The Duke Energy Indiana Updated 2018 Integrated Resource Plan

March 23, 2020

Volume 1

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SECTION I: EXECUTIVE SUMMARY

A. OVERVIEW

Duke Energy Indiana (Company) is Indiana's largest electric utility, serving approximately 840,000 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 guide for 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. Major changes in the 2018 from the 2015 IRP follow.

More Comprehensive Scenarios

The 2018 IRP features five discrete and internally consistent scenarios that enhance analytical robustness by covering a wider range of possible futures. A consulting firm performed the macroeconomic modeling for each scenario using a suite of equilibrium models that defined a set of internally consistent assumptions. The five scenarios are:

Core Scenarios

1. Slower Innovation
2. Reference Case
3. High Technology

Stakeholder-Inspired Scenarios

4. Reference Case without Carbon Legislation
5. Current Conditions Continue

Uncertainty in a Carbon-Constrained Future

Carbon regulation has been talked about for over a decade and the company has modeled various levels and forms of regulation. Although much is still not known about how carbon regulation might be promulgated, the analysis over the last several IRPs has identified it as a major driver for change in the generating portfolio.

Although the Clean Power Plan has been repealed and the Affordable Clean Energy Rule is expected to have minimal impact, public sentiment concern about climate change is growing. Thus, carbon regulation is more a matter of if, than when, and warrants consideration in the plan. Given the magnitude of the change that would be driven by substantive carbon regulation, a measured transition towards a less carbon intensive future is prudent.

In this IRP, the Company included a price on carbon emissions in the Reference Case scenario of $5/ton starting in 2025 and growing $3/ton per year to $41/ton by 2037 and in the High Technology scenario of $10/ton in 2025 increasing $3/ton per year to $47/ton by 2037. This price is a proxy for potential future legislation addressing carbon emissions.

Our current range of CO_2 prices, including a zero price in a number of scenarios, is appropriate given the outcome of past debates over federal climate change legislation, the uncertainty surrounding future U.S. climate change policy, and that the 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.

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.

Retirement 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 Supply Side Resources

Duke Energy Indiana has continued to model EE as a supply-side resource and increased the number of EE bundles in this IRP to 70 from the 10 bundles in the 2015 IRP. Challenges remain in how 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 Load Forecast

Comparing the 2018 load forecast with 2015, the total energy and peak capacity need for Duke Energy Indiana decreased across all customer classes primarily due to weak economic growth, low-cost market power, adoption of federally mandated appliance standards, and energy efficiency programs. Although long-term trends point toward recovery, energy demand is expected to grow less than 1% annually for all 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 G 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. The Company must maintain flexibility to adjust to evolving regulatory, economic, environmental, and operating circumstances. The planning process includes scenario analysis. Macro-level driving forces discussed in stakeholder meetings informed the development of five distinct, internally consistent scenarios.

Five Scenarios

<u>Slower Innovation</u>

- Technology progresses more slowly than in the Reference Case
- Extraction costs do not fall as quickly and as a result, coal and gas prices are higher than in the Reference Case
- Higher fuel costs dampen economic growth
- No carbon regulation

<u>Reference Case</u>

- Baseline forecasts for load, gas, coal and power
- Carbon price \$5/ton in 2025, rising \$3/ton per year

<u>High Technology</u>

- Technology progress more quickly than in the Reference Case
- Extraction costs fall more quickly and as a result, coal and gas prices are lower than in the Reference Case
- Lower fuel costs facilitate economic growth
- Carbon price \$10/ton in 2025, rising \$3/ton per year

Reference Case without Carbon Legislation

- Reference Case assumptions except no price on carbon emissions

Current Conditions Continue

- Extrapolations of market curves for gas, coal and power
- Reference Case load forecast
- No carbon regulation

Nine Portfolios

Once the specific modeling assumptions for each scenario were determined, we used a capacity expansion model to optimize a portfolio for each scenario. We evaluated Nine portfolios organized into two groups 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 five scenarios:

Optimized Resource Plans

1. Slower Innovation Portfolio - minimal near-term changes to fleet
2. Reference Case Portfolio - price on carbon drives a couple of coal retirements in 2020s. A CT and solar are added starting in the mid-2020s
3. High Technology Future Portfolio - a higher price on carbon and lower renewables costs drive a number of coal retirements in the 2020s; a CC and solar are added starting in the mid-2020s
4. Reference Case without Carbon Legislation Portfolio - minimal near-term changes to the fleet
5. Current Conditions Continue Portfolio - minimal near-term changes to the fleet

We developed a group of alternative portfolios by evaluating the optimized portfolios and the results of sensitivity analysis for lessons learned. The portfolios coming out of that process are:

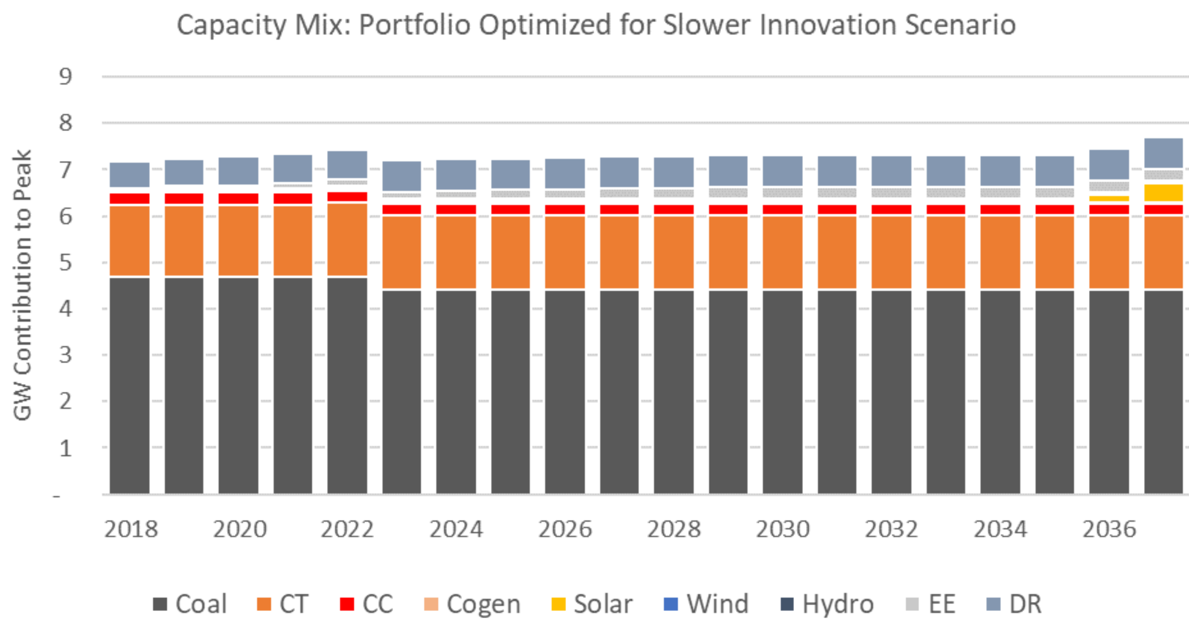
Alternative Portfolios

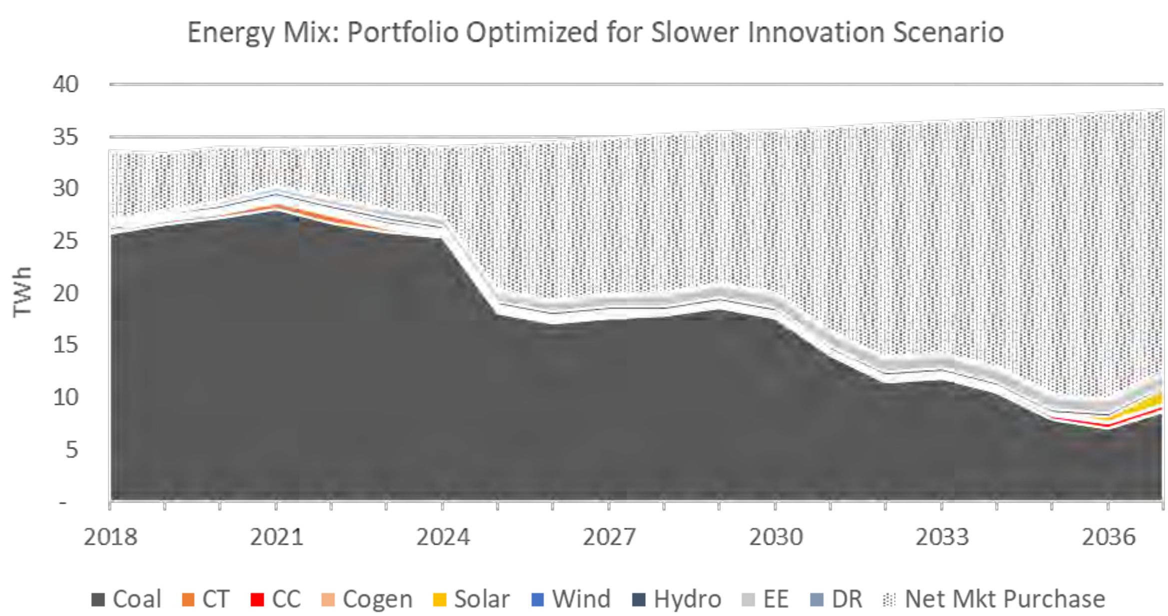
6. Moderate Transition Portfolio - includes three coal unit retirements in the 2020s as well as a CC with solar and wind additions occurring in the mid/late 2020s

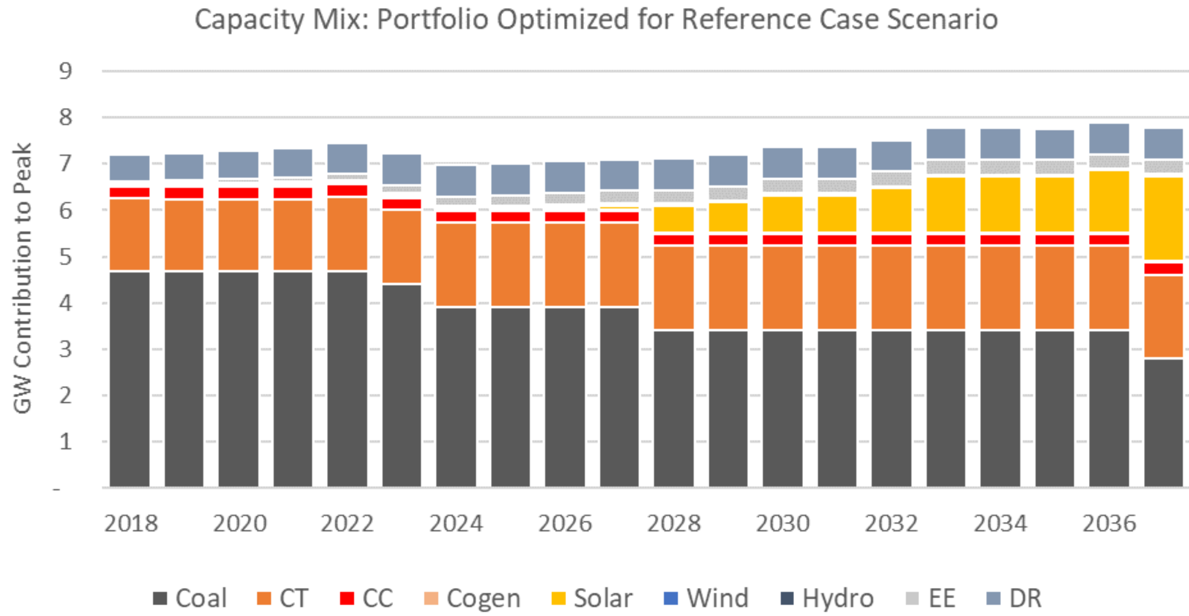
7. Aggressive Transition Portfolio - retires Cayuga and Gibson stations (3,800 MW) by the mid-2030s; adds 3 CCs and solar and wind over time
8. Rapid Decarbonization: CT Portfolio - alters the Aggressive Transition portfolio by replacing 2 CCs (2480 MW) with more wind, solar and CTs
9. Rapid Decarbonization: Batteries Portfolio - alters Aggressive Transition portfolio by replacing 2 CCs (2,480 MW) with additional wind, solar and storage

Figure I.1 includes more detail for each portfolio, including how the energy mix in each portfolio changes over time under the Reference Case scenario.

Figure I.1: Capacity and Energy Mixes for Candidate Resource Portfolios in Reference Case Scenario






Capacity Mix: Portfolio Optimized for Reference Case Scenario
GW Contribution to Peak
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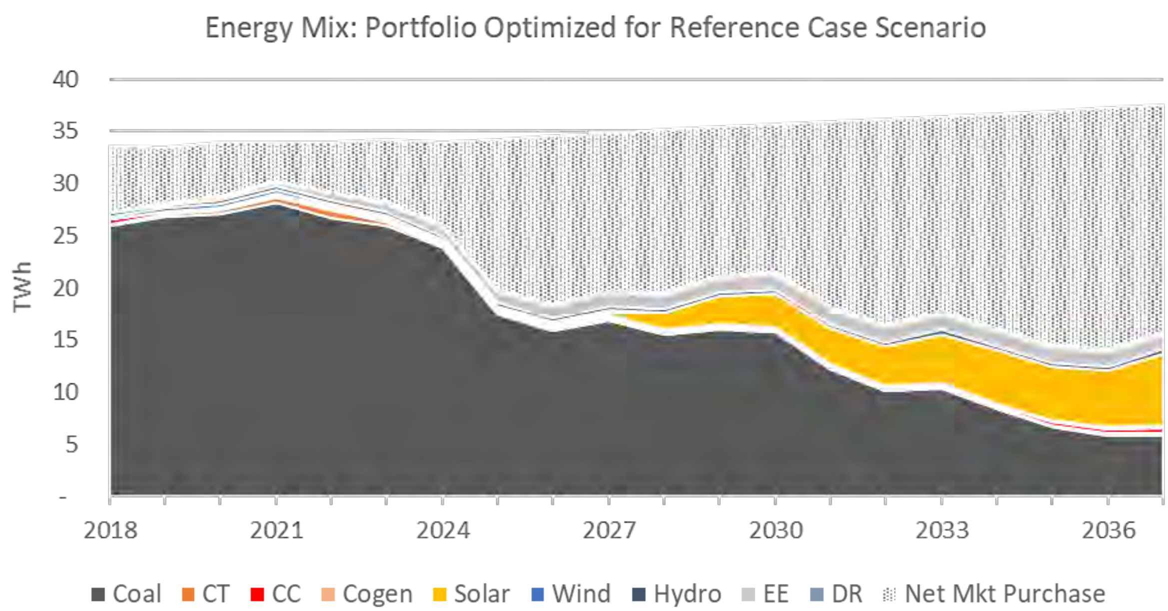
Energy Mix: Portfolio Optimized for Reference Case Scenario
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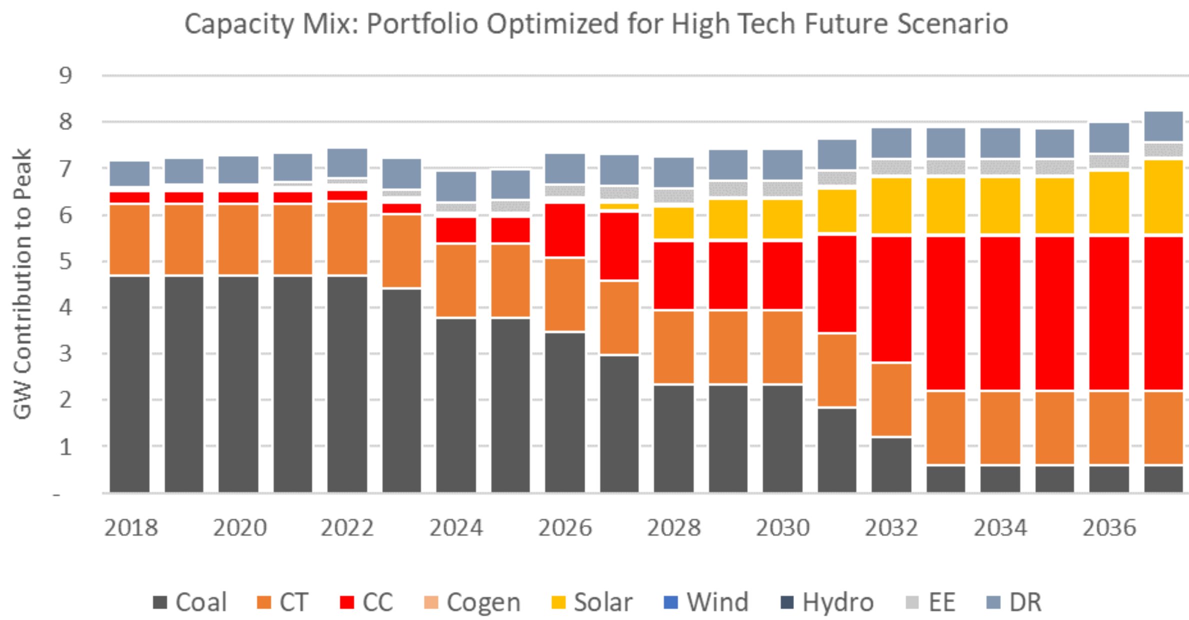
Net Mkt Purchase


Capacity Mix: Portfolio Optimized for High Tech Future Scenario
GW Contribution to Peak
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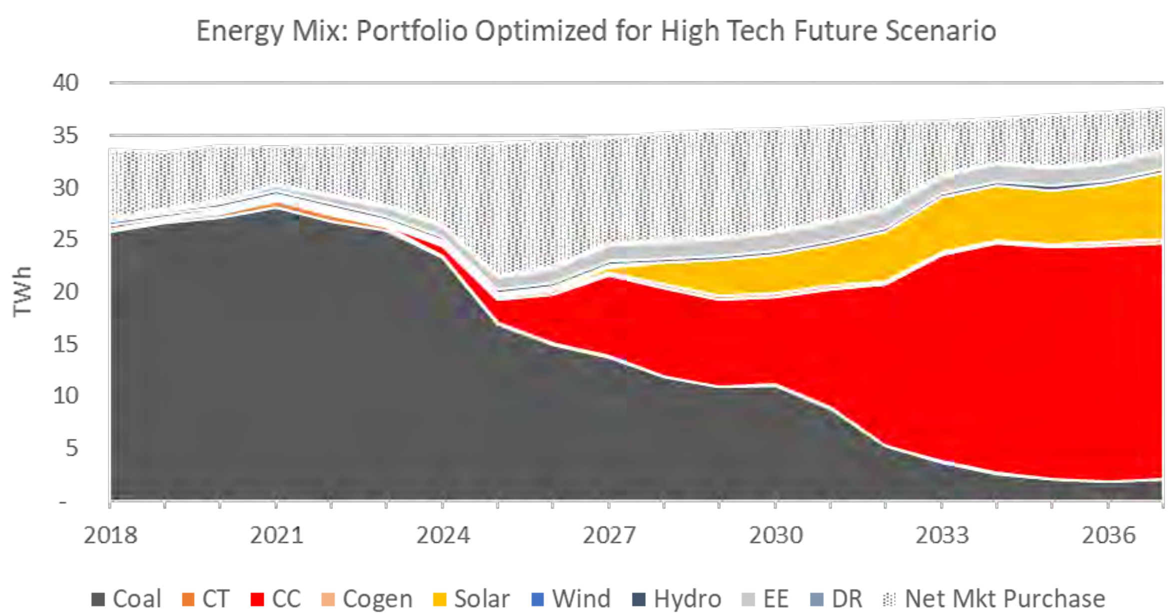
Energy Mix: Portfolio Optimized for High Tech Future Scenario
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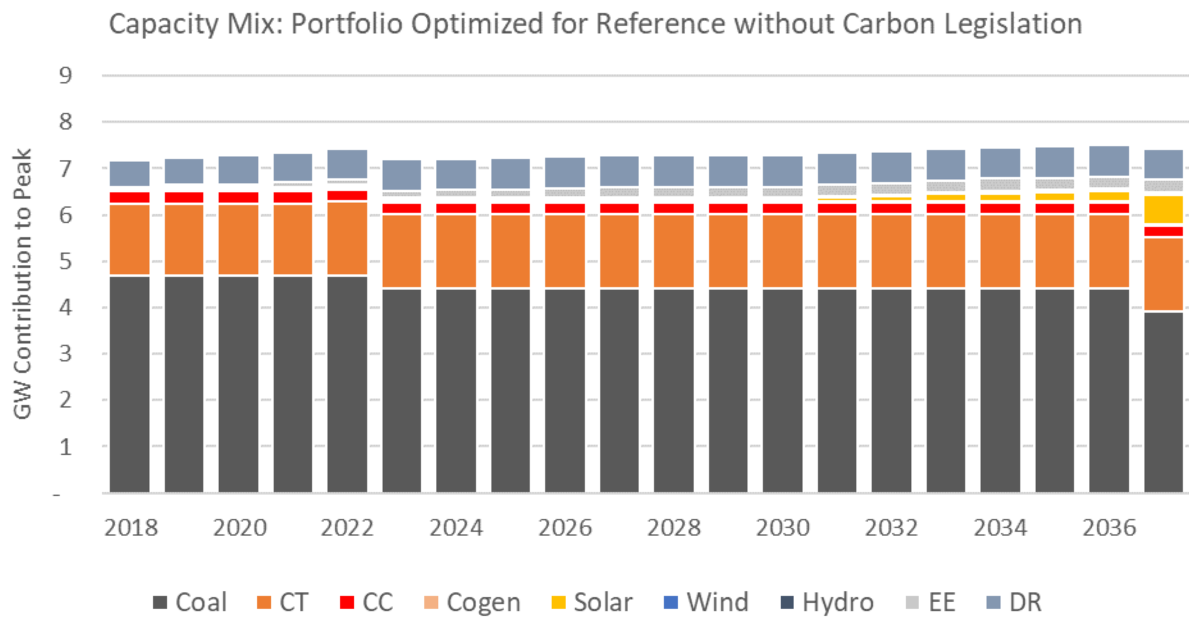
Net Mkt Purchase


Capacity Mix: Portfolio Optimized for Reference without Carbon Legislation
GW Contribution to Peak
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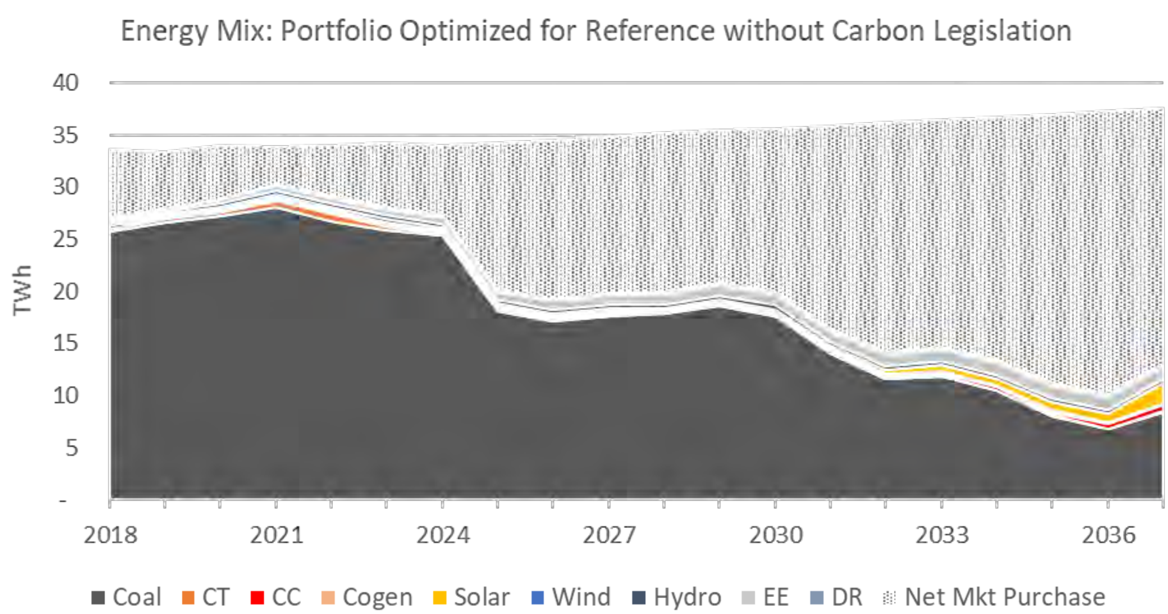
Energy Mix: Portfolio Optimized for Reference without Carbon Legislation
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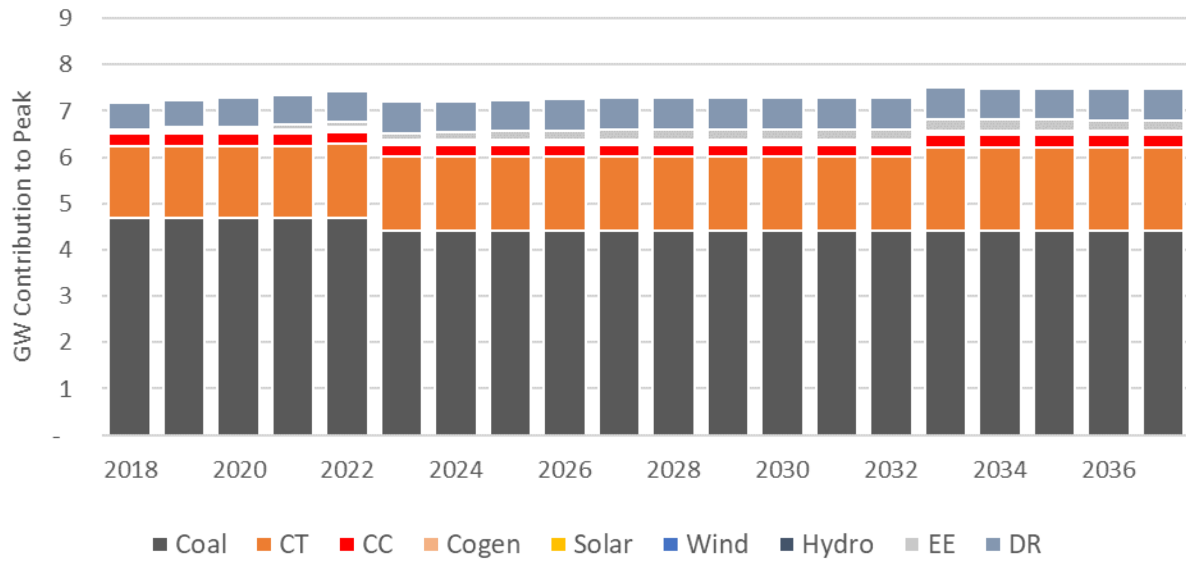
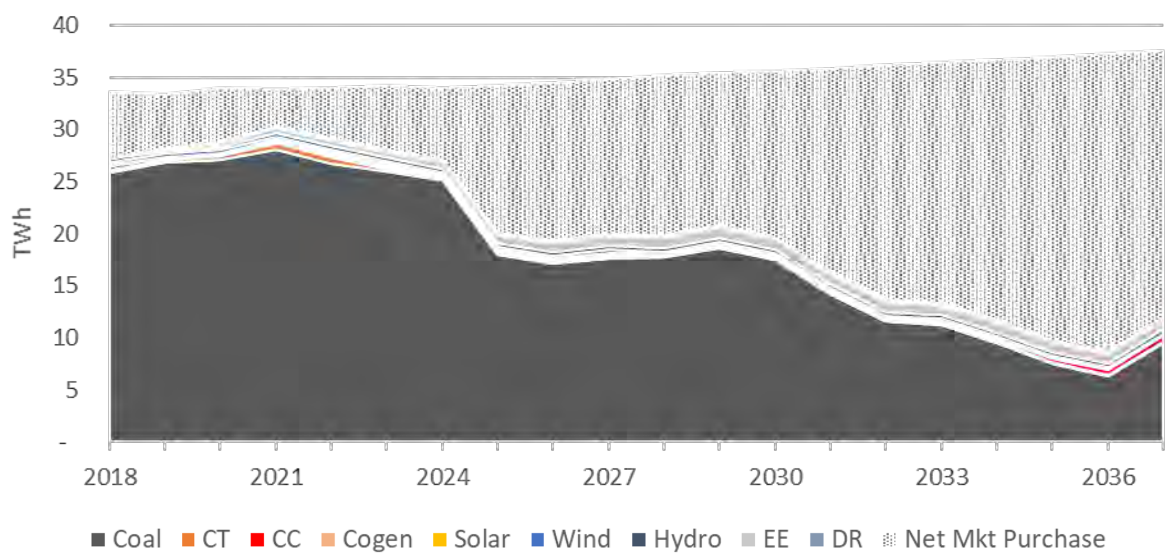
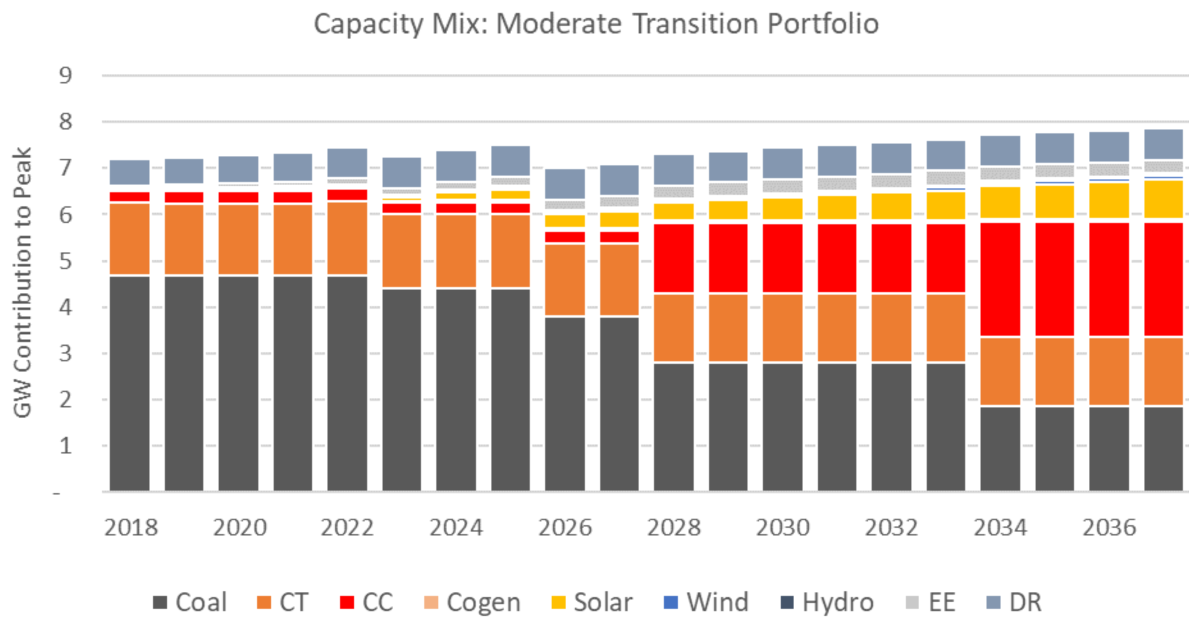
Capacity Mix: Portfolio Optimized for Current Conditions Scenario



