. Emergency Voltage Limits are defined as the upper and lower operating limits of each bus on the system. Voltage limits are expressed as a percent of nominal voltage. All voltages should be maintained within the appropriate Emergency voltage limits.

Transmission System Voltage Limits

Nominal Voltage (kV)	Normal Voltage Limits		Emergency Voltage Limits	
	Minimum	Maximum	Minimum	Maximum
345	95%	105%	90%	105%
230	95%	107%	90%	107%
138	95%	105%	90%	105%

Thermal

The following guidelines shall be used to ensure acceptable thermal loadings:

a) In normal conditions, no facility should exceed its continuous thermal loading capability.
b) For a single contingency, no facility should exceed its emergency loading capability.

Stability

The stability of the Duke Energy Indiana system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC and RFC Reliability Standards. Generating units must maintain angular stability under various contingency situations. Many different contingencies are considered and the selection is dependent on the location within the transmission system.

Fault Duty

All circuit breakers should be capable of interrupting the maximum fault current duty imposed on the circuit breaker.

Single Contingencies

The thermal and voltage limits should not be violated for either normal operations or under the loss of:

a) A single transmission circuit
b) A single transformer
c) A single generating unit

d) A single reactive power source or sink

Severe Contingencies

NERC Reliability Standards include evaluation of extreme (highly improbable) contingency events causing multiple elements to be removed or cascade out of service. Severe contingencies are evaluated to determine the impact on the Duke Energy Midwest and interconnected transmission systems. These evaluations are not intended to be absolute or applied without exception. Other factors, such as severity of consequences, availability of emergency switching procedures, probability of occurrence and the cost of remedial action are also considered in the evaluation of the transmission system.

C. System-Wide Reliability Measure

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

D. Evaluation of Adequacy for Load Growth

The transmission system of Duke Energy Midwest is adequate to support load growth and the expected power transfers over the next ten years if the planned transmission system expansions are completed as currently scheduled. See Section G in this Appendix for details on the major planned transmission projects. Duke Energy Midwest's transmission system can be significantly affected by the actions of others. In an attempt to evaluate these effects, RFC develops a series of power flow simulation base cases that reflect the expected transmission system configuration and expected power transfers. Should actual conditions differ significantly from those assumed in the base cases, a re-evaluation of the adequacy of the Duke Energy Midwest transmission system would be required.

E. Economic/Loss Evaluation

As a member of MISO, Duke Energy Indiana actively participates in the MISO Transmission Expansion Planning (MTEP) assessment and study processes which include economic analysis. MISO utilizes PROMOD, a commercial production cost model, to evaluate potential economic benefits of transmission projects or portfolios. Production cost model simulations are performed with and without each developed transmission project or portfolio. Taking the difference between these two cases provides the economic benefits associated with each project or portfolio. The economic benefits include adjusted production cost savings, reduced energy and capacity losses, and reduced congestion cost. Projects that meet initial qualification criteria will be further evaluated under the appropriate MISO or interregional planning process.

F. Transmission Expansion Plans

The transmission system expansion plans for the Duke Energy Midwest system are developed for the purpose of meeting the projected future requirements of the transmission system using power flow analysis. Power flow representations of the Duke Energy Midwest electric transmission system, which allow computer simulations to determine MW and MVAR flows and the voltages across the system, are maintained for the peak periods of the current and future years. These power flow base cases simulate the system under normal conditions with typical generation and no transmission outages. They are used to determine the general performance of the existing and planned transmission system under normal conditions.

Contingency cases based on the peak load base cases are studied to determine system performance for planned and unplanned transmission and generation outages. The results of these studies are used to determine the need for and timing of additions to the transmission system. As indicated earlier, Duke Energy Indiana, as a member of the MISO actively participate in the MISO MTEP assessment and study processes by reviewing the modeling data, providing simulation scenarios, and reviewing and providing feedback on the results of MTEP assessments and studies. All of Duke Energy Indiana’s transmission facilities, including those transmission facilities owned by WVPA and IMPA but operated and maintained by Duke Energy Indiana, are included in these MISO processes. In addition, MISO reviews Duke Energy Indiana’s proposed plans and makes comments and suggestions. Ultimately, MISO has responsibility for development of the regional transmission plan. MTEP 14 assessed the Duke Energy Indiana transmission system for the period 2014 through 2024 with simulations for years 2016, 2019 and 2024. These models were utilized to simulate both steady state and dynamic performance under a wide variety of credible conditions, such as Summer Peak, Shoulder Peak, and Light Load, to ensure that expected performance meets both NERC and Duke Energy Indiana planning criteria.

The MTEP studies provide an indication of system performance under a variety of conditions to guide the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The planning process identifies solutions to reliability issues that arise from the expected dispatch of network resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects and increased operating expenses from redispatching network resources or other operational actions.

G. Transmission Project Descriptions

The following planned transmission projects include new substation transformers, transmission capacitors, transmission circuits, and upgrades of existing circuits and substations.

Duke Energy Indiana plans to install transmission voltage capacitors totaling over 64.8 MVAR over the next three years. The capacitors will be installed at various existing transmission substations at 69 kV and 138 kV voltages throughout the system. These additions will supplement the existing 2593 MVAR in service the end of 2014. These capacitors are necessary to maintain and improve the over-all transmission voltage profile, reduce system losses, improve reactive margin at generating stations, and reduce interconnection reactive imports. Higher cost alternatives to capacitor installations include construction of additional transmission system capacity, static VAR compensators, and/or local generation.

The Speed to Jeffersonville 138kV line project enhances the bulk electric supply system serving the Clarksville Maritime load area. The Clarksville Maritime Center industrial park has port access off of the Ohio River and by the end of 2016 will be next to a new interstate highway extension from I265 in Kentucky over the Ohio River to I65 in Indiana. Just east of the Clark Maritime Center and the interstate extension is a new developing industrial park called River Ridge Commerce Center. The existing bulk transmission source to the Clark Maritime Center Industrial Park and River Ridge Commerce Center is provided from a tap off of a 138kV circuit that runs between Jeffersonville and Gallagher. The reserving source is off of a 138kV circuit that runs between the Speed substation and the Madison substation. This project will provide for a more secure and reliable 138kV source line for this load area by creating a new looped bulk system source line between the Speed substation and the Jeffersonville substation.

The Bedford to Hoosier Energy Worthington substation 13840 circuit is 33 miles long and was originally constructed in 1943. It terminates at the Hoosier Energy (HE) Worthington substation and the Duke Energy Bedford 345kV substation. A portion of this circuit is owned by Hoosier Energy and will not be rebuilt because the line section contains newer structures and conductor. The change in ownership along this 138kV line occurs at a location approximately 1.5 miles from the HE Worthington substation. There are two distribution substations served from this line: HE Buena Vista and HE Owensburg. Over 30 miles of the total line is constructed using copper transmission line conductor supported by wooden "X" and "H" frames structures. The rebuild of this 138kV line will provide a secure, reliable, and higher thermal capacity circuit.

The Lafayette 230 kV substation is a major bulk power delivery facility in Tippecanoe County. This substation has been a part of the bulk power system for many years. Due to age and condition of the 230 kV breakers, a plan has been developed to not only replace and upgrade the breakers with new equipment but also re-arrange the existing straight bus into a ring bus arrangement. The existing straight bus has an inherent concern that a single bus section failure will remove multiple lines and/or transformers from service. The ring bus design circumvents this problem by allowing only a single supply element outage with its associated bus section failure. This preserves the adjacent bus connected transformers and lines for continued service. Due to the complexity and cost of this effort, the total project was divided into two phases. Phase 1 was completed in 2014, and Phase 2 is scheduled for completion in 2016. The alternative to this project would be to spend on equipment upgrades only, but that retains a past bus design that limits not only reliability, but significantly impedes equipment maintenance due to the difficulty obtaining the required outages of multiple service components at the same time.

Madison 138 kV substation has been in service over 55 years and is in need of refurbishment due to equipment obsolescence, condition, and inadequate relaying protection issues. All three 138 kV line breakers will be replaced with the addition of new bank breakers, with complete system protection, line, and bank relaying functions being upgraded. Modern equipment will be installed to permit continued reliable service. Alternatives of continued operation issues and marginal equipment maintenance are not long term solutions.

Due to the expected retirement of Wabash River units 2-5, transmission improvements will be required. The current proposed transmission plan involves the construction of a new 138 kV circuit from Dresser to Wabash River.

The 2015-2017 cash flows associated with these planned major new Duke Energy Indiana transmission facility projects can be found in Section C of the Transmission Short-Term Implementation Plan (STIP).

H. <u>Economic Projects Comments</u>

Duke Energy Indiana continues to stay abreast of MISO expansion criteria and participate in MISO studies and evaluate transmission projects that provide economic value to Duke Energy Indiana customers.

STIP

Planned New Transmission Facilities

Description of Projects

See the tables below for status of previous projects reported as well as a current projects listing. More detailed descriptions of the current projects can be found in Section 2.G of this Appendix.

Criteria and Objectives for Monitoring Success

Milestones and criteria used to monitor the transmission facilities projects are typical of construction projects and measured on the following factors:

- Comparison of the actual completion date to the targeted completion date
- Comparison of the actual cost to the budgeted cost

Anticipated Time Frame and Estimated Costs

The cash flows associated with the major new transmission facility projects planned are shown below.

STATUS UPDATES AND CHANGES FROM PREVIOUS REPORT
DUKE ENERGY INDIANA TRANSMISSION PROJECTS

				CASH FLOWS ($000)		
PROJECT NAME	**MILES or MVA**	**kV**	**PROGRESS/ COMPLETION DATE**	**2013**	**2014**	**2015**
Qualitech Sub add 345/138 kV bank/terminal	200	138	12/31/2013 completed 9/8/2013 (Note 1)			
Qualitech-Pittsboro 138 kV circuit	2.6	138	12/31/2013 completed 9/8/2013 (Note 2)			
Plainfield South Sub 138 kV terminal	-	138	12/31/2013 completed 9/8/2013 (Note 3)			
TiptonWest –Kokomo Highland Park 230 kV line rebuild	14	230	6/1/2015 completed 7-11-14 (Note 6)			
Westpoint 230 kV Switching Station	-	230	12/31/15 Canceled 6-18-2014 (Note 4)			
Duke- LGE/KU 345 kV Interconnect Kenzig Switching Station.		345	12/31/2014 completed 5-18-15			$516
Lafayette 230 kV Sub Breaker Repl with Ring Bus Phase 1		230	12/31/2014 Completed 12/31/14			
Madison 138 kV Sub Breaker Repl Trans Relaying Upgrade		138	12/31/14 revised to 11-1-15 (Note 5)			$3833

CURRENT DUKE ENERGY INDIANA MAJOR TRANSMISSION PROJECTS

				CASH FLOWS ($000)		
PROJECT NAME	**MILES or MVA**	**kV**	**PROGRESS/ COMPLETION DATE**	**2015**	**2016**	**2017**
Speed to Jeffersonville 138kV line	2.5	138	12/31/16	$903	$4076	$0
Bedford to HE Worthington 138kV line rebuild	33	138	6/1/2017	$1098	$16120	$10666
Lafayette 230 kV Sub Breaker Repl with Ring Bus Phase 2	-	230	12/31/16	$11	$2652	$0
Dresser – Wabash River new 138 kV line	10.5	138	6/1/16	$6995	$4126	$0

*Excluding AFUDC

Anticipated Project Milestones

The completion of these projects, by their planned in-service dates and costs, are the project milestones. Individual project specific notes from the above tables are given as follows:

Note 1, 2, 3 – Project completion early due to favorable construction conditions.
Note 4 – Wind developer requested project to be canceled.
Note 5 – Project delayed to include 34.5 kV breaker replacements.
Note 6 – Project completed early to reduce associated outage times affecting reliability of a large Industrial load.

The Duke Energy Indiana 2015 Integrated Resource Plan

November 1, 2015

Appendix H: Cross-Reference to Proposed Rule

Appendix H: Cross-Reference to Proposed Rule

170 IAC 4-7 (Proposed 10/4/12) Regulatory Requirement	Location in Duke Energy Indiana 2013 IRP Document
Section 0.1 -Applicability	No Reponse Required
Section 1 - Definitions	No Reponse Required
Section 2 - Effects of filing integrated resource planning	No Reponse Required
Section 2.1 - Public Advisory Process	Chapter 3, Section E; Addendum
Section 2.2 - Contemporary Issues Tech Conf	No Reponse Required
Section 3 -Waiver or Variance Requests	No Reponse Required
Section 4 - Methodology and documentation	
(a) IRP Summary Document	Appendix I
(b)(1) inputs, methods, definitions	Chapter 3, Sections B & E; Chapter 4, Sections E & F; Chapter 5, Section F; Chapter 6, Section G; Chapter 8, Section B; Appendix A
(b)(2) forecast datasets	Chapter 3, Section D; Appendix B
(b)(3) consumption patterns	Chapter 3, Section D; Appendix B
(b)(4) customer surveys	Chapter 3, Sections D & E; Appendix B
(b)(5) customer self-generation	Chapter 3, Section C; Chapter 5, Section C
(b)(11) contemporary methods	Chapter 3, Sections B & E; Chapter 4, Sections E & F; Chapter 5, Section E & F; Chapter 6, Section G, H; Chapter 8, Section B; Appendix A & G
(b)(6) alternative forecast scenarios	Chapter 2, Section B; Chapter 3, Section F; Chapter 4, Section D; Chapter 8, Section B
(b)(7) fuel inventory and procurement	Chapter 5, Section B
(b)(8) SO_2 emissions allowances	Chapter 6, Sections H & I
(b)(9) expansion planning criteria	Chapter 1, Section A; Chapter 2, Sections B, C & D
(b)(10)(A) power flow study	Appendix G
(b)(10)(B) dynamic stability study	Appendix G
(b)(10)(C) transmission reliability criteria	Appendix G
(b)(12) avoided cost calculation	Chapter 8, Section B; Appendix D
(b)(13) system actual demand	Appendix B
(b)(14) public advisory process	Chapter 3, Section E; Addendum
Section 5 - Energy and demand forecasts	
(a)(1) analysis of load shapes	Chapter 3, Section B; Appendix B
(a)(2) disaggregated load shapes	Appendix B
(a)(3) disaggregated data & forecasts	Appendix B
(a)(4) energy and demand levels	Chapter 3, Section F; Appendix B
(a)(5) weather normilization methods	Chapter 3, Sections B & E; Appendix B
(a)(6) energy and demand forecasts	Chapter 3, Section F; Appendix B
(a)(7) forecast performance	Appendix B
(a)(8) end-use forecast methodology	Chapter 3, Section E, part (2); Appendix B
(a)(9) load shape data directions	No response required
(b) alternative peak/energy forecasts	Chapter 3, Section F

(Appendix H Index continued)

Regulatory Requirement	Location in Duke Energy Indiana 2013 IRP Document
Section 6 - Resource assessment	
(a)(1) net dependable capacity	Chapter 5, Figure 5-A; Appendix F
(a)(2) expected capacity changes	Chapter 1, Section A; Chapter 5, Section B; Chapter 8, Section B
(a)(3) fuel price forecast	Chapter 1, Section A; Chapter 5, Section B; Chapter 8, Section B
(a)(4) significant environmental effects	Chapter 1, Section A; Chapter 2, Section B; Chapter 5, Section B; Chapter 6, Sections G, H, & I; Appendix E, Section B
(a)(5) transmission system analysis	Appendix G
(a)(6) demand-side programs	Chapter 4, All Sections; Appendix C; Appendix E, Section C
(b)(1) DSM program description	Chapter 4, All Sections; Appendix C; Appendix E, Section C
(b)(2) DSM avoided cost projections	Appendix C; Appendix E, Section C
(b)(3) DSM customer class affected	Chapter 4, Sections D & E; Appendix E, Section C
(b)(4) DSM impact projections	Chapter 1, Section A; Chapter 4, Sections D & E
(b)(5) DSM program cost projections	Appendix E, Section C
(b)(6) DSM energy/demand savings	Chapter 1, Section A; Chapter 4, Section E; Appendix C
(b)(7) DSM program penetration	Chapter 4, Section E; Appendix C
(b)(8) DSM impact on systems	Chapter 4, Section E; Appendix C
(c)(1) supply-side resource description	Chapter 5, Sections E, F & J; Chapter 8, Section B; Appendix A; Appendix E
(c)(2) utility coordinated cost reduction	Chapter 5, Section F
(d)(1) transmission expansion	Appendix G
(d)(2) transmission expansion costs	Appendix G
(d)(3) power transfer	Appendix G
(d)(4) RTO planning and implementation	Chapter 2, Section C; Chapter 5, Section D
Section 7 - Selection of future resources	
(a) resource alternative screening	Chapter 4, Sections F & G; Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix C
(a)(1) environmental effects	Chapter 1, Section A; Chapter 2, Section C; Chapter 6; Appendix E, Section B
(a)(2) environmental regulation	Chapter 1, Section A; Chapter 2, Section C; Chapter 6; Appendix E, Section B
(b) DSM tests	Chapter 4, Section F; Appendix C
(c) life cycle NPV impacts	Chapter 8, Section B; Appendix D
(d)(1) cost/benefit components	Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix C
(d)(2) cost/benefit equation	Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix C
(e) DSM test exception	No response required
(f) load build directions	No response required
Section 8 - Resource integration	
(a) candidate resource portfolios process	Chapter 8
(b)(1) resource plan description	Chapter 1, Sections A & B; Chapter 8, Section B
(b)(2) significant factors	Chapter 1, Sections A & B; Chapter 2; Chapter 6; Chapter 8, Section B
(b)(7)(D) PVRR of resource plan	Chapter 8, Section B; Appendix A
(b)(4) utilization of all resources	Chapter 4; Chapter 5, Sections B, C, F & H; Chapter 8, Section B; Appendix C; Appendix E
(b)(7)(B)(i) risk management	Chapter 1, Section A; Chapter 2, Section B; Chapter 6; Chapter 8, Section B
(b)(7)(D) supply-side selection economics	Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix E

(Appendix H Index continued)

Regulatory Requirement	Location in Duke Energy Indiana 2013 IRP Document
(b)(5) DSM utilization	Chapter 3, Section C; Chapter 4, Section F; Chapter 5, Sections C
(b)(6) plan operating and capital costs	Chapter 8, Section B; Appendix D
(b)(6) average cost per kWh	Chapter 8, Section B; Appendix D
(b)(6) annual avoided cost	Appendix D
(b)(6)(D) plan resource financing	Appendix D; Appendix E
(b)(7)(A&B) regulation assumptions	Chapter 1, Section A; Chapter 2, Section C; Chapter 5, Section B; Chapter 6; Chapter 8, Section B
(b)(8)(A) demand sensitivity	Chapter 3, Section F; Chapter 8, Section B; Appendix B
(b)(8)(B) resource cost sensitivity	Chapter 5, Section F; Chapter 8, Section B
(b)(8)(C) regulatory compliance	Chapter 1, Section A; Chapter 2, Section B; Chapter 6; Chapter 8, Section B
(b)(8)(D) other factor sensitivities	Chapter 5, Section F; Chapter 8, Section B
Section 9 - Short term action plan	
(1)(A) description/objective	Appendix D, Sections A, B & C
(1)(B) progress measurement criteria	Appendix D, Sections A, B & C
(2) implementation schedule	Appendix D, Sections A, B & C
(3) plan budget	Appendix D, Sections A, B & C
(4) prior STIP vs actual	Appendix E

DUKE ENERGY.
INDIANA

The Duke Energy Indiana
2015 Integrated Resource Plan

November 1, 2015

Volume 2:
Summary Document and
Stakeholder Meetings

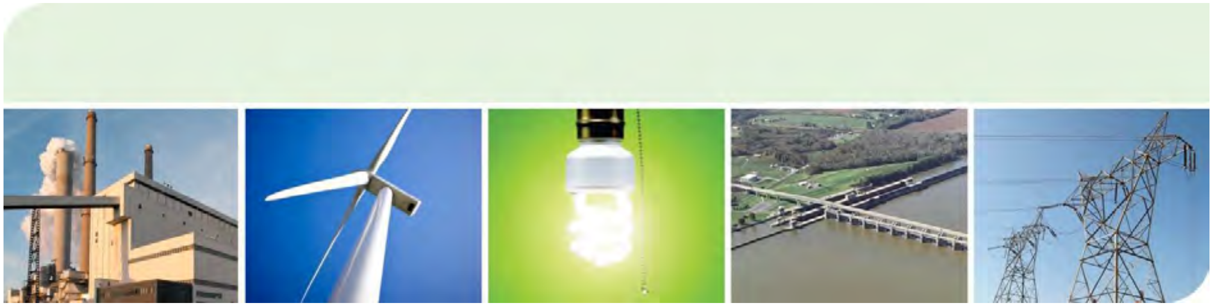


TABLE OF CONTENTS:

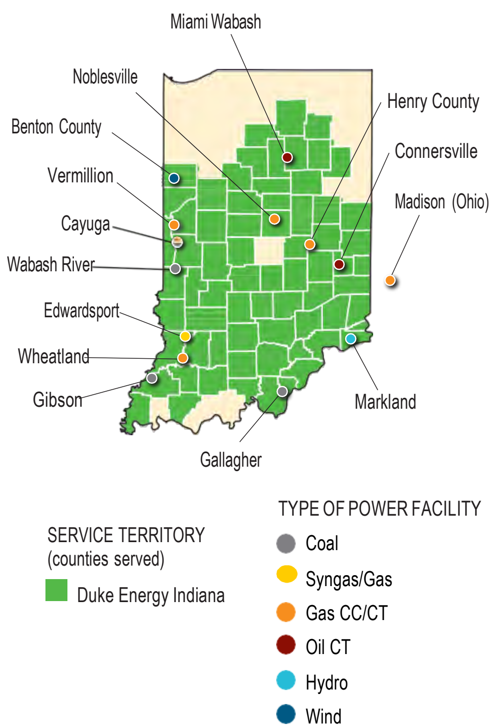
SECTION: **PAGE:**

2015 Duke Energy Indiana
Integrated Resource Plan
11.1.2015

What's Inside

- Duke Energy Indiana, an overview
- What is an IRP?
- Our public advisory process
- Forecasting future energy demand
- Energy supply portfolio and capacity
- Great strides in energy efficiency
- Environmental stewardship
- Partnering to deliver energy

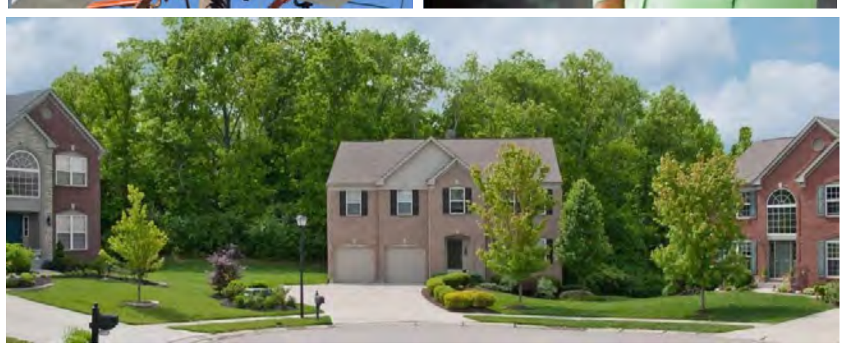
Duke Energy Indiana: an overview



As the state's largest electric utility, Duke Energy Indiana provides affordable, reliable and cleaner energy to approximately 800,000 residential, commercial and industrial electric customers.

- Serving customers in 69 of Indiana's 92 counties
- Service area spans 22,000 square miles across north central, central and southern Indiana
- Supporting cities such as Bloomington, Terre Haute and Lafayette
- Also serving suburban areas near Indianapolis, Indiana, Louisville, Kentucky and Cincinnati, Ohio
- Generating facilities capable of producing 7,507 megawatts of electricity
- Bringing power to our customers through 3,064 miles of transmission lines

Duke Energy Indiana is dedicated to strengthening the communities we serve. We work hard to develop clean and efficient energy sources and to help create jobs that bolster the local economy – helping to make this state a great place to live, work and play.



What is an IRP?

An IRP summary document, such as this one, helps our customers understand how we supply and deliver energy today – and also how we will continue to enhance our service in the future.

Duke Energy Indiana's Integrated Resource Plan is a comprehensive planning document used to forecast customer demand for electricity and our response to those needs. Our goal is to provide affordable, reliable and cleaner energy for our customers today and in the future. The IRP is updated and filed every two years with the Indiana Utility Regulatory Commission (IURC), and it outlines the processes, methods and forecasting models used to create the 20-year plan.

With each IRP, we use current information to keep our long-term plan updated. When it is time to make a near-term decision, we gather the best available information to analyze for that specific decision in detail. This two-level approach enables us to make the best decisions today and prepare for meeting customers' needs in the future.

Our public advisory process

Engagement process overview

- Third-party, unbiased facilitator
- Involving stakeholders from the beginning of the IRP development
- Four stakeholder workshops
- Informative presentations and interactive workshop exercises
- Summaries on public IRP website at duke-energy.com/indiana/in-irp-2015.asp

As part of the public advisory process with our customers, Duke Energy Indiana conducted four stakeholder meetings to gather feedback and discuss the IRP process with interested parties. The four meetings and related activities are summarized below:

Stakeholder Meetings:

Mar. 17, 2015

- Review of 2013 stakeholder process and plan for 2015 process
- Scenario planning overview and discussion of driving forces
- Stakeholder scenario planning exercise

Jun. 4, 2015

- Presentation of proposed scenarios
- Discussion of resource options for portfolio development
- Stakeholder portfolio development exercise

Aug. 4, 2015

- Scenario and portfolio review
- Discussion of preliminary modeling results
- Stakeholder sensitivity analysis exercise

Oct. 16, 2015

- Discussion of final modeling results
- Decision and risk management discussion
- Presentation of preferred portfolio
- Discussion of short-term implementation plan

Materials covered and meeting summaries are posted on the company's website at **duke-energy.com/indiana/in-irp-2015.asp**

Forecasting future energy demand

To address future uncertainty, Duke Energy Indiana develops a comprehensive plan that includes development and analysis of different future scenarios. At the same time, the company must be flexible to adjust to evolving regulatory, economic, environmental and operating circumstances.

We used scenario analysis as part of this year's IRP planning process. Once we identified some key driving forces, including carbon pricing, environmental regulations and fuel prices, we discussed those pressures in our stakeholder meetings. The feedback gathered helped us develop seven separate scenarios:

The first set of scenarios is the "Core" Scenarios:

No Carbon Regulation

- No carbon tax/price or regulation
- Moderate levels of environmental regulation
- No Renewable Energy Portfolio Standard (REPS)

Carbon Tax

- Carbon tax \$17/ton in 2020, rising to \$57/ton by 2035
- Increased levels of environmental regulation
- 5% REPS

Clean Power Plan (based on CPP Proposed Rule)

- Carbon emissions reduced 20%
- Increased levels of environmental regulation
- 5% REPS

The second set is the "Change of Outlook" Scenarios:

Delayed Carbon Regulation

- No Carbon Regulation scenario for the early years of the IRP planning period
- Change to the Carbon Tax scenario for latter part
- Demonstrates impact of delayed carbon regulation

Repealed Carbon Regulation

- Carbon Tax scenario initially
- Change to No Carbon Regulation scenario for latter part
- Demonstrates impact of repeal of carbon regulation

The third set is the "Stakeholder-inspired" Scenarios:

Increased Customer Choice

- Carbon Tax scenario basis
- Roof top solar serves an additional 1% of customer load per year beginning in 2020
- Customers adopt higher levels of Energy Efficiency
- New utility-scale generation served by merchant generators

Climate Change

- Higher summer temperatures increase demand and prices for power and fuel
- Carbon tax same as the Carbon Tax scenario
- Even hotter summer in 2019 and "polar vortex" in 2020, and every 5 years thereafter, causing higher prices and peak energy demand

Energy supply and capacity

Energy planning

We carefully consider which types of generating options we use because each source has its own set of advantages and disadvantages, ranging from costs and environmental attributes to reliability.

Since customers demand different amounts of energy depending on time of day and season, our generation portfolio requires a mix of resources that provides the flexibility needed to meet varying loads. These options include:

- Natural gas
- Renewable energy
- Hydroelectric power
- Biomass energy
- Nuclear
- Energy efficiency
- Demand-based service
- Customer-generated power

Ultimately, our energy portfolio includes a diverse mix of options to provide the most reliable, affordable and clean energy available to our customers.

Once the specific modeling assumptions for each scenario were determined, a capacity expansion model was used to optimize a portfolio for that scenario. Nine portfolios, organized in three groups, were evaluated to further increase the robustness of the planning analysis.

The first group of portfolios was developed as part of the optimization of the assumptions defined by the first three scenarios (No Carbon Regulation, Carbon Tax and Proposed Clean Power Plan).

Optimized Resource Plans:

No Carbon Regulation Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016 and the Miami-Wabash and Connersville CTs in 2018
- Most of the resource additions are natural gas fueled Combustion Turbines (CTs)
- Assumes a significant amount of energy purchased from the market

Carbon Tax Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in the 2030s
- Resource additions are primarily renewables and CTs
- Assumes a significant amount of energy purchased from the market

Proposed Clean Power Plan (P-CPP) Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in 2020
- Resource additions are primarily renewables and CT generation
- Assumes a significant amount of energy is purchased from the market

Energy supply and capacity

The second group of portfolios was developed by substituting natural gas fueled combined cycle (CC) power plants in lieu of some of the new combustion turbines (CT) in the portfolios above. This was done to evaluate the impact of adding additional gas generation on cost, carbon emissions and power market interaction.

Combined Cycle Resource Plans:

No Carbon Regulation Portfolio with additional CC

- Assumes retirement of Wabash River units 2-6 in 2016 and the Miami-Wabash and Connersville CTs in 2018
- Resource additions are primarily CCs and a few combined heat and power (CHP) projects
- Additional CC generation lessens the amount of energy purchased from the market

Carbon Tax Portfolio with additional CC

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in the 2030s
- Resource additions are primarily CCs and renewables
- Additional CC generation lessens the amount of energy purchased from the market

Proposed Clean Power Plan Portfolio with additional CC

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in 2020
- Resource additions are primarily CCs and renewables
- Additional CC generation lessens the amount of energy purchased from the market

The third portfolio group was based on input from stakeholders as part of the IRP stakeholder process.

Stakeholder-Inspired Resource Plans:

Stakeholder Distributed Generation Portfolio

- Developed by stakeholders in IRP stakeholder meetings
- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, both Cayuga units, and Gibson units 1-3 & 5
- Resource additions include CTs and CCs with significant additions of CHP, battery storage and renewables

Stakeholder Green Utility Portfolio

- Developed by stakeholders in IRP stakeholder meeting
- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, both Cayuga units, and Gibson units 1 & 5
- Resource additions include CT and CC generation as well as significant additions (although less than the Stakeholder Distributed Generation Portfolio) of CHP and renewables

High Renewables Portfolio

- Assumes retirement of Wabash River units 2-6 in 2016, Miami-Wabash and Connersville CTs in 2018, Gallagher 2&4 in 2019, and Gibson unit 5 in the 2030s
- Resource additions are significantly higher levels of renewables and CTs
- Assumes a significant amount of energy purchased from the market

Energy supply and capacity

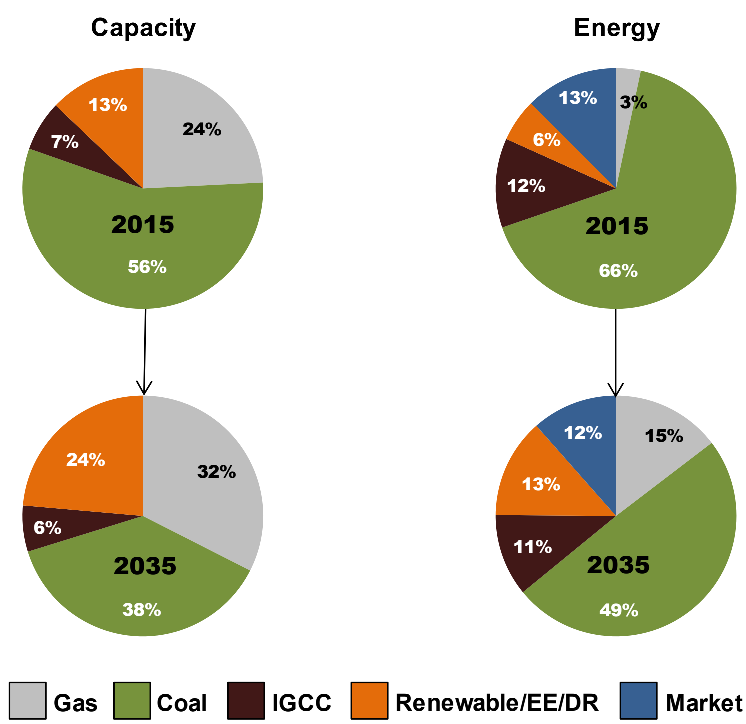
The short-term action plan for several portfolios is very similar. Over the next five years, we expect to:

- Retire several older coal and oil-fired units
- Potentially convert Wabash River 6 to natural gas
- Evaluate renewable generation
- Evaluate new natural gas generation
- Implement energy efficiency programs

New environmental regulations will likely result in the retirement of some additional coal units beyond those previously announced. This capacity will be replaced with the most cost-effective option. Depending on the time and scenario, that could be gas, renewables, nuclear or greater application of energy efficiency methods.