Energy Mix: Portfolio Optimized for Current Conditions Scenario




Capacity Mix: Moderate Transition Portfolio
GW Contribution to Peak
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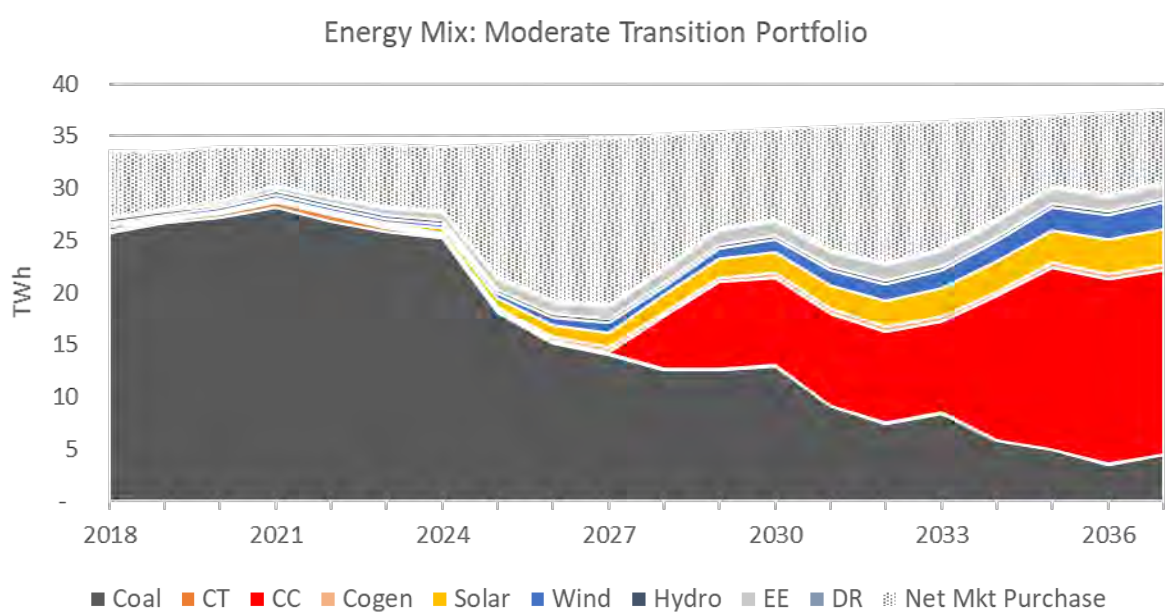
Energy Mix: Moderate Transition Portfolio
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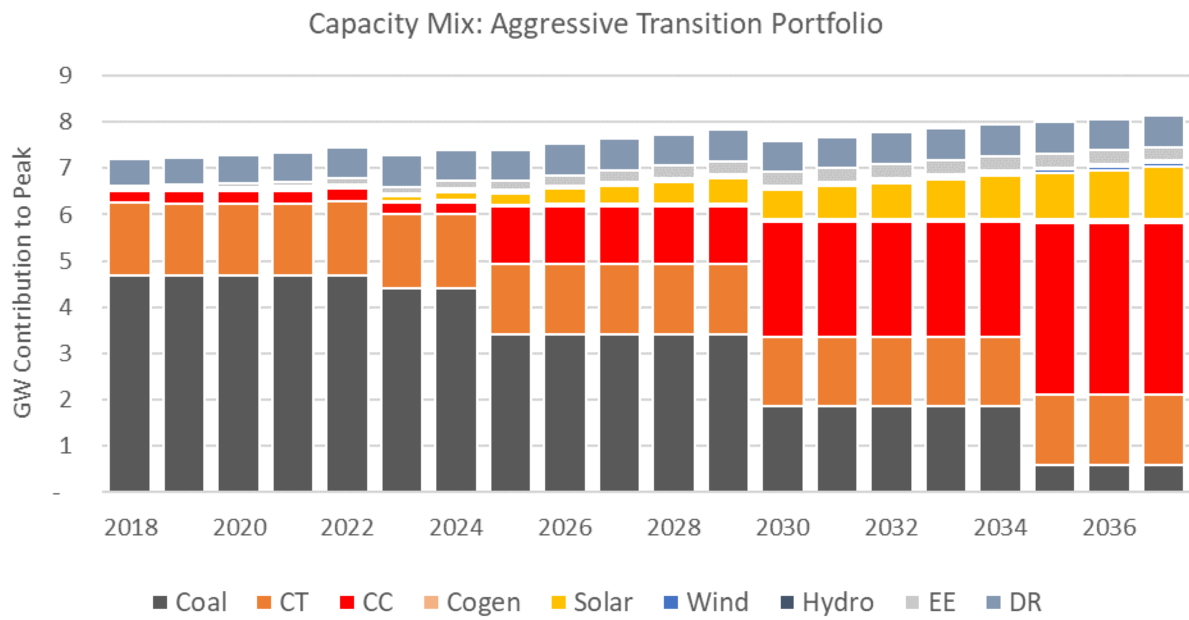

Capacity Mix: Aggressive Transition Portfolio
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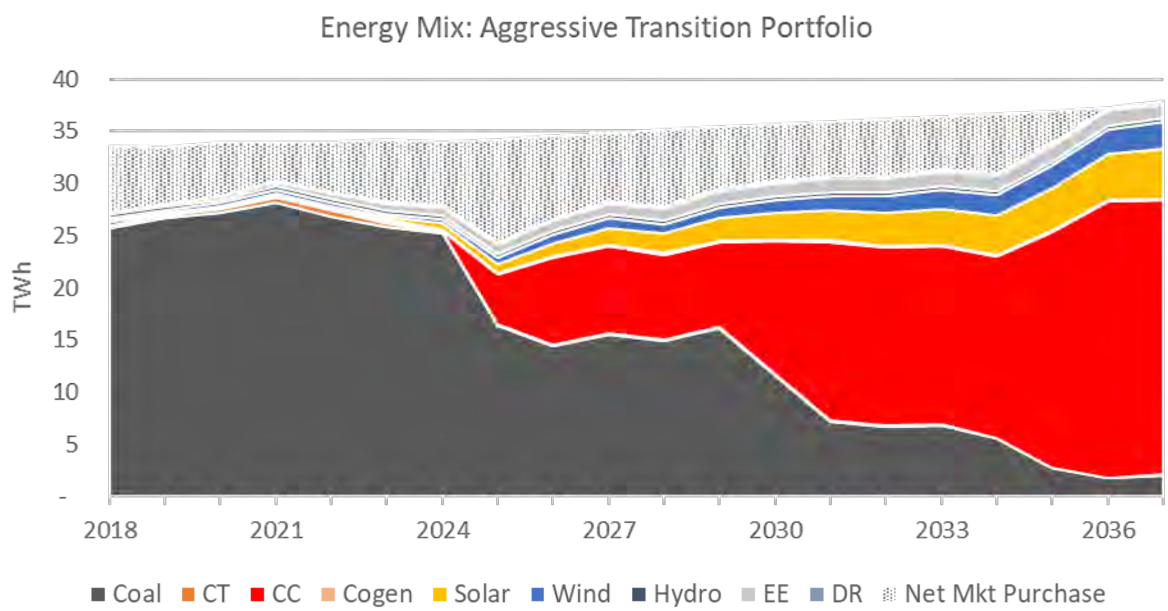

Energy Mix: Aggressive Transition Portfolio
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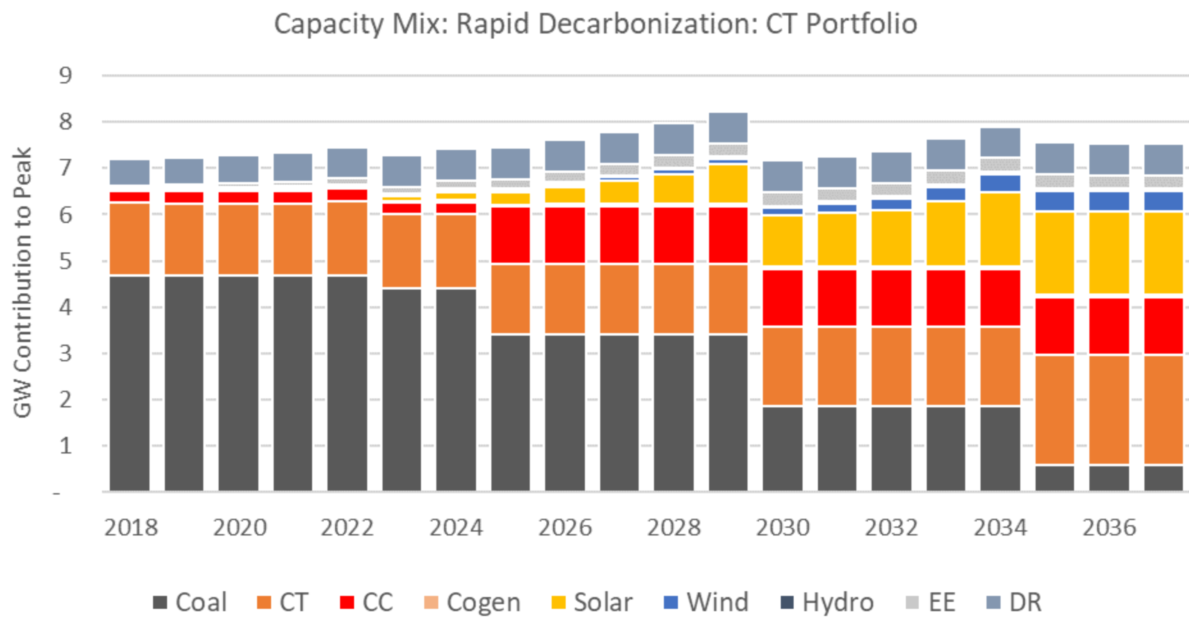
Capacity Mix: Rapid Decarbonization: CT Portfolio
GW Contribution to Peak
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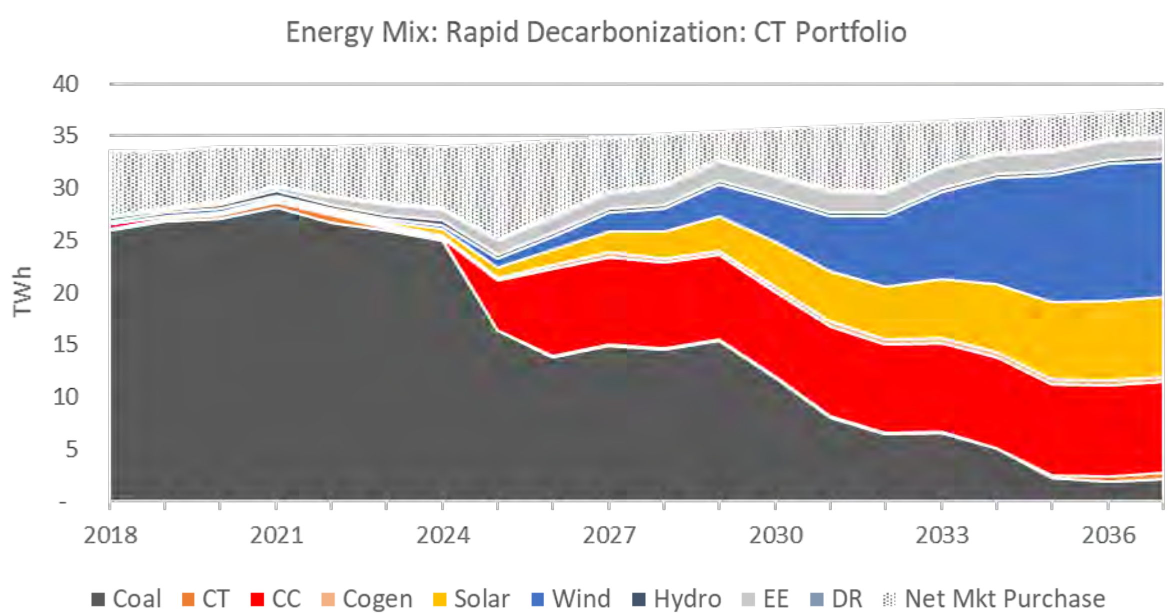
Energy Mix: Rapid Decarbonization: CT Portfolio
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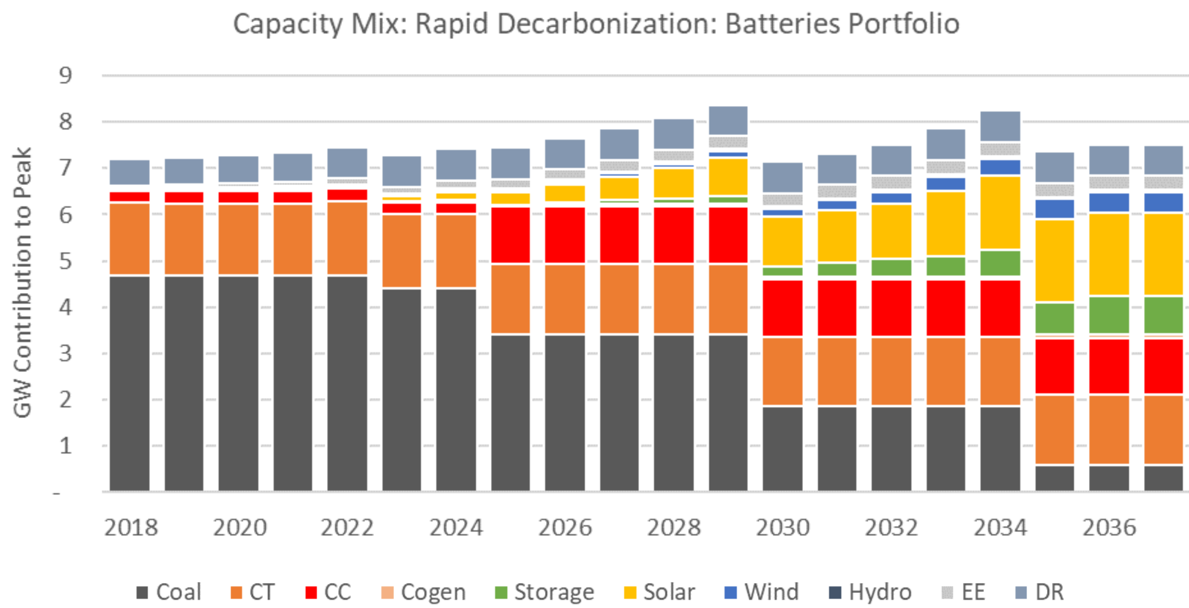
Capacity Mix: Rapid Decarbonization: Batteries Portfolio
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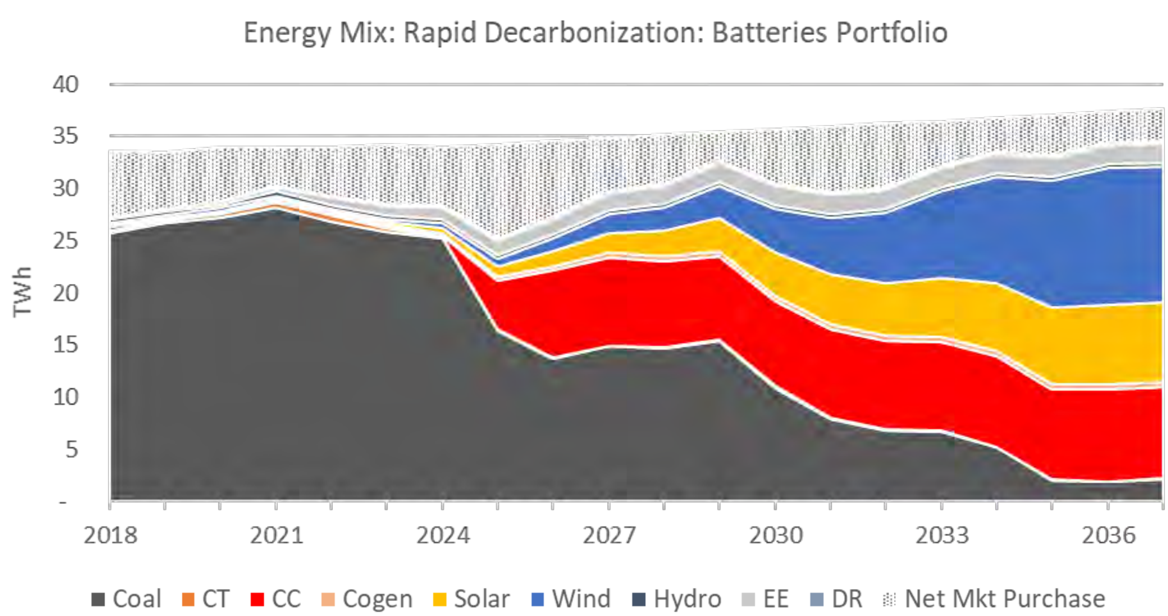
Energy Mix: Rapid Decarbonization: Batteries Portfolio
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Net Mkt Purchase

The objective of the IRP is to produce a robust portfolio that meets the Company's obligation to serve load 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. The selected plan must also meet Midcontinent Independent System Operator, Inc. (MISO)'s 15.0% reserve margin requirement.

C. PREFERRED PORTFOLIO

Based on its superior performance in scenario and sensitivity analyses, the Moderate Transition Portfolio was selected by Duke Energy Indiana as the preferred resource plan. This portfolio stands out due its combination of relatively low cost, lower carbon emissions, greater fuel diversity with lower exposure to market risk. The Moderate Transition portfolio also has the flexibility to adjust for different forms of carbon regulation (including no regulation) as well as changing economics of renewables.

D. SHORT-TERM ACTION PLAN

As can be seen in Table I.1, the Moderate Transition Portfolio features a measured approach with renewable generation progressively added and coal units retired over time. The benefit of this plan is the flexibility to adjust to changing market and regulatory conditions as well as to smoothly transition to a more diverse and less carbon intensive fleet.

E. LONG-TERM ACTION PLAN

Longer term, this portfolio can add more renewable if carbon regulation is more stringent or the cost of renewables decrease more than expected. The Moderate Transition portfolio is better able to take advantage of low cost gas if that should happen. If carbon regulation is delayed, this portfolio has the flexibility to adjust its transition. This portfolio takes the Duke Energy Indiana fleet in a direction with greater flexibility, lower costs, risk and carbon emissions.

Table I.1: Summary of Resource Additions and Retirements Under Preferred Resource Plan

	RETIREMENTS	ADDITIONS	INCREMENTAL DSM MW
2018			27
2019		Storage (10 MW)	66
2020		Storage (50 MW)	124
2021		CHP (16 MW)	169
2022			213
2023	Gallagher 2 & 4 (280 MW)	Solar (100 MW); CHP (16 MW)	262
2024		Solar (150 MW); Wind (50 MW); CHP (16 MW)	280
2025		Solar (150 MW); Wind (50 MW)	311
2026	Gibson 4 (622 MW)	Solar (150 MW); Wind (50 MW); CHP (16 MW)	330
2027		Solar (100 MW); Wind (50 MW)	357
2028	Cayuga 1-4 (1085 MW); Benton County PPA (100 MW)	Solar (100 MW); Wind (50 MW); CC (1240 MW)	370
2029		Solar (100 MW); Wind (50 MW)	382
2030		Solar (100 MW); Wind (50 MW)	381
2031		Solar (100 MW); Wind (50 MW)	379
2032		Solar (100 MW); Wind (50 MW)	387
2033		Solar (100 MW); Wind (50 MW)	396
2034	Gibson 3 &5; Noblesville CC (1204 MW)	Solar (100 MW); Wind (50 MW); CC (1240 MW)	392
2035		Solar (100 MW); Wind (50 MW)	383
2036		Solar (100 MW); Wind (50 MW)	378
2037		Solar (100 MW); Wind (50 MW)	380
TOTAL	3201 MW		

NOTE: All MW values are nameplate

SECTION II: RESOURCE PLANNING PROCESS, METHODS & TOOLS

Duke Energy Indiana files an IRP approximately every three years with the Indiana Utility Regulatory Commission.[1] The IRP includes analysis of firm electric loads, supply-side and demand-side resources, and environmental compliance measures associated with the Duke Energy Indiana service territory. The final product is a twenty-year plan to safely, reliably, efficiently, and cost-effectively meet electric system demand taking cost, risk, and uncertainty into consideration, as required by 170 IAC 4-7.

In this section, we discuss the process, methods and tools Duke Energy Indiana used to develop the IRP. This includes descriptions of how we develop our long-term quantitative forecasts of load, fuel prices, and other variables that could affect resource decisions; descriptions of the models we use and what we use them for; a discussion of the technology screening process by which resource types are determined to be eligible or ineligible for consideration in the development of future portfolios; a discussion of scenario planning and how we deal with uncertainty and risk when developing the IRP; a description of the stakeholder process leading up to the filing of this IRP; and a discussion of potential improvements that could be made to the IRP tools or process in the future.

This section is limited to a discussion of methods. For the actual forecasts, scenarios, and portfolios used in this IRP, please see Section IV: Duke Energy Indiana in the Future and Section V: Candidate Resource Portfolios. Additional technical details about the forecasts used in this IRP are available in the appendix.

A. FORECASTING METHODS

Load Forecasting

Electric energy and peak demand forecasts are prepared each year as part of the planning process by a staff that is shared among Duke Energy Corp. (Duke Energy) affiliated utilities. Each affiliated utility utilizes the same methodology. However, Duke Energy does not perform joint load forecasts among affiliated utility companies. Each forecast is prepared independently. The

[1] The Company's last IRP was filed on November 2, 2015 as Cause No. 44698. In the Commission's most recent proposed rule amendments, Duke Energy Indiana was directed to file its next IRP on November 1, 2018; however, an extension was granted until July 1, 2019.

load forecast is one of the most important parts of the IRP process. Customer demand provides the basis for the resources and plans chosen to supply the load.

The general load forecasting framework includes a national economic forecast, a service area economic forecast, and the electric load forecast. The national economic forecast includes projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. Moody's Analytics, a national economic consulting firm, provides the national economic forecast. Similarly, the histories and forecasts of key economic and demographic variables for the service area economy are obtained from Moody's Analytics. The service area economic forecast is used together with the energy and peak demand models to produce the electric load forecast. In addition, the company conducts customer surveys every three to five years to determine end-use electricity consumption patterns.

Energy sales projections are prepared for the residential, commercial, industrial, street lighting, and public authority sectors. Sales projections and electric system losses are combined to produce a net energy forecast. These forecasts provide the starting point for the development of the IRP. For additional technical details and data, please see Appendix B.

Forecasting Fuel Prices

The Company uses a combination of observable forward market prices and long-term commodity price fundamentals to develop coal and gas price forecasts. The former incorporate data from public exchanges including NYMEX, as well as fuel contracts and price quotes from fuel providers in response to regular Duke Energy fuel supply requests for proposals. The long-term fundamental fuels forecast is a proprietary product developed by IHS Markit Ltd., a leading energy consulting firm[2]. Fuel price forecasts provided by IHS are based on granular, integrated supply/demand modeling using fuel production costs and end-user consumption. The Duke Energy long-term fundamental forecast is approved annually by Duke Energy's leadership for use in all long-term planning studies and project evaluations.

[2] This content is extracted from the IHS Markit North American Power, Gas, Coal and Renewables service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content was approved in advance by IHS Markit. Any further use or redistribution of this content is strictly prohibited a without written permission by IHS Markit. Copyright 2018, all rights reserved.

The development of plausible high and low-price fuel forecasts is necessary to enable creation of a range of future scenarios for long range resource planning. To accomplish this, the Company's long-term fundamental fuel forecasts were adjusted using forecast factors from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). The forecast factors used for low fuel price development are from the AEO 2018 High Oil and Gas Resource and Technology Case and the factors for high fuel price development are from the AEO 2018 Low Oil and Gas Resource and Technology Case. These high and low fuel forecasts will be shown in greater detail in the scenario descriptions in Section IV of this Document.

Fuel Supply Considerations

Duke Energy Indiana generates energy to serve its customers through a diverse mix of fuels consisting primarily of coal, natural gas, and fuel oil; it also 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.

Coal

Over 90% 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 as evaluated by the Fuels Department 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 (such as contract versus short term ratios or 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 2018, over 95% of the coal supplied to base load stations was 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 the 10-12 million annual tons of coal the Duke Energy Indiana typically consumes in such a short timeframe.

The current Duke Energy Indiana supply portfolio includes nine 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 the low capacity factor Gallagher coal station, a much shorter-term procurement policy is used due to the planned retirement of these aging units. Generally, we source lower-sulfur coal for these intermediate units 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.

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 as follows: (1) Midwestern Gas pipeline for gas delivery to Edwardsport, Vermillion, and Wheatland, and 2) Panhandle Eastern Pipeline for delivery to Noblesville. The modeled future CC fuel cost incorporates both the natural gas commodity price and firm transportation cost, and the modeled future CT fuel cost includes the natural gas commodity price and interruptible transportation cost.

Oil

Duke Energy Indiana uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Cayuga Unit CT4 uses oil as a back-up fuel. Oil supplies, are purchased on an as-needed basis, and are expected to be sufficient to meet needs for the foreseeable future.

Forecasting Power Prices

As with fuel prices, we combine near-term observable market prices and long-term fundamental projections to develop power price forecasts. The Company uses PROMOD to develop long-term fundamental power price projections based on scenario-specific fuel price forecasts, a scenario specific generation resource mix for the Eastern Interconnect, and carbon price assumptions. PROMOD incorporates this information and simulates the dispatch of regional power markets to develop a power price forecast for Duke Energy Indiana. We use this method to ensure consistency and provide a linkage between fuel, carbon, and power price assumptions. To better calibrate the way in which dispatch model replicates making real-world generating unit commitment decisions, the IRP dispatch model is not permitted to purchase energy from the market unless the wholesale power price forecast is at least $2/MWh greater than the forecasted marginal cost of energy from company-owned resources.

Forecasting Prices for Carbon Emissions

In the current legislative/regulatory environment it is very difficult to project what a carbon-constrained future will look like. However, the Company believes that a constraint or price on carbon is likely to be imposed at some future date, so it is prudent to incorporate such a constraint into our resource planning. To that end, Duke Energy used an iterative modeling process to develop a forecast of the CO_2 allowance price trajectory that would be required to achieve reductions in CO_2 emissions of 40% by 2030 and 60% by 2050 across the regulated enterprise (DEI, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress, and Duke Energy Florida).

Forecasting Capital Costs

Duke Energy, in conjunction with a third party, developed capital cost projections for all generation technologies included in the IRP optimization models. These projections are based on Technology Forecast Factors from the EIA's Annual Energy Outlook (AEO) 2018. The AEO provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS).

Using 2018 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2016, July 2017)

From *NEMS Model Documentation 2016, July 2017*:

> "*Uncertainty about investment costs for new technologies is captured in the Electric Capacity Planning module of NEMS (ECP) using technological optimism and learning factors.*
>
> - *The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*

- *Learning factors represent reductions in capital costs due to learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

To develop a more accurate forecast for rapidly developing technologies such as solar PV and battery storage, we blended the AEO forecast factors with additional third-party capital cost projections. See Appendix C for all capital cost projections.

B. PLANNING MODELS

System Optimizer (SO) is an economic optimization model used to develop IRPs while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional generating units such as CTs, CCs, coal units, or IGCC and renewable resources such as wind or solar. 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 DSM programs or adding supply-side resources to the system.

Planning and Risk (PAR) is a detailed production-cost model for simulation of the optimal operation of an electric utility's generation facilities. Key inputs include generating unit data, fuel data, load data, transaction data, Demand Side Management (DSM) data, emission and allowance cost data, and utility-specific system operating data.

PROMOD is a fundamental electric market simulation solution that incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations. A generator and portfolio modeling system, PROMOD, provides nodal locational marginal price (LMP) forecasting and transmission analysis.

C. RESOURCE SCREENING

Supply-Side Resources

Supply-side resources may include existing generating units; repowering options for these units; potential bilateral power purchases from other utilities, Independent Power Producers (IPPs) and combined heat and power applications; short-term energy and capacity transactions within the MISO market; and new utility-built generating units (conventional, advanced technologies, and renewables). When considering these resources for inclusion in the portfolio, the Company assesses their technical feasibility, commercial availability, fuel availability and price, useful life or length of contract, construction or implementation lead time, capital cost, operations and maintenance (O&M) cost, reliability, and environmental impacts.

The first step in the screening process for supply-side resources is a technical screening to eliminate from consideration those technologies that are not both technically and commercially available to the Company. Also excluded from further consideration are technologies that are not feasible, available or economically viable in or near the Duke Energy Indiana service territory. Supply-side resources not excluded for availability reasons are included as potential options in the economic optimization modeling process using the SO model.

Additional details on the screening of supply-side resources can be found in Appendix C.

Retirement Analysis

Generating unit retirements are selected in the System Optimizer (SO) model using a three-step process. This is necessary because fixed costs are an input to SO, and the model does not calculate these costs in an iterative fashion. The steps include two SO runs and an intermediate step in which future fixed costs are forecast using a separate tool.

1. An initial SO run is conducted in which the system is modeled over the planning period with no units eligible for retirement. The key output of this run is the capacity factor of each unit in each year of the planning period.
2. A spreadsheet tool is used to forecast future maintenance cycles, capital expenditures for maintenance, and fixed operating costs, all based on forecasted run hours (capacity factors) from the initial SO run. These fixed cost forecasts for each unit are used as an input for a second SO run.

3. The second SO run is conducted using the fixed cost forecasts from Step 2 as an input. All other inputs are identical to the initial run. In this final run, SO selects units for retirement when the present value of future fixed and variable costs exceeds the costs associated with retirement and replacement. That is, if the costs that can be avoided by retiring a unit are greater than the cost of running the system without that unit (including the cost of replacement), then the unit is retired.

Note that the cost of replacing a unit is never as simple as a one-for-one replacement of megawatts based on capital cost. Costs may include new capacity from a variety of sources as well as changes to the dispatch of existing units, and these changes may be realized over multiple years. Furthermore, total replacement capacity will not equal the capacity of the retiring unit due to differences in unit size and changes to peak load over time. The SO model considers all of these factors and their interdependencies over the planning period when selecting resource retirements and additions.

Demand-Side Resources

The Company received approval for its 2017-19 EE portfolio under Cause No. 43955 DSM-4 and is currently implementing that portfolio for 2019. For the purpose of this IRP, the EE forecast is based on the implementation of the portfolio approved in Cause No. 43955 DSM-4 and assumptions for future EE forecasts are based on this portfolio (for 2020) along with information provided in a recent Market Potential Study conducted by Nexant for periods beyond 2020. Further details of the methodology used to forecast beyond 2019 are included in Appendix D.

D. SPECIFYING IRP OBJECTIVES

The purpose of this IRP is to define a robust strategy to furnish electric energy services to Duke Energy Indiana customers in a reliable, efficient, economic manner in accordance with all applicable environmental regulations while remaining dynamic and adaptable to changing conditions. We use scenario planning and sensitivity analysis to address areas of regulatory, economic, environmental, and operating uncertainty. The triennial filing schedule allows the Company to monitor key sources of uncertainty and adjust the plan as necessary, thereby producing an IRP that represents the most reliable and economic path forward based upon robust analysis of emerging information.

Our long-term planning objective is to develop a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community) while maintaining the flexibility to adapt to changing conditions. At times, this involves striking a balance between competing objectives.

Determining a Planning Reserve Margin

We address system reliability and resource adequacy in the planning process by targeting an appropriate planning reserve margin for use in our IRP models. Duke Energy Indiana's reserve requirements are driven by ReliabilityFirst, 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.

Planning Reserve Margin (PRM) can be expressed on either an ICAP (*i.e.*, installed capacity) or UCAP (*i.e.*, unforced capacity) basis. The required MISO PRM_{ICAP} is translated to PRM_{UCAP} using the MISO system average equivalent forced outage rate excluding events outside of management control ($XEFOR_d$)[3] and assigned to each load serving entity (LSE) on a UCAP basis. For the 2018/19 Planning Year, the Company is required to meet a PRM_{UCAP} of 8.4%.

Duke Energy Indiana's IRP models utilize the full installed capacity (ICAP) unit ratings to estimate dispatch so the MISO assigned PRM_{UCAP} is translated to an equivalent Installed Capacity (PRM_{ICAP}) target which is the historical method used by the Company for modeling purposes. For Planning Year 2018/19, the applicable RM_{ICAP} is 17.9%.[4] Because the RM_{ICAP} derived from MISO's PRM_{UCAP} fluctuates annually, Duke Energy Indiana selects a longer-term planning reserve margin near the midpoint of recent MISO annual requirements. The long-term ICAP planning reserve margin utilized for the 2018 integrated resource plan is 15.0%.

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

E. SCENARIO DEVELOPMENT & OPTIMIZED PORTFOLIOS

The basic method for developing an IRP is to predict what the future will be like over the 20-year planning horizon and then design the best resource portfolio possible given that vision. The major challenges are the obvious fact that it is impossible to perfectly forecast the future, and the perhaps less obvious fact that the notion of what is "best" can be difficult to define. We use scenario analysis to explore how different resource portfolios might perform under a variety of future conditions, and to examine the tradeoffs that may need to be considered among potentially competing objectives.

A scenario in this context is a formalized set of assumptions about the future. We do not try to assess every possible future that could unfold over the planning horizon. That would be futile. Instead we describe a small, manageable set of potential versions of the future that we believe captures the full range of plausible possibilities. Each of these is a scenario.

It is important to note that the factors that go into describing a scenario are external to the company. These include market structures and prices; energy demand and peak load; federal, state, and local policy environments; and so on. In this context, scenarios include no assumptions about company actions or resource portfolio decisions. Potential Duke Energy Indiana plans and decisions are evaluated within and across the various scenarios.

The steps involved in scenario development are:

1. *Define the planning objectives and scope of analysis.* The scope of the analysis is largely determined by Indiana IRP rules. The geographic boundary coincides with the Duke Energy Indiana service territory and areas that immediately influence factors in that territory, and the time horizon is the 20-year IRP planning window. The planning objectives are determined by a mix of state and MISO rules governing reliability and cost-effectiveness, and input from stakeholders.
2. *Describe the fundamental trends affecting the company's ability to meet the agreed-upon objectives.* These trends could include regulatory, economic, industry, or technological factors, among others.
3. *Identify key sources of uncertainty.* These should be factors that are very difficult to forecast and that will have a significant impact on portfolio choices. Selection of these variables will be informed by the trends described in Step 2, and the scenario framework will be constructed around them. Factors that are important but that can be

forecast with greater confidence will also be considered, but should not be the focus when developing scenarios.

4. *Describe visions for potential futures in qualitative terms*. These narratives, which should reference the trends and uncertainties explored in the previous steps, will form the central themes for the different scenarios.
5. *Describe the current conditions that are the baseline for planning for the future.* The world as it exists in the present is the starting point for all scenarios, and all forecasts are informed by recent history. The further we look into the future, the more the different scenarios diverge.
6. *Develop quantitative sets of expectations for the future of the market, regulatory, and technical environments in which the company operates.* In order to perform the quantitative analysis that provides the foundation for selecting the preferred portfolio, each scenario must be fully described in quantitative terms. That is, each scenario must have a quantitative forecast for each of the input variables used in the analysis. Forecasts must be consistent within scenarios and with the scenario narratives described in Step 4 for the scenarios to be valid. For instance, all else being equal, a scenario that assumes rapid increases in natural gas prices and also the widespread adoption of gas-fired generation is probably not plausible.
7. *Review scenarios with stakeholders to confirm completeness.* Consult stakeholders in the planning process to obtain feedback on whether the set of scenarios covers the range of plausible futures that needs to be addressed. Add, subtract, or modify scenarios if necessary.

Once the set of scenarios is fully described and each scenario has a complete set of forecasted input variables, we use the quantitative models to design the "optimized" resource portfolio for each scenario. In other words, taking the scenarios one at a time, we plug the full set of input variables into SO (described above) and the model determines which generating resources should be added or retired and when those changes should occur, given the future as defined in the scenario under consideration. The SO model solves for the least cost resource portfolio that meets the planning reserve margin requirement, as measured by the present value of revenue requirements (PVRR) over the 20-year planning period. The resulting resource mix for each scenario is referred to as an optimized portfolio because it is selected entirely by the model.

Although we call these portfolios "optimized," we shouldn't immediately assume that one of them is likely to be the preferred portfolio selected in the IRP. For one thing, each optimized portfolio is created in the context of a specific scenario and may perform poorly under future conditions that differ from the scenario for which it is designed. Second, while the model selects the portfolio that minimizes future costs, it does not help us make judgements about other factors (fuel diversity, environmental impacts, etc.) that may affect the desirability of the resource mix. Finally, the model does not account for many feedbacks that occur in the real world, where resource choices made today may influence the future state of the variables we treat as inputs. So, while the optimized portfolios are a vital first step in the analysis that provide important insight into the resource mixes that may be preferable under different future conditions, further analysis is needed before the preferred portfolio can be selected.

F. ALTERNATIVE PORTFOLIOS & SELECTING THE PREFERRED PORTFOLIO

After developing the optimized portfolio for each of the scenarios under consideration, the next step is to assess their strengths and weaknesses to understand how improvements could be made. This is done by modeling how each optimized portfolio would perform under the scenarios for which it was not specifically designed, and then by performing sensitivity analysis to see how portfolio performance is affected by changing a single assumption of interest while holding others constant.

The first step is to model all portfolio-scenario combinations in our production cost model, PAR (described above). Both the portfolio (resource mix) and the scenario (possible future in which that portfolio would exist) are inputs to PAR. The model output is a detailed estimate of how the resources in the portfolio would operate under that scenario. That includes an hour-by-hour account of how much energy each generator would produce, how much fuel of each type would be consumed, how much energy would be purchased from (or sold to) the MISO market, how many tons of carbon dioxide and other emissions would be produced, and what the total cost of operating that portfolio would be in each hour over the 20-year planning period. This allows us to understand how a given portfolio would operate under each of the scenarios we test, and what the strengths and weaknesses of each portfolio are. Understanding how portfolio performance changes as we change the scenario can also help highlight specific assumptions that we may wish to focus on for additional analysis.

Focus on a single assumption is called sensitivity analysis. This goal is to assess the degree to which portfolio performance or composition would be affected by changing a single assumption that is of particular interest. For example, we may wish to vary only our forecast for the price of natural gas while holding all other assumptions constant.

The results of the portfolio-scenario combinations and the sensitivity analysis provide us with information about how different resource mixes perform under different conditions and about how performance can vary if conditions change. We use these insights to design a small number of alternative portfolios where we aim to capture or build on the positive aspects of the optimized portfolios while minimizing their shortcomings. This could include, for example, adding more of a resource type that provides benefits that the model does not recognize, removing resources that perform well only under certain conditions, or diversifying the resource mix to reduce risk.

We then run the alternative portfolios through the production cost model to test how they would perform under each scenario and, if necessary, we may make additional adjustments to the alternatives to enhance their performance. After all of this we evaluate the full set of model outputs describing the costs and performance characteristics of each portfolio under all scenarios and sensitivity analyses. We use all of this information to select a preferred portfolio that cost-effectively and reliably meets demand while balancing the other objectives identified at the beginning of the process.

G. STAKEHOLDER PROCESS

Prior to submitting the IRP, Duke Energy Indiana conducts a series of stakeholder meetings to discuss the IRP process and gather stakeholder input. Topics covered in the course of the stakeholder process include:

- Background on the IRP process and scenario planning
- Discussion of the specific objectives for current IRP
- Overviews of specific scenarios under consideration for the current IRP
- Solicitation of stakeholder-proposed scenarios and feedback on Duke Energy Indiana-proposed scenarios
- Specific forecasts and model inputs for each scenario

- Review of Duke Energy Indiana-proposed resource portfolios and stakeholder-designed portfolios
- Preliminary modeling results and sensitivity analysis
- Final modeling results and presentation of the preferred portfolio

Materials covered in this IRP and meeting summaries are included in Volume 2 and are posted on the company's website at: https://www.duke-energy.com/home/products/in-2018-irp-stakeholder.

SECTION III: DUKE ENERGY INDIANA TODAY

A. LOAD AND CUSTOMER CHARACTERISTICS

Duke Energy Indiana is Indiana's largest electric utility electric serving approximately 840,000 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, Lafayette, and suburban areas near Indianapolis, Louisville and Cincinnati.

For the purposes of resource planning and load forecasting, customers are segmented into the following categories: residential, commercial, industrial, government, and street lighting. Additionally, Duke Energy Indiana provides power via wholesale contracts with several municipal and cooperative power providers. The number of retail customers in each category, historical retail energy sales by customer category, and historical peak demand and total energy sales, including wholesale, are displayed in the figures below. For additional detail on historical load, see Appendix B.

Figure III.1: Historical Number of Retail Customers by Category (Annual Average)

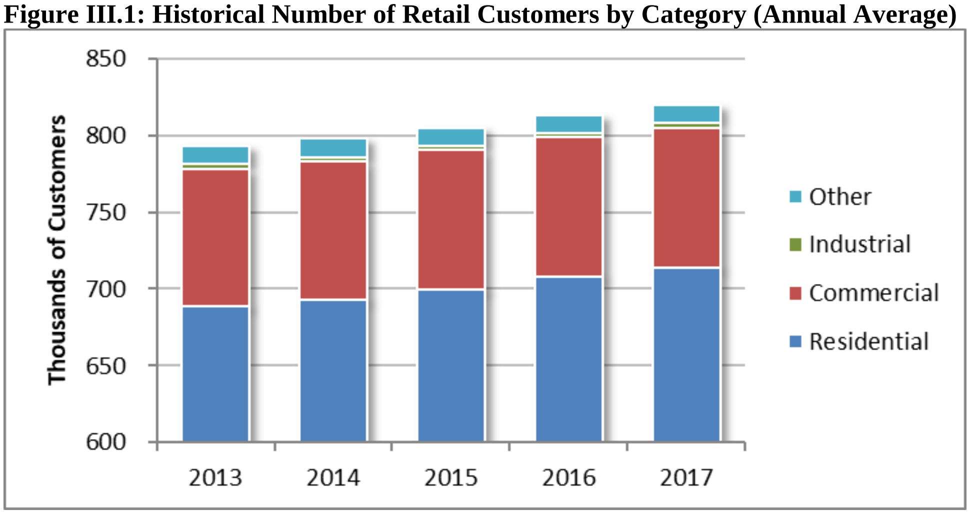


Figure III.2: Historical Retail Energy Sales by Customer Category (after UEE)

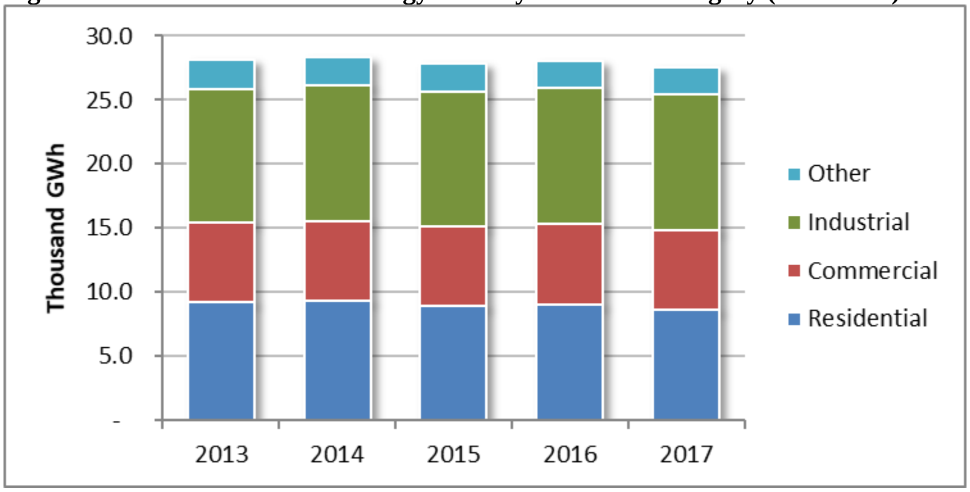


Figure III.3: Historical Peak Demand Including Wholesale (after UEE)

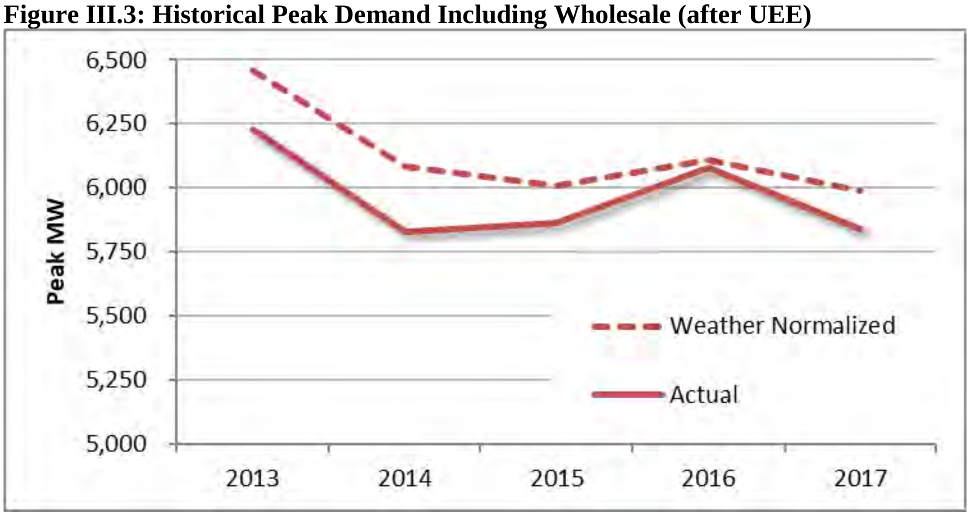
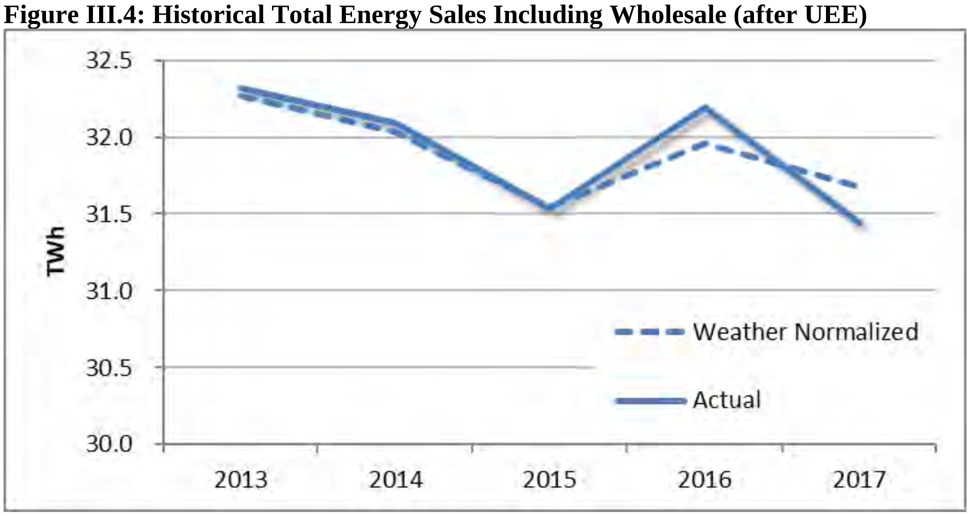


Figure III.4: Historical Total Energy Sales Including Wholesale (after UEE)

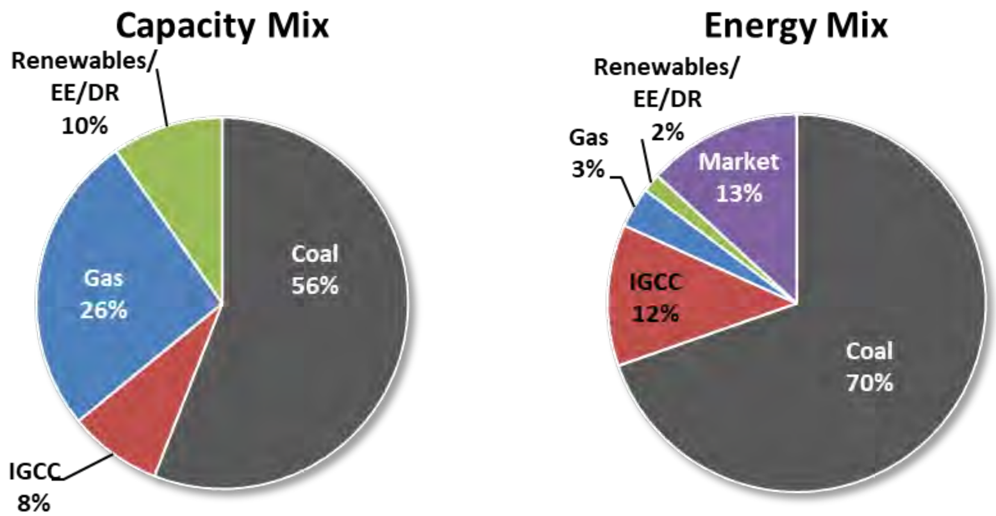


B. CURRENT GENERATING RESOURCE PORTFOLIO

The total installed net summer generation capability owned or purchased by Duke Energy Indiana is currently 6,630 MW. This capacity consists of 4,097 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 264 MW of natural gas-fired CC capacity, 45 MW of hydroelectric capacity, 1,585 MW of natural gas-fired peaking capacity, 10 MW of oil fired peaking capacity and 17 MW (8.5 MW contribution to peak) of owned solar photovoltaic (PV) capacity. Also included are power purchase agreements with Benton County Wind Farm (100 MW, with a 13 MW contribution to peak) and five solar facilities totaling 24MW with a 12 MW contribution to peak.

The coal-fired steam capacity consists of 9 units at three stations (Gibson, Cayuga, and Gallagher). 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 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. The solar capacity consists of a 17 MW fixed-tilt PV plant located at the Naval Station in Crane, Indiana as well as power purchase agreements with four 5 MW fixed-tilt PV facilities located near Brazil, West Terre Haute, Kokomo and Sullivan, Indiana and a 4 MW fixed-tilt PV facility near Staunton, Indiana.

Figure III.5: 2017 Duke Energy Indiana Capacity and Energy Mixes



The Duke Energy Indiana bulk transmission system is comprised of the 345 kilovolt (kV), 230 kV and 138 kV systems. The bulk transmission system delivers bulk power into, from, and across Duke Energy Indiana'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 Indiana 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 2018, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 852 circuit miles of 345 kV lines, 777 circuit miles of 230 kV lines and 1,446 circuit miles of 138 kV lines. Duke Energy Indiana, Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Alliance (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 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. CURRENT DEMAND-SIDE 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.

Current Energy Efficiency Programs

Duke Energy Indiana's current Energy Efficiency (EE) program portfolio was approved by the Commission in Cause No. 43955 – DSM4 for the periods 2017-19 and contains the following set of programs described in greater detail in Appendix D:

<u>Residential Programs</u>

- Smart $aver® Residential
    - HVAC Equipment
    - Attic Insulation and Air Sealing
    - Duct Sealing
    - Heat Pump Water Heater
    - Variable-Speed Pool Pump
    - Referral Programs
    - Free LED Program
    - Specialty Lighting & other energy efficient products
    - Retail Lighting
    - Save Energy and Water Kit
    - Low Income Neighborhood - Neighborhood Energy Saver Program
    - Agency Assistance Portal
    - Low Income Weatherization

- Multifamily Energy Efficiency Products & Services
- Residential Energy Assessments
- My Home Energy Report
- Energy Efficiency Education Program for Schools
- Power Manager® (Demand Response)
- Bring Your Own Thermostat (Demand Response)
- Energy Efficient Appliance
- Manufactured Home
- Multi-Family Retrofit
- Residential New Construction

<u>Non-Residential Programs</u>

- Smart $aver® Non-Residential Incentive Program
  - Prescriptive Incentives
  - Custom Incentives
  - Performance Incentives
- Small Business Energy Saver
- Power Manager® for Business

Current Demand Response Programs

In addition to the Residential Demand Response programs approved in Cause 43955 – DSM4, Duke Energy Indiana also offers the following Non-Residential Demand Response programs under its Rider 70 and other special contracts:

- PowerShare® CallOption
- Special Curtailment Contracts

SECTION IV: DUKE ENERGY INDIANA IN THE FUTURE

Resource planning for an uncertain future requires consideration of the range of operating conditions the Company may face in both the near and long term. Scenario analysis is a useful tool for long range planning as it provides a basis for studying the impact of changes in key variables over time. To achieve this, the scenarios developed must be plausible, internally consistent, sufficiently different from each other to be meaningful and cover a broad range of potential futures.

The key uncertainties that form the basis of scenarios should be those that are most impactful to resource selection, have been or are anticipated to be highly variable, and are difficult to predict with confidence. Through internal analysis and discussions at the first stakeholder meeting, the key variables selected as the foundation for scenario development were natural gas prices, carbon regulation, and the cost of renewable technologies. Once the key variables were determined, base case and alternate forecasts were developed for each and grouped into themes which align with a narrative describing a future world consistent with the forecasts of the key variables. To ensure internal consistency of the scenario, additional modeling was conducted to develop MISO power price projections consistent with the other input variables.