After comparing the expected cost of each portfolio under a variety of scenario assumptions, we selected the Carbon Tax Portfolio with additional CC for the 2015 IRP. This portfolio benefits from a diverse generation mix as well as the ability to respond to emerging regulations. The generation resource mix of the selected portfolio is shown in the chart below.

Current and Projected Capacity and Energy Mix



DUKE ENERGY

Great strides in energy efficiency

At Duke Energy Indiana, we think of energy efficiency as the "fifth fuel," joining coal, natural gas, nuclear and renewables as a critical resource needed to serve the growing energy needs of the communities we serve. We are committed to working with Indiana regulators to develop energy efficiency programs that save our customers money and improve our environment.

We offer residential and business customers many tools, programs and incentives to help save money and energy including:

- Free and discounted bulbs
- Home energy house call
- My home energy report
- Smart $aver®
- Power Manager®
- Appliance recycling

These are only a few of the programs our customers can participate in throughout the Duke Energy Indiana service territory. To learn more about how to earn rebates to help increase energy efficiency in your home or business, visit duke-energy.com.

Environmental stewardship


Duke Energy as a company continues to move toward a lower- carbon future through an aggressive power plant modernization program. By retiring old coal plants, deploying clean energy technologies and improving energy efficiency, the company is reducing the amount of carbon emitted per unit of electricity generated – a measure known as “carbon intensity.”

With the latest developments in renewable energy, such as wind and solar power, and our use of new, advanced-technology coal and natural gas plants, Duke Energy is delivering on its promise to provide cleaner energy from a diverse mix of fuel sources.

Partnering to deliver energy

Duke Energy Indiana is a member of the Midcontinent Independent System Operators (MISO) network, along with electric utilities across 15 U.S. states and the Canadian province of Manitoba. As a member, Duke Energy Indiana is able to supplement its existing energy resources with short-term purchases of energy from the markets operated by MISO.

Duke Energy Indiana participates in MISO’s transmission planning processes and is subject to MISO’s overview and coordination requirements. Duke Energy Indiana performs internal and MISO- coordinated analyses of the transmission system to determine whether new or upgraded facilities are needed to maintain near- and long-term system reliability. This process has identified several projects that are planned for completion over the next few years.

2015 Integrated Resource Plan

Stakeholder Workshop #1

March 17, 2015
Plainfield, IN

Doug Esamann, State President- Indiana, Duke Energy

Welcome

Welcome

- Safety message
- Why are we here today?
- Objectives for stakeholder process
- Introduce the facilitator

DUKE ENERGY.

The Facilitator

- Duke Energy Indiana hired Dr. Marty Rozelle of The Rozelle Group and her colleagues to:
  - Help us develop the IRP stakeholder engagement process
  - Facilitate and document stakeholder workshops

DUKE ENERGY.

Why are we here today?

- Duke Energy Indiana developing 2015 Integrated Resource Plan (IRP)
- Proactively complying with proposed Commission IRP rule
- Today is the first of four stakeholder workshops prior to filing the IRP by November 1, 2015

Objectives for Stakeholder Process

- **Listen:** Understand concerns and objectives
- **Inform:** Increase stakeholders' understanding of the IRP process, key assumptions, and challenges we face
- **Consider:** Provide a forum for productive stakeholder feedback at key points in the IRP process to inform Duke Energy Indiana's decision-making
- **Comply:** Comply with the proposed Commission IRP rule

Agenda

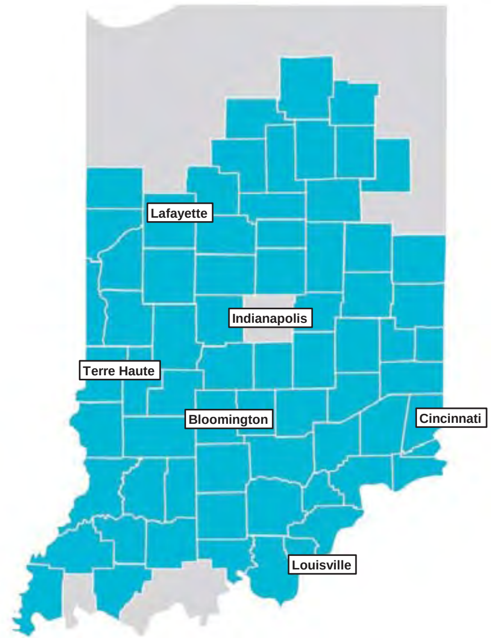
08:30	Registration & Continental Breakfast
09:00	Welcome, Introductions, Agenda
09:30	Overview of Duke Energy Indiana
09:45	Review of 2013 Stakeholder Process and IRP
10:15	Break
10:30	Lessons Learned
11:00	Overview of 2015 Stakeholder Process and IRP
11:45	Lunch
12:30	Scenario Planning Overview
12:45	Scenario Discussion
02:00	Closing Comments

Brian Bak, Lead Planning Analyst

Overview of Duke Energy Indiana

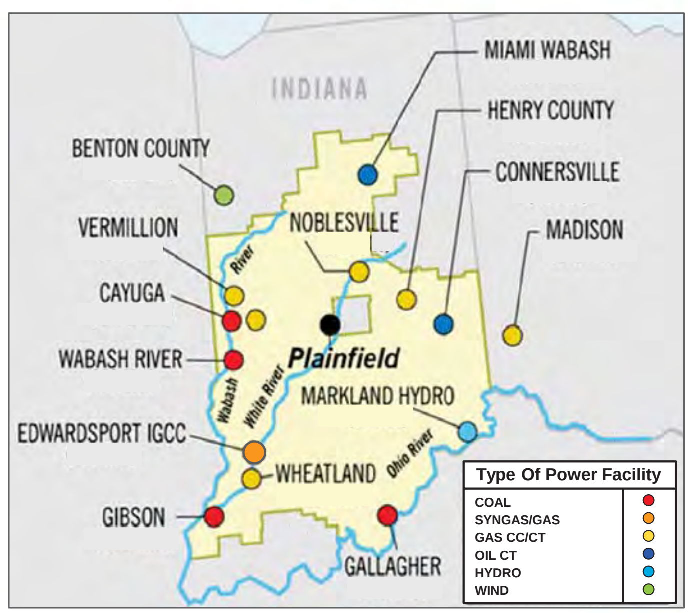
Duke Energy Indiana: Overview

- Indiana's largest electric utility
  - 790,000 customers
  - 22,000 square miles
  - Portions of 69 counties including cities of Bloomington, Terre Haute, Lafayette, and suburban areas near Indianapolis, Louisville and Cincinnati
  - 2,800 miles of transmission lines
  - 30,900 miles of distribution lines



Existing generation resources

- Coal (4,765 MW)
  - Cayuga 1 & 2
  - Gallagher 2 & 4
  - Gibson 1-5
  - Wabash River 2-6 (668MW)
- IGCC (595 MW)
- Combined Cycle (285 MW)
- Combustion Turbine
  - Gas Fired (1619MW)
  - Oil Fired (166MW)
- Hydro (45 MW)
- Wind (100 MW PPA)
- Solar (20 MW PPA)



Planned Near-term Retirements & Additions

- Retirement of Wabash River 2-5
- Suspension of Wabash River 6
- Retirement of oil-fired CTs
- Additional environmental controls:
  - Gibson: Precipitator refurbishments, monitoring
  - Cayuga: SCR addition, monitoring

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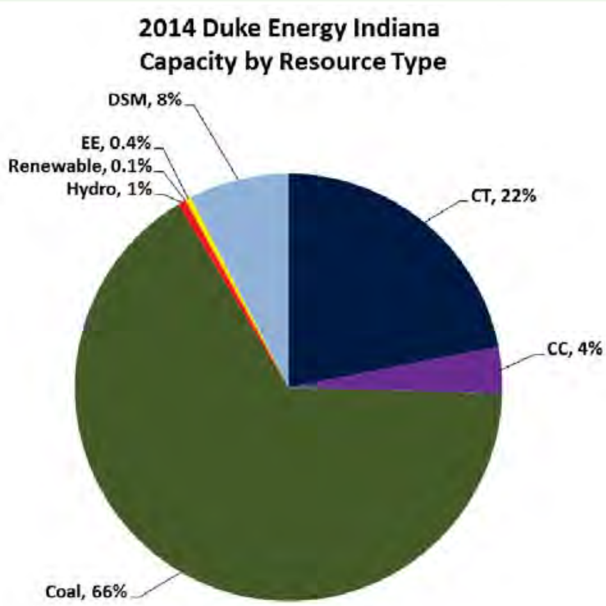
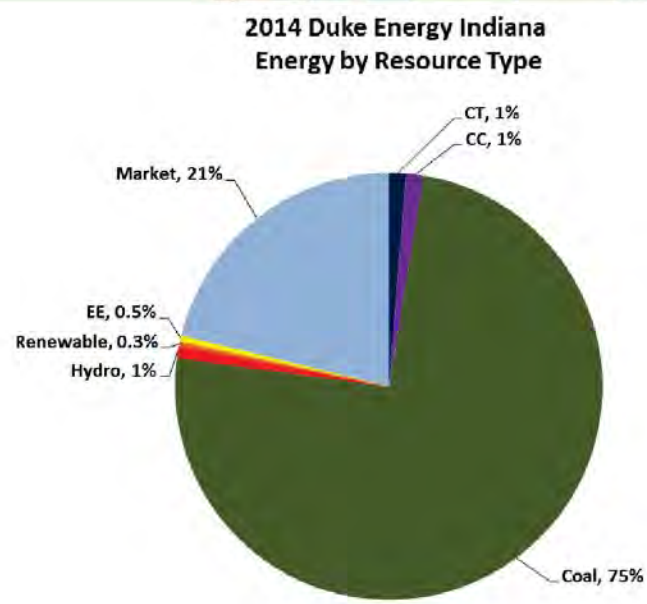
Existing Generation Mix: Capacity and Energy





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Jim Hobbs, Lead Engineer

Review of 2013 Process and IRP

5 Meetings

Meeting 1 – December 5, 2012

Meeting 2 – January 30, 2013

Meeting 3 – April 4, 2013

Meeting 4 – July 19, 2013

Meeting 5 – October 9, 2013

IRP Filing – November 1, 2013

Meetings 1 and 2

Meeting 1

- Process Overview
- Scenario Development
- Driving Forces Exercise

Meeting 2

- Energy Efficiency and Renewable Energy
- Scenario Development Exercise

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Meetings 3 and 4

Meeting 3

- Load and Energy Forecasting
- Fundamentals Forecasting
- Scenario Consolidation
- Exercise: Range of Assumptions

Meeting 4

- Portfolios
- Sensitivities

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Meeting 5 – Three Scenarios and Three Portfolios

Low Regulation Scenario: Traditional Portfolio

- Carbon Emissions Price: $0/ton
- Lower Environmental Requirements
- Higher Fuel Prices

Reference Case Scenario: Blended Approach Portfolio

- Carbon Emissions Price: $17/ton in 2020, $50/ton in 2033
- Internal Assumptions for Environmental Requirements

Environmental Focus Scenario: Coal Retires Portfolio

- Carbon Emissions Price: $20/ton in 2020, $75/ton in 2033
- Stricter Environmental Requirements
- Lower Fuel Prices

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Meeting 5 – Modeling Results

TRADITIONAL PORTFOLIO (Optimized for Low Regulation Scenario)

	2014-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	Coal (948 MW) Oil CTs (166 MW)	6% in 2020 12% in 2033	2% in 2020 4% in 2033 672 MW in 2033
Additions	WR 6 NG Conversion New CT (1400 MW) New CC (680 MW)		

BLENDED APPROACH PORTFOLIO (Optimized for Reference Case Scenario)

	2014-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	Coal (948 MW) Oil CTs (166 MW)	12% in 2020 12% in 2033	3% in 2020 14% in 2033 2344 MW in 2033
Additions	WR 6 NG Conversion New CT (800 MW) New CC (680 MW) New Nuclear (280 MW)		

COAL RETIRES PORTFOLIO (Optimized for Environmental Focus Scenario)

	2014-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	Coal (4765 MW) Oil CTs (166 MW)	12% in 2020 15% in 2033	4% in 2020 15% in 2033 2606 MW in 2033
Additions	New CT (1370 MW) New CC (2720 MW) New Nuclear (1120 MW)		

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Scott Park, Director IRP Analytics - Midwest

Lessons Learned

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Lessons Learned

Feature	2013	We heard/observed…	2015
Scenario Development	Exercise considered driving forces to define a scenario	Appeared to be too much information to process in a short period of time	Participant exercise to focus on driving forces that will be used to develop scenarios
Scenarios	Three	Need more scenarios to cover wider range of potential futures	We plan on using approximately 5 scenarios this year

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Lessons Learned

Feature	2013	We heard/observed…	2015
Portfolios	Optimized portfolios evaluated	Participants want to propose portfolios for consideration	Portfolio attributes will be solicited from participants and included in portfolio development
CHP	Not modeled due to customer choice	Need to include	We are working to get relevant CHP input assumptions and plan on including CHP as a potential resource

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Lessons Learned

Feature	2013	We heard/observed…	2015
Energy Efficiency	Modeled as a load reduction	Model as a resource	We are planning to model EE as a resource
Confidentiality of Inputs	Trends, ranges, and publicly available info shared	Access to confidential information requested	Specific data will be shared in-person at the DEI-Plainfield office on an individual basis after signing confidentiality agreement

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Lessons Learned

Feature	2013	We heard/observed…	2015
Remote participation	Live Meeting	Difficult for in-person attendees to hear callers questions/comments	Presentation slides will be web-posted and callers will be provided a dial in number to participate
Presentation slides	Significant revisions made after initial posting ahead of meetings	Advance slides needed to prepare for meeting	Near-final version of slides will be posted at least 1 week before meetings
One-on-one meetings		This appeared to be a useful effort for the 2014 utilities	We will make one-on-one meetings available as needed

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Scott Park, Director IRP Analytics - Midwest

IRP Overview

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Overview of IRP Process

- Meeting 1- Process Overview & Scenario Development **(Today)**
- Meeting 2 - Resource discussion & Portfolio Development **(early June)**
- Meeting 3 - Preliminary Modeling Results **(August)**
- Meeting 4 - Final Modeling Results **(early October)**

Note- The scenarios and sensitivities are not to be interpreted as predictions of the future but rather as tools used to evaluate possible futures. This is done in order to compare costs and risk profiles of various portfolios.

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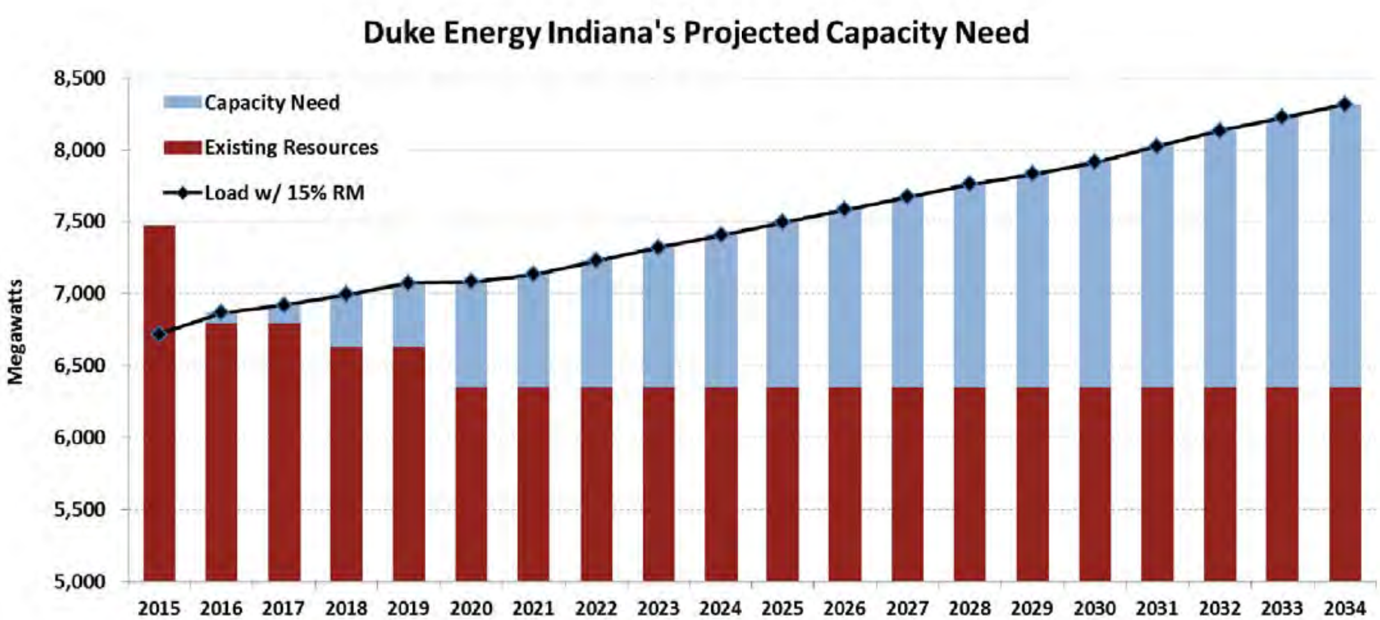
IRP is about "filling the gap"



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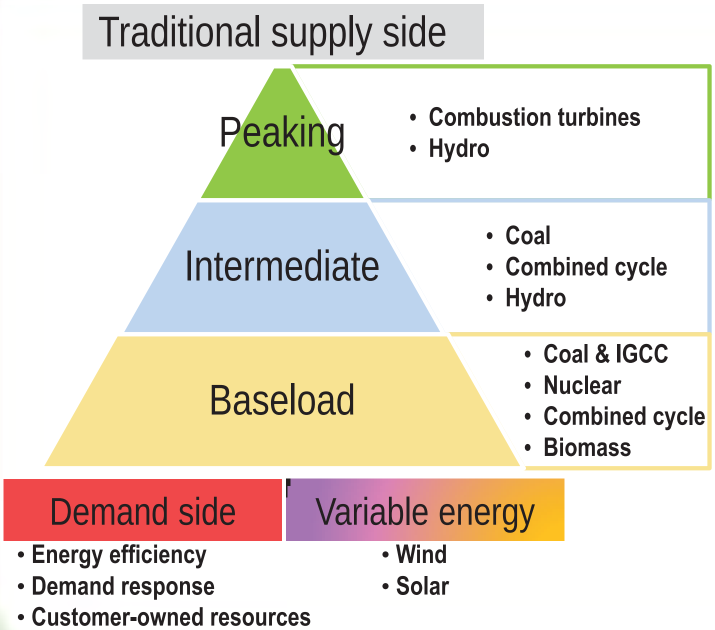
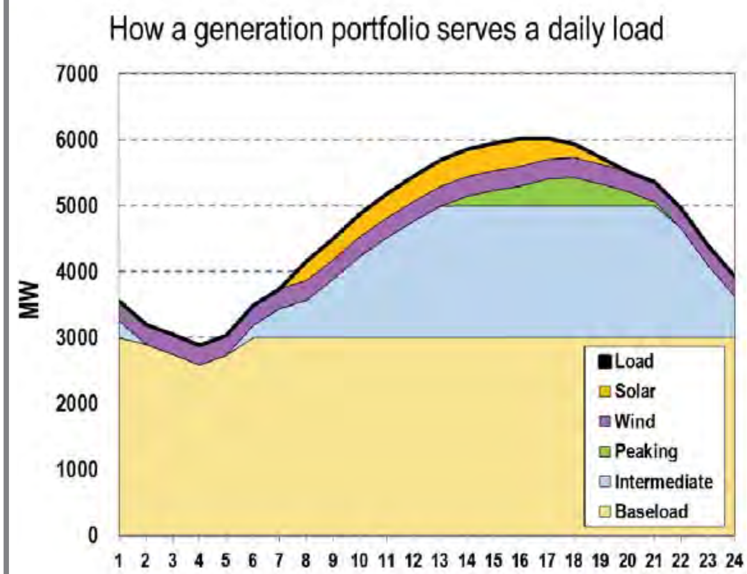
Serving load requires a variety of resource types





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How does the IRP process work?

- Complex process involving input from many internal and external groups
- Some components mandated (e.g. MISO reserve margin requirement)
- Requires extensive modeling and analysis

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Step 1: Data, assumptions, technology screening and scenarios

Step 1 | Step 2 | Step 3 | Step 4

Gather data

- Gather data such as:
  - Operational characteristics of existing generation
  - Anticipated retirement dates
  - Environmental regulations
  - Energy efficiency potential and costs

Create scenarios

- Identify range of driving forces and input assumptions
- Create and refine scenarios to use in Steps 2 and 3

Develop input assumptions

- Develop input assumptions including:
  - Fundamentals (commodity prices)
  - Load forecast
  - Capital costs
  - Environmental compliance costs

Screen technologies

- Screen technologies to determine
  - Feasibility in service area
  - Technical limitations
  - Commercial availability

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Step 2: Develop portfolios

Step 1 | Step 2 | Step 3 | Step 4

Review scenarios

- Review scenarios and impact on fuel costs, energy and capacity markets, and load growth
- Determine range of sensitivities to consider

Develop Optimized Portfolios

- Use model to develop portfolios optimized for each scenario

Develop Stakeholder Portfolios

- Create portfolios that reflect stakeholder's preferred portfolio attributes

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Step 3: Analyze Portfolios & Identify Preferred Portfolio

Step 1 › Step 2 › **Step 3** › Step 4

Analyze portfolios	Risk assessment	Identify preferred portfolio

• Evaluate portfolios in each scenario
• Stress portfolios via sensitivity analysis
	• Consider portfolio risks
	  • Variability of costs
	  • Flexibility
		• Identify the portfolio that performs best overall
		  • Costs
		  • Risk profile

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Step 4: Develop IRP report

Step 1 › Step 2 › Step 3 › **Step 4**

Develop draft report	Management approval	File report
• Work with internal groups to write sections of report • Develop tables and appendices	• Gain approval and ensure the proposed plan meets all regulatory requirements	• File 2015 IRP by Nov. 1, 2015

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Lunch

Scott Park, Director IRP Analytics - Midwest

Scenario Planning

What are scenarios?

A scenario is a well reasoned story that defines a plausible future worth considering in long term planning. When combined, several scenarios can describe a range of futures that add to the breadth and depth of the analysis.

"Each scenario….tells a logical "story" about the future that includes important trends and events, describes the key players and their actions, and explains the dynamics of the system… The aim is not to predict a precise order of events and outcomes, but rather to enable development of robust strategies that will stand up no matter what happens. Scenarios force us to explicitly identify and question our assumptions about the future." – CERA/IHI

"Scenarios are intended to form a basis for strategic conversation – they are a method for considering potential implications of and possible responses to different events. They provide their users with a common language and concepts for thinking and talking about current events, and a shared basis for exploring future uncertainties and making more successful decisions." – Shell

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Scenarios should…

- Help us find an "always acceptable" solution across a range of possible futures instead of an "optimal" solution for one potential future
- Force us to consider a robust range of possible futures
- Focus on key drivers and input variables that drive action and change outcomes
- Incorporate quantitative and qualitative data
- Be internally consistent

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Why do we use scenarios?

- Future is uncertain
- Scenarios are plausible views of what the world might look like over the next 20 years
- Scenario planning intended to make decision-making process more robust
- Preferred portfolio performs best overall across the multiple scenarios and sensitivities

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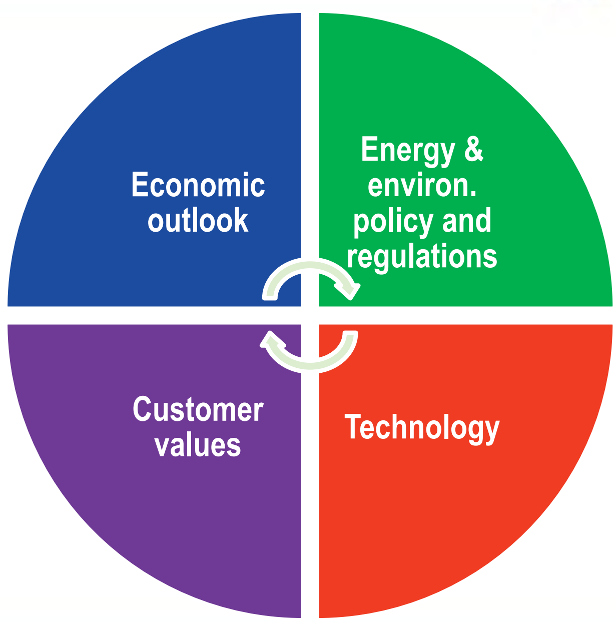
What are the key driving forces?

Economic outlook
- Fiscal policies
- Economic growth
- Interest rates
- International trade policies



Energy & environmental policy and regulations
- Renewable energy
- Energy efficiency
- Air emissions
- Water & waste
- Nuclear

Customer values
- % income spent on electricity
- Usage per customer
- Environmental, health, and safety concerns
- Use of customer-owned resources

Technology
- Capital & construction costs
- Efficiency of existing technologies
- New technology development

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Driving Forces Determine Key Input Variables

Driving Forces

Scenarios

Key model input variables

- Load growth
- Coal prices
- Natural gas prices
- Price of carbon
- Capital & construction costs

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Clean Power Plan

- What is the Clean Power Plan (CPP)?
  - EPA's proposed rule for regulating CO_2 emissions from existing fossil fuel-fired power plants
  - As proposed, the rule is intended to reduce power sector CO_2 emissions by 30% from 2005 levels by 2030
- Emission reduction "building blocks"
  - Block 1: "Make existing fossil fuel power plants more efficient" (invest in plant heat rate improvements)
  - Block 2: "Use lower-emitting power sources more" (run NGCC units at 70% capacity factor to displace coal-fired units)
  - Block 3: "Build more zero/low emitting energy sources" (Renewables, add/retain nuclear, build new NGCC)
  - Block 4: "Use electricity more efficiently" (increase energy efficiency and demand side measures)
- Implementation Timeline:

Summer 2015
Final Rule Issued

Summer 2016
State Implementation Plans (SIP) Due

Summer 2017
Final SIPs due if granted extension

Summer 2018
Due date for multi-state plans

EPA has 1 year to review and approve or disapprove SIPs

2020
Compliance period begins

2020-2029
Interim goal period

2030
Emission reduction goal deadline

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Clean Power Plan (continued)

- Proposed Indiana reduction goal:

2012 Baseline (lbs CO2/MWh)	After Applying Building Block 1	After Applying Building Block 1 & 2	After Applying Building Block 1 - 3	After Applying Building Block 1 - 4	Total Percentage Reduction
1923	1817	1772	1707	1531	-20%

- How is Duke Energy Addressing the CPP?
  - Conducting extensive study of impacts to current system and future resource plans
  - Engaging with EPA on refinement and clarification of proposed rule
  - Continued monitoring of final rulemaking process
- 2015 IRP Impacts
  - Modeling will include both CPP (as proposed) and traditional carbon tax scenarios
  - Will refine modeling where possible as details of final rule are released

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Scott Park, Director IRP Analytics - Midwest

Driving Force & Scenario Discussion

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Overview of driving forces and scenario discussion

Purpose
- Gather a range of information and perspectives on the driving forces that will inform the development of scenarios

Things to remember
- Consider the range and plausibility of input
- Consider various/other stakeholder perspectives for each driving force

Follow-up
- Information will be collected and incorporated into scenarios that will be reviewed and discussed in the second meeting

Driving Forces: Economic, Regulation, Customer Values and Technology (others?)

Stakeholder views: Residential, Low Income, Environmental Focused, Businesses (others?)

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Wrap up

- Combine stakeholder feedback that we heard today and from any post meeting comments
- Develop a number of scenarios that reflect the themes of the discussion and comments
- Specify details of scenarios that will be used for analysis
  - Manageable number of scenarios
  - Quantifiable
  - Plausible
  - Impactful
- Scenarios will be presented in the next stakeholder meeting.

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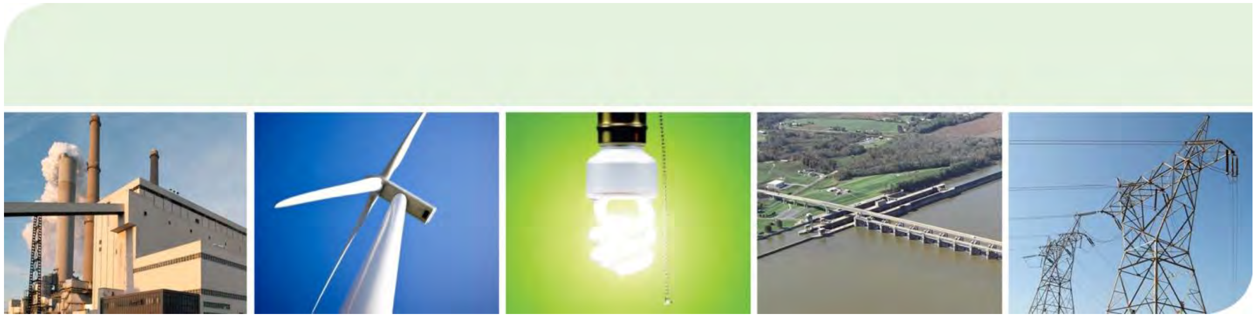
Marty Rozelle, President, Rozelle Group

Closing Comments, Stakeholder Comments

Next Steps

- Please complete comment cards or send by March 24 to Marty at: RGL97marty@rozellegroup.com
- Meeting summary and other materials will be posted on website by March 31 (http://www.duke-energy.com/indiana/in-irp-2015.asp)
- Next workshop tentatively scheduled for June 4



Duke Energy Indiana 2015 Integrated Resource Plan

Stakeholder Workshop 1 Summary
March 17, 2015

Welcome
Doug Esamann, State President- Indiana, Duke Energy

Mr. Esamann welcomed participants, both those who have returned from the last Integrated Resource Plan (IRP) process and those attending for the first time. For his safety message, he pointed out the emergency exits, and cautioned participants to be aware of the electric cords in the room. Mr. Esamann explained the purposes of the meeting. He introduced the facilitator, Dr. Marty Rozelle, as well as the Duke Energy IRP group including Brian Bak, lead planning analyst, Jim Hobbs, lead engineer, and Scott Park, the IRP director for the Midwest. He mentioned that Diane Jenner, Director of Regulated Strategy for Duke Energy Indiana, has retired.

Mr. Esamann emphasized that the company values the thoughts and opinions of its stakeholders, and finds the input helpful in developing the IRP. He thanked participants for their time.

Introductions and Agenda Overview
Dr. Marty Rozelle, The Rozelle Group Ltd.

Dr. Rozelle said that this workshop is the first of four to be held during development of the 2015 IRP, which will be filed by November 1. She reviewed the objectives for the Duke Energy Indiana (DEI) stakeholder process. These include understanding the concerns of stakeholders, providing information to help stakeholders understand the IRP process, listening and considering participant suggestions, and complying with the proposed public consultation rule of the Indiana Utility Regulatory Commission (IURC). She provided an overview of the agenda for today's meeting, and asked those in the room and on the telephone to introduce themselves.

Overview of Duke Energy Indiana
Brian Bak, Lead Planning Analyst

Brian Bak gave a brief overview of the Duke Energy Indiana system and its generating resources. DEI is the largest electric utility in the state, serving nearly 800,000 customers including several very large employers, some of whom are represented here today. Generation assets include coal units, integrated gasification combined cycle (IGCC), combined cycle (CC) and combustion turbine (CT) generators, as well as small amounts of hydropower, wind, and solar generation (coming online at the end of 2015 and early 2016).

Mr. Bak explained planned near-term retirements and additions to the system including retirement of Wabash River units 2 - 5, retirement of oil-fired CTs, and addition of environmental controls at several facilities. He noted that coal still makes up the majority of capacity and energy resources for DEI, supplemented with CT, CC, market purchases, and renewable resources.

Participant questions included the following:

- Is the 100 megawatts (MW) at the Benton County wind farm under litigation, putting Duke's purchase in question?
    - Yes, it is being litigated; however, Duke is purchasing it.
- What is DEI's total MW of capacity and energy?
    - Approximately 7500 MW
- Please clarify where the Edwardsport plant is included in the chart on slide 12. It would be helpful to see it broken out, since it is sometimes fired with natural gas.
    - It is included with coal resources. We don't have the specific data available here today to break it out.

Review of 2013 Stakeholder Process and IRP
Jim Hobbs, Lead Engineer

Jim Hobbs observed that some of the stakeholders here today are returning from last time, and several industrial customers are also attending. He reviewed the five individual meetings that were conducted during the 2013 IRP process, noting that this year's process will be similar. He summarized the three scenarios and three portfolios that were included in the 2013 IRP, including low regulation, reference case, and environmental focus scenarios that made varying assumptions about carbon emissions prices, fuel prices, and environmental regulations. The portfolios included retirements of specific units and proposed additions of generating capacity.

He invited people to look at the "*IRP 101*" document that Duke has posted on its website that explains the planning process and components.

Lessons Learned
Scott Park, Director IRP Analytics - Midwest

Scott Park discussed several features of the last 2013 planning process on which stakeholders provided comments and observations, along with Duke's response to those comments.

At this meeting we will focus on development of driving forces to define scenarios for the next workshop. This year, we plan to develop approximately five scenarios rather than three, in response to stakeholder suggestions. This will be largely defined by what we discuss in the exercise this afternoon.

Mr. Park explained how “optimized portfolios” for each scenario were defined in the previous process, and noted that stakeholders wanted to be more involved in developing portfolios. This year, Duke will discuss portfolio attributes with stakeholders and may evaluate several additional portfolios if suggested by participants.

He explained that combined heat and power, or ‘co-generation’ (CHP), was not modeled in the previous IRP because it was considered a customer choice. In the current process, Duke is working to develop relevant CHP input assumptions to include CHP as a potential resource in the IRP models.

He reminded participants of the definitions of key planning elements:

- Scenario – set of external assumptions used to define a possible, plausible future
- Portfolio – the mix of resources of the utility to meet future generating needs

Regarding energy efficiency (EE), the 2013 plan assumed compliance with the current State of Indiana requirements. Now the state requirements have been suspended, Duke is planning to model EE as a resource in the 2015 plan. However, it is very complex to define and develop assumptions for EE. We will try to create bundles of EE resources that could be included in the models.

Addressing the issue of confidential data, Mr. Park said that this data will not be made public in this process. Consequently, similar levels of data, proxies, and trends will be shown this year in the IRP workshops; however, those who would like to view confidential data may sign a confidentiality agreement at the Plainfield office. (This may also be made available to consultants, at the request of some stakeholders.)

He discussed changes to remote participation, advance posting of presentation slides, and expansion of one-on-one stakeholder meetings if desired.

Group comments and questions included the following:

- Will DEI be looking at the Clean Power Plan this year, and will it be part of the scenarios?
  - Yes. This will be explained more in the following presentations.
- Do you have a timeline for 2015 for implementing a CHP decision?
  - Not at this time
- Will you be limiting the size parameter of CHP for the plan? For example, will it be only for larger size units? Some states (Massachusetts) encourage residential- sized CHP.
  - We don’t plan to cap the size at some arbitrary number, but there will probably be a minimum size that can be captured in a model.
- As was mentioned during the last process, competition and deregulation is a huge underlying risk factor for IRP processes, and assumptions about this should be developed for the current plan.

  - Mr. Park acknowledged that deregulation could be a potential in the long-term future, and we can explore this further in the discussion this afternoon.
- What assumptions will you make for commercial and industrial (C&I) customers regarding EE for this plan?
  - We don't know that yet. The opt-out ability of the new requirement is something we'll need to look at, and we can also look at historical evidence.
- How many MW have been opted out?
  - About 80% of the eligible load has opted out so far.
- In one-on-one meetings, other parties are left out. OUCC suggested that a method be developed for sharing information discussed with other stakeholders.
  - Duke said they would consider a way to do this.

Overview of 2015 Stakeholder Process and IRP
Scott Park, Director IRP Analytics - Midwest

Mr. Park noted that the IURC (Mr. Brad Borum) issued its draft report on the previous IRP stakeholder processes recently; DEI is not able to respond to that at this time but will review the final report when issued and consider it as needed.

He gave an overview of upcoming meetings for this process, noting that the next one in June will include a resource discussion and portfolio development. The third meeting will be in August to show preliminary modeling results, and the final meeting in October will present the final results.

In expanding the number of scenarios evaluated this year, he emphasized that these are not predictions, but tools to evaluate a wider range of possible futures. Scenarios are developed to compare costs and risk profiles of various portfolios.

He showed illustrations of DEI's projected capacity need over the next 20 years, comparing needs to existing resources with predicted load growth and required reserve margin (15%). He described the supply-side resources that are used to fill the demand, including base load (coal and IGCC, nuclear, combined cycle, biomass) that are expensive to build but relatively low cost to operate. Intermediate resources are more expensive to operate and are used as needed (coal, combined cycle, hydro), and peaking resources are used to supplement energy in peak and limited times (CTs, hydro). More recently, demand-side supply includes EE, demand response, and customer-owned resources. Variable energy includes wind and solar generation.

Mr. Park noted that solar has unique attributes such as pushing the peak later in the day as well as intermittency, which make it more taxing on the overall distribution system. Duke is studying these phenomena because solar has quite complicated effects.

He showed another graphic illustrating a summer load and how it might be typically filled using the range of available resources. He said that generally the least-expensive units are turned on first. When economic, excess power can be sold on the market. Similarly, DEI can also make spot power purchases when that is economic. He noted that winter daily profiles would be different. Also, some types of units perform differently in hot and cold weather, and solar is less effective in the winter.

Mr. Park provided an overview of how the IRP process works. It is a complex process involving input from many internal and external groups, and requires extensive modeling and analysis. He showed the specific steps involved. Step 1 includes data gathering, estimating driving forces, scenario development, development of input assumptions, and screening of technologies for viability. A challenge here is that the efficiency gains of some emerging technologies are unknown, so it's risky to commit major costs to them in the planning process.

Step 2 is portfolio development. This includes reviewing scenarios considering fuel costs and other factors and determining a range of sensitivities to consider. Sophisticated computer models are then used to develop portfolios optimized for each scenario. In 2013, DEI identified an optimized (least-cost) portfolio for each scenario; this year we will include additional stakeholder-identified portfolio attributes.

Step 3 includes evaluating portfolios using sensitivity analysis, conducting a risk assessment (e.g. cost, flexibility), and identifying the preferred portfolio that performs best in all scenarios.

The last, step 4 is to prepare and file the Integrated Resource Plan report to the IURC by November 1, 2015.

Stakeholder questions, comments, and suggestions included the following:

- What load are you assuming?
    - This would be specific to each scenario. In the past, it has been between 1% and 3%.
- Does DEI have any time-of-use tariffs?
    - No
- For renewable and solar energy, time-of-use rates can help to reduce the peak, particularly when solar PV units face to the south.
    - We do not have time-of-use, but we've looked at piloting such rates in prior smart grid proceedings that were not approved.
- Regarding treating EE as a resource this time, rather than as an off-model adjustment, will you be talking about that more?
    - Yes, at the next meeting. You need to take EE out of the load forecast in order to add it to the resource base. It's not a homogeneous resource but is a set of programs that vary widely.
- How will the proliferation of products in the energy marketplace be reflected in the process? For example, Germany and California are looking seriously at solar storage as strategies; a company in Hawaii has an inverter that has the capability to regulate voltage island-wide.
        - Adding intermittent resources like wind and solar requires that the system be able to respond to that. DEI may not be able to fully examine adding more variability in this IRP because it takes a great deal of planning to determine how to make the system more flexible. Storage is still very expensive, since the storage needs to be about equal to the generation (e.g., 1 MW generation = 1 MW storage). Scott noted that rates in

Germany have gone up dramatically while carbon emissions have not been reduced significantly.

- Do you have comparable charts for peaks in other seasons? Please revise this slide to indicate that this is a “summer” profile.
    - Yes, seasonal profiles would vary. This was meant to be used for illustrative purposes.
- Different customers have different load profiles. One participant noted that his use is winter-peaking, and solar still generates even in winter and when cloudy.
- What is the MISO reserve margin (not 15%)? Lower margins mean lower costs, of course. Also, you can replace capacity with energy if you purchase from the open market as needed.
    - MISO requires a reserve margin of about 7 to 7.5%, depending on the more sophisticated method that they use. Also, the joint dispatch of energy resources by MISO helps to contain costs. The 15% represents installed capacity.

Lunch

Scenario Planning Overview
Scott Park, Director IRP Analytics - Midwest

Mr. Park provided a description of what the utility means by “scenarios”. These are, essentially, ‘stories’ that describe a reasonable range of futures. Scenarios should help find a solution that works across all possible futures, focus on ‘key drivers’ that can change outcomes, and be internally consistent. The purpose of developing scenarios is to make the decision-making process more robust.

He explained the concept of driving forces that may shape the future. These have been grouped into the main categories of economic outlook, energy and environmental policy and regulations, technology, and customer values. Variations in these can have major effects on the way the industry responds to future conditions. Driving forces provide a framework for defining scenarios. Then, key model input assumptions are developed for factors including load growth, coal and natural gas prices, price of carbon, and capital and construction costs.

Mr. Park noted that one of the scenarios developed for this plan will probably be a “Clean Power Plan” scenario, and explained the current status of the EPA’s proposed rule for regulating CO_2 emissions from existing fossil fuel power plants, with the goal of reducing emissions by 30% from 2005 levels by 2030. He talked about the four emission reduction “building blocks”. He showed the implementation timeline, with summer 2016 being the deadline for state implementation plan submittal, and compliance beginning in 2020. Indiana reduction goals were shown per phase of applying the four building blocks, with a total percentage reduction over time of 20%. Duke will model the proposed rule as if it is the final rule, even though there is a great deal of uncertainty about the regulations at this time as well as possible litigation.

Discussion included the following:

- What percent of national carbon emissions are due to power generation?
  - We don't know for sure, but probably about 40 to 50%.
- If Indiana does not adopt a state implementation plan, will DEI still plan as if the regulations are in place, on a voluntary basis, or at least have a contingency plan? Will you try to meet the 20% reduction goal?
  - We will develop a clean power plan scenario for this IRP based on reasonable assumptions, and at least one other scenario assuming a carbon tax. We will need to see what level of emissions reduction can be achieved using certain assumptions.
- What is your CO2 rate for 2012?
  - There were a substantial amount of market purchases, and we can't really know what the emissions were from these sources, so it's difficult to account for this. We will try to provide cost data for the "buckets" in the various scenarios.
- How does Edwardsport fit into this program? If it is in, would the Clean Power Plan scenario include carbon capture and sequestration?
  - Mr. Park was not sure how Edwardsport would be treated since the rule is only proposed. He also did not want to speculate about sequestration.
  - OUCC said that they included Edwardsport in the calculation for Indiana.
  - It appears that clarification is needed on this point.

Driving Force & Scenario Discussion
Scott Park, Director IRP Analytics - Midwest

Mr. Park introduced a participant exercise to discuss a range of driving forces to be used in shaping scenarios. He said that the purpose of this exercise is to gather a range of information and perspectives that will help Duke to develop scenarios.

Driving Forces Participant Exercise
All

Marty Rozelle explained the worksheets that were distributed. She asked the groups to pick someone to keep notes for each table. Each of the four tables will initially work on one driving force topic, and move on to the others as time allows. Groups will share their thoughts with the larger meeting at the end, and DEI will use the results in developing scenarios.

The results of the group exercise are attached to this summary.

Closing Comments

A participant noted:

- Climate change is the "elephant in the room" that does not directly appear in any of these materials. She suggested that climate change might be a good scenario to include. She referenced four scenarios developed by the Rocky Mountain Institute that represent what should be looked at, and said that she will provide an internet link to this information. The scenarios are:

Maintain – business as usual
Migrate – current system changes to reduce GHG emissions
Renew – utility scale renewables provide 80% of 2050 system
Transform – large capacity of distributed resources, compatible grid

In an email following the meeting this same participant clarified her point by saying that the construct for today's discussion of future scenarios was missing a large component -- and that is the natural world in which Duke operates and its customers live and do business.

She believes that future scenarios should include some that would address the risks of changes in the natural world, such as:

- Drought that would affect the supply of water for electricity generation
- Warm water that would affect the use of water for cooling
- High temperatures that would impact the efficiency of power plants or the demand on the system during the summer
- Damage to infrastructure that could be caused by increasingly severe storms

At least one of the scenarios should be crafted to test portfolios against the risk of changing weather patterns that are already occurring and projected to continue to occur in the coming years in Indiana.

The facilitator reminded participants to please fill out comment forms about the meeting. Additional comments can be emailed to Dr. Marty Rozelle at rgl97marty@therozellegroup.com. The next meeting will likely be on June 4.

2015 Integrated Resource Plan

Stakeholder Workshop #2

June 4, 2015
Plainfield, IN

Welcome

Welcome

- Safety message
- Why are we here today?
- Objectives for stakeholder process
- Introduce the facilitator

The Facilitator

- Duke Energy Indiana hired Dr. Marty Rozelle of The Rozelle Group and her colleagues to:
  - Help us develop the IRP stakeholder engagement process
  - Facilitate and document stakeholder workshops

Why are we here today?

- Duke Energy Indiana developing 2015 Integrated Resource Plan (IRP)
- Proactively complying with proposed Commission IRP rule
- Today is the 2nd of 4 stakeholder workshops prior to filing the IRP by November 1, 2015

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Objectives for Stakeholder Process

- **Listen:** Understand concerns and objectives
- **Inform:** Increase stakeholders' understanding of the IRP process, key assumptions, and challenges we face
- **Consider:** Provide a forum for productive stakeholder feedback at key points in the IRP process to inform Duke Energy Indiana's decision-making
- **Comply:** Comply with the proposed Commission IRP rule

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Agenda

08:30	Registration & Continental Breakfast
09:00	Welcome, Introductions, Agenda
09:20	Meeting 1 Comments and Response
09:40	Updates Since Meeting 1
10:00	Break
10:15	Scenario Discussion
11:30	Lunch
12:15	Resource Discussion
01:30	Portfolio Development Exercise
03:00	Closing Comments

Scott Park, Director IRP Analytics - Midwest

Meeting 1 Comments and Response

Meeting 1 Comments and Response

Topic	We heard/observed…	Response
Wi-Fi	Overloaded Wi-Fi hot spot	Individual guest accounts were created to access vendor network
Scenarios	More information on environmental scenarios	Scenario specifics will be discussed in June 4th meeting
DSM/EE	How will DSM/EE be modeled?	Resources including DSM/EE will be discussed in June 4th meeting
Retirements	Analysis of extending the life of older generating units	The process used to evaluate the economics of retiring generating units will be discussed in meeting #3 (early August)
Health impacts of CO2	Are the health benefits of lower CO2 emissions associated with renewables factored into the analysis?	No; our analysis is directed toward serving customers in the most cost effective manner that complies with laws and regulations.

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Scott Park, Director IRP Analytics - Midwest

Updates Since Meeting 1

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Updates Since Last Meeting

Deregulation call report out

- On May 14th, Duke hosted a call to further discuss with stakeholders ideas about deregulation and customer choice.
- Themes from that call were used to develop a Customer Choice Scenario
  - Will be discussed in more detail in the Scenario section of this morning's meeting
  - Additional information can be found on slide 22

Break

Jim Hobbs, Lead Engineer

Scenarios Part 1

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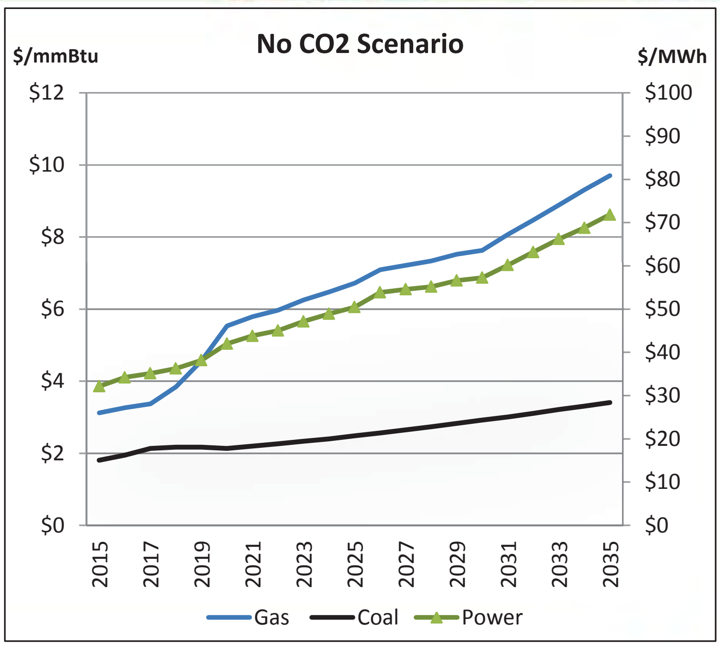
No CO_2 Regulation

- Scenario Narrative
  - No carbon tax/price or regulation
  - Moderate environmental levels of regulation
  - No renewable energy portfolio standard
- Average annual load growth rate: 0.9%



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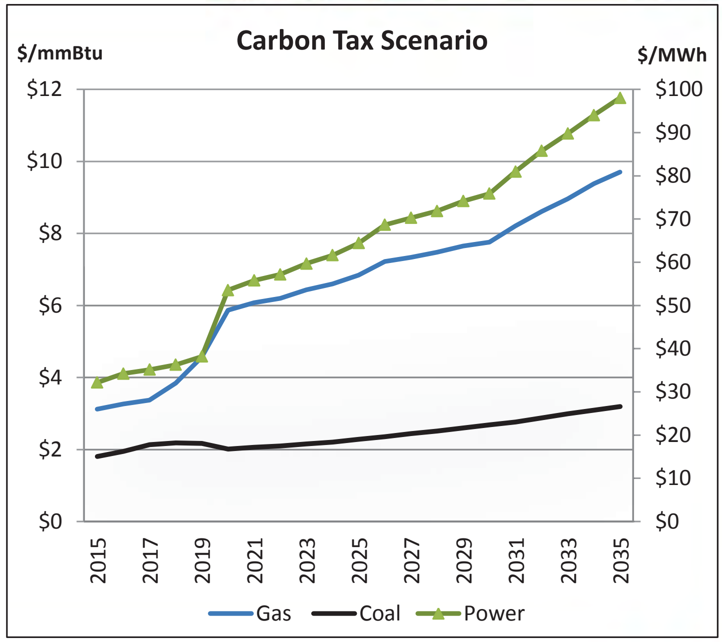
CO_2 Regulation by Price

- Scenario Narrative
  - Carbon tax: $17/ton in 2020, rising to $50/ton
  - Increased environmental levels of regulation
  - 5% renewable energy portfolio standard
- Average annual load growth rate: 0.8%



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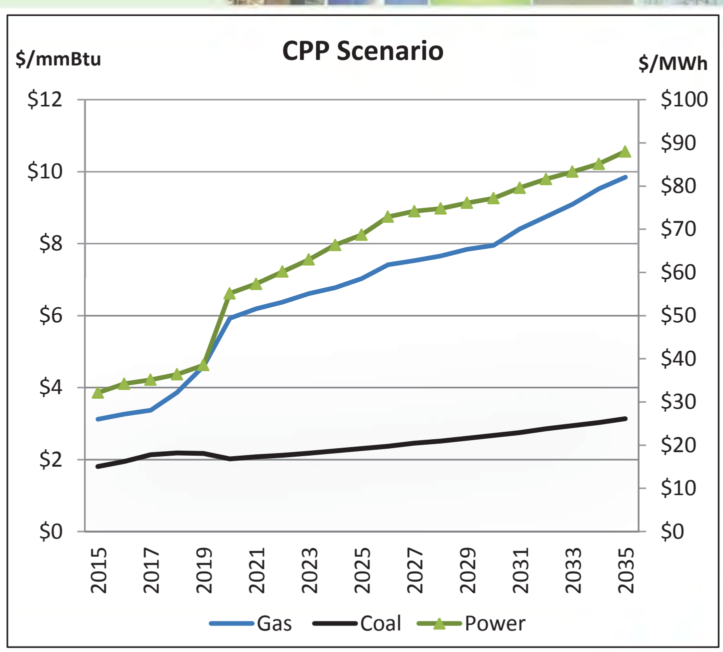
Clean Power Plan (CPP)

- Scenario Narrative
  - Carbon reduced 20%
  - Increased environmental levels of regulation
  - 5% renewable energy portfolio standard
- Average annual load growth rate: 0.8%



DUKE ENERGY.

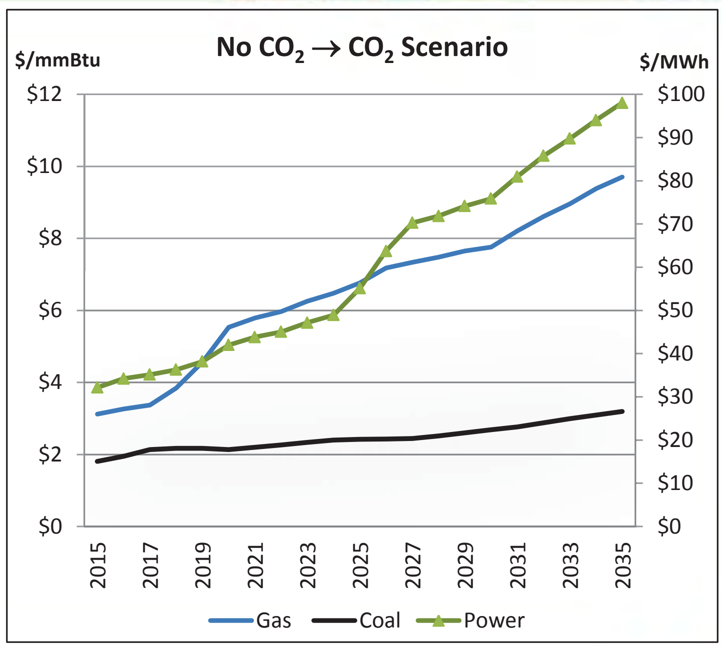
Brian Bak, Lead Planning Analyst

Scenarios Part 2

DUKE ENERGY.

No CO_2 Regulation followed by CO_2 Regulation

- Scenario description:
  - Follows No CO_2 scenario pricing, load growth and regulatory policy for 10 years followed by a gradual shift to CO_2 scenario pricing, load and regulatory policy for remainder of the 20 year planning period
- Average annual load growth rate: 0.8%.
- Value to IRP process:
  - Demonstrates level of resource/portfolio flexibility
  - Adds depth and breadth to portfolio risk analysis



DUKE ENERGY.

CO_2 Regulation followed by No CO_2 Regulation

- Scenario description:
  - Follows CO_2 scenario pricing, load growth and regulatory policy for 10 years followed by a sudden shift to No CO_2 scenario pricing, load and regulatory policy for remainder of the 20 year planning period
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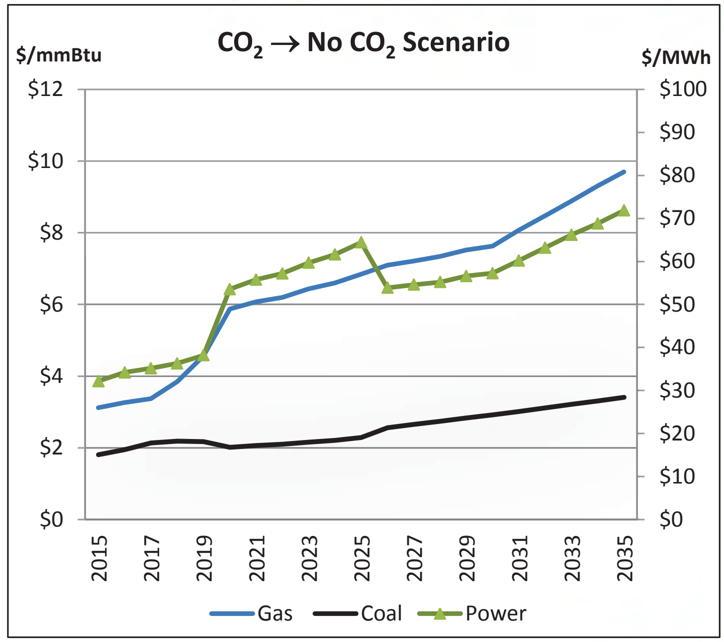

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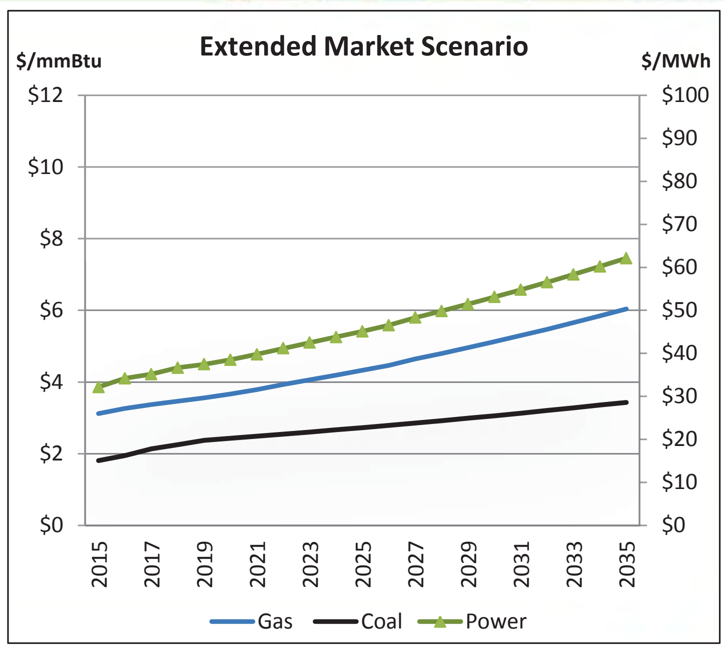
Extended Market Pricing

- Scenario description:
  - Maintains market fuel and power prices for full planning period – no fundamental forecast data
- Typical transition from Market to Fundamental
  - Market pricing for 3 years
  - Transitional 'blend' of market and fundamental forecast pricing for 2 years
  - Fundamental forecast for remaining 15 years
- Extended Market Pricing
  - Market pricing out to limit of visibility/liquidity
  - Extrapolate pricing for remainder of planning period using observed growth rate (CAGR)
- Average annual load growth rate: 0.9%



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Scott Park, Director IRP Analytics - Midwest

Scenarios Part 3

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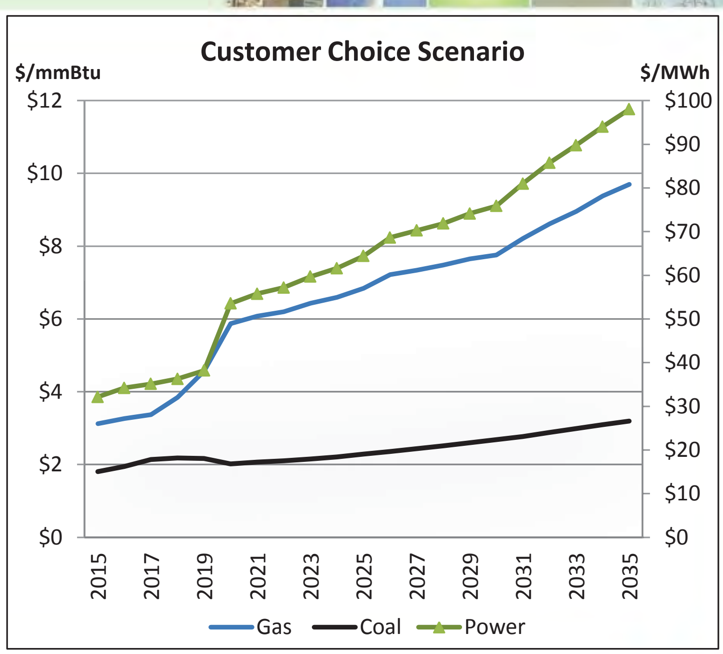
Increased Customer Choice

- Increased roof top solar is installed and a growing number of customers make this decision.
  - Every year, starting on 2020, an additional 1% of load is served with solar at the average cost of rooftop solar for residential and commercial installations
- Customers elect to adopt higher levels of EE
- Carbon tax: $17/ton in 2020, rising to $50/ton
- New generation will primarily be built by merchant generators (e.g. Dynegy or Calpine).
- Average annual load growth rate: 0.8%



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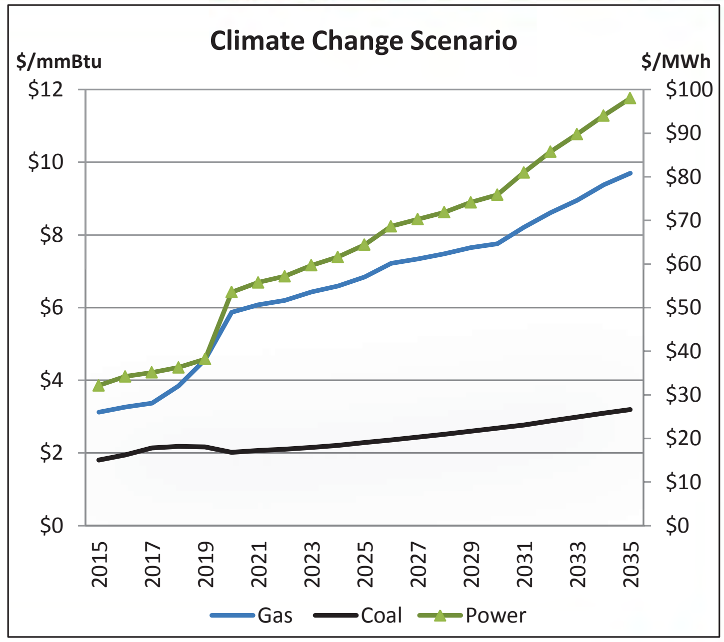
Climate Change Scenario

- The Climate Change Scenario is characterized by higher summer temperatures that drive increased electricity consumption. Increased fuel and power prices as well as a carbon tax of $17/MWh starting in 2020 benefit alternative resources such a renewables, energy efficiency and CHP.



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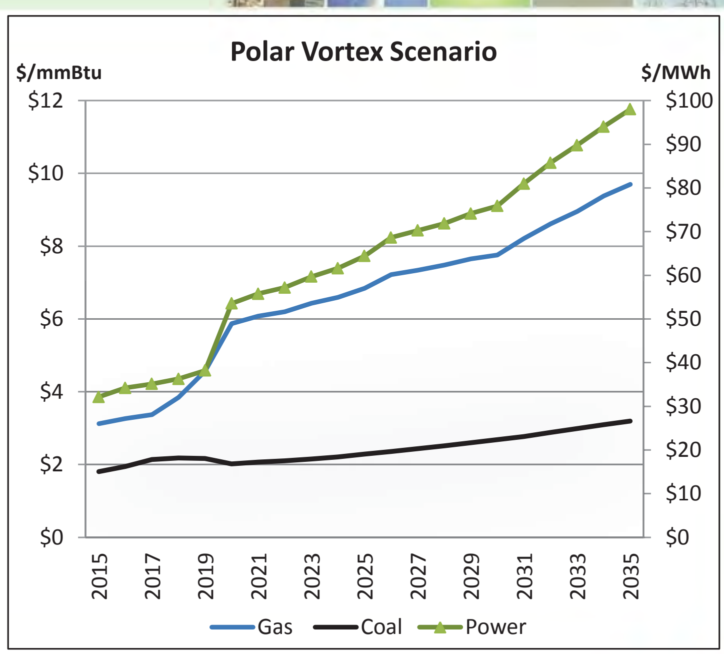
One Year Stress Scenario: Polar Vortex

<u>What is a One Year Stress Scenario?</u>

These scenarios were developed to stress the various portfolios to extreme events. While not frequent enough to warrant a long term scenario, we expect them to be insightful and primarily used for comparative risk analysis.