Duke Energy Indiana initially proposed three scenarios; the Reference Case based upon the corporate base case fundamentals forecasts, the High Tech Future scenario characterized by increased technological innovation and higher economic growth, and the Slower Innovation scenario characterized by decreased technological innovation and slower economic growth. After reviewing these scenarios with stakeholders, two additional scenarios were developed based upon stakeholder feedback; the Reference Case Scenario without Carbon Legislation, and a Current Conditions scenario which assumes the status quo or current trends persists in most input variables. A summary of the five scenarios is shown in the table below followed by more detailed descriptions throughout the remainder of this section.

Table IV.1: Scenario Assumption Summary

Scenario	Gas Price	Coal Price	Load Forecast	Carbon Price	Cost of Solar & Wind	Cost of EE	PTC & ITC
1) Slower Innovation	High	High	Low	None	High	High	Renewed
2) Reference Case	Mid	Mid	Mid	Mid	Mid	Mid	Expire
3) High Tech Future	Low	Low	High	High	Low	Low	Expire
4) Current Conditions	Market	Market	Mid	None	Mid	Mid	Expire
5) Reference Case, No Carbon	Mid	Mid	Mid	None	Mid	Mid	Expire

A. REFERENCE CASE SCENARIO

The Reference Case envisions many aspects and trends of the present persisting into the future. Load growth is moderate with an average annual growth rate of approximately 0.5% over the 20-year planning period. Technological innovation continues to drive down the cost of renewable resources and energy efficiency measures, increasing the economic competitiveness of these resources. Increases in the cost of oil, gas and coal are moderate, based on modest inflation expectations and incremental improvements in extraction technology and methods. Public opinion shows support for a response to climate change resulting in the imposition of a price on carbon emissions of $5/ton beginning in 2025, increasing by $3/ton per year thereafter. The lower capital costs for renewable projects and presence of a carbon price obviates any push to extend federal tax incentives for renewables resulting in their phase out in accordance with current policy.

Figure IV.1: Peak Load Forecast – Reference Case

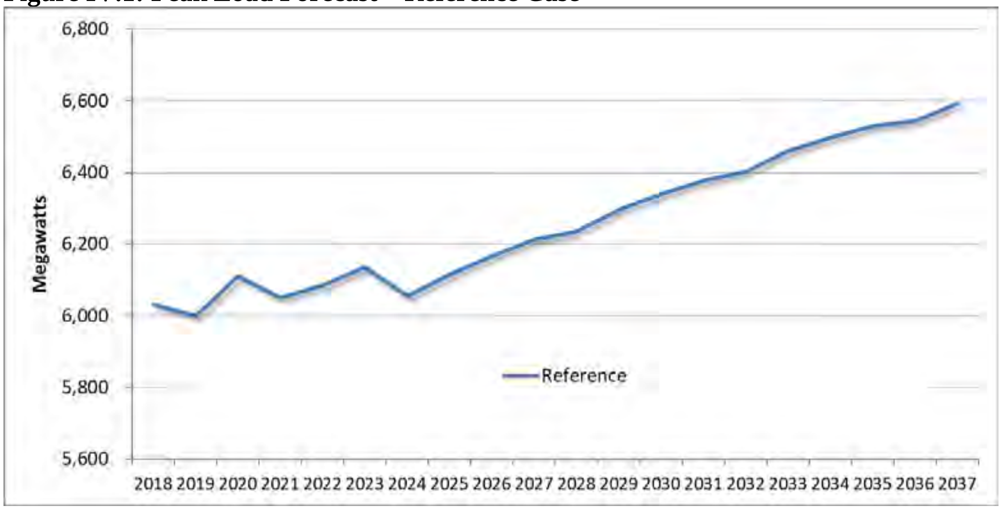


Figure IV.2: Annual Average Coal Price – Reference Case

[redacted]

Figure IV.3: Annual Average Gas Price – Reference Case

[redacted]

Figure IV.4: Carbon Price – Reference Case

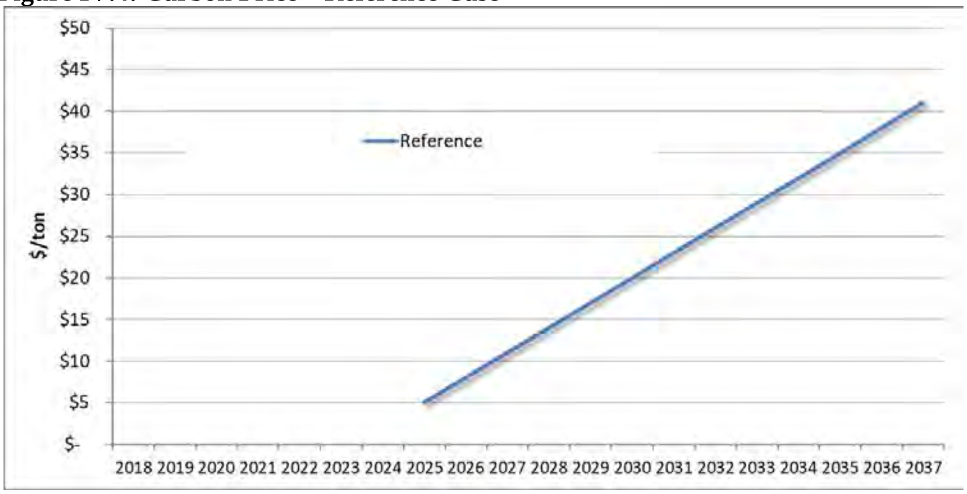


Figure IV.5: Annual Average Power Price – Reference Case

[redacted]

Figure IV.6: Installed Utility-Scale Solar Cost (including AFUDC) – Reference Case

[redacted]

Figure IV.7: Capacity Factor for new Wind – Reference Case

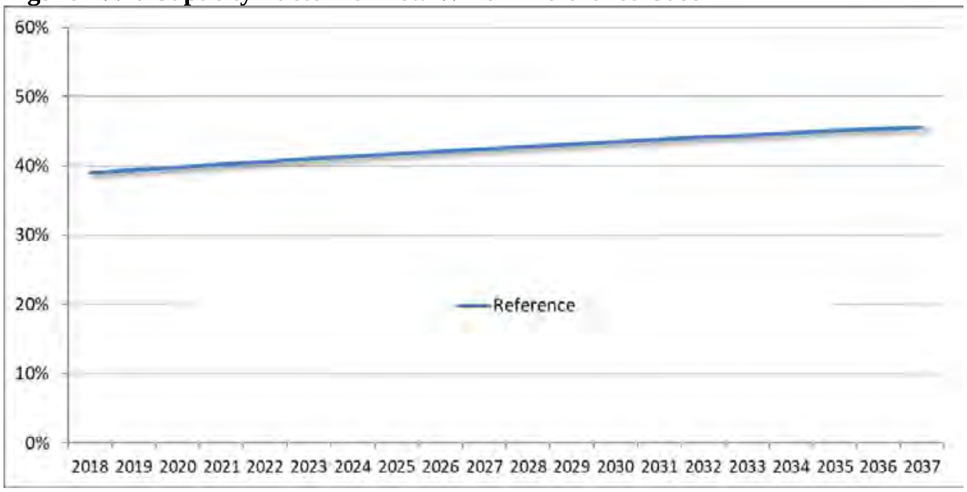


Figure IV.8: Installed Battery Cost (including AFUDC) – Reference Case

[redacted]

B. ALTERNATIVE SCENARIO: SLOWER INNOVATION

The Slower Innovation scenario is characterized by a reduction in the pace of technological advancement and slower economic activity. Reduced technological innovation moderates the cost declines for renewable resources and energy efficiency measures which in turn results in a continued dependence on fossil fuels for power generation and transportation. Higher ongoing demand for fossil fuels combined with higher resource extraction costs puts upward pressure on fuel prices which leads to higher overall energy prices including power prices. These higher energy costs dampen economic activity leading to a lower rate of load growth than the Reference Scenario. Reduced economic growth and high energy prices make a price on carbon politically unpalatable. Slower reductions in the capital costs for renewable projects lead to calls for the extension of federal tax incentives for renewables, which are extended through 2022.

Figure IV.9: Peak Load Forecast – Slower Innovation

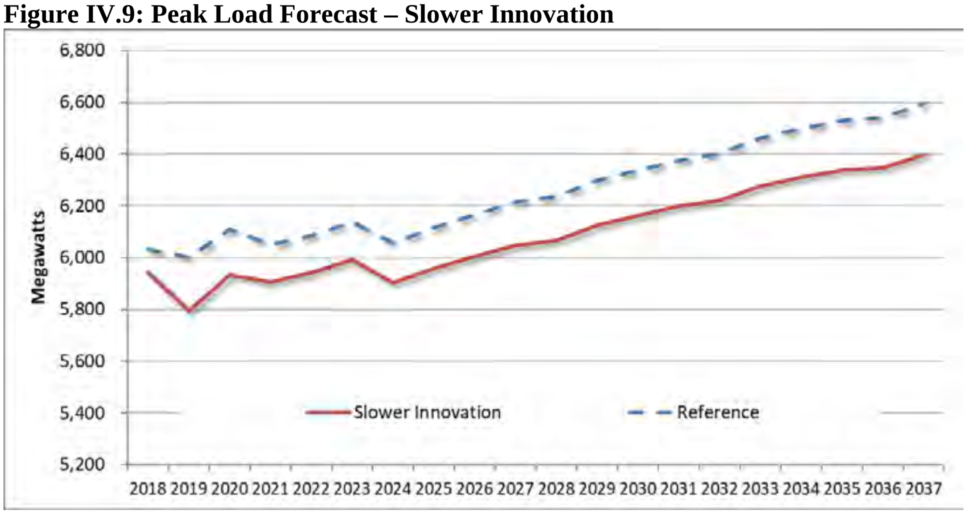


Figure IV.10: Annual Average Coal Price – Slower Innovation

[redacted]

Figure IV.11: Annual Average Gas Price – Slower Innovation

[redacted]

Figure IV.12: Carbon Price – Slower Innovation

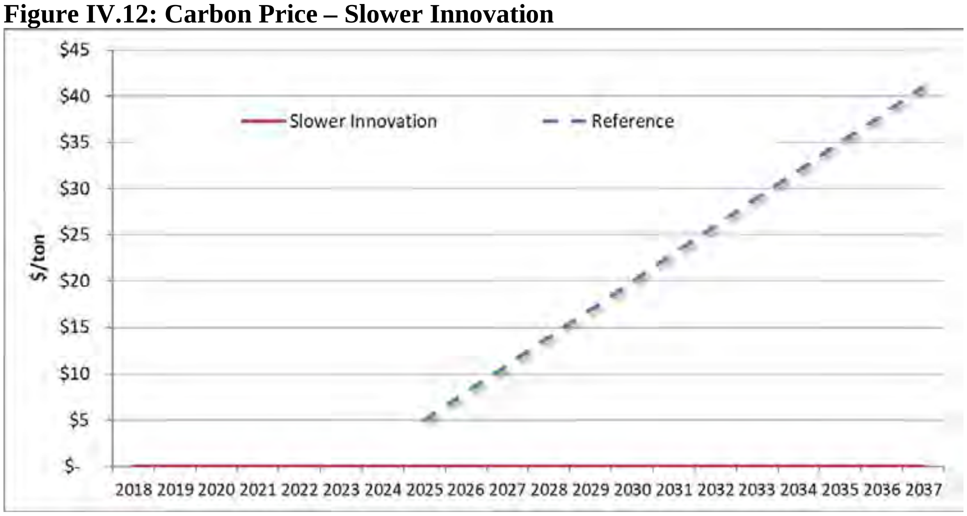


Figure IV.13: Annual Average Power Price – Slower Innovation

[redacted]

Figure IV.14: Installed Utility-Scale Solar Cost (including AFUDC) – Slower Innovation

[redacted]

Figure IV.15: Capacity Factor for new Wind – Slower Innovation

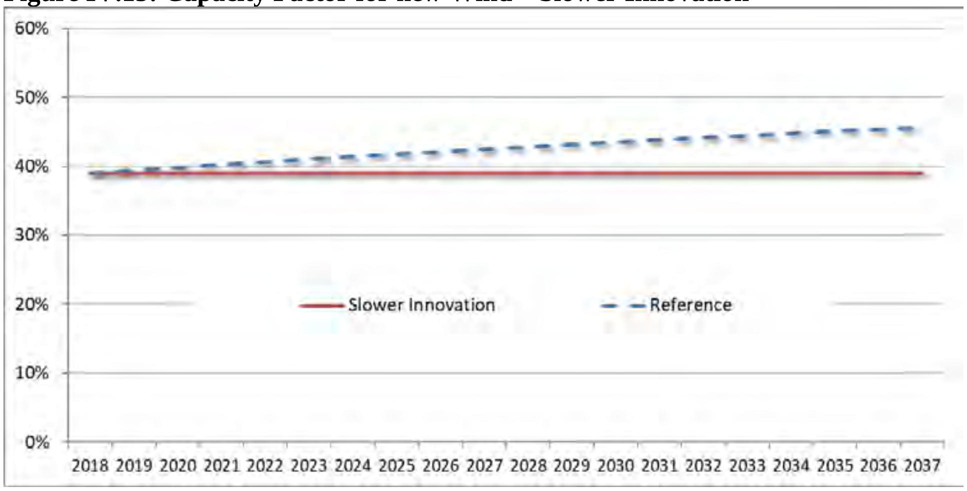


Figure IV.16: Installed Battery Cost (including AFUDC) – Slower Innovation

[redacted]

C. ALTERNATIVE SCENARIO: HIGH-TECH FUTURE

The High Tech Future scenario is characterized by increased levels of technological innovation that hasten the reduction in the cost of renewable resources and energy efficiency measures while also holding down the cost of oil, gas and coal extraction. Load growth is higher than the Reference Scenario as technology gains and lower cost energy spur economic growth. As in the Reference Case, public opinion shows support for a response to climate change which, coupled with lower energy prices, leads to the imposition of a more aggressive price on carbon emissions starting in 2025. Lower capital costs for renewable projects and the presence of a higher carbon price provide significant support for deployment of renewables, mitigating the need for further extension of federal tax credits.

Figure IV.17: Peak Load Forecast – High Tech Future

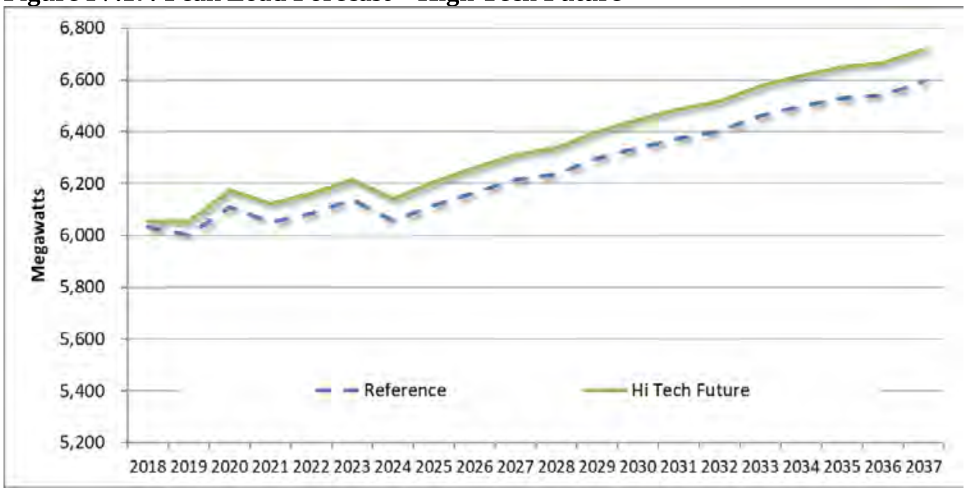


Figure IV.18: Annual Average Coal Price – High Tech Future

[redacted]

Figure IV.19: Annual Average Gas Price – High Tech Future

[redacted]

Figure IV.20: Carbon Price – High Tech Future

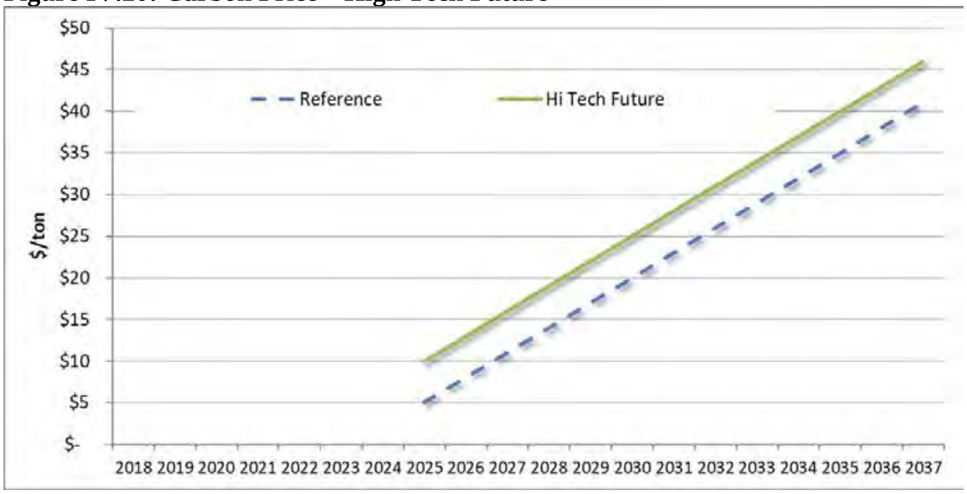


Figure IV.21: Annual Average Power Price – High Tech Future

[redacted]

Figure IV.22: Installed Utility-Scale Solar Cost (including AFUDC) – High Tech Future

[redacted]

Figure IV.23: Capacity Factor for new Wind – High Tech Future

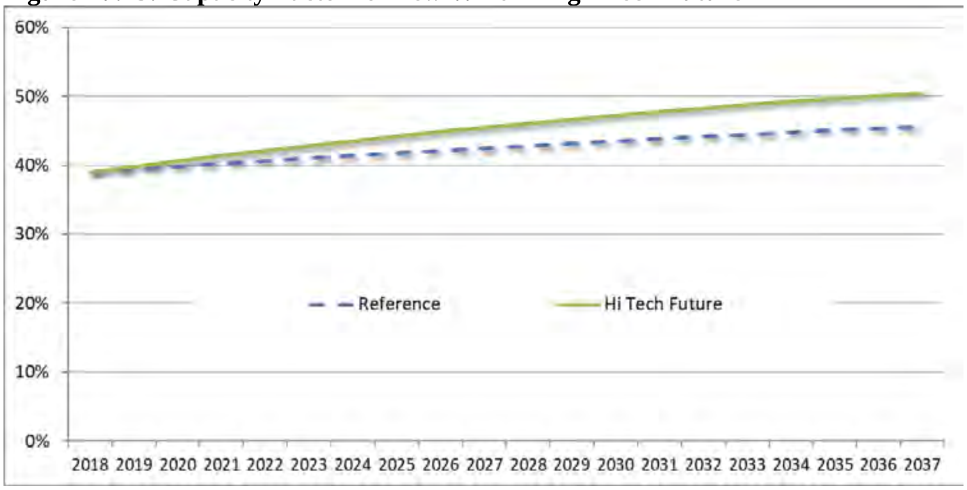


Figure IV.24: Installed Battery Cost (including AFUDC) – High Tech Future

[redacted]

D. ALTERNATIVE SCENARIO: CURRENT CONDITIONS PERSIST

The Current Conditions Case utilizes the same values as the Reference Case for load, renewables cost and capacity factor, and EE cost trends. The changes to Reference Case scenario inputs are the extrapolation of fuel prices from current market curves as well as removal of future carbon legislation. Power prices are projected using MISO market forward curves for five years, then calculated from that point by utilizing the Current Conditions natural gas price extrapolation and implied market heat rate calculated from the observable forward market curves. Tax credits for renewables phase out in accordance with current policy. The charts below show the Current Conditions fuel and power prices. For all other inputs, refer to the Reference Case charts.

Figure IV.25: Annual Average Coal Price – Current Conditions

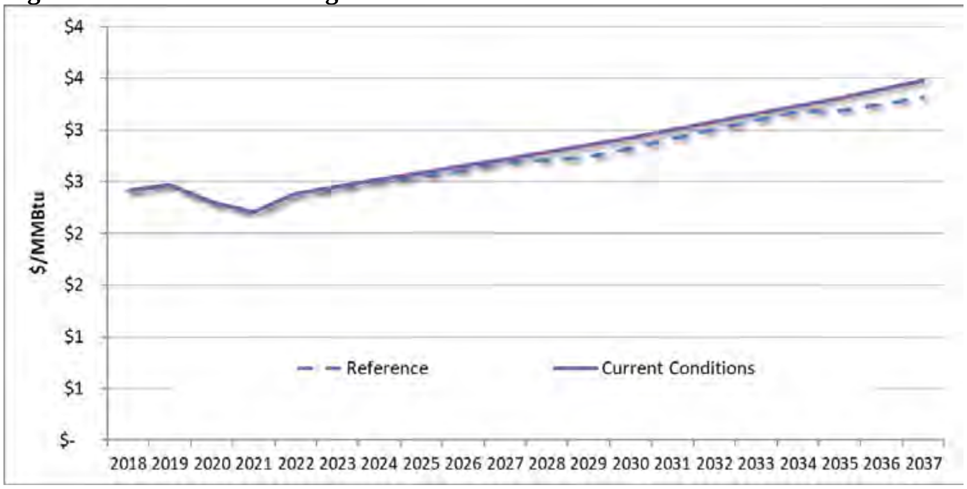


Figure IV.26: Annual Average Gas Price – Current Conditions

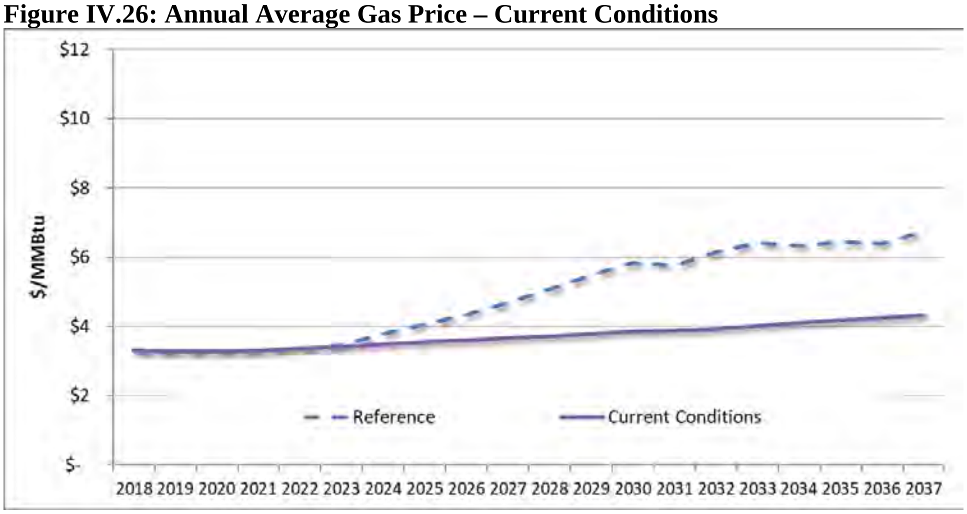
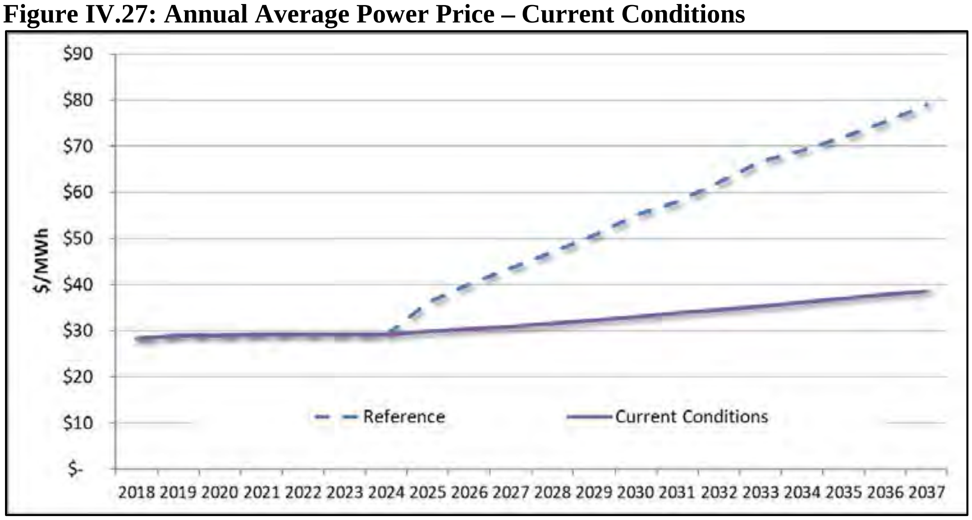


Figure IV.27: Annual Average Power Price – Current Conditions



E. REFERENCE CASE WITHOUT CARBON LEGISLATION

The Reference Case without Carbon Legislation scenario utilizes the same values as the Reference Case for load, fuel, renewables and EE cost trends. The only change to scenario inputs is the removal of future carbon legislation. This change is further reflected in the modeled MISO power prices. This scenario clearly demonstrates the impact of the presence or absence of a price on carbon emissions, assuming all other inputs remain fixed. The chart below shows the difference in MISO power prices resulting from the removal of the carbon price. For all other inputs, refer to the Reference Case charts. Tax credits for renewables phase out in accordance with current policy.

Figure IV.28: Annual Average Power Price – Reference Case without Carbon Legislation

[redacted]

SECTION V: CANDIDATE RESOURCE PORTFOLIOS

This section includes descriptions and analysis of the resource portfolios we evaluated for the 2018 IRP. These include the optimized portfolios, each of which is designed to minimize costs under a particular scenario, and the alternative portfolios, which are designed to improve upon the optimized portfolios and balance our objectives in ways that SO cannot. The first part of this section is a detailed list of the resource types available for selection in the IRP.

A. OBJECTIVES OF THE 2018 IRP

The major objectives of the IRP presented in this filing, developed with input from Duke Energy Indiana stakeholders, are:

- Provide adequate, reliable, efficient, economic service. The metric for this objective is PVRR.
- Maintain the flexibility and ability to alter the plan in the future as circumstances change. All else being equal, portfolios that include more, larger, singular resource decisions are less flexible.
- Minimize environmental impact, including carbon emissions. Because carbon emissions are highly correlated with other environmental impacts, the metric for this objective is annual CO_2 emissions.
- Minimize risk. The most pressing risk factors for this IRP, as determined in consultation with stakeholders, are reliability risk, compliance and cost risk associated with potential carbon legislation, and cost risk associated with over-reliance on net energy purchases from the MISO market. Reliability is addressed via the inclusion of the planning reserve margin requirement in portfolio development, carbon risk is addressed by the inclusion of a carbon price in two of the scenarios for this IRP, and the metric for market risk is the portion of total annual energy demand that is met with market purchases.

B. CANDIDATE RESOURCES FOR THE 2018 IRP

Supply-Side Resources

Based on the technical and commercial availability screening described in Section II.C, the following technologies were excluded from consideration in this IRP: small modular nuclear reactors, solar steam augmentation, fuel cells, supercritical CO2 Brayton cycle, and liquid air energy storage, geothermal, offshore wind, landfill gas, pumped storage hydropower, and compressed air energy storage.

The Company considered for inclusion in this IRP a diverse range of technologies utilizing a variety of different fuels, including pulverized coal units, CTs, CCs, combined heat and power, reciprocating engines, and nuclear stations. In addition, onshore wind, solar photovoltaic, and battery storage options were included in the analysis. Table V.1 below provides an overview of the characteristics of the supply-side resources available for selection in this IRP. Further detail can be found in Appendix C.