<u>Description of Polar Vortex Stress Scenario</u>

This scenario will mimic calendar years 2013 and 2014 and will include higher winter peaks and higher prices for fuel and power. A carbon tax of $17/MWh starting in 2020 will be assumed.



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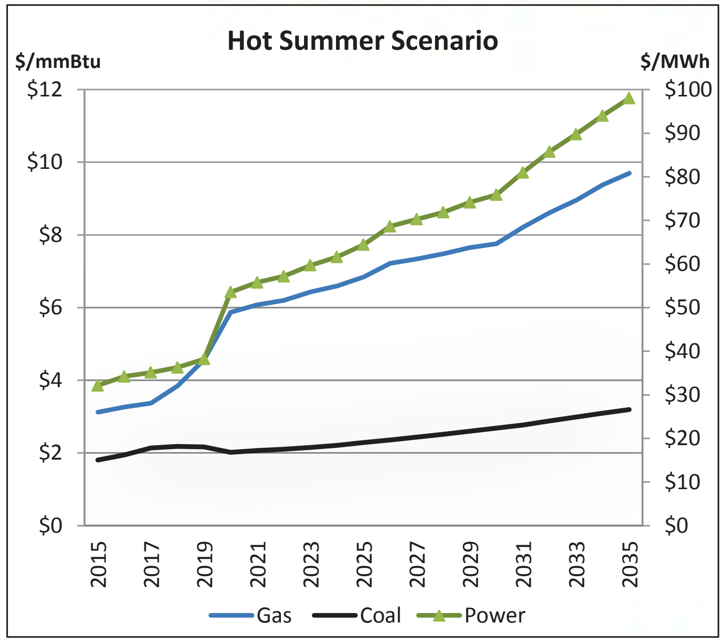
One Year Stress Scenario: Hot Summer (Low Water and High Load)

Description of Hot Summer Stress Scenario

This scenario will feature higher summer temperatures which drive increased demand for electricity. Due to lower river levels, riverside generation will be de-rated. Both of these factors contribute to higher prices for fuel and power. A carbon tax of $17/MWh starting in 2020 will be assumed.



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Lunch

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Jim Hobbs, Lead Engineer

Resources Part 1

Simple Cycle Combustion Turbines (CTs)

Resource Description

- Natural Gas primary, Fuel Oil backup
- 210 MW Nameplate
- Heat Rate 10 MMBtu/MWh
- Capital $31/MWh @ 30% Capacity Factor
- Fuel/O&M $73/MWh @ 30% Cap Factor
- CO2 emissions rate 1200 #/MWh

Advantages

- Low capital cost
- Fast install vs. other conventional options
- Fuel abundant/cheap for now

Disadvantages

- Less efficient than combined cycle
- Fuel price historically volatile

Combined Cycle Combustion Turbines (CCs)

Resource Description

- Natural Gas primary, Fuel Oil backup
- 2 CTs with steam generator (2 on 1 or 2x1)
- 620 MW Nameplate
- Heat Rate 7 MMBtu/MWh
- Capital $16/MWh @ 87% Capacity Factor
- Fuel/O&M $51/MWh @ 87% Cap Factor
- CO2 emissions rate 840 #/MWh

Advantages

- High efficiency
- Versatile - baseload or intermediate service
- Fuel abundant/cheap for now

Disadvantages

- Requires firm gas transportation for reliability
- Fuel price historically volatile

Nuclear

Resource Description

- Uranium fuel
- 1117 MW Nameplate
- Capital $72/MWh @ 90% Capacity Factor
- Fuel/O&M $24/MWh @ 90% Cap Factor
- CO2 emissions rate 0 #/MWh

Advantages

- Low variable cost
- Reliable baseload service
- Fuel supply reliability
- No air emissions

Disadvantages

- High construction cost
- Long lead time
- High water use
- Spent fuel storage

Screened Out Resources

- Geothermal – No local resource
- Advanced Storage – Expensive; Duke R&D efforts continuing.
  - Battery Innovation Center near Crane Naval Surface Warfare Center, $1M funding
- Compressed Air Storage – Expensive, limited experience, high capital, scarce sites
- Small Modular Reactors – Conceptual design and development state
- Fuel Cells – Utility scale application not commercially available
- Animal Waste Digesters – Expensive, operational and permitting hurdles
- Woody Biomass – Expensive, limited by fuel availability, access, and proximity
- Coal-based generation – Potentially risky depending on outcome of carbon regulation

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Battery Storage R&D

Project Name	Location	Technology	Capacity	Interconnection
Notrees	Ector and Winkler counties, TX	Xtreme Power advanced lead acid	36 MW/24 MWh	153 MW Wind Project
Rankin	Gaston County, NC	FIAMM sodium nickel	402 kW/282 kWh	1 MW Solar Project
Marshall	Catawba County, NC	Kokam superior lithium polymer	250 kW/750 kWh	1.2 MW Solar Project
McAlpine Community	Charlotte, NC	Kokam	24 kW/24 kWh	Transformer
McAlpine Substation	Charlotte, NC	BYD lithium iron phosphate	200 kW/500 kWh	50 kW Solar Project
Clay Terrace	Carmel, IN	Toshiba lithium titinate	75 kW/48 kWh	Clay Terrace Micro-grid

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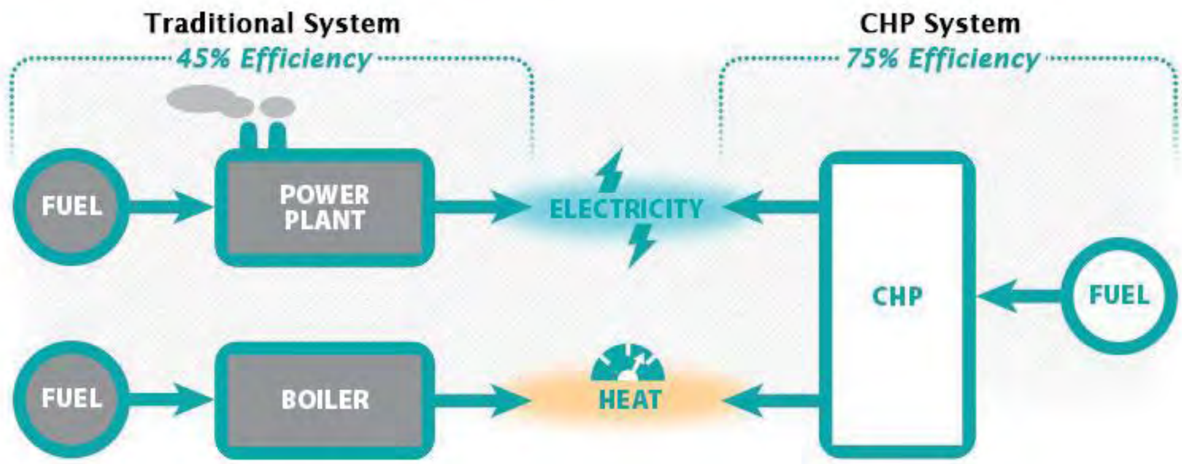
Combined Heat and Power (CHP)



CHP Advantages and Challenges

- Advantages
  - High combined efficiency
  - Low combined carbon emissions
  - Smaller scale could enable better matching to reserve margin requirement
  - Economic development incentive
- Challenges
  - Unique, site and customer specific; must have steady steam load
  - Customer must be convinced that project makes economic and operational sense
  - Customer's business must have favorable long-term economic outlook

CHP Prospects

- Up to 500 MW Technical Potential with suitable customers
  - Universities
  - Bio-refineries
  - Pharmaceuticals
  - Other Industrials
- 2 customer installations now operating
  - Purdue (39 MW-coal and gas)
  - Tate and Lyle (7.4 MW-coal)
- CHP may be an economic alternative for meeting small boiler air emission restrictions

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Brian Bak, Lead Planning Analyst

Resources Part 2

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Duke Energy Indiana renewable resources

- Benton County Wind Farm
  - 100.5 MW
  - 20-year power purchase agreement (PPA) signed in 2006
  - Yields approximately 300,000 MWh/year
- Markland Hydro Facility
  - 51.3 MW run-of-river facility owned by Duke Energy Indiana
  - Also yields approximately 300,000 MWh/year
- New Solar Farms in Clay, Howard, Sullivan and Vigo counties
  - 20-year PPAs totaling up to 20MW (4 x 5MW)
  - 3 facilities expected online by year-end, Sullivan in 1Q2016
- In total, renewable resources provide ~1.5% of our annual energy

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Biomass – Landfill Gas

<u>Resource Description</u>

- Fuel source: Landfill methane emissions
- Internal Combustion Engine
- 5 MW Nameplate
- Capital $65/MWh @ 90% Capacity Factor
- Fuel/O&M: $20/MWh @ 90% Capacity Factor
- Heat Rate: 10.5 MMBtu/MWh
- CO2 emissions rate: 0 #/MWh (considered carbon neutral due to biomass/MSW source)

<u>Advantages</u>

- Low fuel cost
- Baseload power
- Dispatchable
- Reduces flaring/direct emission of landfill methane

<u>Disadvantages</u>

- Limited number of available sites
- Not scalable

Source: EPA Landfill Methane Outreach Program (LMOP) Website and Energy Cost Manual

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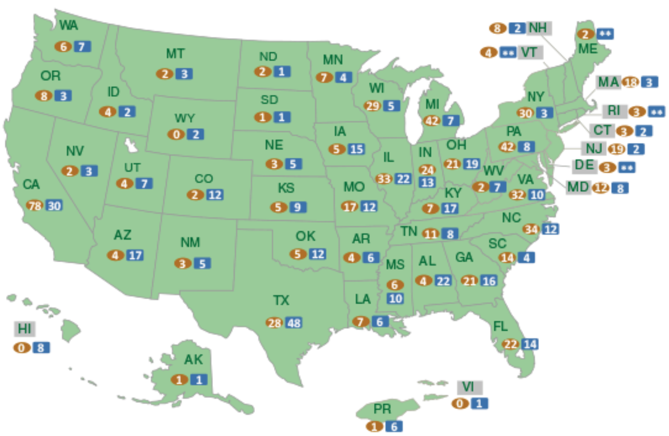
Biomass – Landfill Gas



Nationwide Summary

645 OPERATIONAL Projects (2,066 MW and 298 mmscfd)

~440 CANDIDATE Landfills (855 MW or 475 mmscfd, 42 MMTCO2e/yr Potential)

OPERATIONAL PROJECTS

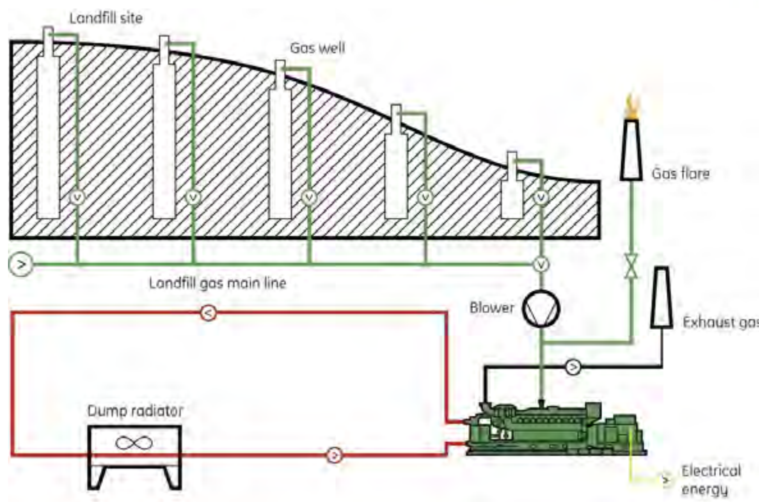
CANDIDATE LANDFILLS*

*Landfill is accepting waste or has been closed 5 years or less, has at least 1 mm tons of waste, and does not have an operational, under-construction, or planned project; can also be designated based on actual interest by the site.

These data are from LMOP's database as of March 4, 2015.

** LMOP does not have any information on candidate landfills in this state.

Typical Landfill Gas Power Plant



Wind

Resource Description

- 20-200 MW Nameplate
- Capital: $56/MWh @ 35% Capacity Factor
- O&M: $13/MWh @ 35% Capacity Factor
- Contribution-to-Peak (MISO Capacity Credit)
  - 14.7% average
  - Site specific: 1.4% - 25.5%

Advantages

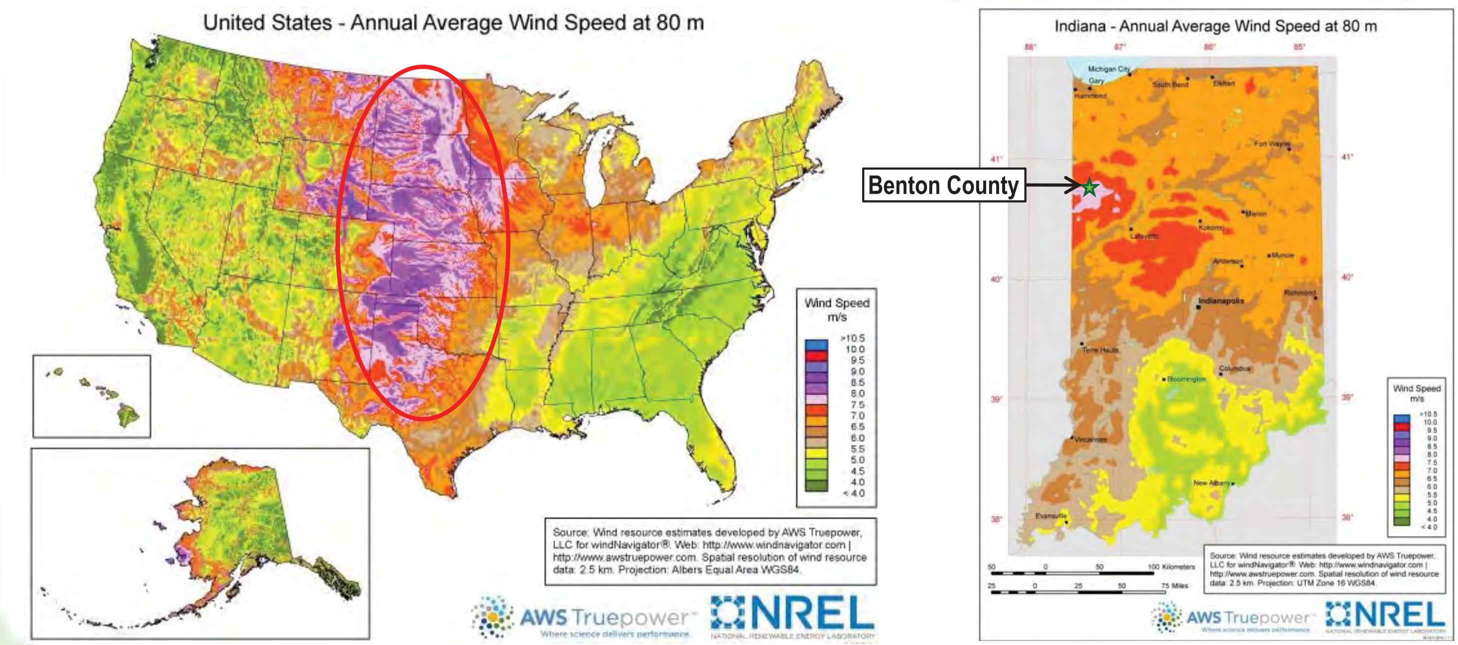
- Zero "fuel" cost
- Zero air emissions
- Renewable resource

Disadvantages

- Distance from load center
  - Transmission / congestion cost
- Siting difficulties (NIMBY)
- Intermittency
- Low contribution to peak load

Source: Lazard Levelized Cost of Energy Analysis – Version 8.0 (Sept. 2014)

Wind Resource Distribution



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Solar

Resource Description

- 5-25 MW Nameplate
- Capital: $79/MWh @ 21% Capacity Factor
- O&M: $7/MWh @ 21% Capacity Factor
- Contribution-to-Peak / Capacity Value
  - MISO Capacity Auction: based on actual metered historical output
  - Time-period based studies can be used to forecast approximate value

Advantages

- Zero "fuel" cost
- Zero air emissions
- Renewable resource

Disadvantages

- Intermittency
- Contribution to serving peak customer load declines as installed MW increase

Source: Lazard Levelized Cost of Energy Analysis – Version 8.0 (Sept. 2014)

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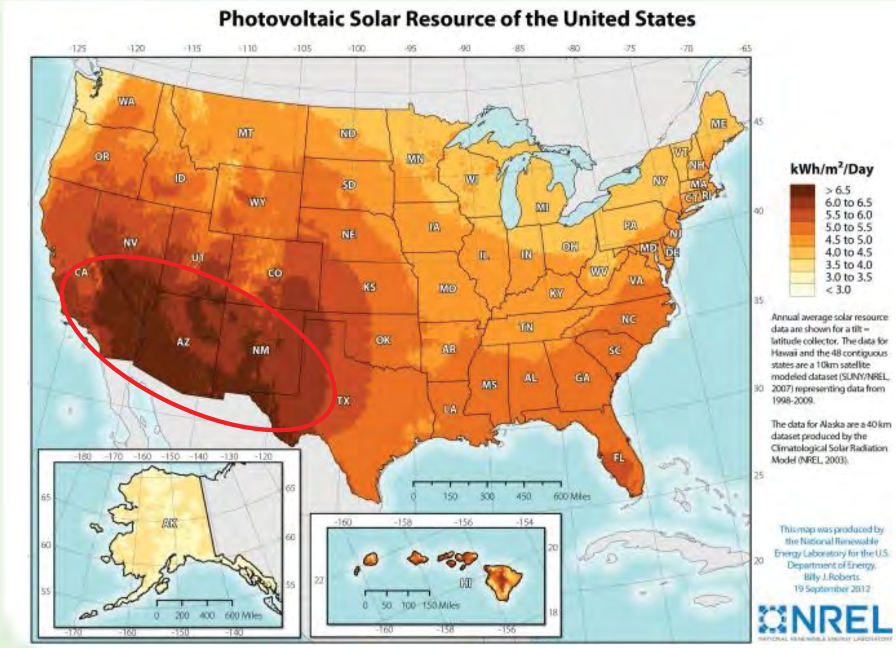
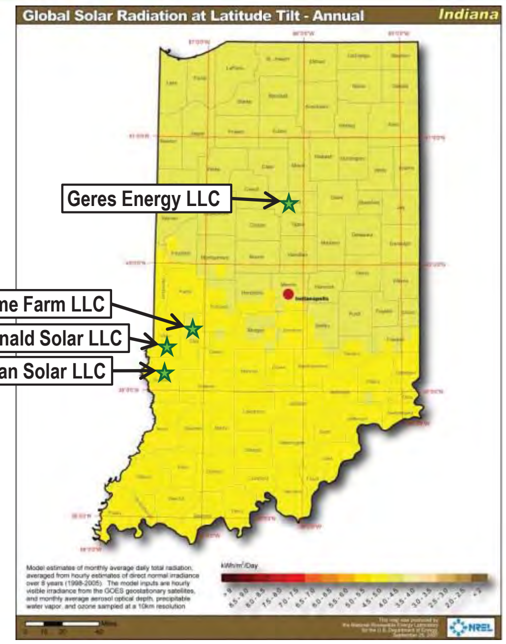
Solar Resource Distribution





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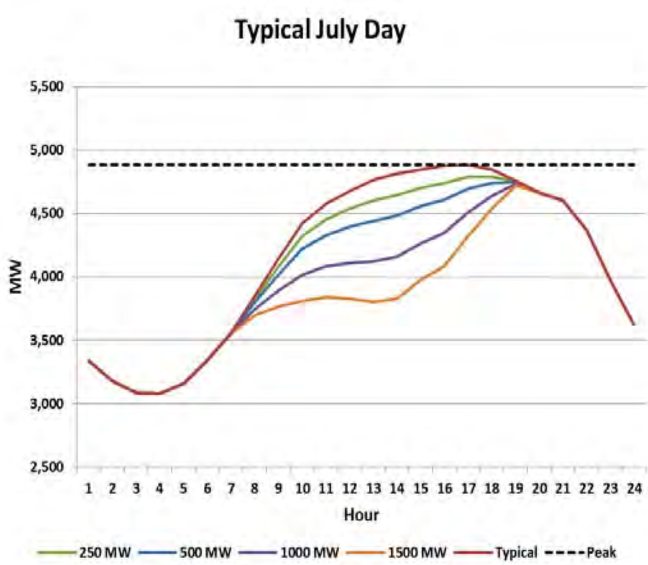
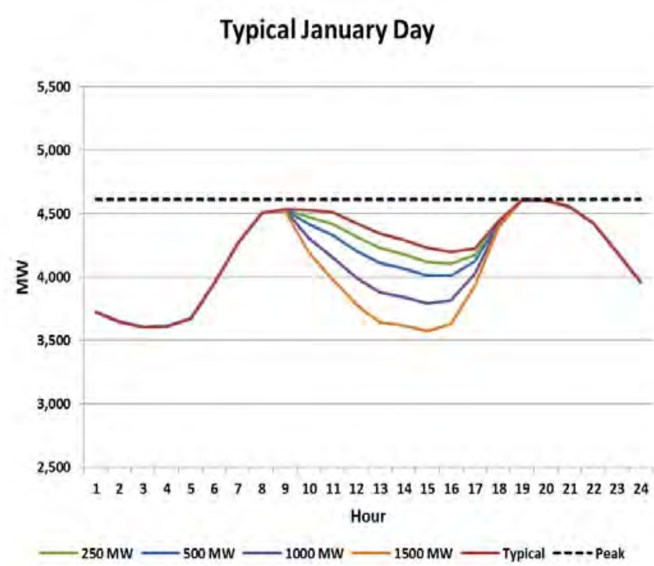
Solar: Contribution to Peak Load – Summer & Winter





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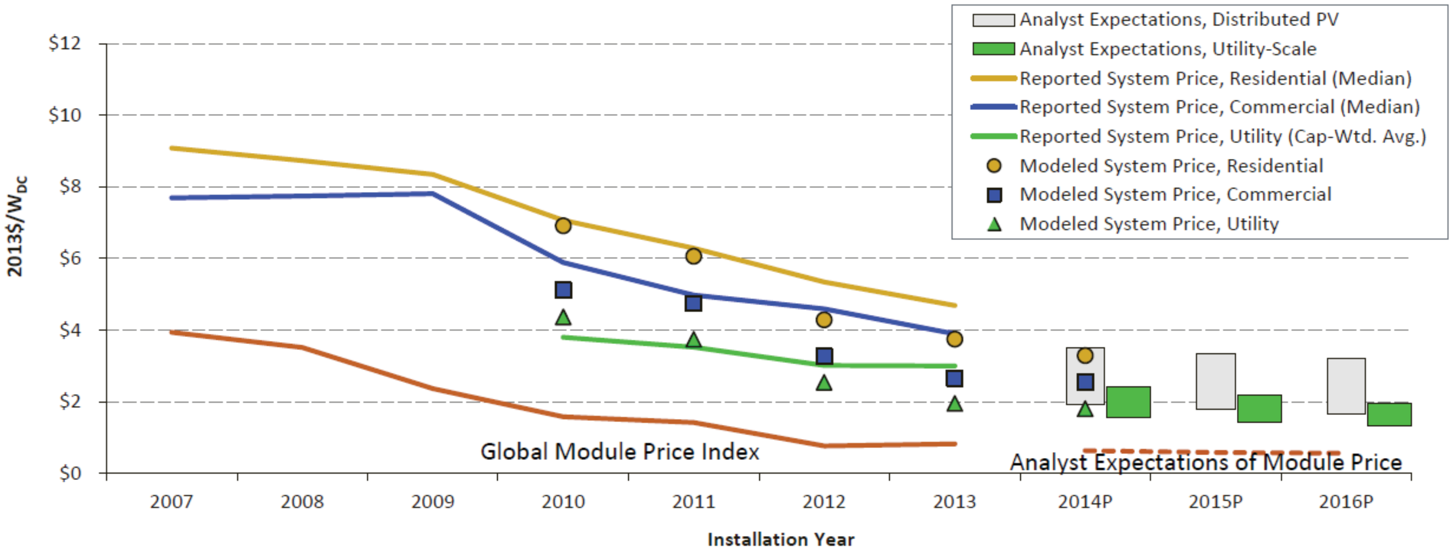
U.S. Photovoltaic System Pricing Trends



- All methodologies show a downward trend in PV system pricing
- Reported pricing and modeled benchmarks have historically had similar results, however have recently diverged

Source: US DOE SunShot Initiative; Sept. 2014 (National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory)

Scott Park, Director IRP Analytics - Midwest

Resources Part 3

Demand Response (DR)

Resource Description

- DR is a resource where the company pays customers an option payment to be able to curtail a customers load during periods of high demand.

Advantages

- Opportunity for customers to lower bill in exchange for being interrupted
- Useful in clipping peak

Disadvantages

- Higher use of DR can drive customers away from program
- Incremental DR capacity gets increasingly expensive
  - Higher payments are needed to incent new participants and that higher rate also gets paid to all participants and drives up the cost of incremental DR.

Energy Efficiency (EE)

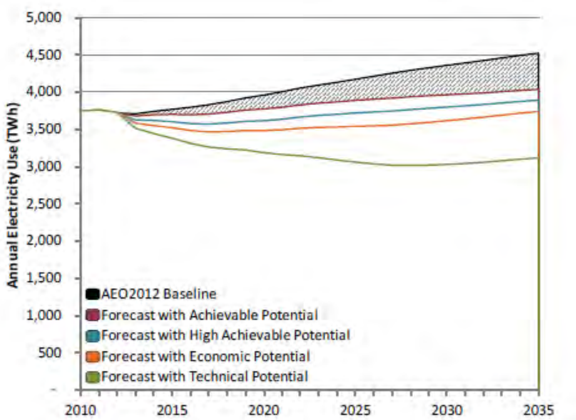
Resource Description

- EE is not a single resource but rather a collection of over five-hundred different measures such as lighting, appliances or motors
- Typically,
  - EE is included in the load forecast implicitly or as a load reduction
  - EE levels are frequently described in terms of
    - Technical potential
    - Economic potential
    - Achievable potential
- In order to model utility sponsored EE as a resource, this portion of EE needs to be removed from the load forecast and put into bundles for economic selection by the resource planning model.

Energy Efficiency (EE)

Resource Description

- EE can be incented by the utility, but requires an action by the customer
  - Participation is less than what purely economic behavior would suggest



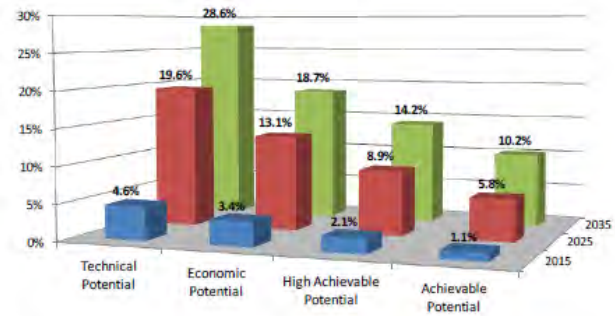


Figure 12
U.S. Summer Coincident Peak Demand Reduction

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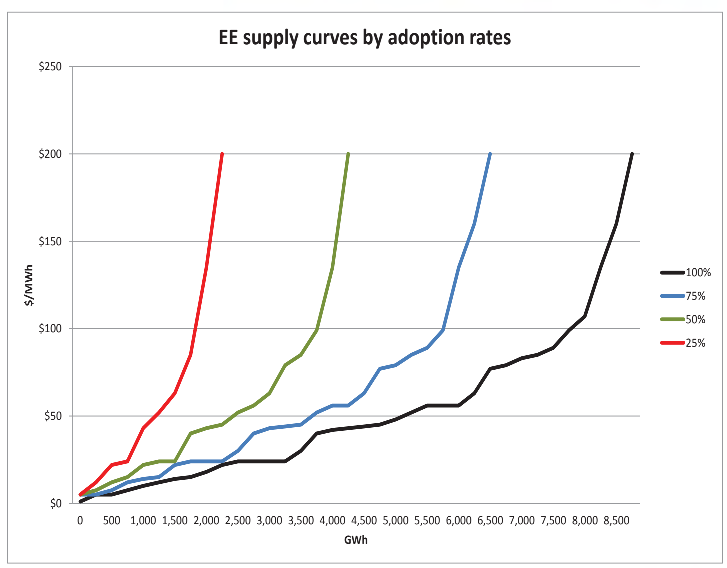
Energy Efficiency (EE)

- Unlike a traditional generation resource such as a gas plant or windmill, EE does not have a single cost for each MWh, but rather has a supply curve for increasing amounts of energy
- Additionally, the supply curve changes as a function of customers adoption rates



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Energy Efficiency (EE)

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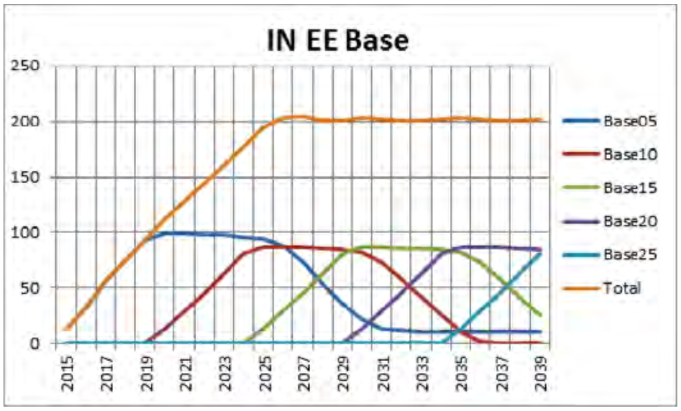

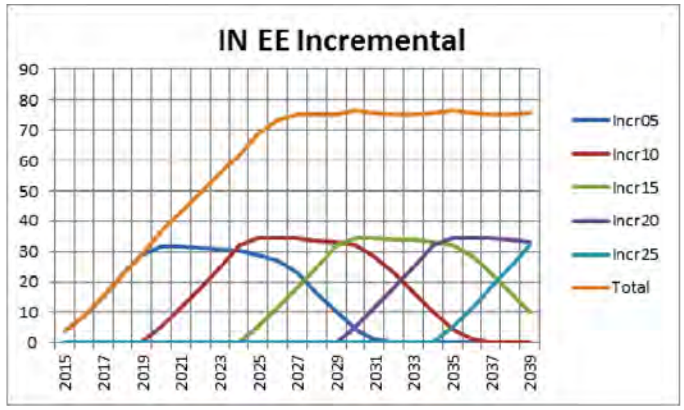

Scott Park, Director IRP Analytics - Midwest

Portfolio Development Exercise

Portfolio Development Exercise

Purpose
- Give stakeholders an opportunity to describe their respective preferred energy mix of DEI's future portfolio

Things to remember
- Consider other stakeholders (800,000 customers but only 1 system)
- System flexibility and fuel diversity
- Tradeoffs between different technologies

Follow-up
- Stakeholders may provide additional input by June 11th
- Duke Energy will specify resources that match stakeholders' preferred energy mix
- Model results will be presented in meeting #3

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Marty Rozelle, President, Rozelle Group

Closing Comments, Stakeholder Comments

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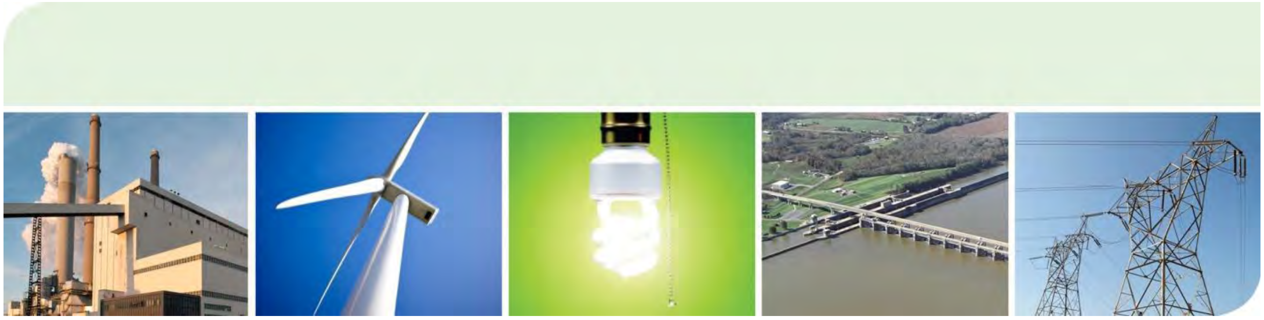
Next Steps

- Please complete comment cards or send by June 11 to Marty at: RGL97marty@rozellegroup.com
- Meeting summary and other materials will be posted on website by June 18 (http://www.duke-energy.com/indiana/in-irp-2015.asp)
- Next workshop is scheduled for the Tuesday, August 4th



Duke Energy Indiana 2015 Integrated Resource Plan

Stakeholder Workshop 2
Summary
June 4, 2015

Welcome
Doug Esamann, State President for Indiana, Duke Energy

Mr. Esamann welcomed participants. He observed that these meetings have changed over time, and he thinks there have been several improvements. He noted the safety messages regarding emergency egress in case of a tornado or other emergency.