Table V.1: Unit Characteristics for Potential Supply-Side Resource Additions

		Natural Gas				Coal			Renewables		
Costs	**Units**	**CT[5]**	**CC**	**Recip[6]**	**CHP[7]**	**Ultra-Supercritical**	**IGCC**	**Nuclear**	**Wind**	**Solar[8]**	**Battery Storage**
Total Capital Cost ($2018)[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
First Year Unit is Available		2023	2024	2023	2023	2026	2026	2028	2020	2019	2019
Fixed Charge Rate (real, levelized)		7.9%	8.0%	7.6%	6.9%	7.1%	7.9%	6.9%	9.1%	6.9%	10.6%
Capital Cost Inflation Rate (nominal)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M Cost ($2018)[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Cost ($2018)[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Characteristics											
Maximum Load											
Winter	MW	927	1,339	202	22	850	620	2,234	150	50	5
Summer	MW	858	1,239	202	16	850	620	2,234	150	50	5
Contribution to Peak	% Summer MW	100%	100%	100%	100%	100%	100%	100%	13%	50%	80%
Minimum Load[4]											
Winter	MW	438	247	7	11	310	217	N/A	N/A	N/A	N/A
Summer	MW	338	157	7	8	310	217	N/A	N/A	N/A	N/A
Heat Rate											
Winter	Btu/kWh	9,720	6,688	8,430	10,150	8,750	9,050	10,130	N/A	N/A	N/A
Summer	Btu/kWh	10,080	6,701	8,470	11,170	8,750	9,050	10,130	N/A	N/A	N/A
Outage Rates											
Planned		3.0%	6.9%	1.8%	2.0%	8.9%	12.0%	3.0%	2.5%	1.0%	1.5%
Unplanned		2.0%	4.6%	3.5%	1.3%	6.6%	8.0%	4.0%	2.5%	1.0%	1.5%
Emissions Rates[2]											
NO_X	lb/MWh	0.323	0.048	0.138	0.056	0.350	0.244	0.00	0.00	0.00	0.00
SO_2	lb/MWh	0.020	0.014	0.017	< 0.02	0.175	0.272	0.00	0.00	0.00	0.00
CO_2	lb/MWh	1,210	820	1,016	1,340	1,794	1,855	0.00	0.00	0.00	0.00

Note: the general rate of inflation is assumed to be 2.5% per year
** See Chapter IV for construction cost escalation curves for solar and battery storage
1 Based on summer maximum load; includes interconnection cost and allowance for funds used during construction
2 Based on summer heat rate
3 Includes cost of firm gas transmission for CC and CHP
4 Applicable for dispatchable technologies only
5 Block of 4 combustion turbines
6 Block of 12 reciprocating engines
7 CHP model assumptions include steam sales at $10 per thousand pounds
8 Single-axis tracker
9 Cost at full load, including duct firing
10 With every 800 MW of solar capacity added to the system, VOM increases by $5/MWh to reflect additional ancillary service costs associated with high solar penetration
11 Includes accrual of funds for replacement of battery once during 15-year project life

In addition to the characteristics listed in the table above, we imposed certain constraints on the model governing when certain resources could be added or retired and how much of each resource could be constructed in each year. The following limitations were imposed:

- No unit was permitted to retire before 2024. This reflects the time it would take for the company to prepare to take a unit offline (including any regulatory filings and design, permitting, and construction of replacement resources), as well as make any required transmission upgrades. The exception is the retirement of Gallagher Units 2&4 in December 2022, to which we are already committed, and for which we have already conducted the necessary up-front preparations. The Gallagher retirement is part of all portfolios considered for the IRP. In addition, Edwardsport IGCC was not considered for retirement in this IRP. The plant is the newest on our system and has the longest estimated life (2045), well past the review period in this IRP. The plant has successfully improved operations over the past several years and going forward will be focused on reducing its ongoing maintenance costs. A diversified portfolio will continue to be a priority with Edwardsport IGCC contributing to the fleet's diversity over the planning period.

- Retirement analysis was conducted only on the coal units. Other units were not considered for economic retirement.
- The SO model is permitted to add fractions of nuclear, coal, CC and CT units to allow us to better understand how the timing of resource needs is distributed and to reflect our ability to partner with other entities on new generating stations.
- Annual capacity additions for each resource type are capped to reflect practical constraints. The caps are: 2,120 MW of ultra-supercritical coal, 2,070 MW of IGCC, 840 MW of nuclear, 3,100 MW of CC, 3,225 MW of CT, 80 MW of CHP, 1,212 MW of reciprocating engines, 2,500 MW of solar, 250 MW of wind, and 250 MW of batteries.
- The time required to permit and construct each unit type is reflected in the first year available shown in Table V.1.
- A variable operating cost of $5/MWh is imposed on solar additions over 800 MW of nameplate capacity. This reflects our estimate of the additional cost of operating the system with a high penetration of solar resource. The cost is increased by $5/MWh for each additional 800 MW tranche of solar.
- Solar and wind resources contribute to meeting the planning reserve margin requirement at less than nameplate capacity, reflecting the fact that these resources may not be fully available at the time of peak load. Solar is counted at 50% of nameplate capacity (0% in winter) and wind at 13%, which is consistent with MISO's treatment of these resource types. Battery storage is valued at 80% of installed capacity to reflect the possibility that the battery may not be fully charged at the peak hour.

Demand-Side Resources

For the purposes of the 2018 IRP, the Company developed 150 sub-portfolios of EE programs (also referred to as "bundles"). These bundles were designed to be treated as demand-side resource options for selection by the IRP process and EE measures were grouped together in these bundles based on the hourly shape of the savings contributed by these measures. For each of these hourly shapes, three different levels of customer participation, a Base Case, a High Case, and an Extra-High Case, were created. In order to reduce the amount of time required for analyzing the overall portfolio of bundles, the Company further consolidated the 150 bundles into a final group of 70 bundles. The consolidation was done by combining together the Base, High and Extra-High cases for certain bundles of hourly shapes where the incremental amounts of the High and Extra-High cases were not large compared to the Base Case. These bundles were available for selection in the SO model alongside the supply-side resource options. Additional details on demand-side resources, bundles and the screening process for demand-side resources are available in Appendix D.

Resource Decisions Common to All Portfolios

Certain resource decisions to which the Company had committed prior to the completion of this IRP analysis are included in all portfolios. These are:

- Retirement of Gallagher Units 2&4 in December 2022
- EE programs through 2020 as approved under Cause No. 43955 DSM-4
- 16 MW CHP project with planned completion in 2021
- 6 MW of solar added in 2019 and 2 MW in 2020
- 10 MW of battery storage added in 2019 and 5 MW added in 2020
- 100 MW Benton County wind PPA expires in 2028
- 21 MW of solar PPAs expire in 2036
- Contracted purchase of 8 MW of CT capacity ends in 2019
- Contracted sale of 50 MW of CT capacity at Henry County ends in 2022
- Demand response is not selected by the model. DR additions are forecasted and the forecast is consistent across all portfolios

C. OPTIMIZED RESOURCE PORTFOLIOS

Recall that an optimized portfolio is designed to be least cost under the assumptions of a specific scenario. Those scenario assumptions are the inputs to the SO model, which selects resource additions and retirements to minimize the PVRR for the portfolio while meeting the planning reserve margin requirement. There are five optimized portfolios, one for each IRP scenario.

Reference Case

The most impactful assumption included in the Reference Case scenario is that a price is imposed on carbon emissions starting in 2025, and that the price increases through the remainder of the period. In response to this measure, the portfolio optimized for the Reference Case scenario includes two coal unit retirements beyond the Gallagher retirements that are already scheduled, as well as the addition of substantial solar power capacity beginning in 2028. However, the carbon price is not high enough, nor the gas price forecast low enough to warrant the addition of a gas-fired combined-cycle generator. Figure V.1 and Table V.2 below describe the capacity mix over time for this portfolio.

Figure V.1: Capacity (contribution to peak) mix by year for portfolio optimized to Reference Case scenario

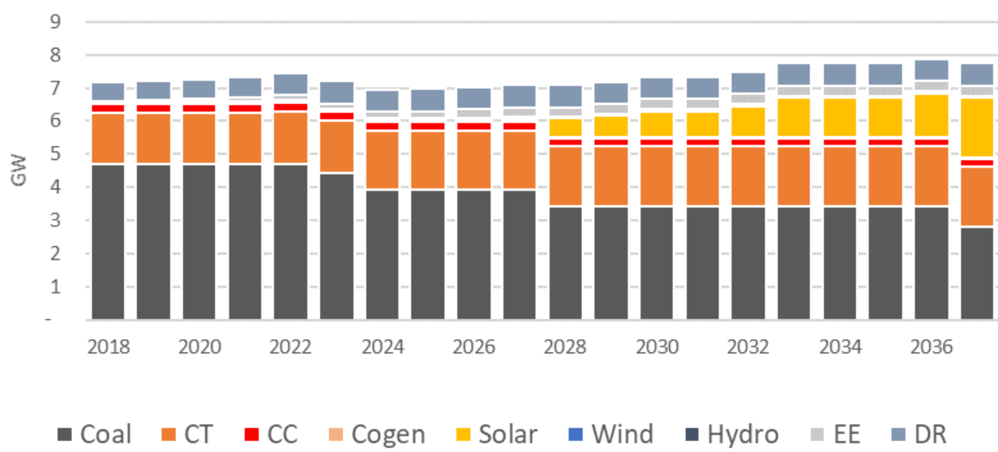


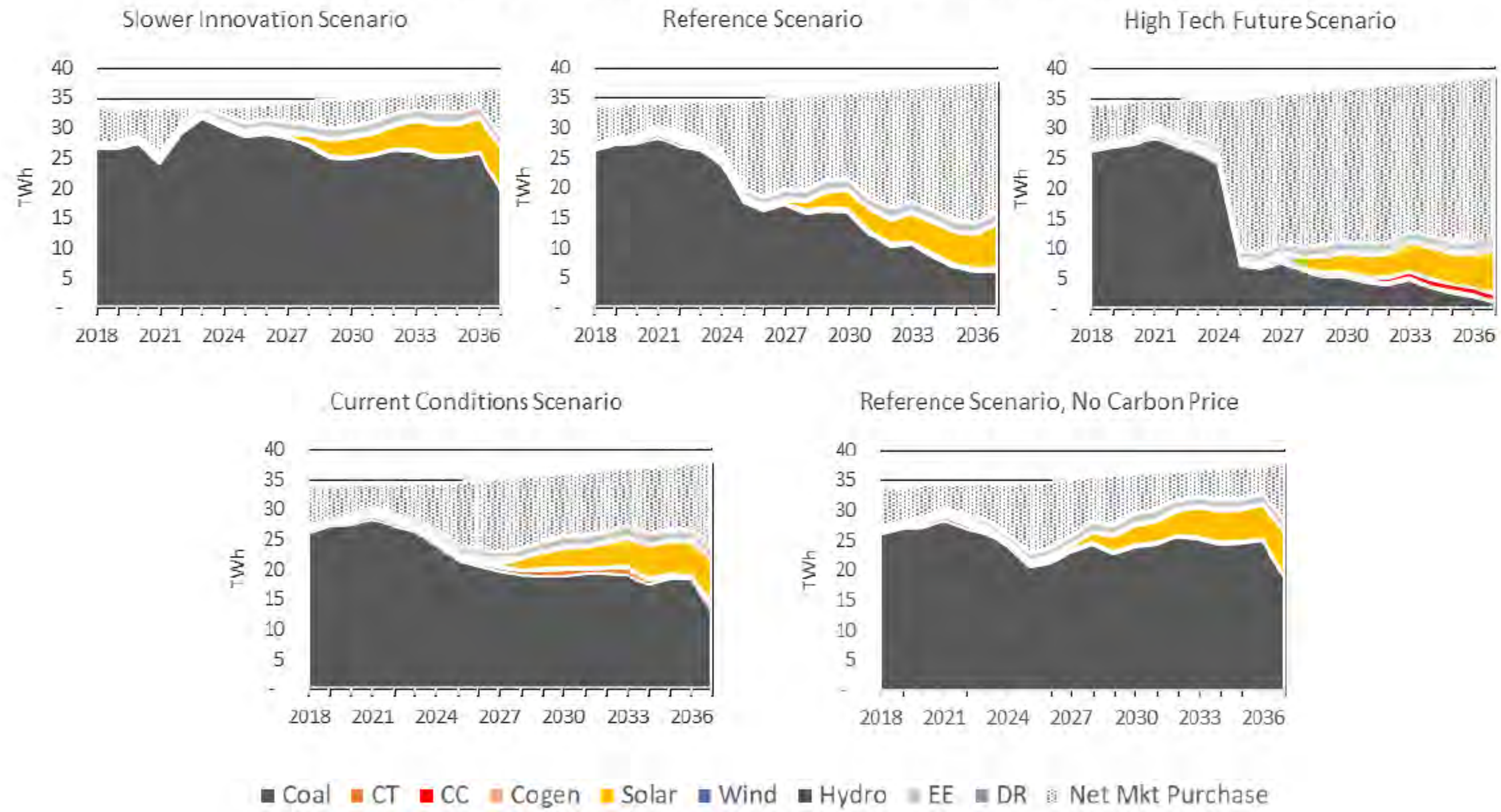
Table V.2: Capacity (nameplate MW) additions by year for portfolio optimized to Reference Case scenario

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	26			
2022	0	50	0	0	0	0	22	29			
2023	0	0	0	0	0	0	21	28	Gallager 2&4	Coal	280
2024	0	215	0	0	0	0	(1)	31	Cayuga 1	Coal	500
2025	0	0	0	0	0	0	0	32			
2026	0	0	50	0	0	0	1	26			
2027	0	0	50	0	0	0	0	26			
2028	0	0	1,000	(100)	0	0	0	19	Cayuga 2	Coal	495
2029	0	0	150	0	0	0	0	14			
2030	0	0	300	0	0	0	0	6			
2031	0	0	0	0	0	0	1	(1)			
2032	0	0	300	0	0	0	0	6			
2033	0	0	500	0	0	0	0	7			
2034	0	0	0	0	0	0	0	(1)			
2035	0	0	0	0	0	0	1	(7)			
2036	0	0	279	0	0	0	0	(6)			
2037	0	0	1,000	0	0	0	0	(5)	Gibson 4	Coal	622

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

As discussed in Section II, the next step after developing the portfolio is to estimate how it would operate under each of the IRP scenarios using the PAR model. The portfolio optimized for the Reference Case scenario relies largely on coal generation in scenarios that do not assume a price on carbon emissions (Slower Innovation, Current Conditions, and Reference Without a Carbon Price), but in scenarios that assume a price on carbon (Reference Case, High Tech Future), the capacity factors of the coal units fall. Because no additional capacity from other resources was selected for this portfolio, the MISO market provides a substantial portion of total energy in scenarios where coal is less economic. This is particularly true in the High Tech Future scenario, which includes a relatively high price on carbon emissions. Generation from the added solar capacity, which has very low variable cost, is the same across all scenarios. Figure V.2 shows the energy mixes over time from this portfolio under each of the IRP scenarios.

Figure V.3: Energy mix by year under all five scenarios for portfolio optimized to Reference Case scenario



Slower Innovation

The Slower Innovation scenario assumes a future with higher fuel prices than in the Reference Case, slower cost declines for renewable resources, and no price on carbon emissions. The portfolio optimized for this future is not very different from the portfolio as it exists today. In a future with higher gas prices and no price on carbon, the existing coal assets remain cost-effective throughout the period and load growth is met with the addition of some solar capacity in the mid-2030s.

Figure V.4: Capacity (contribution to peak) mix by year for portfolio optimized to Slower Innovation scenario

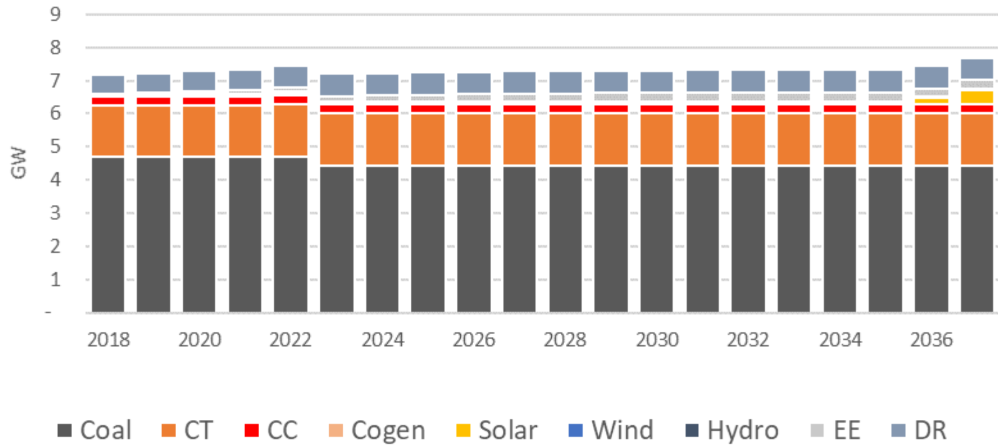


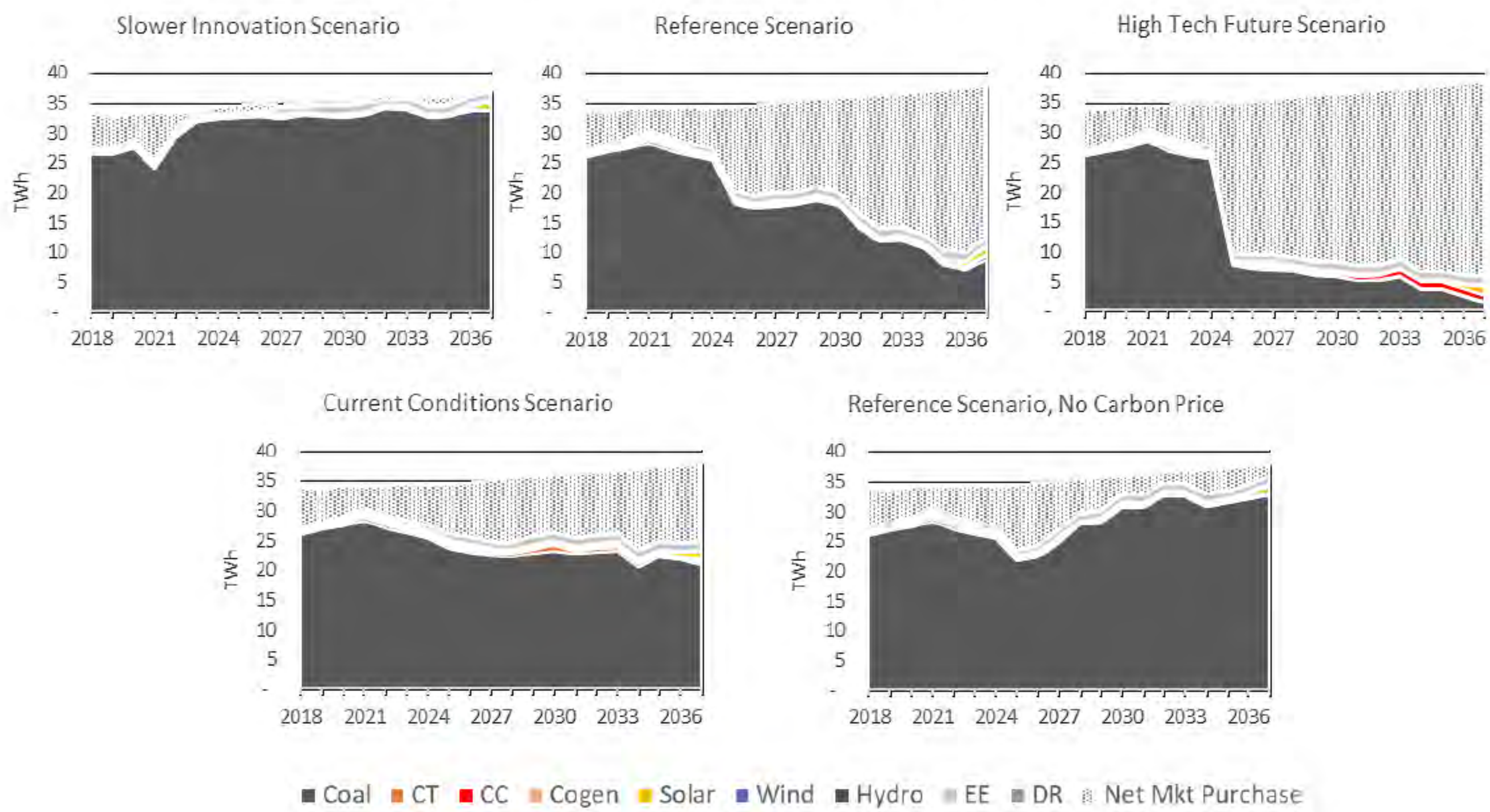
Table V.3: Capacity (nameplate MW) additions by year for portfolio optimized to Slower Innovation scenario

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	23			
2022	0	50	0	0	0	0	22	22			
2023	0	0	0	0	0	0	21	22	Gallager 2&4	Coal	280
2024	0	0	0	0	0	0	(1)	23			
2025	0	0	0	0	0	0	0	21			
2026	0	0	0	0	0	0	1	19			
2027	0	0	0	0	0	0	0	20			
2028	0	0	0	(100)	0	0	0	17			
2029	0	0	0	0	0	0	0	12			
2030	0	0	0	0	0	0	0	5			
2031	0	0	0	0	0	0	1	1			
2032	0	0	0	0	0	0	0	4			
2033	0	0	0	0	0	0	0	5			
2034	0	0	0	0	0	0	0	(1)			
2035	0	0	0	0	0	0	1	(6)			
2036	0	0	279	0	0	0	0	(7)			
2037	0	0	500	0	0	0	0	(1)			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

The portfolio optimized for the Slower Innovation scenario remains weighted towards coal-fired generating capacity throughout the planning period. In scenarios that have no price on carbon emissions, coal-fired generation supplies over half of total energy in all years. However, coal capacity factors do decline in the Current Conditions scenario as lower gas prices challenge the competitiveness of coal in many hours and there is a gradual shift toward purchasing lower cost energy from the MISO market. In the scenarios that include a price on carbon, the coalheavy fleet is much less competitive and the shift towards energy supplied by the market is more dramatic. Note that in the High Tech Future scenario, which includes both a relatively high price on carbon emissions and a lower forecast for gas prices, coal is almost driven out of the energy mix entirely with the market making up the difference.

Figure V.5: Energy mix by year under all five scenarios for portfolio optimized to Slower Innovation scenario



High Tech Future

The High Tech Future scenario describes a world with lower gas prices than in the Reference Case, more rapidly declining costs for renewable resources, and a higher price on carbon emissions. The portfolio optimized for this scenario includes the retirement of all conventional coal-fired generation by the early 2030s and the replacement of that capacity with a combination of gas-fired combined-cycle units and solar power.

Figure V.6: Capacity (contribution to peak) mix by year for portfolio optimized to High Tech Future scenario

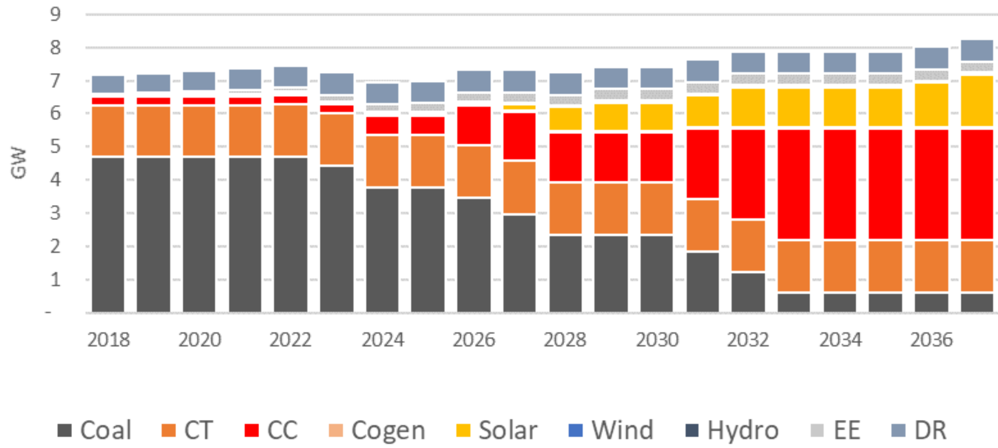


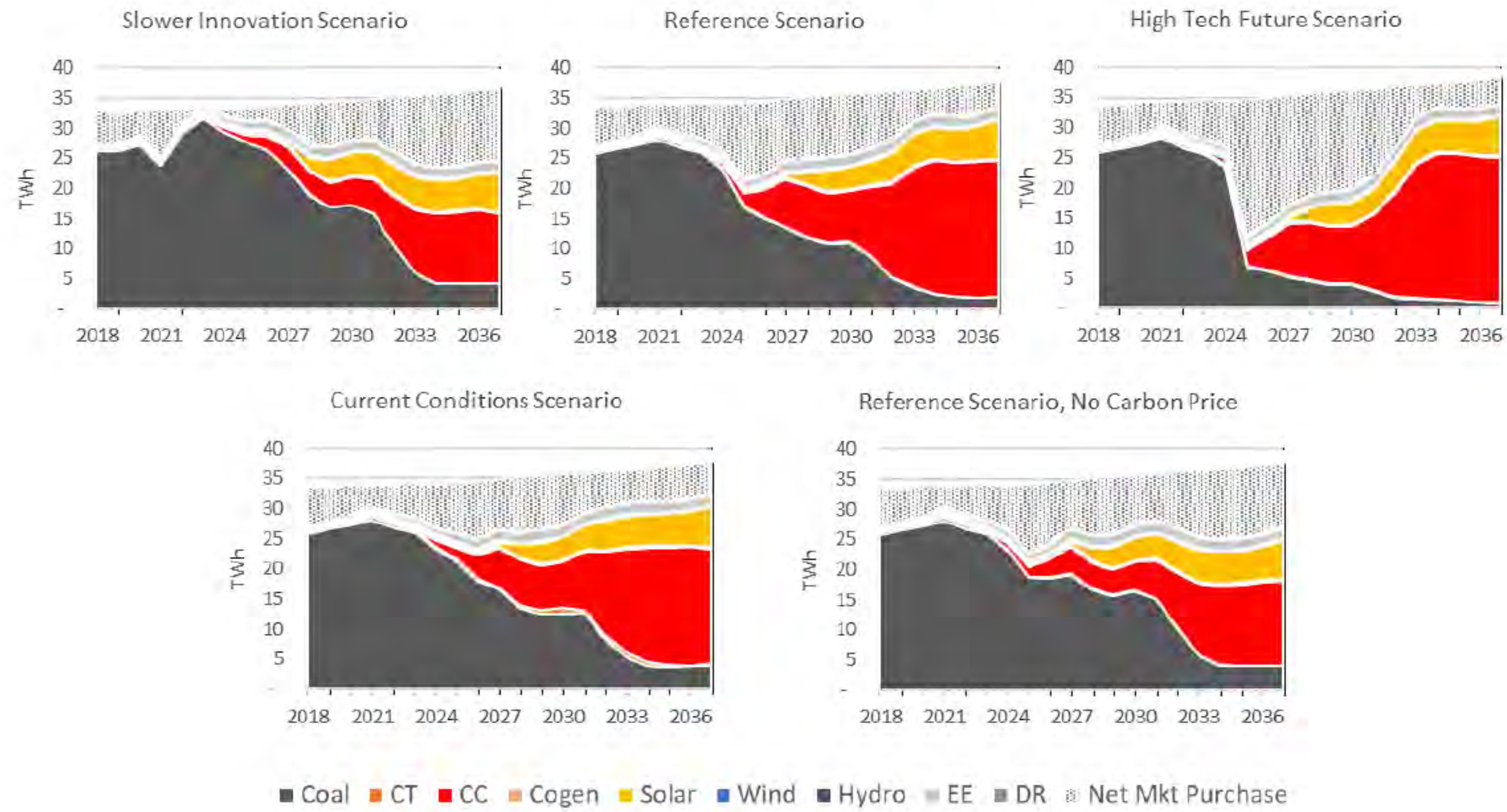
Table V.4: Capacity (nameplate MW) additions by year for portfolio optimized to High Tech Future scenario

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	30			
2022	0	50	0	0	0	0	22	37			
2023	0	0	0	0	0	0	21	35	Gallager 2&4	Coal	280
2024	310	0	0	0	0	0	(1)	39	Gibson 3	Coal	630
2025	0	0	0	0	0	0	0	37			
2026	620	0	0	0	0	0	1	30	Gibson 5	Coal	310
2027	310	0	300	0	0	0	0	27	Cayuga 1	Coal	500
2028	0	0	1,100	(100)	0	0	0	21	Gibson 2	Coal	630
2029	0	0	300	0	0	0	0	14			
2030	0	0	0	0	0	0	0	5			
2031	620	0	200	0	0	0	1	(4)	Cayuga 2	Coal	495
2032	620	0	500	0	0	0	0	4	Gibson 1	Coal	630
2033	620	0	0	0	0	0	0	6	Gibson 4	Coal	622
2034	0	0	0	0	0	0	0	(2)			
2035	0	0	0	0	0	0	1	(8)			
2036	0	0	279	0	0	0	0	(6)			
2037	0	0	500	0	0	0	0	(6)			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

The combined-cycle generation added to the portfolio optimized for the High Tech Future scenario is competitive in scenarios where coal is not, helping to limit market exposure. In Slower Innovation and Reference Scenario, No Carbon Price, which feature higher gas prices than the High Tech Future and no price on carbon emissions, the portfolio optimized for the High Tech Future scenario leans more heavily on energy purchased from the market than do portfolios that retain more coal. Again, the energy from the added solar does not vary by scenario because solar costs are largely fixed, not variable.