He told the group that he has new responsibilities with the Company, requiring him to relocate to Charlotte where he will be an Executive Vice President. He will be responsible for Ohio, Kentucky, Indiana & Florida. Melody Birmingham Byrd will be taking his place as President of Duke Energy Indiana (DEI). She has been here for several years, having come from another utility. Chuck Whitlock will take on electric distribution operations, replacing Ms. Byrd.

Mr. Esamann said that he thinks the agenda for today is an interesting one, and he will be back later in the afternoon for the group exercise.

Introductions & Agenda Overview
Dr. Marty Rozelle, The Rozelle Group Ltd.

Marty Rozelle introduced herself, thanking participants for attending Workshop 2 in this year's Integrated Resource Plan (IRP) process. She asked everyone to introduce themselves, and noted that there are also people calling in on the phone, so requested that participants please speak clearly and use the provided microphones.

There was discussion about how to access the internet accounts that had been set up, and clarification was provided. Several participants had trouble with this, and technical support was called to help. Further instructions were provided. The telephone connection was also unsatisfactory. DEI staff said they will continue to try to fix these issues. After quite a bit of discussion, Dr. Rozelle decided that if we are unable to solve technical difficulties, we just need to proceed since there is a lot to accomplish today.

Meeting 1 Comments & Responses - Updates Since Meeting 1
Scott Park – Director IRP Analytics, Midwest

Scott Park reviewed some of the comments and suggestions that were made at the previous workshop, and discussed how DEI has addressed them. These included Wi-Fi internet access, the range of scenarios, how demand-side management (DSM) and energy efficiency (EE) will be modeled, analysis of unit retirements, and whether health impacts of CO2 emissions would be addressed.

Mr. Park noted that, at this meeting, DEI will be asking participants to make suggestions about scenarios that have been developed based on suggestions at the last workshop. He discussed the conference call in which a “deregulation scenario” was discussed among DEI staff and several stakeholder representatives; this discussion centered on what assumptions might be made to craft such a scenario.

Participant questions included the following:

- A participant requested that the current operations that Duke is using in the State of Ohio should be considered as a scenario. She thought that there should be data available that could be used to build a scenario.
    - Mr. Park explained that in Ohio the utility is essentially taken apart and is deregulated. There are independent generators, customers purchase from the market, and use the transmission system. A big question is who builds the generation. There are also limitations on the transmission system for imported power. It is difficult to make assumptions about generators in building a model. He wondered if this would this be a meaningful scenario for Indiana, and said that DEI will think about it.
- Is there an expectation in Ohio that Duke will provide power to its customers, even though it doesn’t generate any power?
    - Power is now provided through market auctions.
- A suggestion was made that an appropriate role would be to decrease power production and increase grid capacity through smart grid technology.

Scenarios – Part 1
Jim Hobbs, Lead Engineer

Mr. Hobbs told the group that there are 10 scenarios under consideration now, which is quite a few. The first one being considered is “No CO_2 Regulation”, which assumes that there would not be a carbon tax or price, and the load growth rate would be 0.9%. He explained the graph that shows changes in cost of gas and coal resources and power over the planning period.

The second scenario is termed “CO_2 Regulation by Price”. This includes a carbon tax price of $17 per ton in 2020. Gas prices are slightly higher here, as are coal prices. The load rate assumed is 0.8%, and there is a goal of 5% renewable energy in the portfolio.

The third scenario is a Clean Power Plan (CPP) construct that aims to reduce carbon emissions by 20%.

Group comments and questions included the following:

- As generation expires, what are you replacing it with? Will you stay with coal as a resource till 2035?
    - EVA does modeling for the whole Eastern interconnect; their model uses proprietary costs. In the "No CO_2" scenario, there will still be substantial amounts of coal because there is no penalty for coal.
- On the 3 graphs, the coal prices seem to be the same for all. Does that mean that the scenarios will not affect coal at all?
    - Both fuel prices have a very flat supply curve, so they do not vary much.
- Under the CPP, why a 5% renewable, while Indiana Clean Power Compliance Plan is considering a 7% renewable portfolio? EPA is using 7.5% as a data point.
    - These models are based on economics; 5% was the input, and the model would vary that if economical to meet higher requirements.
- Is there any scenario at which the renewable target is set higher than 5%?
    - Not at this time. We can reevaluate that based on model outputs.
- Is there any scenario that just lets the model select a Renewable Portfolio Standard (RPS)?
    - This might be more appropriate to do as a sensitivity. With carbon assumptions, we could try to run a carbon scenario without any RPS input to see what happens.
- Is the dip at 2019 related to retirement of Gallagher?
    - No, this is just supply and demand in the future, and it's not related to Gallagher at all.
- It seems that there is a constant rise in coal prices. Why is that?
    - Primarily due to mining labor costs. The coal fleet drives demand, but fixed production costs will still exist.
- Have you incorporated demand response?
    - Yes. Demand response has been treated more as a resource, which we will talk about more this afternoon.
- The low growth rate is similar in all scenarios. Would you consider a higher load growth scenario?
    - Yes, we've done this in some of the scenarios that will be explained later.
- Are these average nationwide prices for coal and gas?
    - They are Eastern Interconnect prices.
- A participant suggested that the CPP scenario should have 7.5% RPS and also include energy efficiency, to be consistent with the possible Indiana State Implementation Plan.
    - We'll consider it, and may look at it both ways.

Scenarios – Part 2
Brian Bak, Lead Planning Analyst

Brian Bak explained that the scenarios he will describe were designed to test the level of flexibility in the resource portfolio. They combine both carbon regulation and no carbon assumptions over the planning horizon. First, DEI assumes that there is no CO_2 regulation for 10 years, followed by regulation for the remaining 20 years. The next scenario is the opposite, with regulation followed by no regulation.

The third 'stress' scenario is termed "Extended Market Pricing", which tests fixed market prices (currently low) rising steadily over time, without inputting price assumptions.

Participants had the following questions:

- The natural gas curve is identical for the first two scenarios; why is that?
    - It's a very flat part of the supply curve, so there is not much variation when you blend them.
- Then, why do the prices go up at all?
    - To account for inflation over time.
- A participant suggested that the second scenario is not realistic, since it is unlikely that regulations would be rescinded. Another participant disagreed, saying this could happen depending on the current political situation.
- A participant noted that the total price of the "Extended Market" scenario is $65 per megawatt hour (MWh) at the end of the period, compared to $72 for the "No Carbon Regulation" scenario.
- Is the average annual load growth Indiana-specific?
    - Yes.

Scenarios – Part 3
Scott Park

These scenarios are derived from stakeholder suggestions at the last workshop. The first is characterized as "Customer Choice". This incorporates some elements that might be considered aspects of deregulation, as discussed in the previously-mentioned conference call with stakeholders. These include assumptions about increasing use of customer-installed solar, higher levels of EE adoption, a carbon tax on coal, and more merchant generation.

Mr. Park asked the group how this scenario might be improved. They said:

- √ Add combined heat and power (CHP)
- √ This scenario is reasonable. Increasing the target for 'rooftop solar' makes sense because of increased availability and use of battery storage.

Other comments included the following:

- If DEI is only going to assume 1% increase per year of solar, how are you even going to get 1 MW of total generation, given the low measure of efficiency of wind and solar?
    - We are only including customer-generated solar here, not utility scale.
- What's the utilization factor on rooftop solar?
    - About 45%.
- It takes about 5.5 acres of solar installation to generate 1 MW – "that's a lot of roofs".
- Don't call it 'rooftop', call it customer-owned. For example, there are farmers now who have installed solar panels in fields, which they can seasonally adjust.
- Some states have increased their net metering caps from 3% to 6%.
- Is there a scenario that reflects decreased customer choice?

  - Not really; this assumes that customers can adopt distributed generation (rooftop solar) at any time, not factoring in federal subsidies, etc.
- A participant suggested that the power price of $100/MWh would be offset by benefits to society of about $40/MWh, making this scenario cost $60, which is relatively inexpensive.

Mr. Park explained that the next 3 scenarios address climate change issues. He said these may be able to be combined into a single scenario, and asked the group to consider whether this might make sense.

He observed that climate change might include greater volatility in weather, rather than a wholesale change in everything. The "Climate Change" scenario, therefore, is characterized by higher summer temperatures that drive increased electricity consumption as well as increased fuel and power prices and a carbon tax.

Additionally, DEI has developed 2 one-year stress scenarios that test the various portfolios in extreme weather events, mainly as a risk analysis. These include a "Polar Vortex" scenario that mimics conditions of 2013 and 2104 where there were high winter peaks in energy demand, and a "Hot Summer" scenario with high demand in which river levels are lower, resulting in reduced power generation unit output. Both of these factors contribute to higher prices for fuel and power.

Questions, comments, and observations included:
- What years in these charts would reflect the stressors?
  - We would try to mimic recent experiences. The various portfolios would be run through these conditions to allow us to compare costs of portfolios under stress of winter and summer conditions.
- You can't use the same prices for these scenarios; commodity prices would likely be much higher here.
  - Agreed.
- From a climate standpoint, it is predicted that these events will occur on a more regular basis in future, so these scenarios make sense.
- Are you assuming constant load growth throughout all these scenarios?
- Yes, because some assumption could increase load growth while others could decrease it; we assume it would balance out.
- Please review the charts for these scenarios again; they are not clear to participants.
  - These prices would only vary significantly on a seasonal or even daily basis – we haven't built in that level of specificity. Historically, changing demand doesn't necessarily result in cost changes. These are generally based on the previously-described Carbon scenarios.
- If there is a carbon tax and higher demand, it would probably result in a higher adoption of customer solar generation.
- Perhaps you're assuming too much load growth?
  - The Carbon case would be a proxy for that, starting with .8%. The model can select additional levels of EE, rooftop solar, etc. This could even result in a negative load growth for the utility.

- If we collapse the climate scenarios, the events should be assumed to occur close together, perhaps in concurrent years on several occasions over the planning horizon (but not every year).
  - This seems to be a good approach to use. Thank you.
- Consider that average temperatures will continue to rise regardless of drastic events.
- What effect do hot summers have on the system?
  - The ability of plants to take in cooling water is less, so generation efficiency is reduced (say by 40%). The model can reduce the dispatch of units accordingly.

In summarizing the discussion, Mr. Park said the group seems to agree that DEI should proceed with the following:

√ Include the carbon/no carbon scenarios
√ Extended Market scenario represents low sensitivity
√ Customer Choice scenario is acceptable
√ Climate Change scenarios make sense, and it is agreeable to combine them, using suggestions above

Resources – Part 1
Jim Hobbs

Jim Hobbs noted that this discussion is in preparation for the exercise this afternoon dealing with portfolios. He asked the group if anyone had tried playing the Duke Energy online Planning Game, and several had. He provided a brief overview of the remaining presentations, noting that the statistics presented are from EIA.

The first resource discussed was Simple Cycle Combustion Turbines(CT), essentially jet engines fueled by natural gas. These tend to be peaking units.

Questions included:

- Do the data on capital cost include pollution control equipment?
  - Mr. Hobbs didn't know but assumes so.
- What's the energy efficiency of these units? People took issue with the assumption of 30% capacity factor, believing it's much lower.
  - Megawatt cost ($/MWh) is a function of capacity factor, so if you want to cut capacity back, the cost could be cut back commensurately (e.g. 10% capacity = $10/MWh).
- Characterizing cost as dollars per **kilowatt** ($/KW) would be more understandable to stakeholders.

The next resource described was Combined Cycle Combustion Turbines (CC), which are about 3 times larger than a stand-alone CT and tend to serve as baseload units. They cost about $900/KW and have a much higher capacity factor.

Nuclear units are much larger baseload resources, are very expensive to install, but have no carbon emissions. The cost equates to about $5500/KW.

Mr. Hobbs discussed the resources that were looked at but not used in portfolio development for a number of reasons. These are:

- Geothermal – There are no local resources (Some participants did not agree with this characterization.)
- Advanced storage (batteries) – Still very expensive, although research and development are ongoing (Some participants suggested that this should not be screened out, since costs are coming down all the time. Mr. Park noted that the cost is still very high, and batteries need to be replaced several times over the life of a project, adding significantly to cost-effectiveness.)
- Compressed air storage – Indiana geology does not present suitable sites.
- Small modular nuclear reactors (recyclable) – conceptual only at this point
- Fuel cells – not commercially viable at utility scale
- Animal waste digesters (A participant objected to screening this resource out, and said that there are 14MW already being generated in Indiana with anaerobic digesters. There are also a number of other industrial waste streams that could be suitable for these digesters.)
- Woody biomass – inadequate fuel resource in Indiana due to climate (A participant noted that there are resources in southern Indiana that would accommodate this. Also, although the resource may not be suitable for Duke's use it could be viable on a smaller scale for customer generation.)
- Coal – unlikely to be developed as a new resource in the future

A participant said that this information is very confusing. Another wondered if Duke is trying to predict when some of these resources may become available; Mr. Park said it's not practical to include purely hypothetical resources without reliable data, but the repetition of the IRP process every two years accounts for updates of information and inclusion of new approaches. He noted that Duke has an emerging technologies group that tracks these developments.

Mr. Hobbs provided more information about Duke's battery storage research and development activities. He explained how combined heat and power (CHP) works, saying that this would typically be used by an industrial customer who has a need for both steam and process heat. This approach greatly increases plant efficiency, and has a number of other advantages. The challenge is mainly economic, and depends on individual customer needs and budgets. Both Purdue University and Tate and Lyle now operate CHP units, and other customers may emerge in future.

Participant questions included:

- Would CHP be utility-owned or customer-owned?
    - It could be either one.
- Is there a benefit of CHP to the utility in terms of deferred generation, relieving pressure on the transmission system, etc.?
    - Possibly.
- The increase in efficiency and corresponding reduction of CO_2 emissions make CHP a very important technology for future consideration. Purdue has a 39 MW facility.
- Wastewater treatment plants may also be good candidates. Duke should do a market assessment by sector to evaluate this.

- Why isn't gas conversion of existing coal plants included in the list of resources?
    - Converting coal units to gas is inefficient and inflexible, so it won't do much on an energy basis or a capacity basis; therefore, it hasn't been an attractive option to date. The Clean Power Plan may change that thinking. We may look at Wabash River #6 within the context of this IRP, but would probably limit the analysis to that.

Lunch

Resources – Part 2
Brian Bak

Mr. Bak discussed biomass generation from landfill gas. These are small units with a high capacity factor that can provide baseload power. An advantage is that the fuel cost is low; a disadvantage is that sites are limited.

Questions were:
- Are these costs open for stakeholder discussion?
    - They are confidential costs, but could be made available if participants sign a non-disclosure agreement.
- What's the life expectancy of a landfill unit?
    - We don't know exactly, but it's likely to decrease over time.
- Do they need to be located in DEI's service territory to be used?
    - That would be preferable from a transmission standpoint, but it's probably not necessary.
- Can these units be installed retroactively, or do they need to be built along with the landfill?
    - It's probably more efficient to design them into the facility, but they can be retrofitted (e.g., Marshall County, Argos).

Mr. Bak provided an overview of DEI's renewable energy resources, which provide a total of 1.5% of annual energy. These include wind, hydro, and solar. He noted that there are many more wind generators in the region than previously. Wind farms can range from a single turbine to large arrays. Capital costs are relatively low, but the capacity factor is also quite low (about 35%). The biggest challenge is that the resource is intermittent, and the average contribution to peak (MISO capacity credit) is only 14.7% in the MISO region. Transmission may also be a challenge. Advantages include no fuel costs and no emissions. He showed a map of wind resource quality throughout the United States; Indiana is about in the middle of the range.

Regarding solar, this assessment is limited to photovoltaic, on a utility scale. Capital costs are slightly higher than wind, but the capacity factor is lower (about 21%). Maintenance costs tend to be low, and there is no fuel cost. There are no air emissions. Solar is also an intermittent resource and has effects on peak demand. This is illustrated by looking at a series of graphs showing typical summer- and winter-day demand relative to solar output. In summer, solar contributes significantly to peak demand in the late morning and early afternoon, but not in the evening. In winter, there is a dual peak in morning and evening, while solar produces energy between those times; therefore, solar does not significantly contribute to winter demand at all.

Group questions and comments included the following:

- What is MISO Capacity Credit?
  - MISO (Midcontinent Independent System Operator, Inc.) will calculate credit to utilities for providing energy to customers, while maintaining the required reserve margins. This means utilities don't typically get full capacity credit for some resources.
  - A participant from Indianapolis Power and Light (IPL) noted that IPL approaches solar differently, putting a 7% credit on top of the MISO capacity factor. There is not always a direct exchange, and it does not always involve "real" money.
- A participant suggested that there is evidence showing that orienting solar panels due south instead of west may be advantageous to the utility.
- If the orientation of panels is seasonally adjusted, 4 times per year, efficiency can be increased quite a bit. There seems to be a trend toward this in Indiana, according to a participant.
- Do solar generators get credit for the times of day that solar greatly reduces demand?
  - Yes, but that's offset by the opposite times when they need to obtain power from the grid.
- A participant said that solar is being installed in Bloomington for $2.75 per watt; here we still show a cost of more than $4.
  - This is a function of the data being used as inputs here. A participant in the previous workshop had also suggested that costs were much lower in the German system.

Resources - Part 3
Scott Park

Mr. Park talked about customer-driven resources including Demand Response (DR) and Energy Efficiency (EE). DR presents an opportunity for customers to lower their bills in exchange for having their power interrupted during periods of high demand on the system.

The concept of Energy Efficiency includes hundreds of different programs and approaches, not just a single resource. EE is typically described according to 'achievable potential', 'economic potential', and 'technical potential'. Historically, about 50-60% of customers have taken advantage of some kind of EE opportunity. Mr. Park explained how EE will be evaluated in scenario analysis, by 'bundling' programs so they can be economically selected by the resource planning model.

Questions and comments included:

- Why aren't large customers taking advantage of this? Why haven't the utilities been offering incentives for these customers?

  - Mr. Park provided some history of this topic in Indiana, resulting in the current situation whereby the State has taken away EE targets, and industrial users are allowed to opt out of the available programs.
  - Michael Goldenberg of DEI said that the best opportunity at this time may be for the small commercial users, since the large customers have opted out. He noted that this decision is no different from residential customers who don't want to spend a lot of up-front money.
  - A representative of Steel Dynamics, Inc. said that they are the second-largest electricity user in DEI territory. They want a 3-year payback, not a 30-year payback as estimated by the utilities. Although they have opted out, they are still doing what makes economic sense, on their own initiative and not in response to a regulation.
  - A representative from the Office of Utility Consumer Counsel (OUCC) noted that there were probably several reasons for this history. Marketing of the CNI programs at the beginning wasn't very effective. "Energize Indiana" made better sense. Also, along the way there were a number of facilities that made big improvements, and later they resented having to subsidize others who had not made those investments.
- Thank you for including the market potential study in the recent filing. It does seem to be a bit outdated, however.
  - Suggestions and ideas about what should be included in future studies would be welcome.
- Are you accounting for LRAM in the market potential studies?
  - Accounting for lost revenues is part of our analysis of cost-effectiveness.
- Regarding the packaging of EE for modeling, are these bundles of individual programs? Are bundles created by year, incrementally?
  - No, they are an aggregation of a number of programs, which are added incrementally at sequential times in the modeling. We cannot, therefore, evaluate the effects or effectiveness of individual EE programs.
- How are you adjusting reserve margins taking EE into account?
  - We're not; MISO dictates the required reserve margin.

Portfolio Development Exercise
All

Dr. Marty Rozelle explained that the exercise planned was for about 1.5 hours, but we only have about ½ hour left today. She explained the exercise and the worksheets. The goal is to fill in the blank portfolio matrices with a percentage breakdown of resources to be included in a suggested portfolio, taking into account the cost and performance data that's been presented today. She asked participants to please spend a few minutes individually filling out a matrix, and then discuss your ideas with the group at your table to see if you can agree on a shared portfolio. Tables will share their thoughts with the larger group at the end, and DEI will use the results in testing the scenarios.

A participant noted that it would be very helpful to have the information in MW rather than percentages; for example, what does 1% represent? Mr. Park said that that DEI serves about 40 million megawatt hours per year.

After working separately, each table presented their proposals. Group observations about the proposals included the following:

- No one had more than 40% coal in their portfolio in 2035. This will help in reducing emissions.
- Only one included nuclear generation.
- Everyone wants more renewables and EE.
- Combined cycle will also produce some emissions.
- EE and CHP should be taken more seriously, especially by business and industry, since these will ultimately reduce customer costs. These will also help to reduce carbon sources, which is good for all. Duke needs to really help customers reduce energy use.
- Most table groups reduced the level of market purchases. DEI asked why this was suggested; answers were:
  -- There's less financial risk to the company.
  -- As more plants are shut down, there's less power out there to purchase.
  -- It's going to be up to the utility to generate its own power.
  -- Duke needs to show every year that it has enough generating capacity to serve its load. If this is not fully used, customers are still paying for the assets. If we have enough capacity, then why are we buying?

The results of the group exercise are attached to this summary.

Closing Comments

Doug Esamann observed that the various proposals show similar trends, specifically in the suggestions for reduced coal and increased renewables. He promised that DEI will cost these out to see how feasible they may be, and also to evaluate the carbon footprint of the various portfolios. He thanked participants very much for their time today, reiterating that the IRP stakeholder process is very important to DEI and to its customers.

The facilitator reminded participants to please fill out comment forms about the meeting. Additional comments can be emailed to Dr. Marty Rozelle at: rgl97marty@therozellegroup.com.

The next meeting will be on August 4, and the final meeting will likely be in early October.

Summary of Resource Portfolios Suggested by Stakeholders

STAKEHOLDER TABLE 1

RESOURCE TYPE	2014	2025	2035
Coal	75%	47%	22%
Market Purchases	21%	17%	12%
Hydro	1%	1%	1%
Combined Cycle	1%	14%	25%
Combustion Turbine	1%	1%	1%
Energy Efficiency	1%	5%	10%
Solar	0%	5%	10%
Wind	0%	5%	10%
CHP	0%	3%	5%
Nuclear	0%	0%	0%
Other 1 (Fuel Cell)	0%	1%	2%
Other 2 (LFG/ Digester)	0%	1%	2%
TOTAL	**100%**	**100%**	**100%**

STAKEHOLDER TABLE 2

RESOURCE TYPE	2014	2025	2035
Coal	75%	25%	15%
Market Purchases	21%	25%	25%
Hydro	1%	1%	1%
Combined Cycle	1%	1%	1%
Combustion Turbine	1%	0%	0%
Energy Efficiency	1%	15%	18%
Solar	0%	8%	10%
Wind	0%	8%	10%
CHP	0%	8%	10%
Nuclear	0%	0%	0%
Other 1 (Biomass)	0%	8%	10%
Other 2 ( )	0%	0%	0%
TOTAL	**100%**	**99%**	**100%**

STAKEHOLDER TABLE 3

RESOURCE TYPE	2014	2025	2035
Coal	75%	50%	40%
Market Purchases	21%	16%	10%
Hydro	1%	1%	1%
Combined Cycle	1%	10%	16%
Combustion Turbine	1%	1%	1%
Energy Efficiency	1%	5%	10%
Solar	0%	2%	3%
Wind	0%	5%	7%
CHP	0%	10%	13%
Nuclear	0%	0%	0%
Other 1 ( )	0%	0%	0%
Other 2 ( )	0%	0%	0%
TOTAL	**100%**	**100%**	**100%**

STAKEHOLDER TABLE 4

RESOURCE TYPE	2014	2025	2035
Coal	75%	50%	35%
Market Purchases	21%	15%	10%
Hydro	1%	1%	1%
Combined Cycle	1%	20%	20%
Combustion Turbine	1%	5%	10%
Energy Efficiency	1%	5%	5%
Solar	0%	1%	4%
Wind	0%	1%	4%
CHP	0%	1%	4%
Nuclear	0%	0%	5%
Other 1 (Fuel Cell)	0%	0%	1%
Other 2 (Battery)	0%	1%	1%
TOTAL	**100%**	**100%**	**100%**

STAKEHOLDER TABLE 5

RESOURCE TYPE	2014	2025	2035
Coal	75%	48%	30%
Market Purchases	21%	12%	3%
Hydro	1%	1%	1%
Combined Cycle	1%	16%	25%
Combustion Turbine	1%	1%	2%
Energy Efficiency	1%	7%	14%
Solar	0%	4%	8%
Wind	0%	11%	16%
CHP	0%	2%	5%
Nuclear	0%	0%	0%
Other 1 ( )	0%	0%	0%
Other 2 ( )	0%	0%	0%
TOTAL	**100%**	**102%**	**104%**

(AVERAGE OF TABLES)

RESOURCE TYPE	2014	2025	2035
Coal	75%	44%	28%
Market Purchases	21%	17%	12%
Hydro	1%	1%	1%
Combined Cycle	1%	12%	17%
Combustion Turbine	1%	2%	3%
Energy Efficiency	1%	7%	11%
Solar	0%	4%	7%
Wind	0%	6%	9%
CHP	0%	5%	7%
Nuclear	0%	0%	1%
Other 1 (Biomass)	0%	2%	2%
Other 2 (Battery & Fuel Cell)	0%	0%	1%
TOTAL	**100%**	**100%**	**101%**

2015 Integrated Resource Plan

Stakeholder Workshop #3

Aug 4, 2015
Plainfield, IN

Welcome

Welcome

- Safety message
- Why are we here today?
- Objectives for stakeholder process
- Introduce the facilitator

DUKE ENERGY.

The Facilitator

- Duke Energy Indiana hired Dr. Marty Rozelle of The Rozelle Group and her colleagues to:
  - Help us develop the IRP stakeholder engagement process
  - Facilitate and document stakeholder workshops

DUKE ENERGY.

Why are we here today?

- Duke Energy Indiana developing 2015 Integrated Resource Plan (IRP)
- Proactively complying with proposed Commission IRP rule
- Today is the 3rd of 4 stakeholder workshops prior to filing the IRP by November 1, 2015

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Objectives for Stakeholder Process

- **Listen:** Understand concerns and objectives
- **Inform:** Increase stakeholders' understanding of the IRP process, key assumptions, and challenges we face
- **Consider:** Provide a forum for productive stakeholder feedback at key points in the IRP process to inform Duke Energy Indiana's decision-making
- **Comply:** Comply with the proposed Commission IRP rule

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Agenda

08:30	Registration & Continental Breakfast
09:00	Welcome, Introductions & Agenda
09:20	Meeting 2 Comments & Responses
09:45	Scenario Review
10:15	Break
10:30	Portfolio Review
11:30	Lunch
12:15	Modeling (Results; Observations; Next Steps)
01:30	Sensitivity Exercise
02:45	Closing Comments

Scott Park, Director IRP Analytics - Midwest

Meeting 2 Comments & Responses

Meeting 2 Comments and Response

Topic	We heard/observed...	Response
Conference Call	Poor sound quality	Raised issue with IT and corrected
Wi-Fi	Poor Wi-Fi connectivity	Since internet access is not critical to the meeting, stakeholders will now be responsible for providing for their own internet access
CO2 footprint	What is the CO2 footprint of the portfolios?	Reductions in CO2 data will be provided for each portfolio in each scenario

Meeting 2 Comments and Response

Topic	We heard/observed...	Response
Stakeholder Exercise	Exercise was very helpful and informative	We felt that having stakeholders develop specific input and present that to the group was very productive and we will make use of a similar exercise format in future meetings
One on One Conference Call	Due to problems with the conference call sound quality, several calls were conducted with two stakeholders to review the content of the June 4th meeting as well as discuss IRP issues	Conference calls were productive and overall understanding between stakeholders and Duke Energy Indiana improved, but differences of opinions still exist

Jim Hobbs, Lead Engineer

Scenario Review

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Seven Scenarios

Core Scenarios

1. No Carbon Regulation
2. Carbon Tax
3. Clean Power Plan (Proposed Rule)

Change of Outlook Scenarios

4. Hybrid scenario 1 (No Carbon Regulation changing to Carbon tax)
5. Hybrid scenario 2 (Carbon tax changing to No Carbon Regulation)

Stakeholder-Inspired Scenarios

6. Increased Customer Choice
7. Climate Change

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Core Scenarios

- No Carbon Regulation
  - No carbon tax/price or regulation
  - Moderate levels of environmental regulation
  - No Renewable Energy Portfolio Standard (REPS)
- Carbon Tax
  - Carbon tax $17/ton in 2020, rising to $50/ton
  - Increased levels of environmental regulation
  - 5% REPS
- Clean Power Plan (CPP) (Proposed Rule)
  - Carbon reduced 20%
  - Increased levels of environmental regulation
  - 5% REPS

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Change of Outlook Scenarios

- Hybrid scenario 1 (No Carbon Regulation changing to Carbon tax)
  - No Carbon Regulation scenario initially
  - Change to Carbon Tax scenario for latter part
  - Demonstrates impact of delayed carbon regulation
- Hybrid scenario 2 (Carbon tax changing to No Carbon Regulation)
  - Carbon Tax scenario initially
  - Change to No Carbon Regulation scenario for latter part
  - Demonstrates impact of repeal of carbon regulation

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Stakeholder-Inspired Scenarios

- Increased Customer Choice
  - Carbon Tax scenario basis
  - Roof top solar serves additional 1% of load per year beginning 2020
  - Customers adopt higher levels of Energy Efficiency
  - New utility-scale generation served by merchant generators, e.g., Dynegy or Calpine
- Climate Change
  - Higher summer temperatures increase demand and prices for power and fuel
  - Carbon tax same as Carbon Tax scenario
  - Even hotter summer 2019 and "polar vortex" 2020, and every 5 years thereafter, causing higher prices

Break

Brian Bak, Lead Planning Analyst & Jim Hobbs, Lead Engineer

Portfolio Review

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Nine Portfolios

1. Optimized No Carbon Tax
2. Optimized Carbon Tax
3. Optimized Clean Power Plan
4. Portfolio 1 w/ CC's
5. Portfolio 2 w/ CC's
6. Portfolio 3 w/ CC's
7. Stakeholder Distributed Generation
8. Stakeholder Green Utility
9. High Renewables

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Portfolio Template

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT					
CHP					
CC					
EE & IVVC					
Solar					
Wind					
Biomass					

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit					
MW					

MARKET (Annual average GWh)	Total	2016-20	2021-25	2026-30	2031-35
Market Purchases					
Market Sales					

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Optimized No Carbon Tax Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	1,040	208	208	416	208
CHP	44	29	15		
CC					
EE & IVVC	220 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	1 / 3.1%
Solar					
Wind					
Biomass					

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			

MARKET (Annual average GWh)	Total	2016-20	2021-25	2026-30	2031-35
Market Purchases	3,647	4,577	2,731	3,490	3,791
Market Sales	(2,211)	(1,810)	(2,533)	(2,329)	(2,170)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

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Optimized Carbon Tax Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	734	**318 (WR6)**		416	
CHP	44	29	15		
CC	448			448	
EE & IVVC	224 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	5 / 3.2%
Solar	270	20	180	70	
Wind	400		250	150	
Biomass	14	2	6	6	
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4		Gib5	
MW	(1,424)	(1,114)		(310)	
MARKET (Annual average GWh)					
Market Purchases	**6,467**	5,078	5,198	**7,140**	**8,450**
Market Sales	(868)	(1,600)	(1,004)	(558)	(310)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

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Optimized Clean Power Plan Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	29	15	15		
CC	896	**896**			
EE & IVVC	220 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	1 / 3.1%
Solar	290	20	130	110	30
Wind	400		300	100	
Biomass	14	2	6	6	
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			
MARKET (Annual average GWh)					
Market Purchases	**7,878**	5,230	**7,720**	**8,395**	**10,168**
Market Sales	(815)	(1,718)	(585)	(540)	(416)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

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Portfolio 1 w/ CC's Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624			416	208
CHP	44	29	15		
CC	448	**448**			
EE & IVVC	220 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	1 / 3.1%
Solar					
Wind					
Biomass					
RETIREMENTS					
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			
MARKET (Annual average GWh)					
Market Purchases	2,521	4,287	1,452	2,067	2,277
Market Sales	(2,797)	(2,001)	(3,366)	(3,046)	(2,773)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

Portfolio 2 w/ CC's Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	44	29	15		
CC	896	**448**		448	
EE & IVVC	224 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	5 / 3.2%
Solar	300	20	200	80	
Wind	400		250	150	
Biomass	14	2	6	6	
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4		Gib5	
MW	(1,424)	(1,114)		(310)	
MARKET (Annual average GWh)					
Market Purchases	5,082	4,706	3,655	5,166	**6,803**
Market Sales	(1,499)	(1,704)	(1,834)	(1,587)	(873)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

Portfolio 3 w/ CC's Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT					
CHP	29	15	15		
CC	1,344	896			**448**
EE & IVVC	220 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	1 / 3.1%
Solar	320	20	140	120	40
Wind	400		300	100	
Biomass	14	2	6	6	

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

MARKET (Annual average GWh)	Total	2016-20	2021-25	2026-30	2031-35
Market Purchases	**7,578**	5,230	**7,715**	**8,377**	**8,991**
Market Sales	(951)	(1,718)	(586)	(546)	(953)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

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Stakeholder Distributed Generation - Target vs Model

Energy Mix (%)	2025 Target	2025 Model	2035 Target	2035 Model
Market Purchases	11%	9%	8%	13%
Coal	36%	42%	19%	16%
Hydro	1%	1%	1%	1%
CC	8%	12%	9%	17%
CT	1%	0%	1%	0%
EE	11%	5%	16%	8%
Solar	7%	7%	10%	10%
Wind	10%	10%	13%	13%
CHP	9%	8%	12%	11%
Nuclear	0%	0%	3%	3%
Battery/Fuel Cell	1%	1%	2%	2%
LFG/Digester/Biomass	5%	5%	6%	6%
	100%	100%	100%	100%

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Stakeholder Distributed Gen Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832		208		624
CHP	**609**	131	290	15	174
CC	1,344		896		448
EE & IVVC	**650 / 8.5%**	189 / 2.8%	203 / 5.7%	138 / 7.3%	120 / 8.5%
Solar	**2,480**	670	970	420	420
Wind	**2,050**	450	800	550	250
Biomass	303	106	137	60	

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs	Gal2,4 Cay1,2 Gib1,5		Gib2,3
MW	(4,283)	(834)	(2,189)		(1,260)

MARKET (Annual average GWh)	Total	2016-20	2021-25	2026-30	2031-35
Market Purchases	3,920	3,682	2,716	3,910	5,372
Market Sales	(2,707)	(2,824)	(2,554)	(2,872)	(2,580)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

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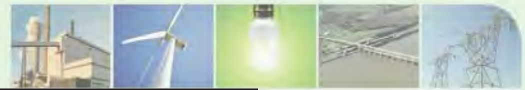
Stakeholder Green Utility - Target vs Model



Energy Mix (%)	2025 Target	2025 Model	2035 Target	2035 Model
Market Purchases	16%	16%	13%	19%
Coal	50%	58%	38%	36%
Hydro	1%	1%	1%	1%
CC	18%	13%	19%	20%
CT	3%	0%	6%	0%
EE	5%	6%	8%	8%
Solar	2%	2%	4%	4%
Wind	3%	3%	6%	6%
CHP	2%	2%	5%	5%
Nuclear	0%	0%	0%	0%
Battery/Fuel Cell	0%	0%	0%	0%
LFG/Digester/Biomass	0%	0%	0%	0%
	100%	100%	100%	100%

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Stakeholder Green Utility Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624		624		
CHP	261	29	73	73	87
CC	**1,344**		896		448
EE & IVVC	**650 / 8.5%**	189 / 2.8%	203 / 5.7%	138 / 7.3%	120 / 8.5%
Solar	**930**	40	380	300	210
Wind	**800**		250	300	250
Biomass	16	2	6	8	
RETIREMENTS					
Unit		WR2-6 Oil CTs	Gal2,4 Gib5 Cay1,2		Gib1
MW	(3,023)	(834)	(1,559)		(630)
MARKET (Annual average GWh)					
Market Purchases	**6,035**	4,575	5,739	**6,537**	**7,289**
Market Sales	(1,077)	(1,832)	(814)	(746)	(914)

Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

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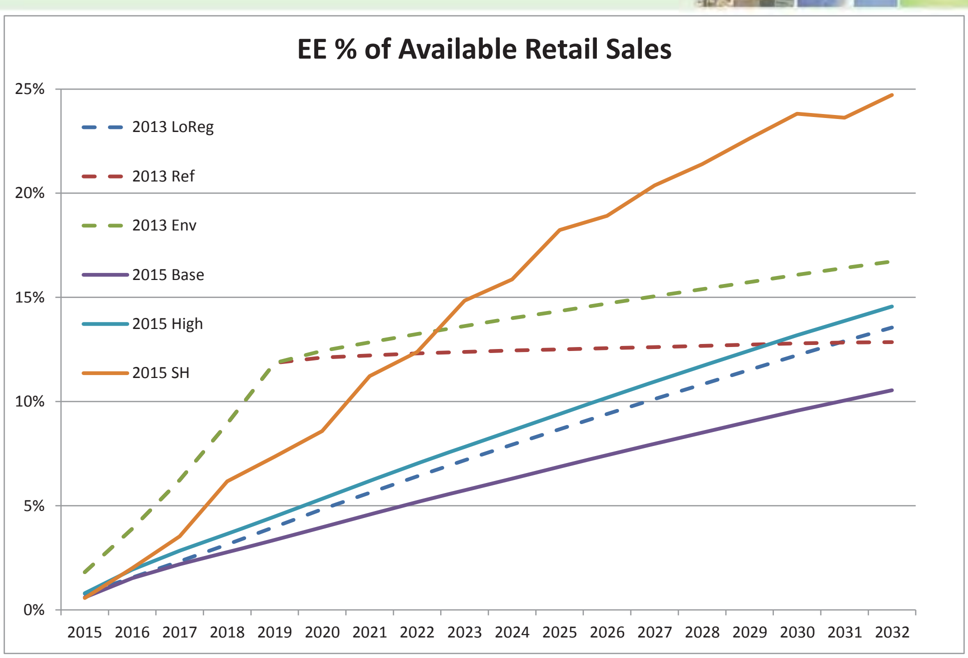
High Renewables Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	526	**318 (WR6)**	208		
CHP	44	29	15		
CC	448				448
EE & IVVC	220 / 3.1%	126 / 1.9%	82 / 3.1%	11 / 3.1%	1 / 3.1%
Solar	1,010	20	130	**260**	**600**
Wind	2,300		300	**500**	**1,500**
Biomass	14	2	8	4	
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)
MARKET (Annual average GWh)					
Market Purchases	5,701	5,052	4,753	**6,662**	**6,336**
Market Sales	(1,247)	(1,614)	(1,190)	(747)	(1,437)

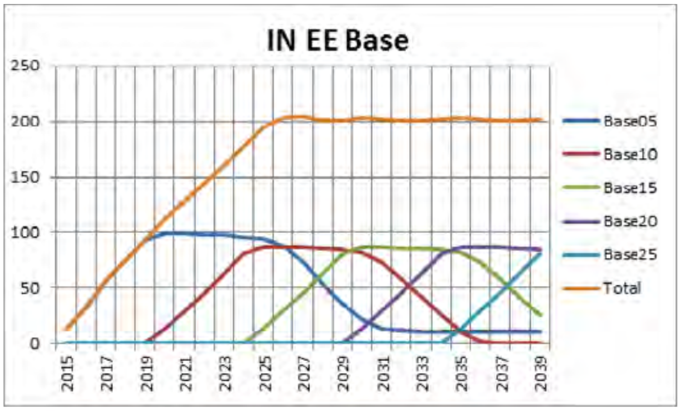
Note- Portfolio components are preliminary and might change during the more detailed modeling phase
- Energy efficiency percentages are cumulative EE over total annual retail sales

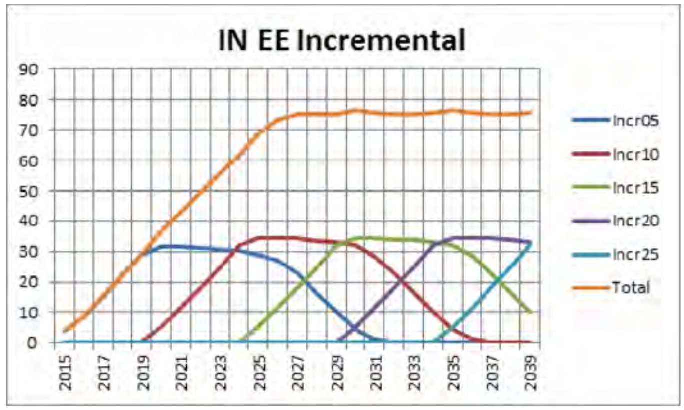
EE Summary



Energy Efficiency Bundles

- In order to model utility sponsored EE as a resource, this portion of EE needs to be removed from the load forecast and put into bundles for economic selection by the resource planning model.





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Lunch

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Scott Park, Director IRP Analytics – Midwest & Brian Bak, Lead Planning Analyst

Modeling

Modeling Overview

- Modeling to date, has been conducted using *System Optimizer* and results should be viewed as preliminary
  - System Optimizer is a long term optimization model for resource selection
  - Prosym is a detailed dispatch model to better measures detailed system performance
- 7 scenarios
- 9 portfolios
- For each of the 63 scenario-portfolio pairs, the following will be presented
  - PVRR
  - CO2 reduction
  - Energy served from market purchases
  - Observations from modeling results across each scenario

No CO2 Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	**16,832**	17,313	17,355	**16,875**	**17,277**	17,380	23,202	19,429	17,617
CO2 Emissions (+/-)	15%	4%	1%	12%	1%	-2%	**-49%**	**-24%**	**-11%**
Mkt Purch (max/avg)	15% / 9%	15% / 10%	**15% / 7%**	**15% / 6%**	**15% / 7%**	**15% / 6%**	**15% / 7%**	17% / 12%	15% / 8%

Scenario Observations

- The No CO2 Optimized & No CO2 Optimized w/CC portfolios had the lowest PVRR's
  - Gas generation appears to work best in this scenario for the majority of resource needs
  - The CC portfolio is only slightly more costly than CT portfolio but has only 2/3 the market purchases
- While being the lowest cost portfolios by on the order of $500 MM, they had the greatest increase in CO2 emissions
- The profile of market purchases are relatively equal across all portfolios in the No CO2 scenario and do not appear to be a distinguishing risk factor

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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CO2 Tax Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	23,402	**23,196**	**23,224**	23,447	23,248	**23,243**	27,237	24,345	23,445
CO2 Emissions (+/-)	2%	-4%	-9%	-3%	-9%	-13%	**-55%**	**-33%**	**-22%**
Mkt Purch (max/avg)	24% / 16%	23% / 17%	**18% / 13%**	19% / 13%	**18% / 13%**	**17% / 12%**	**15% / 10%**	19% / 15%	19% / 15%

Scenario Observations

- The portfolios optimized for carbon reduction as well as the High renewables portfolio have the lowest PVRR's
  - The range (variability) of costs across all portfolios is less than that in the No CO2 scenario
  - Overall costs are up approx. 35% primarily due the carbon tax
- CO2 emissions are down in most portfolios with the Stakeholder and High Renewables portfolios achieving the greatest reductions
- Market purchases are relatively high in all portfolios and provide some foresight that the interaction with the market takes on increasing importance in a carbon constrained world

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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CPP Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	19,498	19,185	**18,664**	19,221	**18,913**	**18,686**	23,010	19,853	19,470
CO2 Emissions (+/-)	-3%	-7%	-11%	-7%	-11%	-13%	**-52%**	**-27%**	**-24%**
Mkt Purch (max/avg)	38% / 31%	36% / 29%	**27% / 20%**	32% / 25%	29% / 23%	24% / 19%	**22% / 10%**	**32% / 17%**	36% / 27%

Scenario Observations

- The portfolios optimized for carbon reduction have the lowest PVRR's
  - The range (variability) of costs across all portfolios is somewhat greater than the No CO2 scenario
  - Overall costs are up ~10% vs the No Carbon scenario primarily due to the carbon emissions constraint
- CO2 emissions are down in all portfolios, with the largest reduction in the Stakeholder and High Renewables portfolios
- Market purchases are high in this scenario across all portfolios indicating potential price risk to customer bills

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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No CO2/CO2 Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	**21,672**	**21,705**	21,742	**21,704**	21,718	21,766	26,080	23,089	21,930
CO2 Emissions (+/-)	-4%	-4%	-9%	-9%	-13%	-13%	**-55%**	**-33%**	**-22%**
Mkt Purch (max/avg)	25% / 16%	23% / 16%	**18% / 12%**	23% / 13%	**16% / 12%**	**16% / 11%**	**15% / 9%**	19% / 15%	19% / 14%

Scenario Observations

- The No CO2 Optimized & No CO2 Optimized w/CC portfolios had the lowest PVRR's
  - Gas generation appears to work best in this scenario for the majority of resource needs
  - The CC portfolio is only slightly more costly than CT portfolio but has 20% lower market purchases
  - The range of costs across all portfolios is less than that in the No CO2 scenario (~$260vs800MM)
- CO2 emissions reductions are greatest in the Stakeholder and High Renewables portfolios. Significant reductions are also achieved in the carbon optimized portfolios with added CCs
- Market purchases are higher than the No CO2 scenario across all portfolios due to the carbon tax in the latter 10 years, although this was mitigated somewhat in the w/CC portfolios

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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CO2/No CO2 Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	**18,495**	18,598	18,761	**18,540**	**18,635**	18,786	23,558	20,703	18,953
CO2 Emissions (+/-)	13%	9%	2%	9%	0%	-1%	**-47%**	**-24%**	**-7%**
Mkt Purch (max/avg)	15% / 9%	15% / 11%	15% / 8%	**15% / 7%**	**15% / 7%**	**15% / 7%**	15% / 8%	17% / 13%	15% / 9%

Scenario Observations

- The portfolios optimized for no CO2 tax and CO2 with CC portfolio have the lowest PVRR's
  - The range (variability) of costs across all portfolios is similar to that of the No CO2 scenario
  - Overall costs are 7% higher than the no carbon and 19% lower than the carbon tax scenario
- CO2 emissions showed the greatest reduction in the Stakeholder and High Renewables portfolios
- Market purchases rise initially with the carbon tax in 2020 then decline following the carbon tax removal in 2025.
  - Overall purchases are only slightly higher than the No CO2 scenario

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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Increased Customer Choice Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	25,321	**25,138**	**25,136**	25,339	**25,147**	25,157	28,090	26,017	25,349
CO2 Emissions (+/-)	-18%	-23%	-26%	-22%	-26%	-28%	**-61%**	**-44%**	**-36%**
Mkt Purch (max/avg)	15% / 11%	15% / 12%	**15% / 9%**	**15% / 9%**	15% / 10%	**15% / 9%**	**16% / 9%**	20% / 12%	15% / 11%

Scenario Observations

- The portfolios optimized for carbon reduction have the lowest PVRR's
  - The range of costs (variability) across all portfolios is the lowest of any scenario
  - Overall costs are 7% higher than the carbon tax scenario and 41% higher than the No CO2 scenario
- CO2 emissions showed the greatest reduction in the Stakeholder and High Renewables portfolios
  - Overall emission reduction was greatest in this scenario due to the very large solar deployment
- Market purchases were lower than in the Carbon Tax and CPP scenarios due to the excess nameplate capacity from the added solar deployment

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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Climate Change Scenario

METRIC 2016-2035	PORTFOLIOS								
	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR ($MM)	23,800	23,702	**23,559**	23,815	**23,605**	**23,606**	27,391	24,647	23,905
CO2 Emissions (+/-)	-3%	-9%	-19%	-9%	-20%	-23%	**-60%**	**-42%**	**-35%**
Mkt Purch (max/avg)	38% / 21%	38% / 21%	**35% / 17%**	37% / 18%	35% / 18%	**34% / 17%**	**26% / 13%**	35% / 20%	37% / 19%

Scenario Observations

- The portfolios optimized for carbon reduction have the lowest PVRR's
  - Overall costs are in line with the carbon tax scenario and ~33% higher than the No CO2 scenario
- CO2 emissions reductions were seen across all portfolios with the greatest reduction in the Stakeholder and High Renewables portfolios
  - Across the board reductions likely due to the de-rate of coal units in the hot, dry summer periods
- Market purchases were higher than all scenarios other than CPP due to reliance on the market to serve higher average energy demand and spikes during the hot summer and polar vortex years

Note: -Baseline year for CO2 reduction is 2016; carbon intensity of market purchases assumed to be equal to that of DEI fleet
- Portfolio components are preliminary and might change during the more detailed modeling phase

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Modeling Next Steps

- Extend scenario-portfolio modeling into Prosym
- Supplement with sensitivity analysis
- Analyze and evaluate the output data
  - How variables change over time
  - Hot summer and polar vortex years in Climate Change scenario
- Aggregate and package data into a usable format that supports
  - Discussion
  - Decision making

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Scott Park, Director IRP Analytics - Midwest

Stakeholder Exercise

Sensitivity Development Exercise

- Whereas scenarios are a set of correlated assumptions and describe possible futures
- Sensitivities are meant to assess a portfolios response to changes in a key variable
  - Not so much of an expectation of the future
  - But rather a view into *"what happens if…"*

<u>Stakeholder Exercise</u>

- Discuss at each table
  - List sensitivities
  - Define upper and lower levels
  - Present to the larger group
- Stakeholder data will be used to inform final sensitivity analysis

Marty Rozelle, President, Rozelle Group

Closing Comments, Stakeholder Comments

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Next Steps

- Please complete comment cards or send by August 11 to Marty at: RGL97marty@rozellegroup.com
- Meeting summary and other materials will be posted on website by August 18 (http://www.duke-energy.com/indiana/in-irp-2015.asp)
- Next workshop is scheduled for the Friday, October 16th

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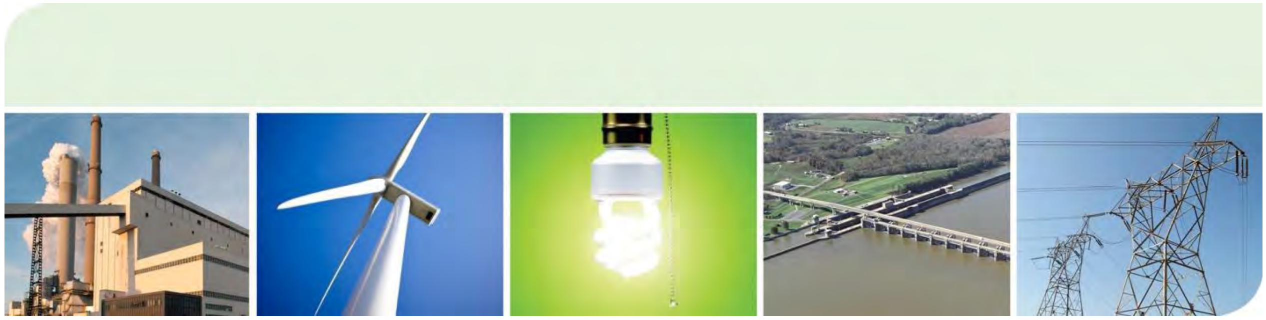

Duke Energy Indiana 2015 Integrated Resource Plan

Stakeholder Workshop 3
Summary
August 4, 2015

Welcome and Introductions
Dr. Marty Rozelle, The Rozelle Group Ltd.

Marty Rozelle, the facilitator, welcomed everyone to the third public workshop for the Duke Energy Indiana 2015 Integrated Resource Plan (IRP). There were several attendees on the phone as well. For the safety reminder, she said that in case of emergency, everyone should exit the building and go to the grassy area, or shelter in place in the basement. She introduced herself and repeated the objectives of Duke's stakeholder process. She asked participants to introduce themselves. There were 22 in-person attendees including a Commissioner from the Indiana Utility Regulatory Commission, and 4 people joined by telephone.

Agenda Overview
Scott Park – Duke Energy Director IRP Analytics, Midwest

There is a very full agenda today. A similar format to past meetings will be used. The main focus of new material is scenario and portfolio modeling that has been performed since the last meeting. Mr. Park reminded participants that scenarios represent possible states of the world, and portfolios are sets of resources. He said that today Duke will be presenting cost, carbon reduction, and market purchases for each of the 63 combinations of scenarios and portfolios that were evaluated. The workshop includes a participant exercise to help develop sensitivities for additional modeling.

Meeting 2 Comments, Responses, and Updates
Scott Park

Mr. Park mentioned some comments received at the last meeting, and Duke's response to those. Due to a series of technical challenges at past meetings, WiFi is not being provided at this meeting. The conference call-in line has been fixed. Participants suggested analyzing the carbon footprint of portfolios, and this has been done, as presented later today. Some people commented that the stakeholder exercise was helpful, so the one included in the meeting today will be similar.

Finally, Mr. Park said that Duke had made follow-up calls to two stakeholders who weren't able to adequately participate in the last meeting due to these technical difficulties. One of them thanked Duke for doing this, and said he appreciated the quality of the conversation. He mentioned remaining concerns he has, observing that the coal industry is dying, and utilities cannot 'just say no' to the Clean Power Plan that as just been finalized, as the Indiana Governor has done. He also suggested that these meetings should be held in the downtown Indianapolis area, and should include access to Wi-Fi for the convenience of the participants, and he objects to not having it provided.

Scenario Review
Jim Hobbs, Duke Energy Lead Engineer

Jim Hobbs reviewed the scenarios discussed at the last meeting. He said that Duke has looked at 7 alternatives, describing them as three subgroups characterized as "core" scenarios, "change of outlook" scenarios, and "stakeholder inspired" scenarios. Scenarios used for modeling include the following:

Core Scenarios:

1. No carbon regulation
2. Carbon tax
3. Clean Power Plan (CPP) (proposed rule)

Change of Outlook Scenarios:

4. Hybrid 1 – no carbon regulation changing to carbon tax
5. Hybrid 2 – carbon tax changing to no carbon regulation

Stakeholder-inspired Scenarios:

6. Increased customer choice
7. Climate change

Participant questions and comments included the following:

- Is carbon tax same as carbon price, and would that work with cap and trade?
    - For modeling, Duke used a tax of $17/ton, or in some scenarios used a shadow price that mimics a tax.
- Has there been consideration of changes in the market behavior that would occur as a result of a carbon-constrained world; for example, assumption of no Appalachian coal being available in future?
    - Coal prices were provided by Duke's vendor EVA, who evaluates major coal basins and make assumptions about them. These assumptions reflect reductions in demand for coal.
- The "clean power plan" scenario is looking at a reduction of 20% in emissions (from 2012), and the newly-released final Clean Power Plan calls for a 32% reduction from 2005 levels. Based on that, do you think you're capturing the CPP goals?
    - They may be similar, but since the CPP just came out yesterday the model was not specifically modeling it. Some of the portfolios that were modeled, however, show significant emission reductions.
- Is this 20% rate-based or mass-based? Is there any scenario here that would accommodate the higher reduction rates inherent in the CPP?

  - The percentages used in modeling using rate-based is much more complex, so rates have been converted to mass – what we show here are absolute carbon emission reductions. Rates are more a construct of the proposed rule.
- A participant thanked Duke for providing a range of scenarios.

Portfolio Review
Brian Bak, Duke Energy Lead Planning Analyst
& Jim Hobbs

Brian Bak explained that 9 portfolios have been developed, and will be discussed today. Two of these were specifically designed to meet stakeholder suggestions developed at the last workshop. The portfolios are characterized as:

1. No Carbon Tax (optimized)
2. Carbon Tax (optimized)
3. Clean Power Plan (optimized)
4. No Carbon Tax with Combined Cycle
5. Carbon Tax with Combined Cycle
6. Clean Power Plan with Combined Cycle
7. Distributed Generation (stakeholder suggested)
8. Green Utility (stakeholder suggested)
9. High Renewables

The model *System Optimizer* was used to calculate portfolio attributes. The model looks for the least-cost plan, and tended to favor combustion turbines. He explained the format of the tables he will present here, which show elements of each portfolio in terms of new additions, unit retirements, and annual market purchases needed to serve loads, over 5-year increments from 2016 to 2035. He noted that market purchases can be considered a risk factor, where large purchases are required, as they could affect consumer costs.

Participants had several clarifying questions, and then comments were provided for each of the portfolios.

- Are customer-installed combined heat and power (CHP) systems counted here?
  - The model output can be viewed as a mix of customer and utility-owned cogeneration.
- Where is gas conversion of coal-fired boilers reflected here? This is a very different category of gas unit.
  - It was originally used as a separate category, but has been combined in to other gas categories in the data presented here.
- Please define the acronym IVVC.
  - Integrated volt-var control, which is a smart grid technology.
- Participants had several questions about the EE (energy efficiency) & IVVC category and asked for further clarification. They asked that EE and IVVC be presented separately for the next meeting, and wanted more information on what is included in the EE ‘bundles’. Duke clarified that distributed energy is not included in the EE category but is reflected in the solar category.

- Is the combustions turbine (CT) category truly CT, not gas conversion?
  - Yes.
- How are retirements modeled? Are they inputs or outputs?
  - They are outputs, at the request of stakeholders.
- Is there a revised set of slides from Saturday? Those on the phone do not have the same version.
  - The minor page numbering differences were explained.
- Are environmental regulations included in these portfolios?
  - Yes, but only those we know about today.
- Can Duke calculate the customer rate effect of the portfolios?
  - No, we just look at present value of revenue (PVRR) in the modeling group. Ratemaking is separate, and comes 'after the fact'.

1.Optimized No Carbon Tax Portfolio

Questions and comments on this scenario were as follows:

- A participant stated that he disagrees strongly with the EE/IVCC data leveling out over time, particularly in this portfolio. He feels that the market will respond to this situation by forcing more EE adoption. The market does not "do nothing", even if politicians might not do anything.
- A participant noted that Duke Energy's CEO issued a statement yesterday saying that emissions from power plants have been reduced by 22% over the past decade. She felt this indicated that even the utility believes more diversity will be required. She pointed out that this portfolio does not foster diversity.
  - Mr. Park responded that this portfolio is actually 'cleaner' than current conditions as it includes more gas generation.
- Please explain the Miami-Wabash and Connersville units.
  - These units are all older; 166 megawatts (MW) of oil-fired combustion turbine units would be retired in this portfolio.
- If the utility is going to buy solar from a developer, where would that show up here?
  - In the solar category.
- What does 'optimized' mean?
  - The lowest cost option for meeting the objectives built into the model.
- A participant suggested adding a category to include the demand forecast used in each case, which would clarify the purpose of the portfolios.
- Are transmission and distribution expenditures included in these portfolios?
  - No. These are only generation-based portfolios.
- A participant asked for clarification of data totals on the charts.
  - Duke explained that these numbers aren't directly additive, because each type of unit has a different capacity factor.

Optimized Carbon Tax Portfolio

Mr. Bak noted that a distinguishing feature of this plan is that market purchases tend to increase quite a bit in the later years of the planning horizon. Participants said:

- It would be helpful to know the target load being used here.
- Now that the Clean Power Plan has been finalized, do you think the carbon tax scenario is likely or unlikely?
    - This scenario was an attempt to make assumptions about a carbon-constrained future. If we'd had the final rule earlier, this portfolio would have been different. However, due to the timing, Duke won't be able to do full modeling of the proposed CPP before filing this IRP.

Optimized Clean Power Plan Portfolio

This portfolio also results in relatively high market purchases, and includes the addition of 896 MW of combined cycle gas generation.

- A participants asked if the model makes assumptions about the carbon intensity of market purchases.
    - Yes. Market purchases are assumed to have the same carbon profile as the overall Duke fleet.
- Does the implicit or shadow price of carbon used in the models have a relationship to MISO (Midcontinent Independent System Operator)? What's the source of the shadow price?
    - The MISO price is higher in this scenario. EVA develops the shadow price (outputs) which Duke used as input to its model. There will be more modeling done here as a result of the Clean Power Plan.
- What efficiencies were used as capacity factors for solar and wind?
    - Wind capacity factor was assumed to be 40% for the first 300 megawatts, and 30% for further, less desirable, sites. The solar capacity factor was about 20%.
- Why are market purchases so significantly higher in these last two portfolios?
    - Market purchase prices are based on EVA-provided data. If the market prices are assumed to be lower than the price of adding new generation, the model will select it. Scott Park noted that in the 'real world', the utility may elect to build new generation rather than take the risk of higher market dependence.
- Were market costs developed specifically for each portfolio?
    - Yes, they vary among them.
- A participant believes that the failure to incrementally increase EE adoption levels in these portfolios is a fatal flaw error, which compromises the credibility of the work.

Portfolio 1 (No Carbon) with Combined Cycle

Mr. Bak noted that this portfolio brings down the market purchases generally in line with market sales.

Portfolio 2 (Carbon Tax) with Combined Cycle

In this portfolio, the model selects a CC early in the planning process, and has an elevated level of market purchases in later years.

Portfolio 3 (Clean Power Plan) with Combined Cycle

Participants had these comments and questions on this portfolio:

- Gallagher 2 and 4 would retire in all cases. Why does Gibson 5 retirement move around to different timeframes in the various portfolios?
    - The cost of keeping the plant running becomes uneconomical faster in the CPP scenario, whereas in other options it won't happen until the cost of coal makes it uneconomical. The model makes these selections based on economics.
- A participant observed that the Edwardsport plant has higher emissions and is more expensive to run than some others, so why doesn't the model select its retirement? Is this an artificial input?
    - No, the model would select it for retirement if it was economical to do so.
- Do you assume you'd recover costs using the current rates?
    - No, the model doesn't calculate cost recovery but assumes that costs would be recovered.
- Wouldn't the high cost of market purchases drive the model to build additional resources earlier in the planning period?
    - The model could have been forced to build resources earlier, but this is what the model selected. On the other hand, you could look at construction of CCs as 'insurance' against the higher cost of market purchases.
- Looking at EE and IVVC, a participant pointed out that the state mandate is to reach 2%, but these models show achieving more than 3%.
    - Duke clarified that the mandate actually gets to 11.9%, as a function of total sales, but in reality one must look at total available sales, which reflects opts out and reduced ease of installing additional conservation measures after a certain point.
- Are you assuming that opt-out customers would continue to install voluntary EE measures?
    - This 3% is utility EE and does not include customer-installed systems, which are only reflected in the load forecast. This is a challenge in trying to model EE as a supply-side resource.
- The participant suggested that this could be achieved by making 'off-model' adjustments.
    - Mr. Park said he would look into this.

Stakeholder Distributed Generation Portfolio

Jim Hobbs introduced two portfolios that were developed directly based on stakeholder suggestions at the last workshop. He noted that neither of the stakeholder-developed portfolios were optimized in the modeling, but dispatch of resources was optimized.

To explain the 'distributed generation' portfolio he showed the chart of a portfolio suggested by participants at the last IRP workshop, with desired percentages of each generation type. In comparing this with the developed portfolio, he noted that, for reasons already discussed, the desired level of EE could not be achieved in the Duke modeled scenario. There are much higher levels of renewable resources than included in other portfolios.

- A participant observed that the "numbers don't add up" on this portfolio, considering the capacity factor of wind and solar, and the level of predicted market purchases.
    - Mr. Park explained that part of the higher market sales included non-dispatchable solar and wind resources that are sold when not needed. CC units have a very high capacity factor to offset this.
- How is the Customer Choice Scenario being reflected in the portfolios?
    - Generally, the desire for increased distributed generation from that scenario has been added to all portfolios.

Stakeholder Green Utility Portfolio

Mr. Hobbs explained that this portfolio closely resembles the mix of resources suggested by stakeholders; however, the model would not select as much combined cycle as stakeholders suggested, nor is the level of coal quite as low.