Figure V.7: Energy mix by year under all five scenarios for portfolio optimized to High Tech Future scenario



Current Conditions

The Current Conditions scenario is characterized by low gas prices and no legislation restricting carbon emissions. The portfolio optimized for this scenario is very similar to that optimized for the Slower Innovation scenario in that it involves very little change from today. The primary difference is the addition of CT capacity in 2033 to meet load growth, whereas the higher gas prices in Slower Innovation make solar a more cost-effective way of serving new load in that scenario.

Figure V.8: Capacity (contribution to peak) by year for portfolio optimized to Current Conditions scenario

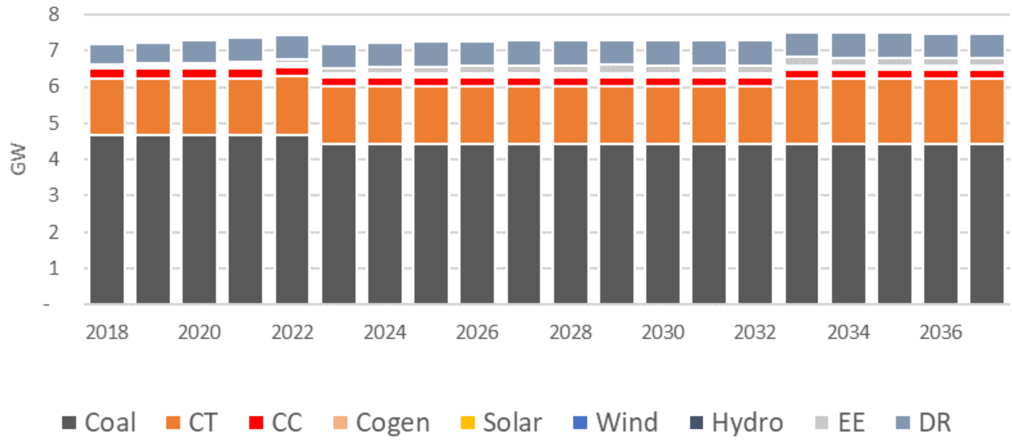


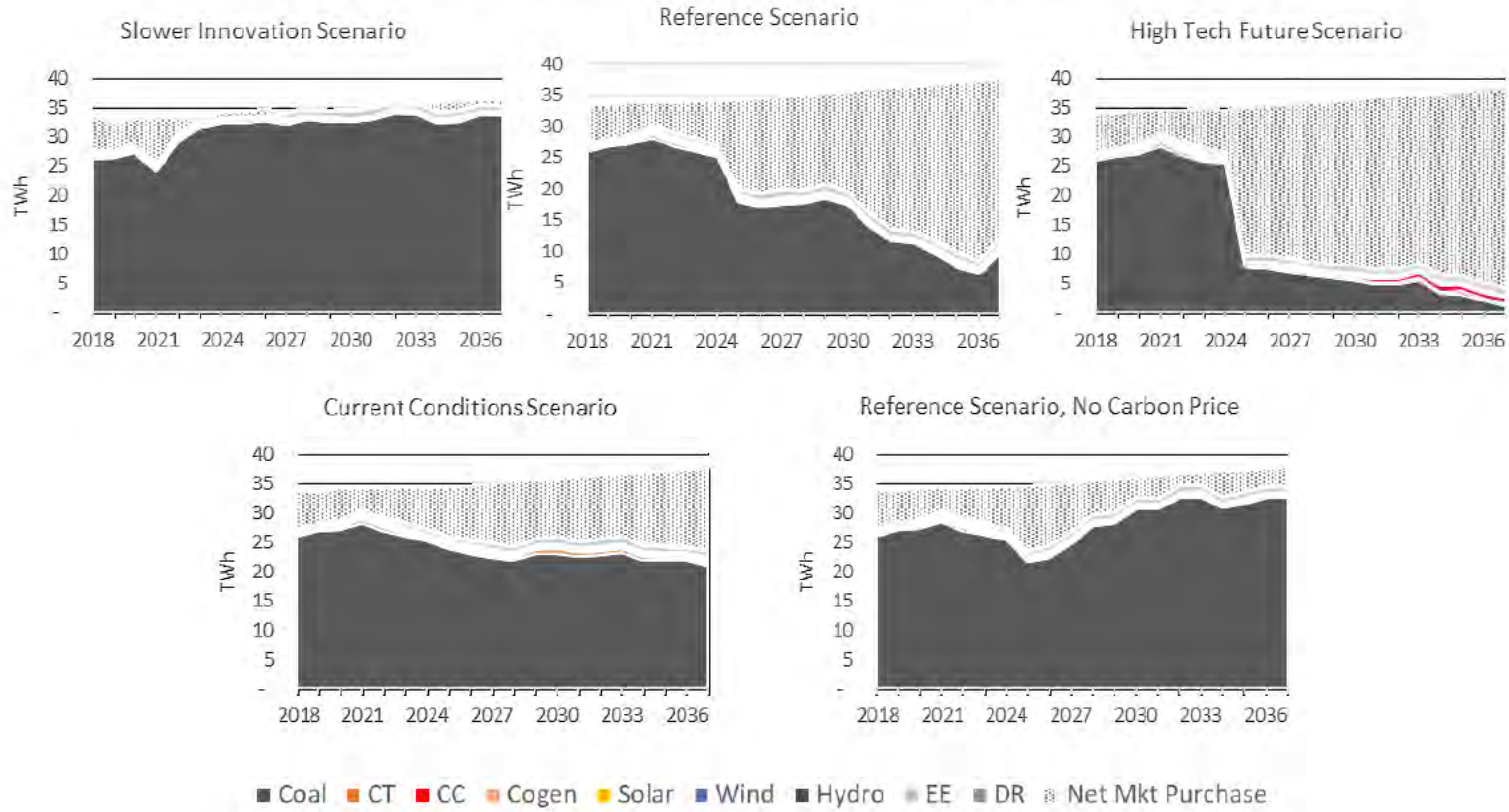
Table V.5: Capacity (nameplate) additions by year for portfolio optimized to Current Conditions scenario

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	21			
2022	0	50	0	0	0	0	22	19			
2023	0	0	0	0	0	0	21	19	Gallager 2&4	Coal	280
2024	0	0	0	0	0	0	(1)	23			
2025	0	0	0	0	0	0	0	24			
2026	0	0	0	0	0	0	1	21			
2027	0	0	0	0	0	0	0	16			
2028	0	0	0	(100)	0	0	0	10			
2029	0	0	0	0	0	0	0	5			
2030	0	0	0	0	0	0	0	(2)			
2031	0	0	0	0	0	0	1	(5)			
2032	0	0	0	0	0	0	0	0			
2033	0	215	0	0	0	0	0	5			
2034	0	0	0	0	0	0	0	(3)			
2035	0	0	0	0	0	0	1	(5)			
2036	0	0	(21)	0	0	0	0	(4)			
2037	0	0	0	0	0	0	0	0			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

The portfolio optimized for the Current Conditions scenario remains dependent on coal as the primary energy source. In scenarios where the economics of coal are challenged, the capacity factors of the coal units fall and the amount of energy purchased from the market increases. In the High Tech Future scenario, this portfolio would result in the Company looking to the market to supply almost 90% of the total energy need by the end of the planning period.

Figure V.9: Energy mix under all five scenarios for portfolio optimized to Current Conditions scenario



Reference Case Without Carbon Legislation

Legislative action imposing a price on carbon emissions is one of the most impactful assumptions we consider in this IRP. For this reason, we created a portfolio optimized for a scenario identical to our Reference Case scenario in all respects except for the carbon price. The portfolio optimized for the Reference Case Without Carbon Legislation is very similar to the portfolio optimized for the Slower Innovation scenario, with few changes until the end of the planning period when some solar capacity is added to serve new load. One significant difference is the retirement of Cayuga 2 in 2037, the final year of the planning period. Recall that gas prices are lower in the Reference Case Without Carbon Legislation than they are in Slower Innovation.

Figure V.10: Capacity (contribution to peak) by year for portfolio optimized to Reference Case Without Carbon Legislation

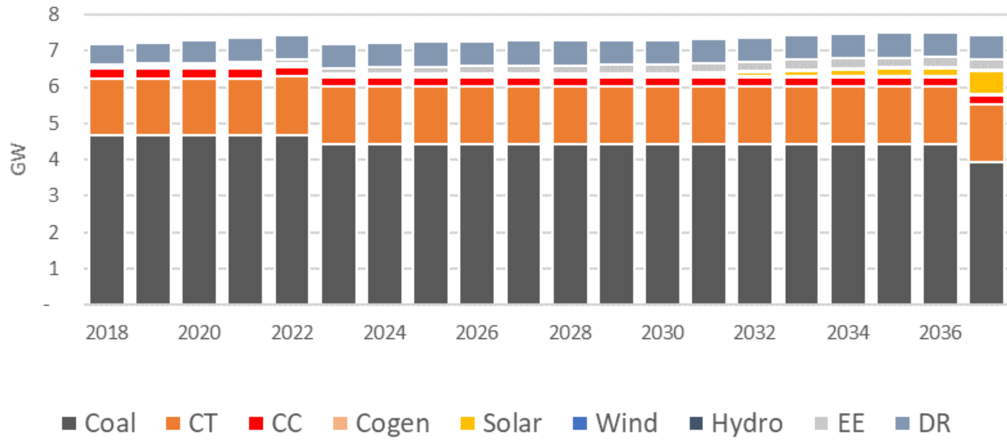


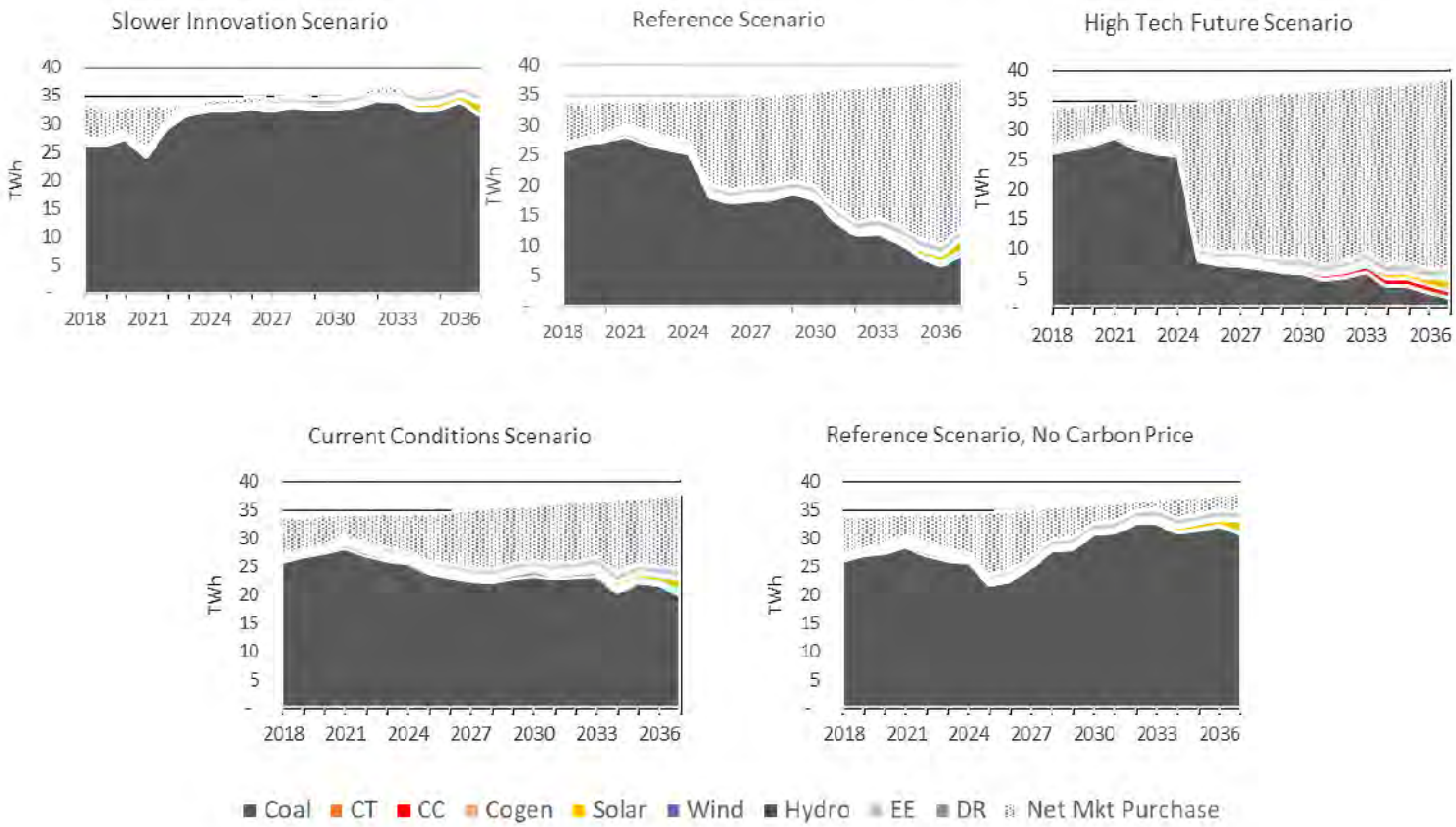
Table V.6: Capacity (nameplate MW) additions by year for portfolio optimized to Reference Case Without Carbon Legislation

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	21			
2022	0	50	0	0	0	0	22	19			
2023	0	0	0	0	0	0	21	19	Gallager 2&4	Coal	280
2024	0	0	0	0	0	0	(1)	22			
2025	0	0	0	0	0	0	0	21			
2026	0	0	0	0	0	0	1	19			
2027	0	0	0	0	0	0	0	18			
2028	0	0	0	(100)	0	0	0	15			
2029	0	0	0	0	0	0	0	9			
2030	0	0	0	0	0	0	0	2			
2031	0	0	100	0	0	0	1	(1)			
2032	0	0	50	0	0	0	0	7			
2033	0	0	100	0	0	0	0	10			
2034	0	0	50	0	0	0	0	4			
2035	0	0	50	0	0	0	1	(1)			
2036	0	0	29	0	0	0	0	2			
2037	0	0	850	0	0	0	0	3	Cayuga 2	Coal	495

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

This portfolio operates very similarly to the other portfolios that retain all or most of the existing coal assets, resulting in very similar energy mixes to those other portfolios in each of the five scenarios. Once again, coal-fired generation provides most of the energy in scenarios with higher gas prices and no carbon legislation, and the capacity factors of the coal units fall with lower gas prices (Current Conditions scenario) and the addition of carbon legislation (Reference Case, High Tech Future).

Figure V.11: Energy mix under all five scenarios for portfolio optimized to Reference Case Without Carbon Legislation



Key Insights from Optimized Portfolios

The resource additions and retirements that the SO model selected when optimizing the portfolio for the conditions under each of the five different scenarios are very helpful in understanding which assumptions drive significant resource changes and what those changes are. Similarly, the PAR model runs in which the optimized portfolios are dispatched in each of the scenarios showing us what the resulting energy mixes would be, help us understand how a given resource mix would respond to a variety of future conditions. Some of the most important insights from this exercise are:

- In a future without carbon legislation, the least cost portfolio is one that retains the existing coal assets for capacity purposes and adds little new capacity. This is true even in a future with very low gas prices, as in the Current Conditions scenario.
- A price on carbon emissions would accelerate coal retirements, resulting in a shift towards CCs, CTs, and solar.
- Gas and solar are consistently selected over wind, which has a low capacity value (13% of nameplate) and tends to generate more energy at times when demand is low.
- If the portfolio remained weighted towards coal, the Company would rely heavily on the MISO market for low cost energy if a price were imposed on carbon emissions. With a more diverse portfolio, the Company would be more self-reliant across a broader range of conditions.

D. SENSITIVITY ANALYSIS

As discussed in Chapter 2, sensitivity analysis is an important tool for assessing how changes to individual assumptions could impact our resource selections. If a change to a particular assumption results in a significant change to the portfolio, then we know that it is very important to either forecast that variable correctly or, more reasonably, to maintain flexibility and be ready to respond to different outcomes for that variable. Reviewing the similarities and differences across the optimized portfolios helps us understand which inputs warrant further examination via sensitivity analysis.

Fuel Prices

The economic competitiveness of our coal assets is heavily influenced by the price of coal relative to the price of natural gas. The price of coal is a major driver of our cost of generation, and the price of gas is a major driver of price of energy in the MISO market. The relative economics of coal generation are an important factor in retirement analysis, so it is necessary for us to analyze both high gas prices relative to coal and low gas prices relative to coal. We expect coal prices to be very stable throughout the planning period, so we focus on gas prices, which are much more volatile, for this analysis. Because coal prices are stable, our Slower Innovation scenario is essentially a “high gas” case. Similarly, our Current Conditions scenario is a "low gas" case. The other assumptions are similar enough between those two scenarios for us to be confident that comparing the respective optimized portfolios can tell us whether we need to explore the question of fuel prices further. Since the two optimized portfolios are nearly identical, we conclude that fuel prices alone will not be a major driver of coal retirements. No additional sensitivity analysis is required.

Load

The top priority for the IRP is to design a resource portfolio that will reliably serve load throughout the planning period. That makes the load forecast a very important input to the process. If our load forecast is too low then reliability may be impacted, but if the forecast is too high then we may build more capacity than necessary, adding unnecessary cost. The former risk is mitigated by the inclusion of the planning reserve margin by which we retain capacity slightly in excess of what we expect to need. In addition, some resources, like combustion turbines and solar plants, can be added relatively quickly and in relatively small increments. For these reasons, we conclude that the high load forecast included in the High Tech Future scenario adequately addresses the possibility of actual load growth being more rapid than what is anticipated in our Reference Case forecast.

Similarly, our analysis of optimized portfolios indicates that major new capacity additions will be driven largely by coal retirements rather than by load growth. Therefore, we expect that the risk of over-building capacity is relatively low. However, because capacity additions cannot be undone, the decision to build carries more risk than the decision to wait. For this reason, we conducted an additional "flat load" sensitivity analysis to assess how our portfolio decisions might be impacted by load growth below even our "low load" forecast.

For this analysis, we re-ran the SO model under the Reference Case and High Tech Future scenarios assuming load remains fixed at current levels (flat load) over the entire planning period (no other assumptions were changed). We selected the High Tech Future in addition to the Reference Case because that is the scenario with the highest load forecast, so we would expect that the flat load assumption would be most impactful on the optimized portfolio for the High Tech Future. The differences between the original optimized portfolios for those scenarios and the new optimized portfolios that result from the flat load assumption provide insight into which resource decisions are influenced by load growth assumptions. The resulting capacity mix shown in Figure V.12 indicate that in the absence of load growth under the Reference Case scenario it would be cost-effective to delay the retirement of Cayuga Units 1 & 2 to 2027 and 2029, respectively, and to forego the addition of 215 MW of CT capacity. If load growth were eliminated in the High Tech Future scenario, the resulting optimized portfolio would include 620 MW less CC capacity, but coal retirements would be unchanged, as shown in Figure V.13. The changes to the portfolio optimized for the Reference Case scenario are relatively minor, suggesting that the composition of that portfolio is robust with respect to low load risk. The results of the same analysis in the High Tech Future scenario indicate that further analysis would be warranted before the addition of a third new CC station.

Figure V.12: Capacity (contribution to peak) by year for portfolio optimized to Reference Case Using Flat Load Assumption

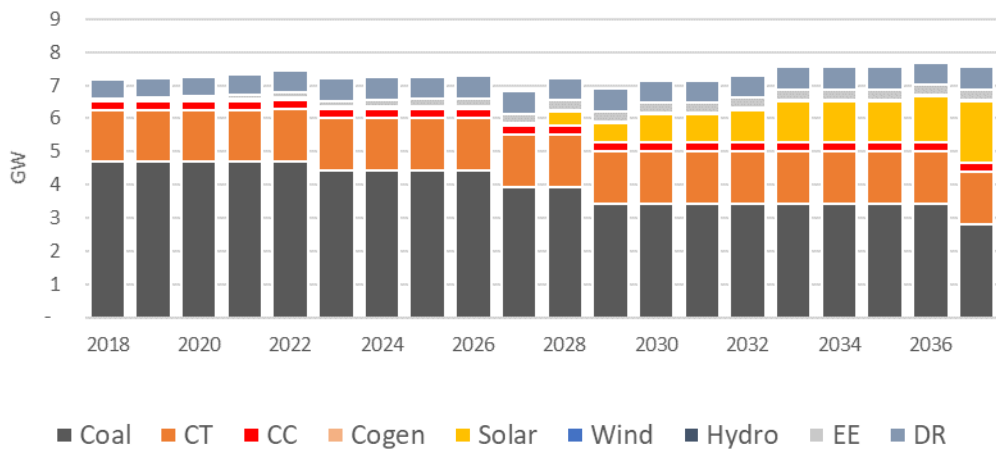
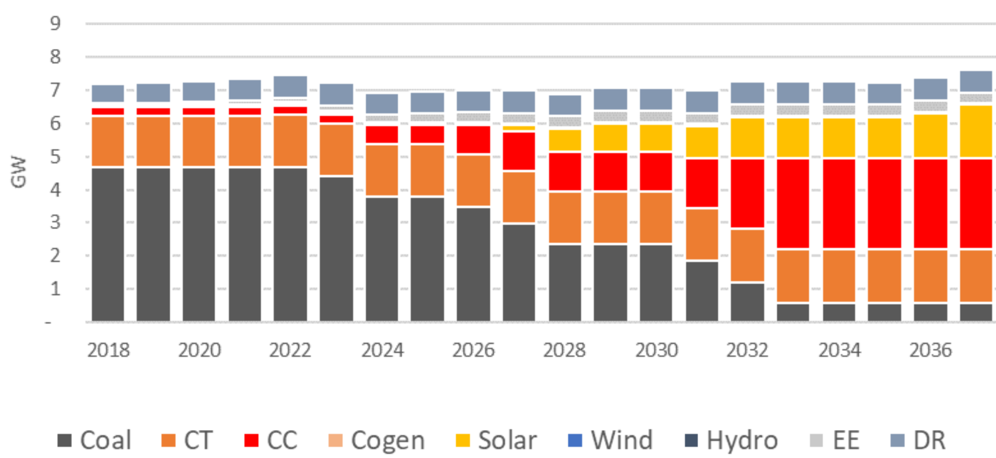


Figure V.13: Capacity (contribution to peak) by year for portfolio optimized to High Tech Future Using Flat Load Assumption



Cost of Renewables

Forecasting the cost of renewable energy technologies over the IRP planning period is difficult at best. Not only is there substantial uncertainty around our forecasts, but it can even be hard to assess what the price is currently in the Indiana market. As discussed in Chapter 2, the Company relies on a combination of internal experience and third-party market research to develop our assumptions for wind and solar costs, but there is still room for interpretation. Over the course of our stakeholder process for this IRP, stakeholders suggested that wind and solar resources may be available at costs lower than we assumed in our scenario analysis. To address these concerns, and because the cost of renewables is an important input to our analysis, we decided to run additional cases in SO to model new optimized portfolios for the Reference Case scenario keeping all assumptions constant except the cost of wind and the cost of solar. We also ran low cost wind and solar cases in the Reference Case Without Carbon Legislation to assess how much of the resulting renewable capacity additions were driven by our carbon price assumptions. For this sensitivity analysis we reduced the all-in capital cost of wind by 25% for the low cost of wind cases. For the low cost of solar cases, we reduced the all-in cost of solar to $1,250/kW (29% lower than the 2018 Reference Case assumption) for the first 10 years of the analysis, a figure informed by stakeholder input, and then reverted to our Reference Case assumption. Figures V.14 and V.15 show the resulting capacity mixes.

Figure V.14: Capacity (contribution to peak) by year for portfolio optimized for low cost of wind in Reference Case and Reference Case Without Carbon Legislation scenarios

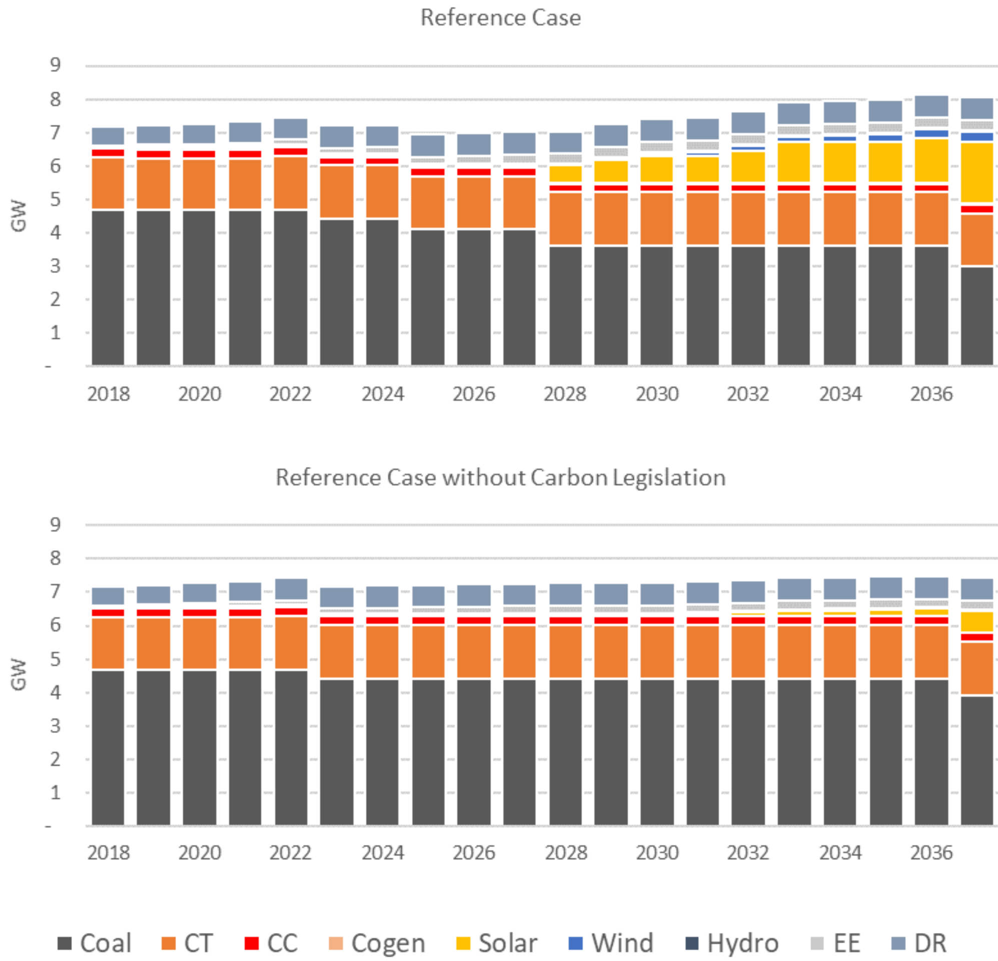
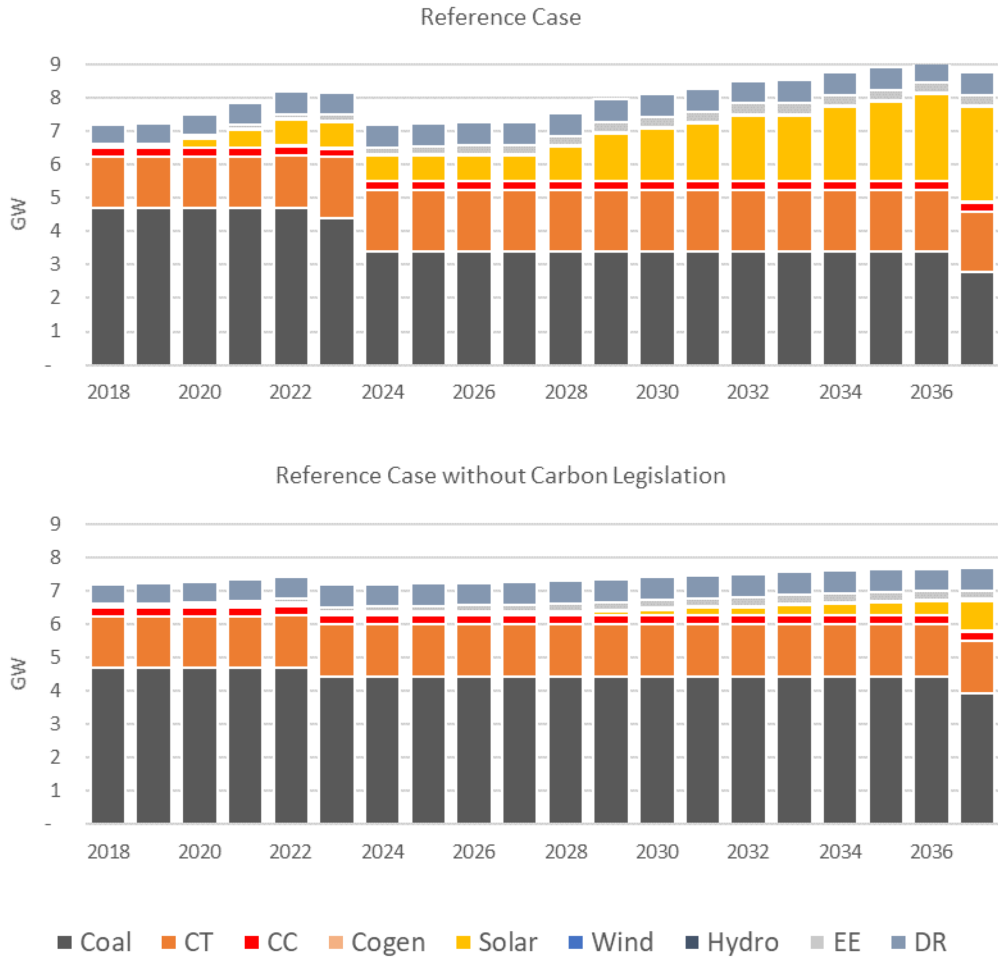


Figure V.15: Capacity (contribution to peak) by year for portfolio optimized for low cost of solar in Reference Case and Reference Case Without Carbon Legislation scenarios



Notice that the new portfolios optimized for the Reference Case Without Carbon Legislation do not include any additional renewable capacity, wind or solar, until the second half of the planning period. This suggests that without a price on carbon, it is not cost-effective to add renewable capacity to the system, even at capital costs well below our Reference Case assumptions, for at least a decade. However, if we could be certain that carbon legislation would pass and when, of which the model has perfect foresight in this scenario, then it would make sense to start adding solar capacity in the relatively near term if it could be secured at very low cost. Given the state of carbon policy, we do not have the certainty to justify such large scale immediate action.

E. ALTERNATIVE PORTFOLIOS

Developing optimized portfolios helped us understand how the resource mix should be adjusted to adapt to changes in key variables like load, fuel prices, and carbon legislation. Running those portfolios through the PAR model showed us given resource mixes would operate under different future conditions. Our sensitivity analysis provided additional insight to how the resource mix might be adjusted if load were below even our low forecast, and how the Company might (or might not) be able to take advantage of lower-than-expected renewable energy costs in the absence of a near-term capacity need. All of this provides a starting point for developing alternative portfolios designed to retain the strengths of the optimized portfolios while minimizing risks. We identified the following as areas of focus for alternative portfolios:

- There are dramatic differences between portfolios optimized for a future with carbon legislation and those optimized for a future without. Given the unpredictability of this issue, we need a plan that prepares us for a low carbon future without incurring major costs prematurely.
- Several of our optimized portfolios would rely heavily on market energy under certain scenarios. The SO model selects resources as if our market price forecasts are 100% accurate, but we could be exposed to considerable cost risk if prices exceed our expectations. We need a plan that limits market exposure while still allowing us to capture some of the potential benefits of low market prices.
- The SO model does not account for feedbacks by which resource choices may change the trajectory of certain inputs. This is particularly true in the case of renewables, where extensive adoption of solar capacity could dramatically affect daytime power prices. We need a plan that accounts for the fact that the relative value of wind may increase in the future.
- Unit retirements selected by the SO model are based entirely on as modeled cost and capacity need. The model does not account for other practical constraints such as known differences in condition among similar units, joint ownership, site costs shared with other units, transmission constraints, etc. We need a plan that is operable in the real world.

- Perhaps most importantly, the SO model optimizes around cost. We need a plan that balances the goal of keeping costs low with other objectives, particularly the goal of reducing carbon emissions.

The alternative portfolios described below address these concerns.

Moderate Transition

The Moderate Transition portfolio is designed to gradually diversify the resource mix without steeply increasing cost to customers over a short period. This portfolio accelerates coal unit retirements, replacing that coal capacity with a mix of CC, solar, wind, and EE. Wind and solar capacity is added gradually to limit cost impacts in any one year. Coal retirements are grouped in a way that would be feasible given practical constraints that are not captured in the SO model.

Figure V.16: Capacity (contribution to peak MW) by year for the Moderate Transition portfolio

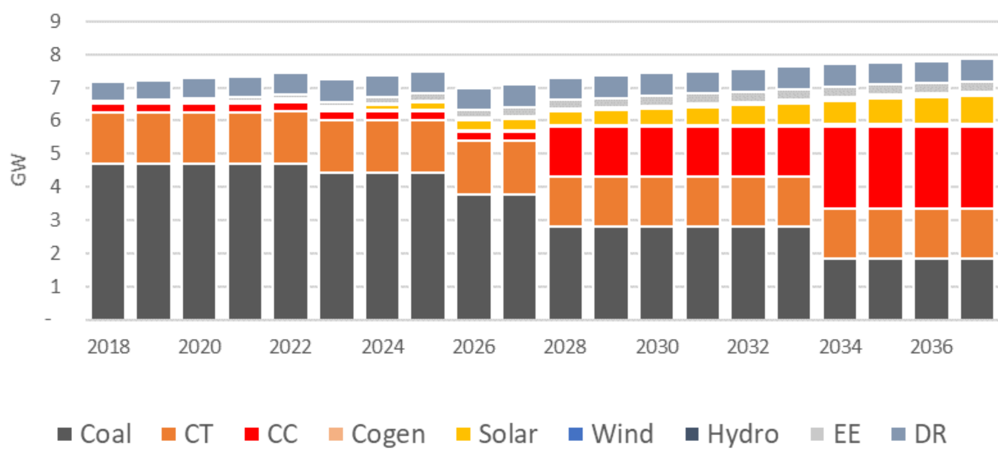


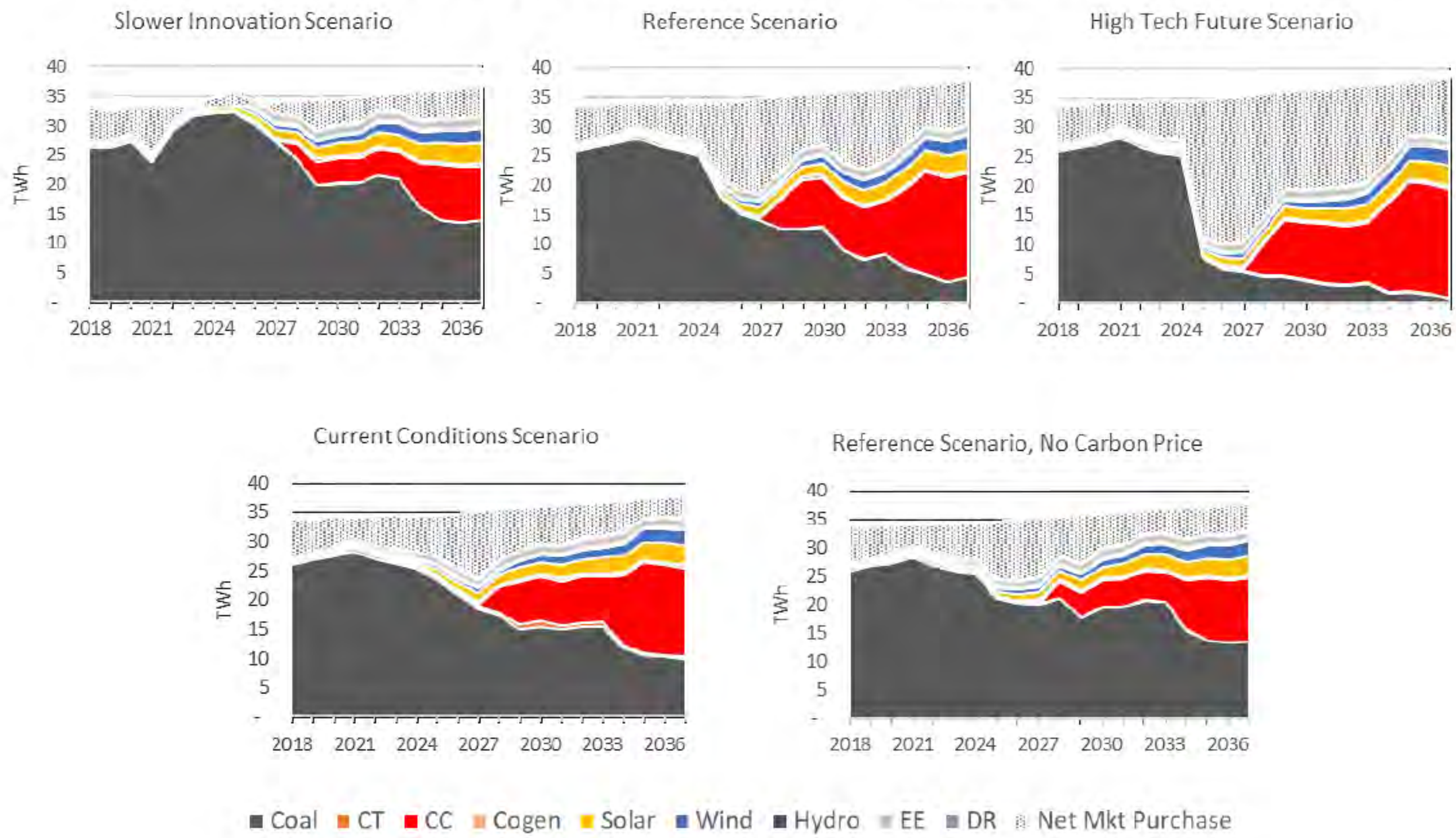
Table V.7: Capacity (nameplate MW) additions by year for the Moderate Transition portfolio

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	24			
2022	0	50	0	0	0	0	22	24			
2023	0	0	100	0	0	0	21	24	Gallager 2&4	Coal	280
2024	0	0	150	50	20	0	(1)	27			
2025	0	0	150	50	0	0	0	29			
2026	0	0	150	50	20	0	1	23	Gibson 4	Coal	622
2027	0	0	100	50	0	0	0	26			
2028	1,240	0	100	(50)	0	0	0	19	Cayuga 1-4	Coal, CT	1,085
2029	0	0	100	50	0	0	0	15			
2030	0	0	100	50	0	0	0	6			
2031	0	0	100	50	0	0	1	1			
2032	0	0	100	50	0	0	0	7			
2033	0	0	100	50	0	0	0	8			
2034	1,240	0	100	50	0	0	0	1	Gibson 3&5, Noblesville	Coal, CC	1,204
2035	0	0	100	50	0	0	1	(5)			
2036	0	0	79	50	0	0	0	(4)			
2037	0	0	100	50	0	0	0	(2)			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

The Moderate Transition portfolio would reduce the carbon intensity of the energy mix across all scenarios relative to the current level, and would purchase less energy from the market in most cases.

Figure V.17: Energy mix under all five scenarios for the Moderate Transition portfolio



Aggressive Transition

The Aggressive Transition portfolio is designed to accelerate coal retirements more dramatically than Moderate Transition, placing a greater emphasis on transitioning to lower carbon generation and somewhat less emphasis on controlling costs. Under this portfolio, more coal is retired by 2030, as is the Noblesville CC facility. The first new CC is added in 2025 and considerable solar is added in the late 2020s and throughout the 2030s.

Figure V.18: Capacity (contribution to peak MW) by year for the Aggressive Transition portfolio

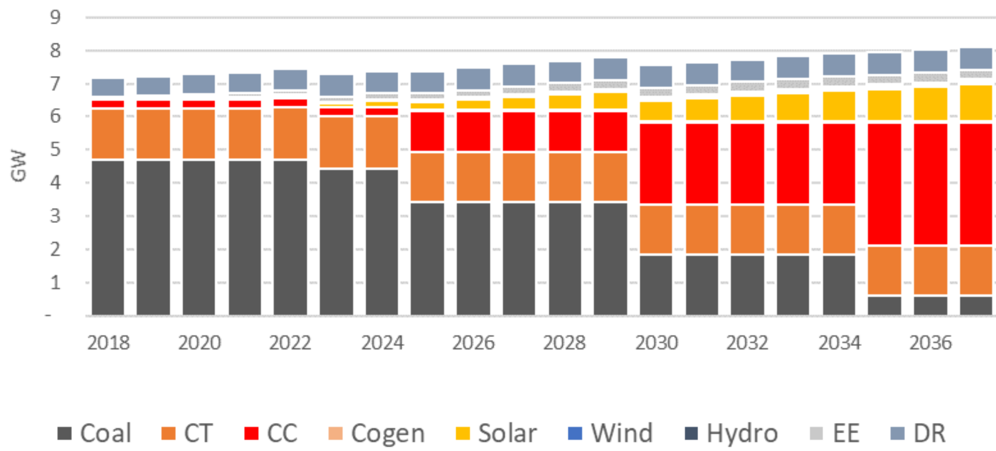


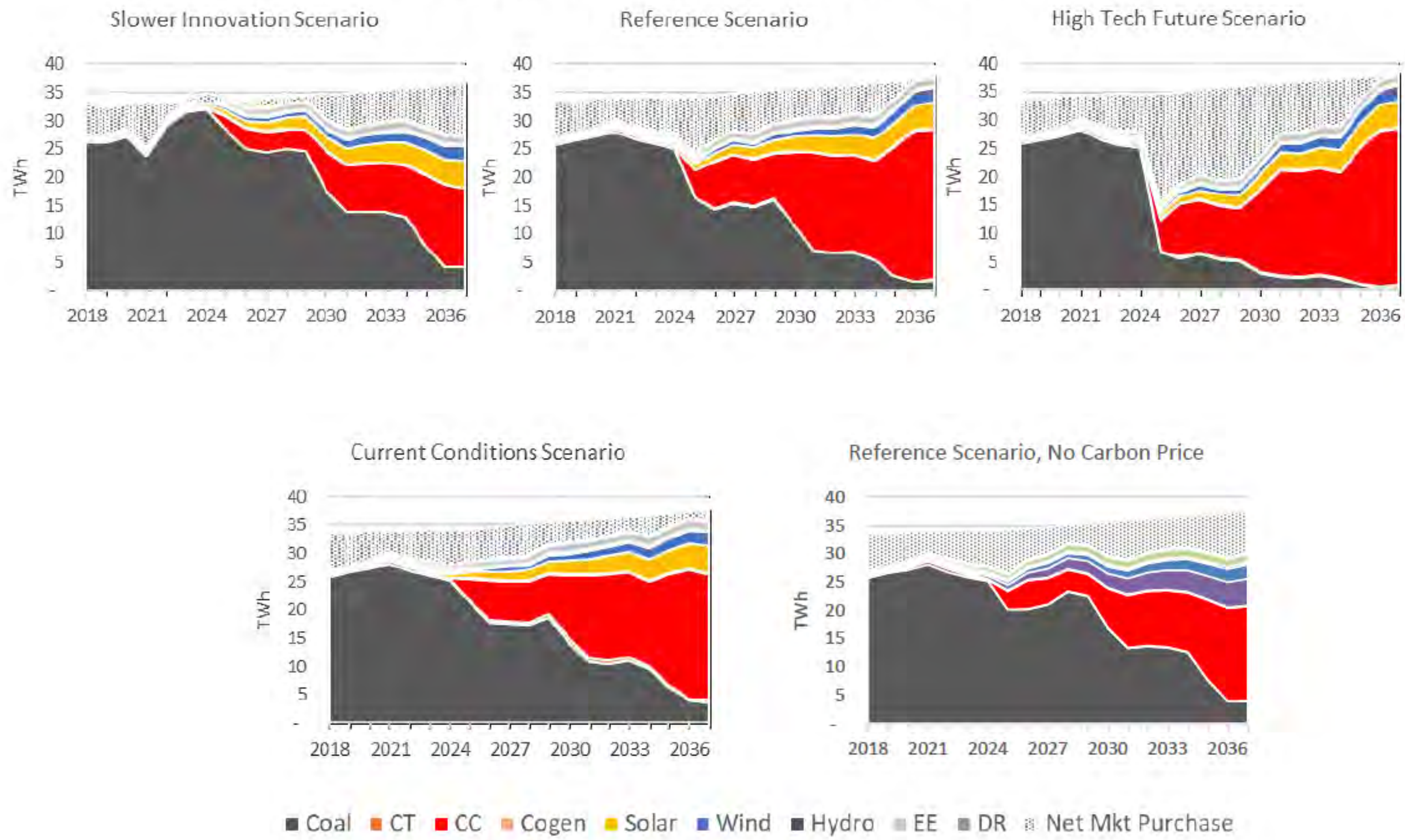
Table V.8: Capacity (nameplate MW) additions by year for the Aggressive Transition portfolio

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	23			
2022	0	50	0	0	0	0	22	22			
2023	0	0	150	0	0	0	21	22	Gallager 2&4	Coal	280
2024	0	0	150	50	20	0	(1)	26			
2025	1,240	0	150	50	0	0	0	29	Cayuga 1-4, Noblesville	Coal, CT, CC	1,349
2026	0	0	150	50	20	0	1	23			
2027	0	0	150	50	0	0	0	26			
2028	0	0	150	(50)	0	0	0	20			
2029	0	0	150	50	0	0	0	15			
2030	1,240	0	150	50	0	0	0	6	Gibson 3-5	Coal	1,562
2031	0	0	150	50	0	0	1	2			
2032	0	0	150	50	0	0	0	8			
2033	0	0	150	50	0	0	0	9			
2034	0	0	150	50	0	0	0	1			
2035	1,240	0	150	50	0	0	1	(4)	Gibson 1&2	Coal	1,260
2036	0	0	129	50	0	0	0	(4)			
2037	0	0	150	50	0	0	0	(2)			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

The earlier addition of a CC in 2025 in the Aggressive Transition portfolio helps mitigate market exposure in the mid-2020s under low gas price or high carbon price scenarios, and would reduce carbon emissions relative to the coal it would replace.

Figure V.19: Energy mix under all five scenarios for the Aggressive Transition portfolio



Rapid Decarbonization: CT

The Rapid Decarbonization: CT portfolio is modeled on the Aggressive Transition portfolio in that the retirement schedule is the same, but with this portfolio we replace that retired capacity almost entirely with renewables rather than including several gas-fired CCs. The first CC is still added in 2025, but after that, wind and solar account for most other additions, with just enough CT capacity added to meet the winter planning reserve margin requirement each year.

Figure V.20: Capacity (contribution to peak MW) by year for the Rapid Decarbonization: CT portfolio

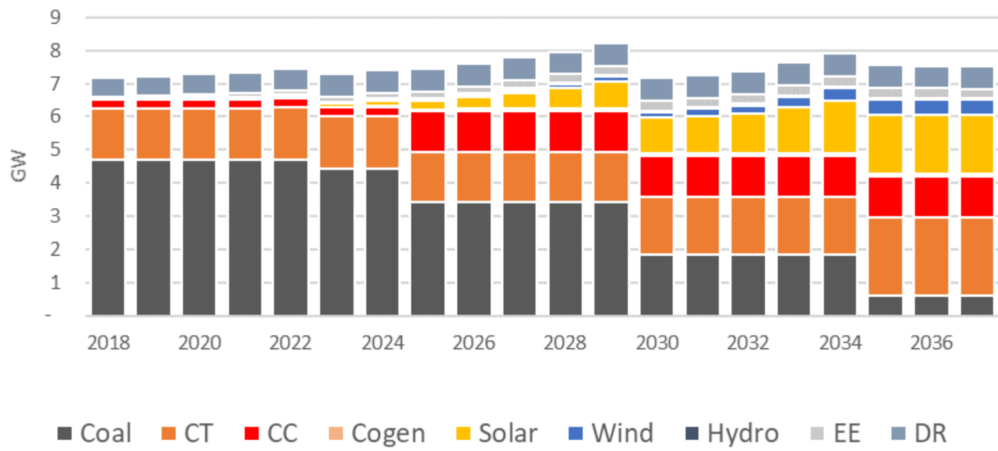


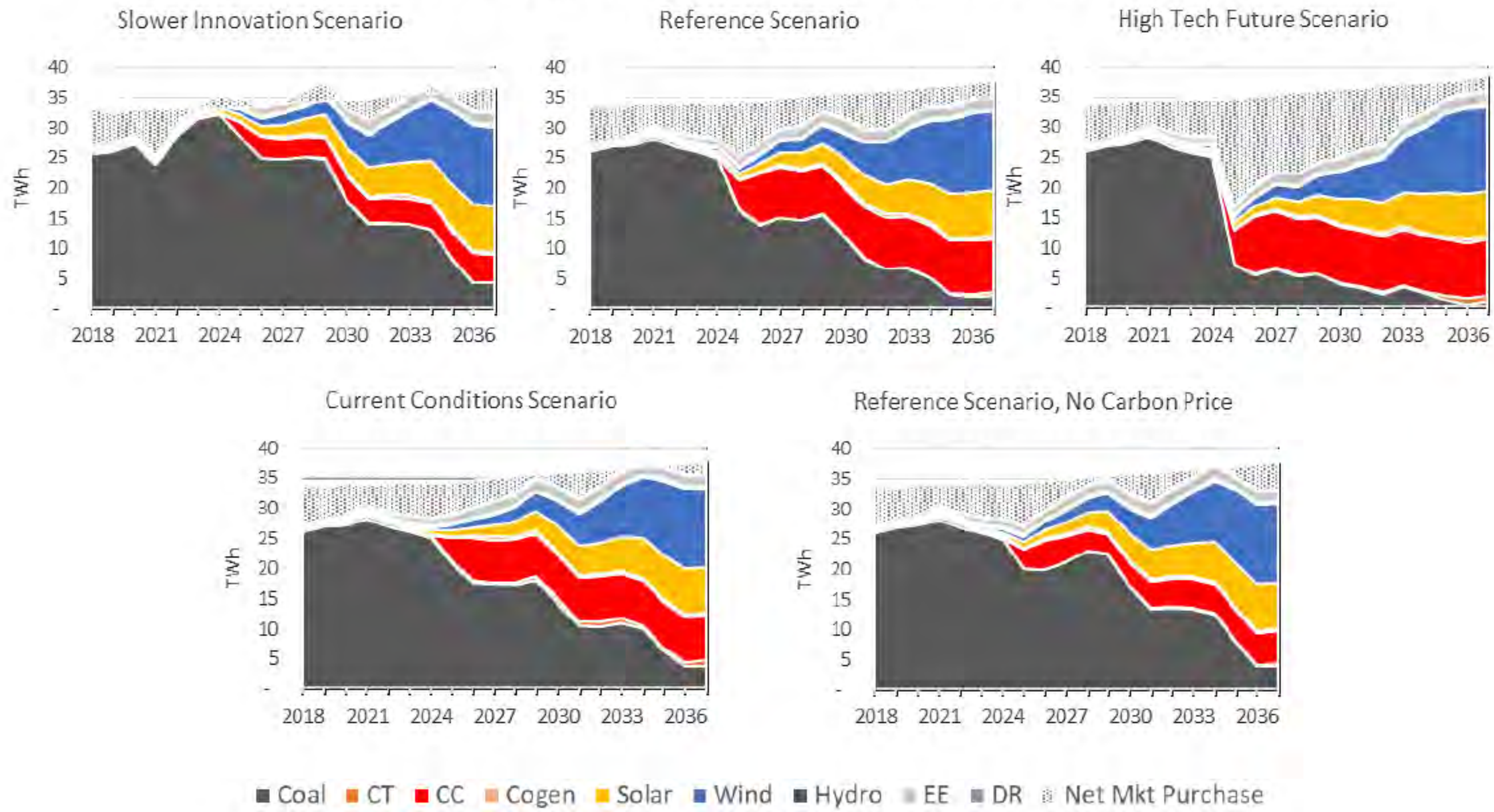
Table V.9: Capacity (nameplate MW) additions by year for the Rapid Decarbonization: CT portfolio

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	23			
2022	0	50	0	0	0	0	22	22			
2023	0	0	150	0	0	0	21	22	Gallager 2&4	Coal	280
2024	0	0	150	100	20	0	(1)	26			
2025	1,240	0	200	100	0	0	0	29	Cayuga 1-4, Noblesville	Coal, CT, CC	1,349
2026	0	0	200	150	20	0	1	23			
2027	0	0	250	150	0	0	0	26			
2028	0	0	300	100	0	0	0	20			
2029	0	0	400	250	0	0	0	15			
2030	0	215	500	300	0	0	0	6	Gibson 3-5	Coal	1,562
2031	0	0	100	350	0	0	1	2			
2032	0	0	100	400	0	0	0	8			
2033	0	0	400	450	0	0	0	9			
2034	0	0	400	500	0	0	0	1			
2035	0	645	400	500	0	0	1	(4)	Gibson 1&2	Coal	1,260
2036	0	0	(21)	0	0	0	0	(4)			
2037	0	0	0	0	0	0	0	(2)			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

The Rapid Decarbonization: CT portfolio includes a much greater proportion of low variable cost resources (cost for renewables is almost entirely fixed and is mostly spent up front on development and construction), making the energy mix much less sensitive to market conditions. For that reason, the energy mix for the Rapid Decarbonization: CT portfolio looks very similar across all five scenarios and there is little market exposure.

Figure V.21: Energy mix under all five scenarios for the Rapid Decarbonization: CT portfolio



Rapid Decarbonization: Batteries

The Rapid Decarbonization: Batteries portfolio is designed to take the analysis one step further and explore how the portfolio would perform if we used battery storage instead of CTs to bolster the winter reserve margin. The retirements follow the same schedule as the Aggressive Transition portfolio, and the first CC is still added in 2025, but after that all supply-side resource additions are wind, solar, and batteries.