High Renewables Portfolio

This alternative was developed to illustrate high rates of adoption of renewable resources, but not as high levels as the stakeholder-suggested portfolios. Participants asked:

- How are coal plants being used in this case? New capacity doesn't seem to match retirements.
    - Capacity factors of the coal units go down, but not so much as to drive new capacity in all timeframes.
- Does Wabash River gas conversion qualify as a renewable? Does that conversion push out solar and wind to later years? Why does this appear in a high renewable portfolio?
    - No, Wabash River is not considered a renewable. Any capacity addition is going to delay other resource additions. The model selected Wabash conversion over renewables, because this is not an exclusive renewables portfolio.

<u>Energy Efficiency Discussion</u>

Scott Park provided some additional information on the EE components of these portfolios. He said that Duke wanted to compare what was included in the 2013 IRP under the mandate with now, after the mandate has been removed. To illustrate, he showed charts that showed how it was handled in these models. EE tends to be a heterogeneous ‘resource’, which makes it difficult to model as a supply-side resource. Because there are hundreds of EE programs, each having its own supply curve, these programs were ‘bundled’ in the model, to be included incrementally. Mr. Park noted that these models are preliminary and more refined assumptions may be possible in later versions.

Participants asked for clarification on what these charts include and how they should be read. Mr. Park said that “EE base” bundles include the lowest-cost bundle of different vintages over time. Incremental EE includes another series of higher cost bundles. Programs included here only include utility-sponsored programs. Some participants thought this topic needed more refinement and possibly quite different assumptions. Mr. Park again noted that it’s challenging to model EE as a supply-side resource, because Duke can only include utility-sponsored programs since these are the only ones they can make assumptions about.

Lunch

Modeling Results, Observations, Next Steps
Scott Park

Mr. Park explained that Duke has only used the *System Optimizer* model to date, and the next phase will using *Prosym* to look at details such as hourly dispatch. In this presentation, he reviewed each of the 63 scenario-portfolio pairs, showing the PVRR cost, carbon dioxide (CO2) reduction, market purchases, and observations on the results. He explained the matrix used to show each element of the discussion, noting that each portfolio is going to perform differently in each of the “worlds” described in the various scenarios.

Assumptions for modeling are that the baseline year for CO2 reduction is 2016, and the carbon intensity of market purchases are assumed to be equal to that of the Duke Energy Indiana fleet. He reminded participants that the stakeholder-driven portfolios are not optimized in the model.

These results highlight the tradeoffs inherent in different approaches, looking at overall costs versus carbon reductions versus the need to purchase power from the market.

Several participants asked when stakeholders can have access to the models and the underlying data. Mr. Park said stakeholders can come in to the Duke Energy Indiana office and sign a nondisclosure agreement. They can also have electronic access if provisions are made.

<u>No CO2 Scenario</u>

Not surprisingly, this is the least-cost scenario, but does not reduce carbon emissions in most portfolios except the more “green” ones suggested by stakeholders. The addition of combined cycles adds value in reducing carbon emissions. Comments included:

- Can we quantify what type of gas generation we're talking about?
- These models do not specify gas resources, except where CC is specified in the portfolio.
- A participant suggested that this scenario is misnamed, and should be called "no CO2 penalty" or "price" scenario. People might think it means "CO2-Free", which it doesn't.
- A participant suggested that if all utilities do similar IRPs that rely heavily on gas, then the market prices of gas will change, and it could change the cost models.

Carbon Tax Scenario

This scenario has higher costs but reduces emissions under all portfolios. Market purchases, however, are quite high. As with other scenarios, gas generation is an important component.

CPP Scenario

As might be expected, the portfolios that are more heavily reliant on renewable resources reduce carbon emissions the most. Participant questions were:

- Focusing on the market risk question, why do market purchases increase in portfolios that have the most renewables?
    - It's most likely a function of price, but Duke agrees that this question probably needs more discussion with modeling experts.
- A participant asked for clarification about the types of gas generation that are included.
    - Mr. Park cautioned participants not to focus on Wabash River 6 gas conversion, since this is a very small contribution to the models.
- How do market purchases increase potential price risk to customer bills?
    - Duke would be subject to buying more energy in a volatile market.

No CO2 to CO2 Scenario & CO2 to No CO2 Scenario

These models combine years of no carbon regulation with later years of regulation and costs of emissions. They result in high market purchases and various levels of CO2 emissions over the planning period.

Increased Customer Choice Scenario

This scenario assumes there will be incremental 1% per year distributed generation starting in 2020. This increases costs of the plan by quite a bit because rooftop solar is expensive, but even in the "no CO2" portfolio there is an overall reduction in emissions, and market purchases are relatively low.

There was discussion about assumptions on costs and contributions of rooftop solar, and whether these should be included as utility costs and benefits.

Climate Change Scenario

Carbon-constrained portfolios perform better in this climate change scenario that in some other scenarios. Market purchases are high, as may be expected. Comments included the following:

- A participant said this information is very hard to comprehend and evaluate properly, without access to the modeling data. She felt that more explanation of each slide might help.
- Another person observed that the scenarios and portfolios are much better than those included in the last IRP process.
- If and how will transmission be factored into these results?
  - We won't really be doing that. Transmission is a completely separate effort and requires unique optimization. However, utilities try to coordinate generation and transmission planning to the extent possible.

Next Steps

Mr. Park said that the next step in the modeling process is to use the *Prosym* model, supplemented with sensitivity analysis. Participants had the following comments:

- A participant observed that the information provided was exactly what some stakeholders had expected. He referred to an IURC report saying that utility-preferred options were 'hard-wired' in favor of the utilities. He was concerned that now that the first stage of the modeling is completed it's more difficult to ascertain that.
  - Mr. Park assured participants that there are no preferred alternatives at this point, and nothing is 'hard wired in' – the model has been allowed to select options.
- Another comment was that in all the scenarios across all portfolios, the PVRR ranges are relatively small, essentially within 'modeling error'; therefore, when evaluating portfolios, cost may not be the most important discriminating factor.
  - Mr. Park agreed, and said these data are used mainly to help decide what directions Duke wants to take.
- Is customer cost of rooftop solar included in the PVRR?
  - That cost is only included in the Stakeholder Distributed Generation portfolio.
- Is this reliance on market purchases typical of other parts of the Duke system?
  - It's more common when you're part of a Regional Transmission Organization (RTO) such as MISO in Indiana.

Sensitivity Development Exercise
All

Scott Park introduced the exercise for today in which participants could suggest what types of factors might be changed in the models to evaluate sensitivity of the portfolios to changes in scenario assumptions. They were asked to work in groups at tables, to identify sensitivity factors and a range of variation by percentages. The tables then reported back to the whole group.

Suggestions of the groups were as follows:

Sensitivity	Rationale	Up%	Down%
Natural gas prices	Everyone will need gas, so range needs to be bigger	300	10
Energy efficiency prices & rates of adoption		high	low
Cost of renewables		5	50
Combined Heat & Power		Cut barriers in half	No down side
Load forecast		5	2
Extreme weather	Forced outage rates of generation (would cause transmission line losses)		
Carbon emissions		100	No less than CPP
Roll back Opt Out provision in EE	Back to conditions of 2013 before opt out		
Energy storage costs	There is no activity today to benchmark from	0	25
Market prices		30	30
Deregulation potential		dereg	
Transmission expansion costs	Increase in market cost could cause more creative demand-response solutions, such as MISO MTEP transmission expansion plan to carry wind/solar energy across territories, to lower market price.	add	
Those on the phone said they may provide more			

Closing Comments

The next and last meeting will be on October 16, probably here in Plainfield. He reminded participants to please complete the comment forms, which are very helpful to Duke in improving the process.

The facilitator reminded participants to please fill out comment forms about the meeting. Additional comments can be emailed to Dr. Marty Rozelle at: rgl97marty@therozellegroup.com.

2015 Integrated Resource Plan

Stakeholder Workshop #4

October 16, 2015
Plainfield, IN

Welcome

Welcome

- Safety message
- Why are we here today?
- Objectives for stakeholder process
- Introduce the facilitator

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The Facilitator

- Duke Energy Indiana hired Dr. Marty Rozelle of The Rozelle Group and her colleagues to:
  - Help us develop the IRP stakeholder engagement process
  - Facilitate and document stakeholder workshops

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Why are we here today?

- Duke Energy Indiana developing 2015 Integrated Resource Plan (IRP)
- Proactively complying with proposed Commission IRP rule
- Today is the 4th of 4 stakeholder workshops prior to filing the IRP by November 1, 2015

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Objectives for Stakeholder Process

- **Listen:** Understand concerns and objectives
- **Inform:** Increase stakeholders' understanding of the IRP process, key assumptions, and challenges we face
- **Consider:** Provide a forum for productive stakeholder feedback at key points in the IRP process to inform Duke Energy Indiana's decision-making
- **Comply:** Comply with the proposed Commission IRP rule

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Scott Park, Director IRP Analytics - Midwest

Agenda and
Meeting 3 Comments & Responses

Agenda

08:30	Registration & Continental Breakfast
09:00	Welcome, Introductions & Agenda
09:15	Meeting 3 Comments & Responses
09:30	Scenario Review
10:00	Break
10:15	Portfolio Review
10:45	Scenario Modeling Results
11:45	Lunch
12:30	Sensitivity Modeling Results
01:00	Decision Making (Preferred Portfolio & Short Term Implementation Plan)
01:45	Lessons Learned from 2015 IRP Stakeholder Process
02:15	Closing Comments

Meeting 3 Comments and Response

Topic	We heard/observed...	Response
Clean Power Plan (Final Rule)	Will the final rule of the Clean Power Plan be modeled?	No; the release of the final rule happened too late in the IRP process to model it in time for submission of the IRP. See separate slide on the CPP.
Wi-Fi	Not having Wi-Fi access makes participation in the stakeholder process more difficult	We are working to provide Wi-Fi access to stakeholders in meeting #4
Energy Efficiency	The amount of EE being presented in most portfolios is too low	The amount of EE shown in the portfolios is only a subset of total EE and is result of how EE is subdivided for modeling purposes. Later in the meeting, a comprehensive view of EE will be shown.

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Scott Park, Director IRP Analytics - Midwest

Scenario Review

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Seven Scenarios

Core Scenarios

1. No Carbon Regulation
2. Carbon Tax
3. Clean Power Plan (Proposed Rule)

Change of Outlook Scenarios

4. Delayed Carbon Regulation
5. Repealed Carbon Regulation

Stakeholder-Inspired Scenarios

6. Increased Customer Choice
7. Climate Change

Core Scenarios

- No Carbon Regulation
  - No carbon tax/price or regulation
  - Moderate levels of environmental regulation
  - No Renewable Energy Portfolio Standard (REPS)
- Carbon Tax
  - Carbon tax $17/ton in 2020, rising to $57/ton
  - Increased levels of environmental regulation
  - 5% REPS
- Clean Power Plan (CPP) (Proposed Rule)
  - Carbon reduced 20%
  - Increased levels of environmental regulation
  - 5% REPS

Change of Outlook Scenarios

- Delayed Carbon Regulation
  - No Carbon Regulation scenario initially
  - Change to Carbon Tax scenario for latter part
  - Demonstrates impact of delayed carbon regulation
- Repealed Carbon Regulation
  - Carbon Tax scenario initially
  - Change to No Carbon Regulation scenario for latter part
  - Demonstrates impact of repeal of carbon regulation

Stakeholder-Inspired Scenarios

- Increased Customer Choice
  - Carbon Tax scenario basis
  - Roof top solar serves additional 1% of load per year beginning 2020
  - Customers adopt higher levels of Energy Efficiency
  - New utility-scale generation served by merchant generators, e.g., Dynegy or Calpine
- Climate Change
  - Higher summer temperatures increase demand and prices for power and fuel
  - Carbon tax same as Carbon Tax scenario
  - Even hotter summer 2019 and "polar vortex" 2020, and every 5 years thereafter, causing higher prices

Final Clean Power Plan Rule

- The final rule of the Clean Power Plan was released in early August of this year.
- The time to read, understand and develop modeling, plus the absence of any specific SIP details precluded the final rule from being explicitly modeled in the 2015 IRP
- The proposed rule was modeled as a scenario based on the belief that the final rule would be similar to the proposed rule
- The final rule differed from the proposed rule in a number of signifcant ways
- Between the Carbon Tax scenario and the proposed rule some lessons were learned regarding how portfolios respond to carbon regulation
- Continuing to evaluate a wide range of compliance options such as renewables, gas conversion and gas co-firing (i.e. Wabash River 6 gas conversion)
- Duke Energy Indiana will be evaluating the final rule and will work with the State and stakeholders to better understand the implications of the final Clean Power Plan.

Break

Brian Bak, Lead Planning Analyst

Portfolio Review

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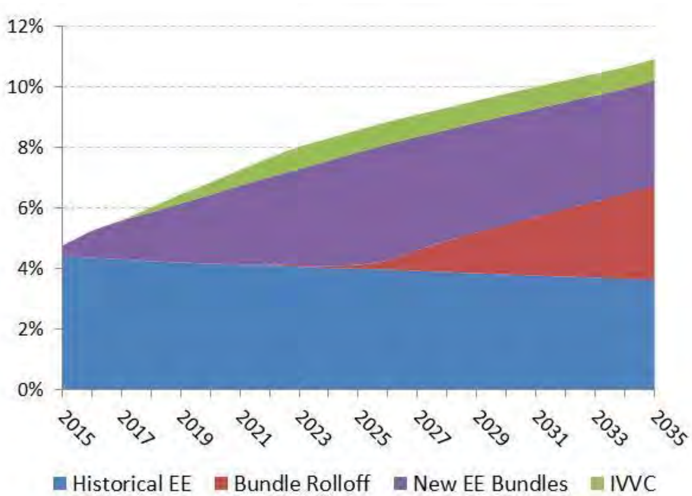
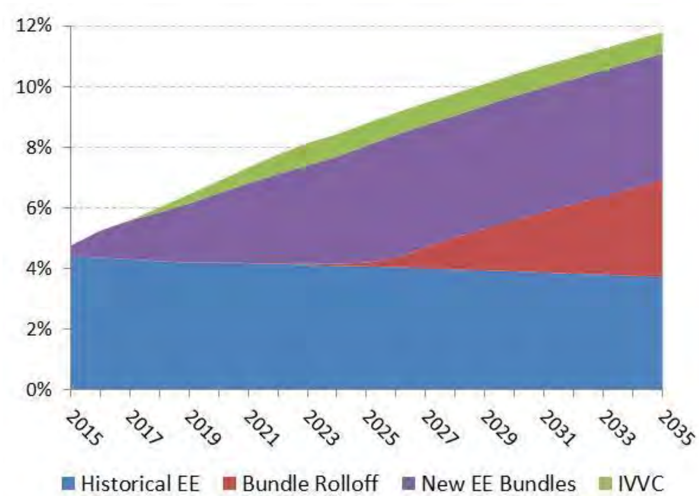
Cumulative Energy Efficiency % of Retail Sales

Portfolios 1 & 4



Portfolios 2, 3, 5, 6, 9



Notes: 1.) Cumulative EE calculated by adding back both historical EE (embedded in load forecast) and roll-off of new EE programs to both EE and load
2.) EE shown is based on *year-end* MWh attainment, *gross* of free-riders as a percentage of *retail* sales

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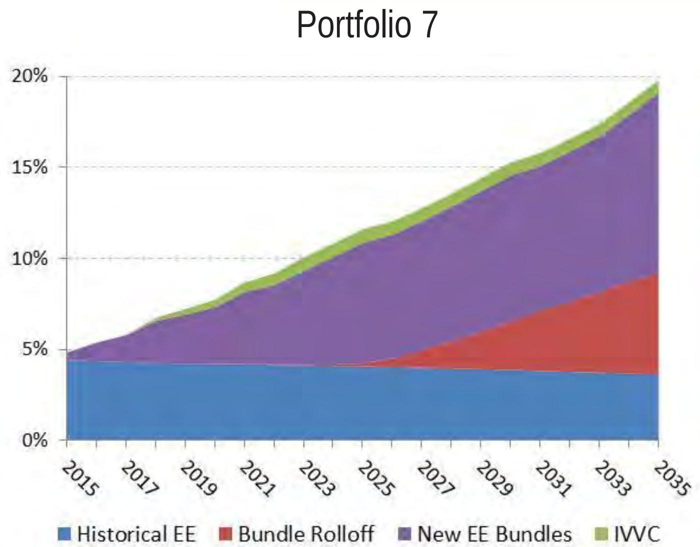
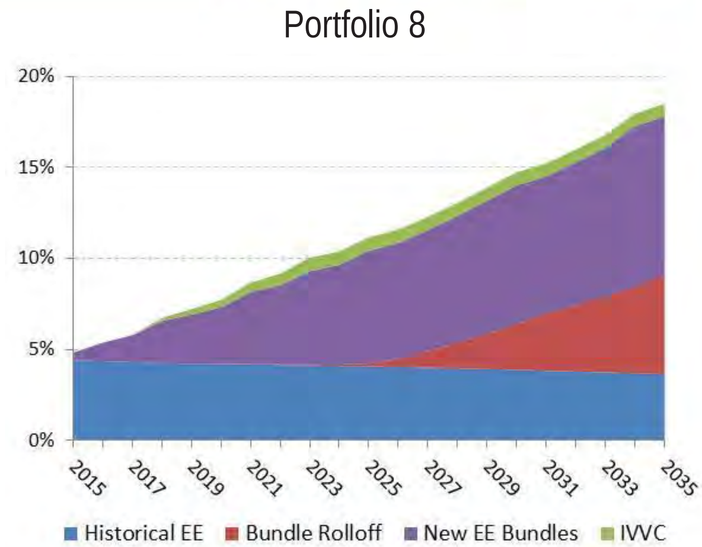
Cumulative Energy Efficiency % of Retail Sales





Notes: 1.) Cumulative EE calculated by adding back both historical EE (embedded in load forecast) and roll-off of new EE programs to both EE and load
2.) EE shown is based on year-end MWh attainment, gross of free-riders as a percentage of retail sales

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Nine Portfolios

1. Optimized No Carbon Tax
2. Optimized Carbon Tax
3. Optimized Proposed Clean Power Plan
4. Portfolio 1 w/ CC's
5. Portfolio 2 w/ CC's
6. Portfolio 3 w/ CC's
7. Stakeholder Distributed Generation
8. Stakeholder Green Utility
9. High Renewables

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Portfolio Template

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT					
CHP					
CC					
EE & IVVC					
Solar					
Wind					
Biomass					
RETIREMENTS					
Unit					
MW					
Load Growth (MW)					
Reserve Margin					

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Optimized No Carbon Tax Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832	208	208	208	208
CHP	44	29	15		
CC					
EE & IVVC	244 / 3.1%	124 / 1.9%	105 / 3.2%	11 / 3.2%	4 / 3.1%
Solar					
Wind					
Biomass					
RETIREMENTS					
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			
Load Growth (MW)	1,288	501	259	261	267
Reserve Margin	15.8%	15.9%	15.4%	16.3%	15.6%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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Optimized Carbon Tax Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	416			208
CHP	15	15			
CC	448				448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	10	140	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	15.5%	15.9%	15.9%	14.7%	15.5%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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Optimized Clean Power Plan Portfolio (Proposed Rule)

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	208		208	208
CHP	44	29	15		
CC	448	448			
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	20	130	120	
Wind	450		300	100	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	15.3%	15.8%	15.3%	14.8%	15.3%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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Portfolio 1 w/ CC's Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	416			208	208
CHP	44	29	15		
CC	448	448			
EE & IVVC	244 / 3.1%	124 / 1.9%	105 / 3.2%	11 / 3.2%	4 / 3.1%
Solar					
Wind					
Biomass					

RETIREMENTS					
Unit		WR2-6 Oil CTs			
MW	(834)	(834)			

Load Growth (MW)	1,288	501	259	261	267
Reserve Margin	17.1%	16.7%	18.7%	16.9%	16.1%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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Portfolio 2 w/ CC's Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	15	15			
CC	896	448			448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	15.9%	16.0%	16.5%	15.2%	16.0%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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Portfolio 3 w/ CC's Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	44	29	15		
CC	896	896			
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		300	100	50
Biomass	14	2	6	6	

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs Gal2,4 Gib5			
MW	(1,424)	(1,424)			

	Total	2016-20	2021-25	2026-30	2031-35
Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	17.5%	16.6%	19.4%	18.1%	15.9%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based on *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

Stakeholder Distributed Gen - Target vs Model

	2025		2035	
Energy Mix (%)	Target	Model	Target	Model
Market Purchases	11%	9%	8%	13%
Coal	36%	42%	19%	16%
Hydro	1%	1%	1%	1%
CC	8%	12%	9%	17%
CT	1%	0%	1%	0%
EE	11%	5%	16%	8%
Solar	7%	7%	10%	10%
Wind	10%	10%	13%	13%
CHP	9%	8%	12%	11%
Nuclear	0%	0%	3%	3%
Battery/Fuel Cell	1%	1%	2%	2%
LFG/Digester/Biomass	5%	5%	6%	6%
	100%	100%	100%	100%

Stakeholder Distributed Generation Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832		208		624
CHP	667	160	290	15	203
CC	1,344		896		448
EE & IVVC	725 / 8.8%	171 / 2.5%	239 / 5.7%	134 / 7.1%	181 / 8.8%
Nuclear	140				140
Battery	370		180	90	100
Solar	2,480	670	970	420	420
Wind	2,050	450	800	550	250
Biomass	353	106	162	60	25

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit		WR2-6 Oil CTs Gal2,4	Gib5 Cay1,2 Gib1		Gib2,3
MW	(4,283)	(1,114)	(1,909)		(1,260)

	Total	2016-20	2021-25	2026-30	2031-35
Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	20.2%	18.6%	18.9%	21.6%	21.8%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

Stakeholder Green Utility - Target vs Model

	2025		2035	
Energy Mix (%)	Target	Model	Target	Model
Market Purchases	16%	16%	13%	19%
Coal	50%	58%	38%	36%
Hydro	1%	1%	1%	1%
CC	18%	13%	19%	20%
CT	3%	0%	6%	0%
EE	5%	6%	8%	8%
Solar	2%	2%	4%	4%
Wind	3%	3%	6%	6%
CHP	2%	2%	5%	5%
Nuclear	0%	0%	0%	0%
Battery/Fuel Cell	0%	0%	0%	0%
LFG/Digester/Biomass	0%	0%	0%	0%
	100%	100%	100%	100%

Stakeholder Green Utility Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	832	208	624		
CHP	261	29	73	73	87
CC	1,344		896		448
EE & IVVC	635 / 7.8%	171 / 2.5%	209 / 5.3%	134 / 6.7%	121 / 7.8%
Solar	930	40	380	300	210
Wind	800		250	300	250
Biomass	14	4	4	6	
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4	Gib5 Cay1,2		Gib1
MW	(3,023)	(1,114)	(1,279)		(630)
Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	20.1%	15.6%	20.0%	23.0%	21.9%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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High Renewables Portfolio

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	624	416		208	
CHP	29	15	15		
CC	448				448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	1,010	20	130	260	600
Wind	2,300		300	500	1,500
Biomass	14	2	8	4	
RETIREMENTS					
Unit		WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)
Load Growth (MW)	1,071	446	176	194	255
Reserve Margin	17.7%	15.9%	16.6%	16.8%	21.4%

EE Notes: 1.) MW shown are incremental EE MW, net of roll-off in each period
2.) Percentages shown are cumulative new EE MWh, net of roll-off based in *hourly* MWh, *net* of free-riders as a percentage of *total* (not retail) sales

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Scott Park, Director IRP Analytics – Midwest

Scenario Modeling Results

Modeling Overview

- A robust scenario analysis was conducted in order to develop a variety of portfolios as well as test the respective performance of each across a range of assumptions
- The probabilities of the presence as well as the timing of CO2 regulation were varied to further test the flexibility of each portfolio
- In addition to cost, two other variables are presented to gain additional insight into each of the portfolios with respect to market exposure and changes in CO2 emissions
- Where scenario analysis evaluates portfolios at a more macro level, sensitivity analysis was also conducted to further evaluate each portfolio to changes in a number of key variables

Scenario Results (PVRR in MM$)

	PORTFOLIOS								
SCENARIOS	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
No CO2 Tax	20,297	20,655	20,891	20,379	20,677	20,931	27,465	22,623	21,219
CO2 Tax	27,549	27,186	27,209	27,617	27,243	27,334	31,559	28,131	27,611
CPP	23,699	23,173	22,960	23,419	22,977	22,645	26,864	23,397	23,715
Delayed CO2 Reg	25,443	25,513	25,606	25,667	25,569	25,662	30,292	26,586	25,901
Repealed CO2 Reg	22,136	22,092	22,335	22,236	22,137	22,401	28,732	24,183	22,683
Inc Cust Choice	30,882	30,505	30,524	31,009	30,561	30,642	34,799	31,316	30,937
Climate Chg	28,060	27,752	27,800	28,052	27,760	27,758	31,840	28,575	28,082

Observations

1. Portfolios optimized for CO2 regulation tend to be lower cost across the range of scenarios
2. Portfolios high in renewable resources tend to be higher costs across the range of scenarios

Note – Color coding scheme: In each row, 3 top portfolios shaded in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Probability Weighted Scenario Results (PVRR in MM$)

SCENARIO PROBABILITIES				PORTFOLIOS								
No CO2 Tax	Delayed CO2 Reg	Repealed CO2 Reg	CO2 Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
25%	25%	25%	25%	23,856	23,862	24,010	23,975	23,906	24,082	29,512	25,381	24,353
40%	20%	20%	20%	23,144	23,220	23,386	23,256	23,260	23,452	29,103	24,829	23,727
20%	20%	20%	40%	24,595	24,526	24,650	24,703	24,573	24,732	29,922	25,931	25,005
55%	15%	15%	15%	22,433	22,579	22,762	22,537	22,614	22,821	28,693	24,278	23,100
15%	15%	15%	55%	25,333	25,191	25,289	25,432	25,241	25,383	30,331	26,481	25,656
70%	10%	10%	10%	21,721	21,938	22,138	21,818	21,969	22,191	28,284	23,726	22,473
10%	10%	10%	70%	26,072	25,856	25,929	26,160	25,908	26,033	30,740	27,031	26,308

Observations

1. The CO2 Optimized portfolio is relatively low cost across the range of probabilities
2. The No CO2 Regulation Optimized & the CO2 Optimized portfolios are low cost in most probabilities
3. Portfolios high in renewable resources tend to be higher costs across the range of probabilities

Note – Color coding scheme: In each row, 3 top portfolios shaded in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Scenario Results (CO2 Emissions) (Reduction from 2016 – 2035)

SCENARIO PROBABILITIES				PORTFOLIOS								
No CO2 Tax	Delayed CO2 Reg	Repealed CO2 Reg	CO2 Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
25%	25%	25%	25%	6.5%	0.9%	-1.3%	2.4%	-1.9%	-4.0%	-43.5%	-23.2%	-12.8%
40%	20%	20%	20%	7.8%	0.8%	-1.1%	3.6%	-2.0%	-3.8%	-45.7%	-24.2%	-13.1%
20%	20%	20%	40%	5.5%	-0.3%	-2.2%	1.0%	-3.4%	-5.3%	-46.5%	-25.3%	-15.2%
55%	15%	15%	15%	9.2%	0.7%	-0.9%	4.8%	-2.1%	-3.7%	-48.0%	-25.2%	-13.4%
15%	15%	15%	55%	4.5%	-1.4%	-3.1%	-0.4%	-5.0%	-6.7%	-49.6%	-27.4%	-17.6%
70%	10%	10%	10%	10.5%	0.6%	-0.6%	6.1%	-2.3%	-3.5%	-50.3%	-26.1%	-13.6%
10%	10%	10%	70%	3.6%	-2.6%	-4.0%	-1.8%	-6.5%	-8.0%	-52.7%	-29.5%	-20.0%

Observations

1. Portfolios with higher levels of renewables show the largest decrease in CO2 emissions
2. Portfolios with CC's fare better with respect to CO2 reduction
3. Portfolios with CT's provide the least amount of CO2 reduction

Note – Color coding scheme: In each row, 3 top portfolios shaded in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Scenario Results (Market Purchases)

SCENARIO PROBABILITIES				PORTFOLIOS								
No CO2 Tax	Delayed CO2 Reg	Repealed CO2 Reg	CO2 Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
25%	25%	25%	25%	11.4%	11.9%	11.2%	9.6%	10.1%	9.6%	8.0%	12.3%	10.6%
40%	20%	20%	20%	11.0%	11.4%	10.8%	9.1%	9.5%	9.2%	7.8%	12.2%	10.1%
20%	20%	20%	40%	11.8%	12.3%	11.7%	10.0%	10.5%	10.1%	8.2%	12.5%	11.0%
55%	15%	15%	15%	10.5%	10.9%	10.4%	8.6%	9.0%	8.7%	7.6%	12.0%	9.6%
15%	15%	15%	55%	12.2%	12.7%	12.1%	10.5%	10.9%	10.5%	8.4%	12.6%	11.4%
70%	10%	10%	10%	10.1%	10.5%	10.0%	8.1%	8.5%	8.2%	7.4%	11.9%	9.1%
10%	10%	10%	70%	12.6%	13.1%	12.5%	11.0%	11.3%	10.9%	8.6%	12.8%	11.9%

Observations

1. Portfolios with CT's rely most heavily on market purchases
2. Portfolios with CC's replace market purchases with higher capacity factor generation
3. Portfolios with renewables replace market purchases with lower capacity factor generation

Note – Color coding scheme: In each row, 3 top portfolios shaded in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Commentary on Scenario Analysis

Seven scenarios is a significant increase in the number of scenarios compared to previous IRP's

- Improved insight on a portfolio's robustness

Overall Observations

- Optimized portfolios tended to be the lower cost portfolios
- Portfolios optimized to comply with some form of carbon regulation tended to be lower cost across the range of scenarios
- Portfolios high in renewable resources tend to be higher costs across the range of probabilities
- Optimized portfolios performed well in scenarios where the timing of CO2 regulation changed
- Optimized portfolios preferred peaking capacity and market purchases for energy
  - Lower cost, but greater market exposure
- Portfolios with CC's replace market purchases with higher capacity factor generation
- Portfolios with renewables replace market purchases with lower capacity factor generation

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Brian Bak, Lead Planning Analyst

Sensitivity Modeling Results

Sensitivity Analysis

- Where scenario analysis evaluates portfolios at a more macro level, sensitivity analysis was also conducted to further evaluate each portfolio to changes in a number of key variables
- Scenarios are beneficial since they provide a view of the world where the variables are modeled in a correlated fashion.
  - Better for higher level comparisons
- Sensitivities are beneficial more as a measure of risk and less of a possible outcome.
  - Changes in correlated variables are not made or kept to a minimum
  - Allows for better understanding of how the change in a single variable impacts a portfolio

Natural Gas Price Sensitivity (PVRR Change)

- Natural gas is becoming an increasingly important fuel for electric generation in the midwest
- The natural gas price sensitivity was conducted at +/-30%

No Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Gas Prices	1.0%	1.6%	2.2%	1.3%	1.9%	2.5%	1.4%	3.4%	1.1%
Lower Gas Prices	-2.1%	-2.8%	-3.6%	-2.8%	-3.4%	-4.3%	-2.9%	-5.0%	-2.3%
AVERAGE	-0.53%	-0.58%	-0.70%	-0.76%	-0.78%	-0.93%	-0.74%	-0.79%	-0.57%

Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Gas Prices	0.6%	1.0%	1.6%	1.0%	1.4%	1.9%	1.2%	2.6%	0.7%
Lower Gas Prices	-2.6%	-3.1%	-3.8%	-3.5%	-3.8%	-4.6%	-3.1%	-4.7%	-2.8%
AVERAGE	-1.02%	-1.00%	-1.10%	-1.24%	-1.20%	-1.36%	-0.93%	-1.04%	-1.06%

Observations

1. Most portfolios show an increase in costs of approx. 1-2% with higher gas prices
2. Portfolios with CC's enjoy the greatest benefit with lower gas prices

Note – Color coding scheme shades 3 top portfolios in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Market Prices Sensitivity (PVRR Change)

- Participation in MISO increase the market interaction with respect to coal, gas and power prices
- The market price sensitivity was conducted at +/-30%

No Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Market Prices	10.9%	10.6%	10.7%	10.8%	10.5%	10.6%	5.0%	10.1%	9.5%
Lower Market Prices	-12.7%	-12.3%	-12.4%	-12.6%	-12.2%	-12.3%	-6.4%	-11.6%	-11.2%
AVERAGE	-0.91%	-0.85%	-0.84%	-0.90%	-0.84%	-0.84%	-0.69%	-0.79%	-0.83%

Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
Higher Market Prices	7.0%	7.4%	7.6%	7.2%	7.5%	7.7%	4.1%	7.4%	6.8%
Lower Market Prices	-8.7%	-9.1%	-9.4%	-9.0%	-9.4%	-9.6%	-5.7%	-9.0%	-8.5%
AVERAGE	-0.83%	-0.82%	-0.86%	-0.91%	-0.92%	-0.96%	-0.76%	-0.82%	-0.84%

Observations

1. Most portfolios show very similar average sensitivity to changes in market prices
2. Portfolios with greater amounts of renewables show less sensitivity to changing prices

Note – Color coding scheme shades 3 top portfolios in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Increased CHP Sensitivity

- The number of generic CHP projects that could be selected was increased

No Carbon Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	High Renewables
Base Case (MW)	44	29	44	44	29	44	29
Increased CHP (MW)	87	87	87	87	87	87	87

Carbon Tax	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	High Renewables
Base Case (MW)	44	15	44	44	15	44	29
Increased CHP (MW)	87	87	87	87	87	87	73

Observations

1. Cost is not the limiting factor when it comes to CHP
2. Duke Energy Indiana is increasing efforts to develop cost effective CHP projects

Note – Color coding scheme shades 3 top portfolios in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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Higher Carbon Tax Sensitivity

- In addition to the CO2 Tax and Proposed CPP scenarios, a sensitivity was conducted to measure the portfolio's responsiveness to a higher CO2 Tax

Carbon Tax Scenario	No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	Stakeholder Dist Gen	Stakeholder Green Utility	High Renewables
PVRR Change	24.8%	24.7%	23.6%	23.5%	23.4%	22.2%	12.2%	19.6%	22.9%
Additional CO2 Reduction	-7.3%	-8.3%	-8.4%	-9.3%	-10.3%	-10.1%	-5.6%	-10.2%	-9.2%

Observations

1. Portfolios with higher levels of renewable and CC generation are better able to absorb a higher tax on carbon
2. Portfolios with CC generation have more dispatch-able diversity in their respective fleets and appear to be better able to reduce CO2 emissions

Note – Color coding scheme shades 3 top portfolios in green; middle 3 portfolios in yellow; and bottom 3 portfolios in red

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EE Cost Sensitivity

- The cost (cost/kWh) for Energy Efficiency was varied +/-20%

No Carbon Tax		No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	High Renewables
Lower EE $/MWh	MWh	26%	27%	27%	26%	27%	22%	16%
	PVRR	-0.6%	-0.2%	-0.9%	-0.5%	0.0%	-0.6%	-1.1%
Higher EE $/MWh	MWh	-38%	-20%	-20%	-38%	-20%	-20%	-20%
	PVRR	0.1%	0.8%	0.0%	0.1%	0.9%	-0.2%	0.3%

Carbon Tax		No CO2 Opt	CO2 Opt	CPP Opt	No CO2 Opt w/ CC	CO2 Opt w/ CC	CPP Opt w/ CC	High Renewables
Lower EE $/MWh	MWh	26%	27%	22%	26%	27%	22%	16%
	PVRR	-1.2%	-0.2%	-0.6%	-1.3%	-0.1%	-0.6%	-0.9%
Higher EE $/MWh	MWh	-24%	-20%	-21%	-39%	-20%	-21%	-20%
	PVRR	-0.3%	0.8%	0.3%	-0.4%	0.7%	0.2%	0.2%

Observations

1. Cost has a significant impact on economic selection of EE programs across all portfolios
2. Incentives have an impact on adoption rates, but the additional cost affects cost effectiveness
3. Customer behavior may not align with economic incentives (e.g. free light bulbs)

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Commentary on Sensitivity Analysis

- Portfolios with balance between CC and coal generation are better able to respond to variation in gas prices
- Portfolios with higher levels of renewables have higher fixed costs and costs overall, but are better able to withstand changes in variable cost factors (i.e. market prices, carbon taxes)
- CHP is cost effective across all portfolios if transactions can be made at generic cost assumptions
- Cost effectiveness and adoption rates (customer behavior) are a key and interrelated variables for Energy Efficiency programs

Explicit sensitivities not performed and rationale

- Load forecast: load variation was indirectly addressed by the different load assumptions in the various scenarios
- Roll back EE opt-out: speculative and difficult to specify
- Energy storage: screened out due to current high cost and short useful life; technology has niche applications
- Deregulation: difficult to specify without numerous speculative assumptions
- Transmission costs: difficult to incorporate transmission costs without siting specifics potentially at the MISO footprint level

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Scott Park, Director IRP Analytics - Midwest

Decision Making

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Portfolio Selection

- The Optimized CO2 Tax Portfolio w/ CC is the preferred portfolio for the DEI's 2015 IRP
  - Cost competitive relative to other portfolios across the range of scenario probabilities
  - Below average levels of market purchases
  - Relatively favorable response to changing gas prices
  - No significant shortcomings in the other sensitivities
  - Flexible in the near term and positioned well for future carbon regulation

Portfolio details:

ADDITIONS (MW)	Total	2016-20	2021-25	2026-30	2031-35
CT	208				208
CHP	15	15			
CC	896	448			448
EE & IVVC	276 / 3.6%	124 / 1.9%	106 / 3.3%	28 / 3.6%	18 / 3.6%
Solar	270	30	120	120	
Wind	450		150	250	50
Biomass	14	2	6	6	

RETIREMENTS	Total	2016-20	2021-25	2026-30	2031-35
Unit	0	WR2-6 Oil CTs Gal2,4			Gib5
MW	(1,424)	(1,114)			(310)

Note- The IRP preferred portfolio is not a set of specific resource decisions and will be updated in the analysis of the Final Rule of the Clean Power Plan
* Energy efficiency MW shown are incremental EE MW, net of roll-off in each period; percentages shown are cumulative new EE MWh, net of roll-off, over total annual MWh

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Lessons Learned

Lessons Learned Exercise

Group exercise to discuss improvement opportunities for each of the major topics in the IRP stakeholder process

- Each table is assigned a topic and can pick one other
- Each person at a table writes down
  - What they thought went well & what they would like to improve (and how)

Topics

1. Meeting structure: scenarios => portfolios => modeling => decision making
   a. Stakeholder exercises
   b. Duke Energy's role; Stakeholder's role
2. Scenario development
3. Portfolio development
4. Modeling
5. Decision making

Marty Rozelle, President, Rozelle Group

Closing Comments, Stakeholder Comments

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Next Steps

- Please complete comment cards or send by October 23rd to Marty at: RGL97marty@rozellegroup.com
- Meeting summary and other materials will be posted on website by November 2nd (http://www.duke-energy.com/indiana/in-irp-2015.asp)

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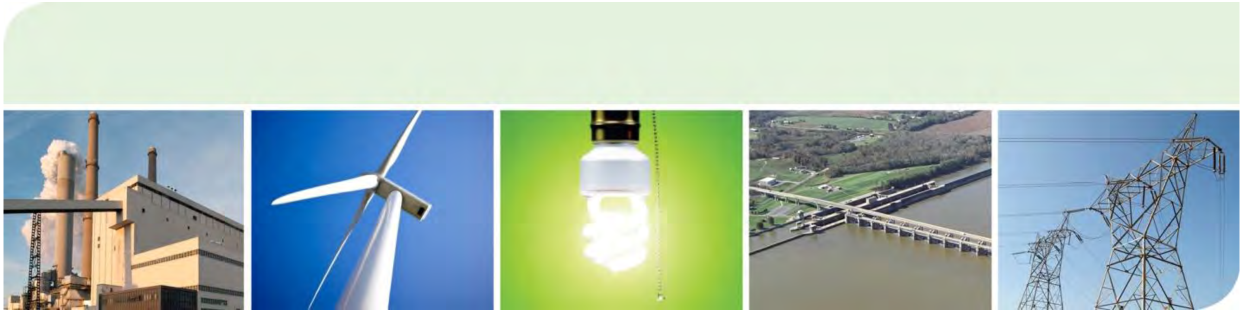

Duke Energy Indiana 2015 Integrated Resource Plan

Stakeholder Workshop 4
Summary
October 16, 2015

Welcome & Introductions

Dr. Marty Rozelle, The Rozelle Group Ltd.

Marty Rozelle welcomed everyone to the fourth and last stakeholder workshop for the 2015 Duke Energy Indiana (DEI) Integrated Resource Plan (IRP). She asked those in the room to introduce themselves. She said she'd check in with those on the phone occasionally to make sure they could hear the speakers. (Denise Hoffman, NAACP) She reviewed the objectives of the stakeholder process, as had been done at all previous meetings.

Agenda Overview

Scott Park – Duke Energy Director IRP Analytics, Midwest

Scott Park gave an overview of the agenda. He explained that this workshop will review scenarios and portfolios developed in previous meetings, and provide modeling results for the portfolios and the sensitivity analyses performed on them, which resulted in DEI's selection of a preferred portfolio for inclusion in the 2015 IRP. To help DEI improve future stakeholder processes, there will be an exercise for participants to evaluate the process and provide lessons learned.

Meeting 3 Comments, Responses, and Updates

Scott Park

Mr. Park discussed some of the comments made by participants at the last meeting and how they have been addressed. Regarding the request to incorporate the Clean Power Plan (CPP) into the IRP process, he noted that the final CPP rule was released too late to incorporate in the IRP process.

Participants had the following comments and questions about the treatment of the CPP:

- Could Duke request an extension for filing the IRP this year until January, to allow incorporation of the CPP? The participant noted that the state will be relying heavily on input from the utilities in developing the State Implementation Plan (SIP).
    - Mr. Park said that January would be too soon to be able to fully understand the rule and work with the consultant who models the national picture. This effort will, essentially, model ‘a new world’. The utilities will need time to develop assumptions. There may be in interim step before the next 2-year IRP cycle to update this. Duke is assessing how it can communicate to stakeholders what they’re learning from this process.
- A participant noted that the SIP won’t be submitted until Sept 2018, so this timing may not be too bad. Also, the SIP requires stakeholder engagement as part of that process.
- A participant noted that DEI has modeled a number of scenarios that may adequately address these concerns, at least in the interim.
- A participant said that the Office of Utility Consumer Counsel’s (OUCC) Susanne Brown is on the committee that’s looking at the SIP. Everything is quite preliminary, so we just need to do our ‘best guesses’ at this time.
- In the trading scenario anticipated in the federal CPP, corporations will be allowed to determine if they sell credits or not; since Duke will be a position to do this, it would be helpful to know how the company will deal with this.
    - Mr. Park responded that multistate generators could take generation in one state and allocate it to another state. He thinks states will actually take steps to prevent this from happening, but the suggestion is not very defined at this time.

Previous workshop participants expressed concerns about Wi-Fi access in the meeting room, for which a number of approaches have been tried. DEI believes these issues have been solved for this meeting. The company recognizes that people make a significant commitment to spending all day at these meetings, and doesn’t want to make that a hardship.

DEI has addressed comments made about energy efficiency (EE) with an approach that will be explained in this meeting. It has been modeled in a different way to better accommodate stakeholder concerns about the assumed level of EE adoption.

Scenario Review
Scott Park

Mr. Park reminded stakeholders that Duke has looked at 7 scenarios, describing them as three subgroups characterized as “core” scenarios, “change-of-outlook” scenarios, and “stakeholder-inspired” scenarios. To recap, scenarios used for modeling are the following:

Core Scenarios

1. No Carbon Regulation, defined as:
    - No carbon tax/price or regulation
    - Moderate levels of environmental regulation
    - No Renewable Energy Portfolio Standard (REPS)

2. Carbon Tax
    - Carbon tax of $17/ton in 2020 rising to $57/ton
    - Increased levels of environmental regulation
    - 5% REPS
3. Clean Power Plan (CPP) (proposed rule)
    - Carbon reduced by 20%
    - Increased levels of environmental regulation
    - 5% REPS

Change of Outlook Scenarios

4. Delayed Carbon Regulation
    - No initial carbon regulation changing to carbon tax later
5. Repealed Carbon Regulation
    - Carbon tax changing to no carbon regulation

Stakeholder-inspired Scenarios

6. Increased Customer Choice
    - Carbon tax scenario basis
    - Rooftop solar serves additional 1% of load/year starting in 2020
    - Customers adopt higher levels of EE
    - New utility-scale generation served by merchant generators
7. Climate Change
    - Higher summer temperatures increase demand & prices for power
    - Carbon tax same as Carbon Tax scenario
    - Even hotter summers & 'polar vortex' in 5-year increments increase prices

Participants had the following observations:

- A participant suggested that the core scenarios should be termed "carbon price" rather than "carbon tax".
- Because the carbon scenarios include trading of carbon credits, is Duke factoring in the benefit of selling carbon credits in scenarios that include retiring coal plants? If you look at costs you should also look at benefits.
    - A carbon tax is not the same as trading, but could be viewed as a market price for carbon. This might be similar to what is done for sulfur dioxide ($SO_{2)}$ allowance trading. We will need to further evaluate the Final Rule.
- Indiana Utility Regulatory Commission (IURC) staff suggested that a better modeling construct might be a trading assumption rather than a tax. At least, please describe this concern in the IRP for the stakeholders.
    - The compliance plan that addresses a future SIP would be the next level of detail to look at this, and DEI is not yet in a position to evaluate that.
- On the CPP scenario, are you going to quantify the assumed 20% reduction in carbon emissions?
    - As described later in this workshop, DEI has attempted to quantify changes emissions associated with the various portfolios.
- Under the SIP, the goal will be to reach a reduction target, and won't be prescriptive about how you get there. The utilities will need to suggest these

approaches. It seems, therefore, that all the utilities should want to be involved in this, which means that you can be more proactive about making assumptions.
  - DEI understands that the state will be looking to the utilities for help, and will be working with stakeholders.

Mr. Park talked about how DEI considered the CPP in developing the IRP. Although the final plan could not be explicitly modeled due to time constraints, certain assumptions were made based on the proposed rule. The final rule is quite different from the proposed, and DEI is evaluating the rule to determine what it needs to do to comply, while considering a wide range of compliance options. For example, it might make sense to convert Wabash River Unit 6 under this rule. The company will continue to work on this and adjust planning accordingly.

Participants had several comments:

- Is natural gas co-firing an option for Wabash River 6?
  - The unit could be converted to gas generation, which would have the operational characteristics of a coal plant with lower levels of emissions. We want to preserve the option of doing that. Co-firing is more of a fleet-wide option.
- A participant observed that Wabash River 6 is being packaged as a compliance mechanism, but one thing that remains is a boiler. It pushes timeframe of renewable adoption about 5 years down the road. Is the plant dispatchable?
  - DEI is not suggesting that gas conversion of Wabash River 6 is a renewable resource. They need to evaluate whether it makes economic sense to do the conversion, and they are not able to make that decision yet.
- A participant noted that other things can be used to co-fire with coal, e.g. biomass, and suggested that DEI consider these options.

Portfolio Review
Brian Bak, Duke Energy Lead Planning Analyst

Before addressing the portfolios, Brian Bak provided an explanation of how DEI has looked at EE in this current modeling, in response to several stakeholder comments. He showed charts that illustrated this concept. He explained that the term ‘bundle roll-off’ means that as the effects of the EE programs are evidenced through customer adoption, they get incorporated into the load forecast. This analysis illustrates the cumulative EE efficiencies of the portfolios as a percentage of retail sales, before the effects are rolled back into the load forecasts. This presents a truer level of overall EE.

Mr. Bak explained that 9 portfolios have been developed, as described at the August meeting. There have been only minor changes to these. Two of these were specifically designed to meet stakeholder suggestions developed at the last workshop. He used data tables to compare the results of the stakeholder portfolios developed by DEI to the suggestions made by stakeholders at the June workshop.

The portfolios analyzed are:

1. Optimized No Carbon Tax
2. Optimized Carbon Tax
3. Optimized Clean Power Plan (based only on the Proposed Rule, not Final)
4. Portfolio 1 with CC's (No Carbon Tax with Combined Cycle)
5. Portfolio 2 with CC's (Carbon Tax with Combined Cycle)
6. Portfolio 3 with CC's (Proposed Clean Power Plan)
7. Distributed Generation (stakeholder suggested)
8. Green Utility (stakeholder suggested)
9. High Renewables

He reviewed data tables from the last meeting summarizing generation additions and retirements for each portfolio as well as load growth and reserve margin calculations.

Participants had the following questions:

- There is a 20% carbon reduction goal for the CPP portfolio. Lately, it has been discussed that the Indiana goal will be 32%. Is 32% the right number to use when updating these portfolios? That would be a material change.
    - Duke observed that 38.5% might be the goal for Indiana. The company is still examining how a higher goal would look. Consequently, they can't lean too heavily on the current assumptions about the CPP.
- For Gibson 5, would waiting until after 2019 to close it require significant upgrades to the existing plant? If so, why does the Optimized Carbon Tax with CC portfolio show retirement in the 2031-35 timeframe?
    - DEI thought that a scrubber upgrade would be needed in 2023. However, in the absence of carbon regulation, CO_2 price ramps up quickly, so by the 2030's the price is so high it drives closure.
- Gibson is jointly owned, so how do you make decisions about that unit?

Scenario Modeling Results
Scott Park

The objective of the modeling process was to create a robust analysis. DEI did this by developing a variety of portfolios and testing performance across a range of assumptions. Finer-grained sensitivity analyses were also conducted for each portfolio, in which only one variable was changed.

Mr. Park showed tables that provided the relative cost (in Present Value of Revenue Requirements (PVRR in millions of dollars) of each portfolio in each combination of events (scenarios). The results for the 9 portfolios were color-coded on these tables for ease of viewing, with each color representing the lowest, middle, and highest 3 groups. He noted that combined cycle (CC) was added to several portfolios in order to see the cost, emissions, and level of market purchases change to the optimized portfolios.

He explained that DEI did a probability weighting for the portfolios. This looked at a range of various probabilities that 4 different ways that carbon regulation might occur to estimate the resulting costs of the 9 portfolios.

Participants had the following observations on this analysis:

- Some of differences in PVRR seem to be within the margin of error, and not significant.
- DEI is modeling a CPP that's the draft rule, not the final rule, and the final rule is materially different in multiple respects.
- There used to be a distinguishing of constraints that were 'musts' and constraints that were 'wants'. This participant suggested that carbon constraints in today's world should be a 'must' constraint. In other words, carbon constraints are highly likely today and, therefore, some of the other scenarios would just drop out.
    - Yes, in this model, it was assumed that the probability of occurrence of driving assumptions was 100%. The probability weighting runs show different probabilities.
- The high renewables portfolio is just out of the yellow (mid-cost) range, and is not far from the lowest cost, given a margin of error. None of the probabilities (or portfolios) seem to include increased carbon regulation, which is what we actually have in the final CPP rule. Even if this is struck down in the short term, it is still highly likely that there will be strong carbon regulation in the future.
    - DEI didn't know about the doubling of restrictions in the final rule until the day before the last workshop. We simply did not have the time and capability to include those assumptions in these models.
- Another participant echoed this observation, and suggested that the color scheme used on the slides might be more refined to show the small differences.
- Another participant was in favor of having a wide range of alternatives, but suggested that you can't assign probabilities to non-compliant scenarios. So, this table needs to be more complex because there are only certain compliant scenarios in a carbon-constrained world.
    - All these scenarios assume different compliance constructs. When we get to the point of being able to model the final rule, we can look at variations; but, we are not necessarily taking the final rule as the only option. Even if a certain carbon price isn't assumed, market forces will come into play that 'de-carbonize' the availability of resources.

Mr. Park said that another analysis was done to calculate the absolute carbon emissions reduction that would result from each portfolio during the 2016 to 2035 timeframe. He pointed out that, in general, the lowest-cost portfolios tended to perform the worst in terms of carbon reduction, while the highest-cost portfolios did the best job of reducing emissions.

An assessment was also done to look at the level of market purchases required for each portfolio. In general, portfolios with combustion turbines (CTs) rely most heavily on market purchases, while portfolios with CCs replace market purchases with higher-capacity-factor generation. Portfolios with renewables replace market purchases with lower-capacity-factor generation. Questions asked by participants were:

- Is it correct to say that there has previously been an assumption that the carbon intensity of the market portfolio is the same as the Duke portfolio? Is that still true today?
  - We think so, but we don't know for sure; the market purchases come from a number of sources. The DEI fleet will become less carbon-dependent over time, and we assumed the overall market would be composed similarly. Generation after market purchases today is composed of about 90% coal, producing 1900 pounds of emissions per megawatt hour in carbon intensity. This will probably drop to about 1700 pounds.

Mr. Park emphasized that the IRP is not a decision document, but is a plan providing a direction. It can and does change over time as conditions change. In summarizing the scenario analysis, he noted that modeling a larger number of scenarios, compared to the last IRP process, gave DEI greater insight into the robustness of portfolios. Overall, the optimized portfolios tended to be the lower-cost options, even when optimized to comply with some form of carbon regulation. Optimized portfolios preferred peaking capacity and market purchases to provide energy. Portfolios high in renewable resources tended to have higher costs across the range of probabilities.

Sensitivity Modeling Results
Brian Bak

Mr. Bak explained that scenarios represent different world views, while sensitivities are a micro-level look at varying one element. He showed a chart that evaluates changes in PVRR of the portfolios that would occur from varying the natural gas price by 30% either way, up or down. Most portfolios show an increase in costs of approximately 1-2% with higher gas prices. Portfolios with CCs enjoy the greatest benefit with lower gas prices. He clarified that these prices are the average of all portfolios to that change.

A similar analysis was done to evaluate changes in market purchase prices of 30%. Most portfolios show similar average sensitivity to changes in market prices, and portfolios with higher amounts of renewables are less sensitive to changing prices.

Another sensitivity model was done to look at the effects of increasing the level of combined heat and power (CHP) included in the portfolios. This showed that cost is not the limiting factor for CHP. Mr. Bak told participants that DEI is increasing its efforts to develop cost-effective CHP projects. He mentioned as an example that Jim Hobbs has transferred to a group working on developing CHP programs for Duke. The key concern for effective CHP implementation is finding projects that work for both the utility and the private partners.

A final sensitivity was done for higher carbon prices. Not surprisingly, portfolios developed for carbon regulation handled higher carbon costs better.
DEI also looked at EE cost sensitivity, varying the cost by 20%. If the costs of EE bundles are lowered by 20%, the model will select more of them. This was the first time DEI tried to model EE as a resource. Mr. Bak noted that if a utility wants to raise EE adoption rates, they would need to offer a greater incentive to customers to do that, which in turn raises the overall program costs. It is, therefore, a complicated process to

analyze this, and there are a number of unknown variables. Cost effectiveness and customer adoption rates seem to be the key interrelated variables for EE programs.

Comments about the EE sensitivity included the following:

- A participant said that he understands the analytical reasons for doing this in this way, but he observed that DEI and other investor-owned utilities are pricing investor demand-side management (DSM) out of the marketplace. For example, in recent testimony the OUCC said that the IURC shouldn't approve the utilities' DSM plans because they are too costly. He feels that the cost assumptions made here for these analyses are erroneous, and EE is a critical resource in any plan.
  - Mr. Park agreed that it's an important part of the resource selection process. He pointed out that the load forecast does include some EE.
  - DEI's attorney noted that these are pending cases, and we can't debate them here.
- A participant said that, despite the pending cases, stakeholders are here to talk about cost effectiveness.
  - Duke agreed that cost effectiveness is a primary consideration for them as well.
- A participant referenced an observed increase in energy consumption by customers who are on budget billing. She asked how many DEI customers are on budget billing, observing that this seems to be a disincentive for energy saving.
  - DEI said that this reference was to Auto Pay, not budget billing. It's true that these customers tend to consume more energy.
  - DEI couldn't answer the question about the number of Auto Pay customers. OUCC offered that the IURC has a billing symposium going on now, indicating that about 18-20% of customers for all utilities (not just electric) use electronic bill-pay.
- Regarding the concept of rollback EE, a participant observed that people who are opting out aren't buying more Duke power. There are more market options for energy management now, such as distributed generation, and these will continue. Even though these options are not utility sponsored, they do affect these models; some way needs to be developed to capture this. He noted, however, that way EE is accounted for in this discussion is a big step forward.

In summarizing observations about the sensitivity analyses, Mr. Bak observed that portfolios with a balance between CC and coal generation are better able to respond to variations in gas prices. Portfolios with higher levels of renewables, although they have higher fixed costs and costs overall, are better able to respond to a variety of variable cost factors. CHP seems to be cost effective across all portfolios. He also explained why certain sensitivities suggested by stakeholders were not performed, mainly because of assumptions could not be made about certain elements like transmission costs, deregulation, or the potential for energy storage.

A stakeholder noted that the Stakeholder Green Portfolio performs well in all the sensitivities.

Lunch

Decision Making
Scott Park

Mr. Park told the group that DEI has selected the Optimized CO_2 Tax Portfolio with CC (Portfolio 2 w/CC) as the preferred portfolio for DEI's 2015 IRP. This portfolio was optimized for a carbon tax but included combined cycle, because it is cost competitive.

He pointed out to participants that the earlier years of the preferred plan are similar to the early years of the Optimized No Carbon Tax Portfolio and the High Renewables Portfolio. The benefit of this is that if the future evolves towards no carbon regulation or one that requires more renewables, the preferred portfolio can be redirected towards that future.

Participants had the following questions and comments:

- Is the capacity of a CT pretty close to a gas conversion? Does installation of CT push the timeframe for renewable installation out farther?
    - This is a generic CT. Wabash River 6 is not included in this profile. The CTs are more efficient than conversion of Wabash River 6, but this could show up again. We need 400 MW of peaking capacity, and natural gas conversion is a good peaking source, as are CTs. They both have higher heat rates so they won't be run much, but CT might run a bit more.
- Can you give another example of gas conversion similar to what you have in mind for Wabash River 6?
    - South Carolina Lee Unit 3. Mr. Park said this type of conversion is relatively easy to do, with boilers using gas instead of coal dust, and is inexpensive capacity in terms of dollars per kilowatt.
- How is this different from the same issue when it arose at Gallagher? There was an idea of installing a pipeline to Gallagher for gas conversion, but that didn't happen. Is there already a pipeline to Wabash River 6? This participant is skeptical of the feasibility of this proposal, suggesting that it is 'wishful thinking'. He will look at Lee Unit 3 to see the actual costs and what has been done.
    - Wabash River 6 is over 300 megawatts (MW), while Gallagher generates 140 MW per unit. Wabash River has convenient gas access; Gallagher would be more expensive and not justified. Under certain assumptions, gas conversion at Wabash River could be cost effective.
- How do you justify 416 MW of CT in the long term under a high renewables portfolio? This participant thinks that gas will also come under scrutiny in later years of the planning horizon.
    - We took forecasts for solar and wind, and cut this down by 25%, then let the model select. This produced more than 3000 MW of renewables, but there is still a preference for some CT. We recognize that this takes away from EE and other generation resources. This portfolio does not assume storage, which has a high fixed cost and wears out more quickly than most other resources.
- There was discussion about how load growth was estimated.

    - Mr. Park agreed that this is an issue that needs to be to tracked over time, since some variables aren't known. For example, increased customer generation would affect load growth. At this time, load growth percentage is decreasing and leveling out nationwide.
- A participant thought that 1000 MW of load growth is an overestimation, so that not as much gas generation might be needed in reality as portrayed here.
- A participant gave an example of this relative to a previous Gallagher case. When will demand reach the 2008 level?
    - We will have to look that up.
- Uncertainty, not carbon regulation, is what's challenging the utility industry. Once the uncertainty is resolved, investment decisions can be made more confidently.

In summary, DEI feels that the preferred portfolio is flexible in that it can transition in various directions over the planning period depending on world conditions. It is similar to the 'greener' portfolios in the near term, and can be more easily repositioned once some of the current uncertainties are resolved.

Lessons Learned from 2015 IRP Stakeholder Process
Group exercise

Marty Rozelle introduced the exercise to evaluate the overall stakeholder process for this IRP. She said we'd like to look at what's gone well and what could be improved. She asked people to discuss this in 5 topic areas, with each topic discussed at a table. Participants were asked to join the table topic of most interest to them. Ideas and suggestions from stakeholders are shown in the following table.

Topic: Meeting Structure	
Keep	**Change**
Great facilitator	Webcast option not available
Duke made great strides forward – excellent staff support, discussion, staff experts	Phone problems in not being able to mute those on phone
Good materials	Phone connection problems
Website distribution of materials	Not enough feedback time on modeling results, e.g. CPP proposed v. final rule
Duke more open to using stakeholder input in scenarios	Extent to which corporate decision making structure limits final plan
Duke responsive to questions and concerns	What should stakeholder relationship/role be to that process?
Higher level of engagement in discussions – more discussion of issues	How do you address changes that happen during the life of the IRP
Respect and openness to each other	A broader more diverse representation of stakeholders would be very helpful, e.g. Industrial customers, economic development interests, academia. Should we formally invite them?
Great meals	More 'user-friendly' ways of presenting information, to reach broader audiences. Perhaps produce published digest of meetings, e.g. news release – would this

	attract more participation? What about YouTube videos? Prepare something that will grab attention and communicate major findings.
Open flow of communication	
Comment: OUCC says attendance at public participation events has declined a lot, but they typically get lots of written comments via online opportunities	
Suggestion: Consider developing a 3-level stakeholder process 1. large group meetings 2. subgroups on technical details, interact with modelers, in between workshops 3. broad public outreach	

Topic: Scenario Development	
Keep	**Change**
	Need to be as comprehensive as you can be to make sure you're covering all the possibilities ('branches of the decision tree')

Topic: Portfolio Development	
Keep	**Change**
Improvement in explanation and treatment of EE, better graphics	More discussion and explanation of EE impacts
	Still confusion between scenarios and portfolios – more clarity on how scenarios "tilt" evaluations of portfolios
	Is this process designed to reflect reality or to change reality?

Topic: Modeling	
Keep	**Change**
Duke was much more receptive to stakeholder modeling assumptions.	We don't understand the model, so we need to just trust inputs (black box) -- might be addressed through the suggestion for technical subgroups working with Duke
Robust discussion of scenarios = better decision making	
Post modeling discussion of results was enlightening (stakeholders get to see "art" behind the "science")	
Comment: Commission might have a more active role under new rulemaking procedures Statute 412 Commission must do more of its own analysis and to look at statewide needs, e.g. in the current EE rule – also requires stakeholder engagement	

Topic: Decision Making	
Keep	**Change**
	Explain cost effectiveness, e.g. who are these solutions cost effective for?
	The company's business plan drives the process and the decisions, and presents constraints on decisions. The stakeholders role is to push that process toward their ends.
	Improve contextual information that's presented; i.e. many tables and data need better explanation/graphics for comparison

Closing Comments

Scott Park endorsed the idea of increasing the diversity of participants, and asked attendees to provide any suggestions they have to do so. It was suggested that DEI work with their commercial accounts executives to encourage industry participation. A participant reported that there are experts at Indiana University and Purdue who teach these topics, so consider inviting them and their students. Mr. Mullett offered to send DEI a reference to an IU expert in human behavior and energy.

Mr. Park asked participants if they had any final suggestions for improving the evaluation of EE. The following ideas were offered:

- Consider other opportunities for enhancing the efficiency of energy delivery, such as IVVC . For example, small water and sewer utilities have a great need for better efficiency, but they don't have the capital resources to do it. So utilities should look at how to help them. If you can achieve energy savings, it doesn't matter who does it, utility or user.
- There are other resources out there such as ACEEE. What happened to the EE market potential studies that used to be done? It's just a wrong assumption that EE levels decrease as time goes on, because the nature of things is that technologies get more efficient over time.
- DEI should look more closely at 3rd-party efficiency and opt-outs. These can have big effects on the IRP.
- How do you get the data for input to the EE modeling? Is it actual reductions in energy consumption from customers, or is it an assumption of what the measure is supposed to do, e.g. CFL light bulbs. Are outages included as energy savings?
    - Historical consumption is part of forecast. Yes, outages are included in energy savings.

The facilitator thanked participants for their hard work, continued attendance, and helpful suggestions throughout the process. She reminded participants to send any additional comments by October 23. Additional comments can be e-mailed to Dr. Marty Rozelle at: rgl97marty@therozellegroup.com