Figure V.22: Capacity (contribution to peak MW) by year for the Rapid Decarbonization: Batteries portfolio

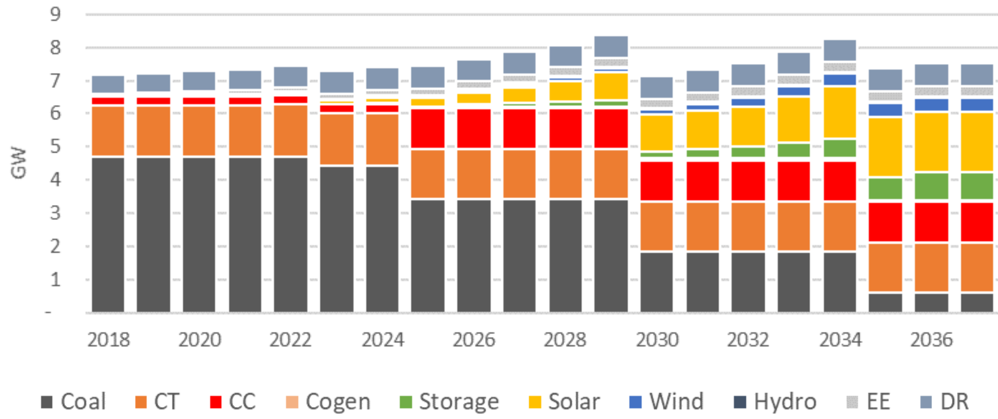


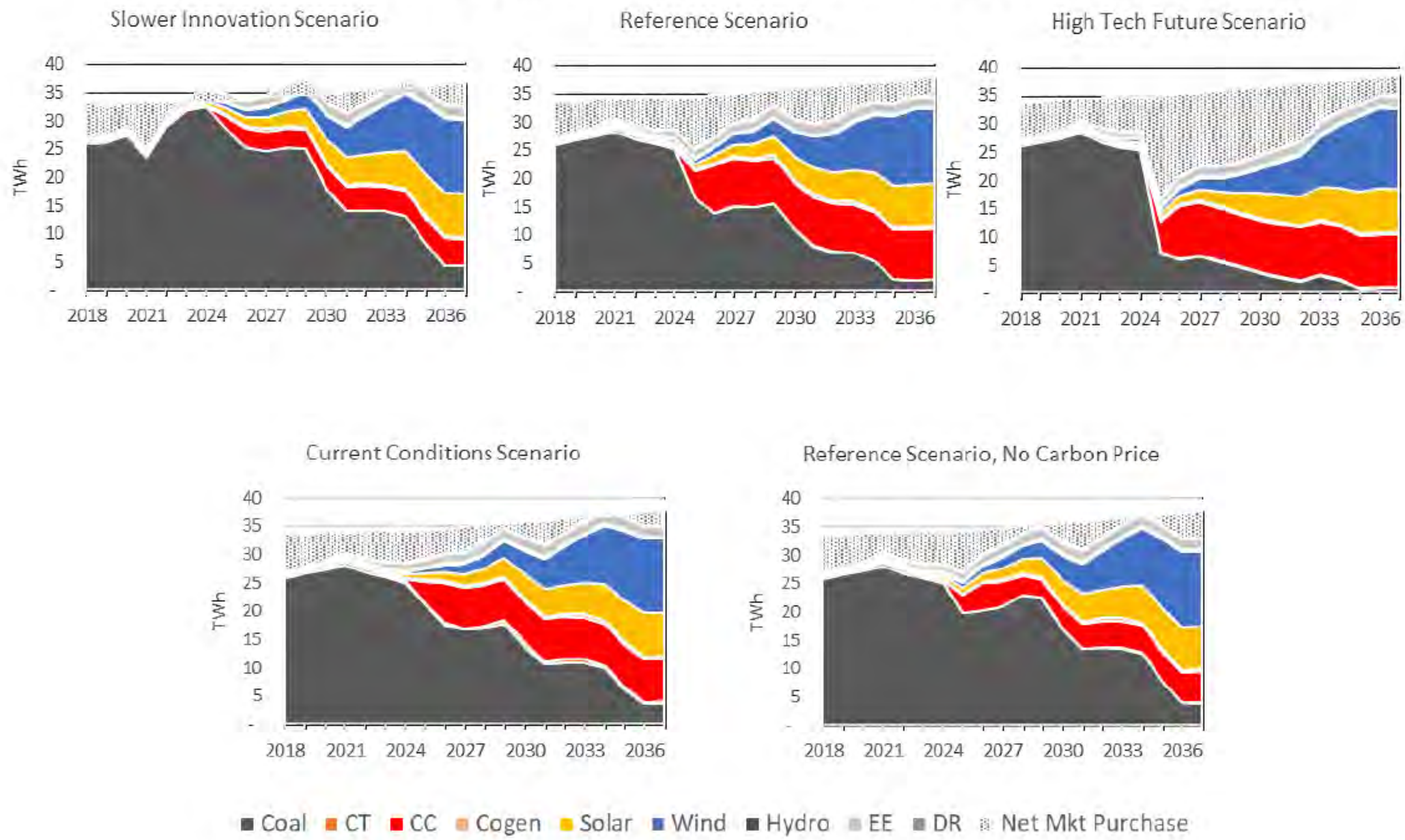
Table V.10: Capacity (nameplate MW) additions by year for the Rapid Decarbonization: Batteries portfolio

	Net Additions (MW)*								Retirements		
Year	CC	CT	Solar	Wind	Cogen	Storage	DR	EE	Units	Fuel	MW
2018	0	0	0	0	0	0	74	5			
2019	0	(8)	6	0	0	10	13	26			
2020	0	0	2	0	0	5	28	22			
2021	0	0	0	0	16	0	23	23			
2022	0	50	0	0	0	0	22	22			
2023	0	0	150	0	0	0	21	22	Gallager 2&4	Coal	280
2024	0	0	150	100	20	0	(1)	26			
2025	1,240	0	200	100	0	0	0	29	Cayuga 1-4, Noblesville	Coal, CT, CC	1,349
2026	0	0	200	150	20	50	1	23			
2027	0	0	250	150	0	50	0	26			
2028	0	0	300	100	0	50	0	20			
2029	0	0	400	250	0	50	0	15			
2030	0	0	500	300	0	50	0	6	Gibson 3-5	Coal	1,562
2031	0	0	100	350	0	100	1	2			
2032	0	0	100	400	0	100	0	8			
2033	0	0	400	450	0	100	0	9			
2034	0	0	400	500	0	150	0	1			
2035	0	0	400	500	0	150	1	(4)	Gibson 1&2	Coal	1,260
2036	0	0	(21)	0	0	200	0	(4)			
2037	0	0	0	0	0	0	0	(2)			

*Additions are net of program roll-off or contract end. EE additions continue throughout the period, but are offset in later years by the roll-off of previously selected programs, resulting in net additions close to zero.

Similar to the Rapid Decarbonization: CT portfolio, the shift to low variable cost resources makes the energy mix very consistent across scenarios and dramatically reduces market purchases. Note that because batteries do not actually provide energy (they are net energy consumers because 100% efficiency is impossible), they do not appear in the energy mix.

Figure V.23: Energy mix under all five scenarios for the Rapid Decarbonization: Batteries portfolio



F. SUMMARY OF CANDIDATE RESOURCE PORTFOLIOS

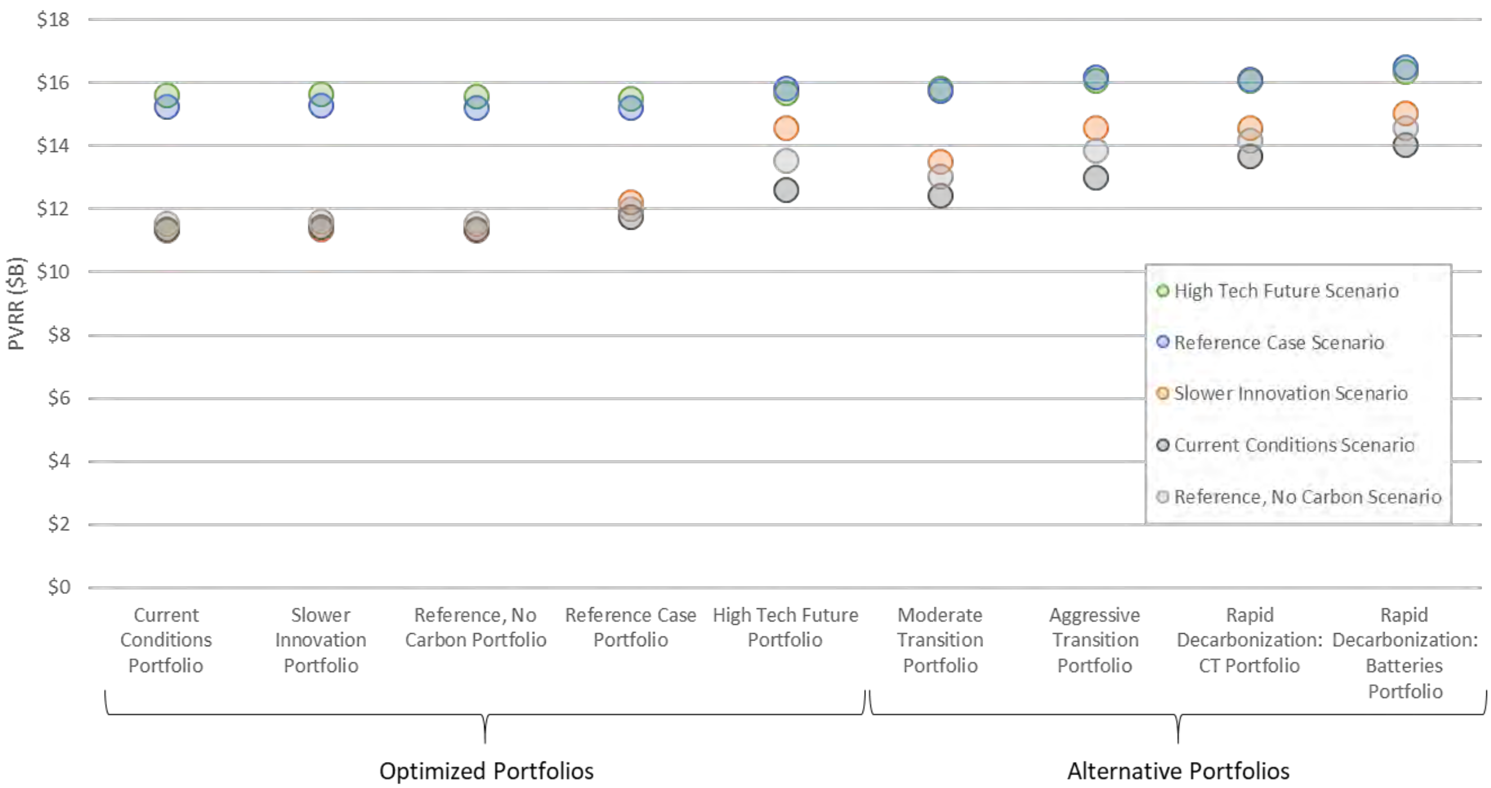
This section summarizes the performance of the resource portfolios described in this chapter with respect to the key objectives for this IRP. All portfolios must satisfy the planning reserve margin requirement that establishes reliability, so we focus on cost, risk, and carbon emissions in this section.

PVRR

PVRR includes both fixed (largely capital) and variable (operating) costs over the planning period. Because operating cost are included, PVRR for a single portfolio can vary across scenarios based on differing fuel and other cost assumptions and different unit dispatch decisions. Recall that the PVRR figures reported in the IRP exclude costs that have been or will be incurred regardless of portfolio composition (e.g., construction costs for existing units, unit retirement costs).

Figure V.24 below shows the PVRR for each of the optimized and alternative portfolios under each of the five IRP scenarios. Portfolios are along the horizontal axis and scenarios are represented by color. Different PVRRs for the same portfolio are stacked vertically, with each color representing the PVRR under a different scenario.

Figure V.24: PVRR for each portfolio under each of the five IRP scenarios

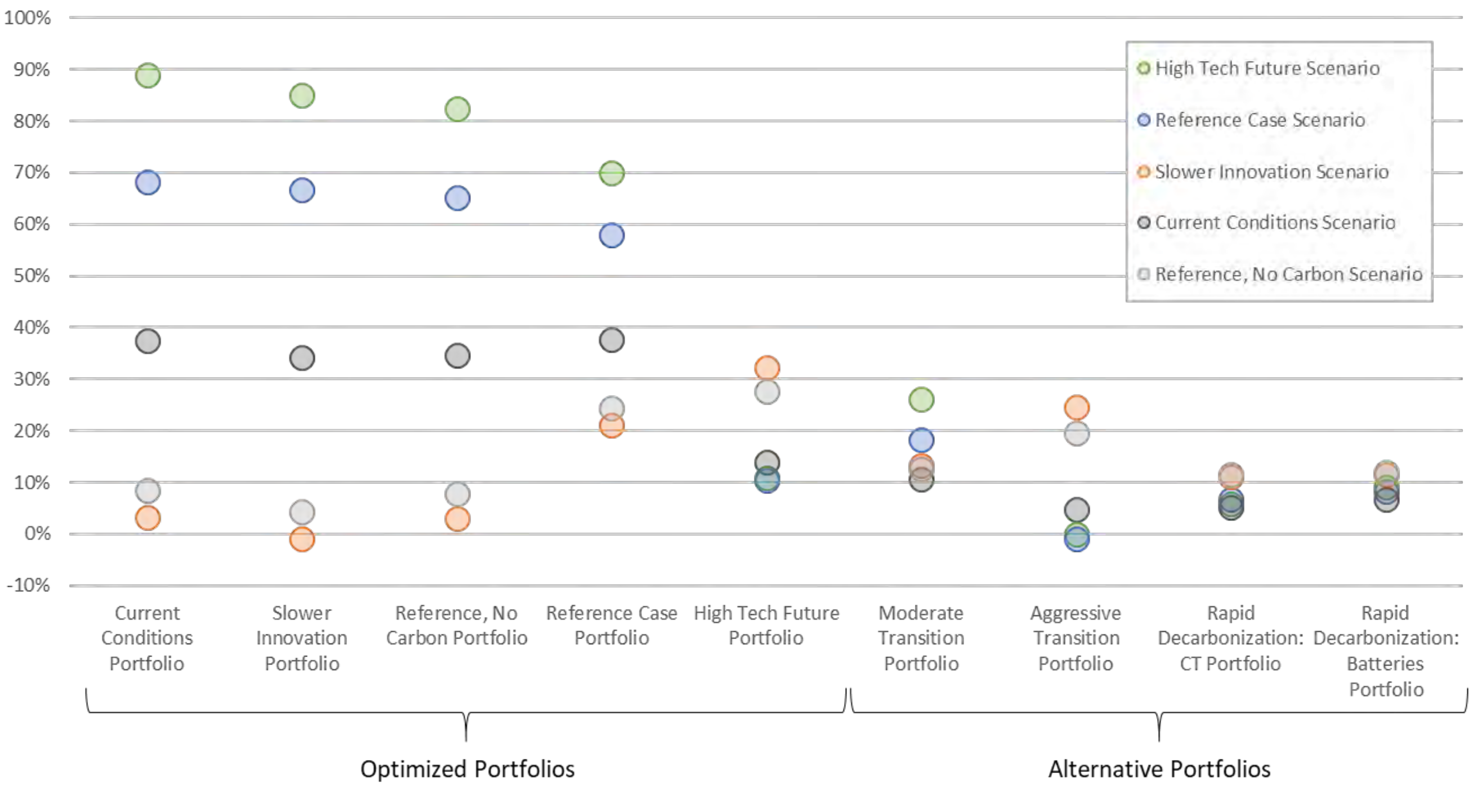


As expected, all portfolios are more expensive in scenarios that assume legislation imposing a price on carbon emissions (Reference Case and High Tech Future, blue dots and green dots respectively in Figure V.24). Also as expected, portfolios that include fewer retirements and less investment in new generation are less expensive in scenarios that do not include carbon legislation. However, those portfolios that are lowest cost in scenarios that resemble the status quo also show the widest range of PVRR values across scenarios, which is an indicator of their riskiness. Portfolios that have greater expenditures on new generating capacity have tighter PVRR spreads across scenarios. Those portfolios are more expensive on average, but also less risky.

Market Exposure

A major risk factor is the extent to which a portfolio relies on the market to provide low-cost energy. Those portfolios that retain most or all existing coal capacity take on significant market exposure in scenarios in which coal is not an economic energy source. Portfolios with a higher proportion of efficient new combined-cycle capacity and low variable cost renewables supply more energy from company-owned resources on average.

Figure V.25: Percent of total energy demand that is served by net market purchase in 2037

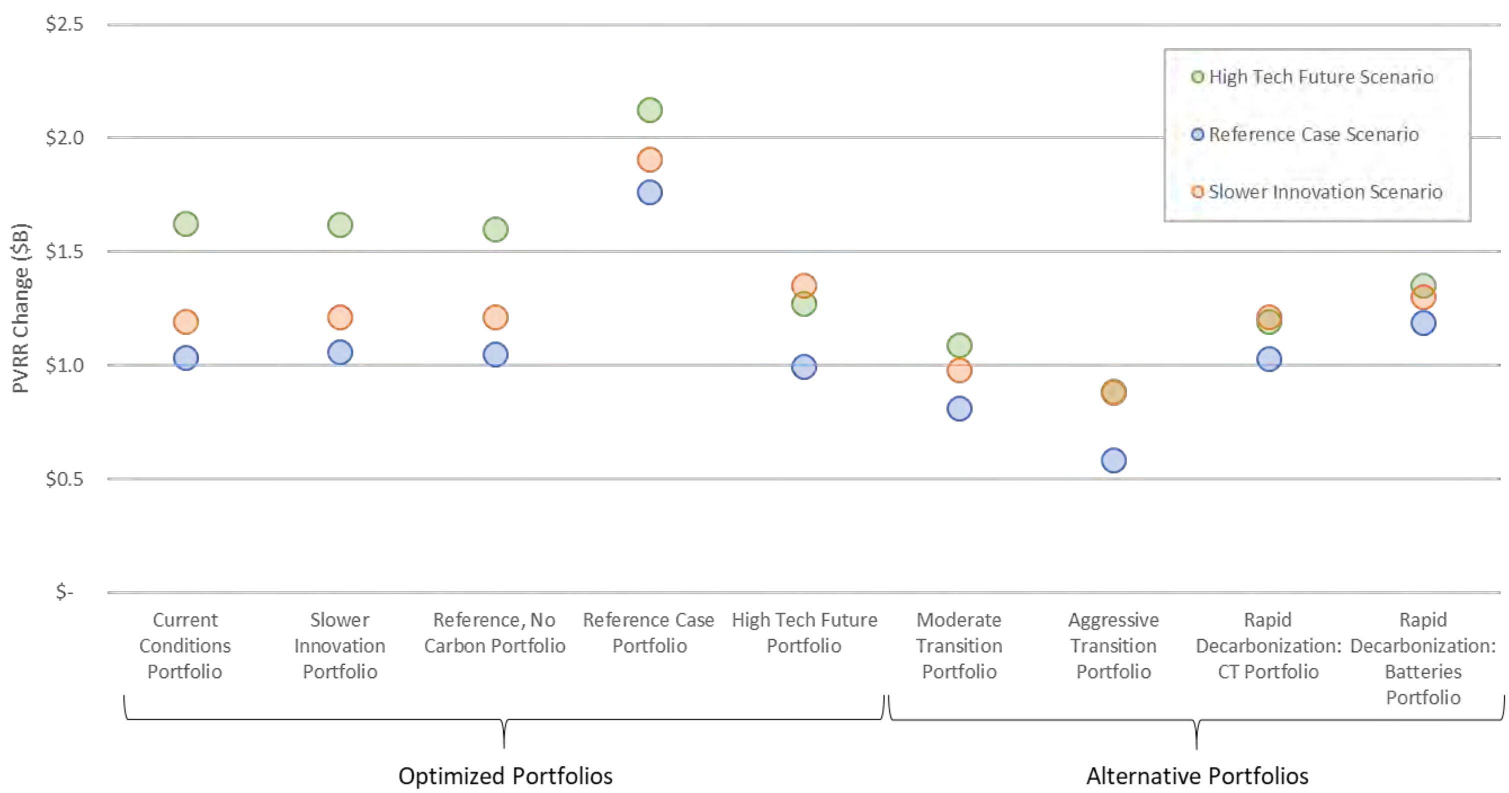


The PAR model selects market energy when the forecasted wholesale power price is lower than the marginal cost of energy from the Company's own generators. The market option makes it possible to diversify the energy mix even when the portfolio lacks fuel diversity. If the actual future market power price is higher than what is forecast, then the PVRR of portfolios with substantial market exposure would also rise. Any cost increase would be capped at the cost of meeting all energy demand with the company's own resources.

Access to the MISO energy market also allows the Company to run the generating fleet as efficiently as possible, even when doing so does not perfectly serve load. It can be costly to meet rapid fluctuations in demand with coal units, and the market can be a cost-effective alternative to doing so. Higher-than-forecast power prices limit this benefit.

To quantify the risk associated with relying on the market, we conducted additional PAR model runs that did not include the market as an energy source. This simulates a situation in which the wholesale power price is consistently above the cost of energy from the Company's own resources. Figure V.26 below shows how much the PVRR of each portfolio would increase without recourse to the market.

Figure V.26: PVRR increase when market energy is prohibitively expensive



The portfolios optimized for the Current Conditions, Slower Innovation, Reference Case Without Carbon Legislation, and Reference Case scenarios show the largest cost increases on average when forced to supply 100% of energy from company-owned resources. The portfolio optimized for the Reference Case scenario is particularly sensitive to this assumption because it retains substantial coal capacity and the added solar does not provide the flexibility required to run the coal units at peak efficiency, nor is it sufficient to shield the Company from the cost of carbon legislation. The Aggressive Transition portfolio, which retires most of the Company's coal units in favor of new combined-cycle capacity, wind, and solar, is least sensitive to high market prices. The combined-cycles provide flexible, reliable generation, and the renewables decrease the carbon-intensity of the total energy mix. The Rapid Decarbonization portfolios, which include more renewables, lack the flexibility provided by the combined-cycles. In addition to the PVRR impacts listed above, neither the portfolio optimized for the Reference Case scenario nor the Rapid Decarbonization: Batteries portfolio is able to reliably serve load in all hours without relying on the market. When the market is unavailable, these portfolios, which lack sufficiently flexible and reliable generation (effectively CTs or CCs), fail to supply enough energy to meet all demand in hundreds of hours per year by the end of the planning period.

CO_2 Emissions

Reducing carbon emissions is a main objective for the preferred portfolio selected through the 2018 IRP process. Figure 5.27 below shows reduction in annual emissions achieved by 2037 from the 2005 Duke Energy Indiana baseline of 37.4 million tons. Purchases were not a significant energy source in 2005 but, looking to the future, some portfolios could rely heavily on the market to cost-effectively serve load. To account for this, our emissions calculations for 2037 include estimated carbon-intensity for market purchases under each scenario (Table V.11).

As expected, portfolios that replace coal capacity with efficient new gas-fired combined-cycle units and renewables result in the lowest carbon emissions across all scenarios. Portfolios that do not retire as much coal show lower emissions reductions in scenarios where coal capacity factors would be high, but achieve greater reductions in scenarios where coal capacity factors would be low by purchasing less carbon-intensive energy from the market.

Figure V.27: Reduction in CO2 emissions by 2037 from 2005 baseline (includes estimate of emissions associated with energy purchased from the market)

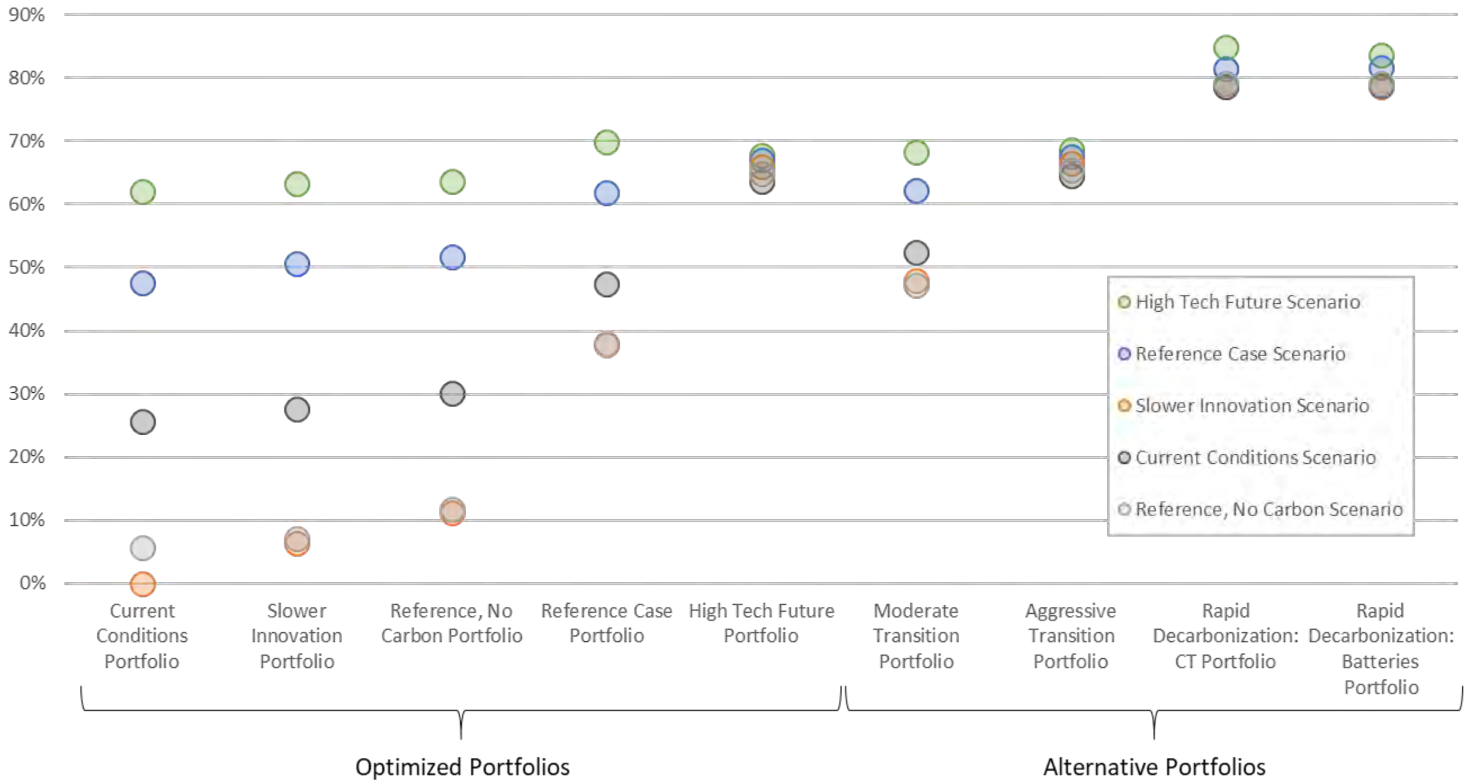


Table V.11: Estimated carbon-intensity of market energy in 2037 by scenario

Scenario	lbs/kWh
High Tech Future	0.7
Reference	0.7
Current Conditions	1.0
Slower Innovation	1.2
Ref No Carbon Reg	1.3

Summary

The results of the analysis presented in the preceding sections highlight the tradeoffs that we faced in selecting the preferred portfolio for this IRP. Portfolios that achieve greater emissions reductions and limit market exposure tend to be more expensive. The results for all portfolios under the Reference Case scenario are summarized in Table V.12.

Table V.12: Summary of key results under Reference Case scenario

	Portfolio	PVRR ($B)	Energy from Market in 2037 (% of total energy)	CO2 Emissions Reduction from 2005 Baseline
OPTIMIZED	Current Conditions	$15.3	68%	48%
	Slower Innovation	$15.3	67%	51%
	Reference, No Carbon	$15.2	65%	52%
	Reference Case	$15.2	58%	62%
	High Tech Future	$15.8	10%	67%
ALTERNATIVE	Moderate Transition	$15.8	18%	62%
	Aggressive Transition	$16.2	-1%	68%
	Rapid Decarbonization: CT	$16.1	7%	81%
	Rapid Decarbonization: Batteries	$16.5	8%	82%

SECTION VI: PREFERRED PORTFOLIO FOR 2018 INTEGRATED RESOURCE PLAN

A. PREFERRED PORTFOLIO

We have selected the Moderate Transition portfolio described in Chapter V as the preferred portfolio for the 2018 IRP. The energy and capacity mixes for this portfolio are shown in Figures V.16 and V.17. Based on the results of our analysis discussed in Chapter 5, Section F, we have concluded that this portfolio best balances the objectives of the 2018 IRP. Figure VI.1 shows the range of outcomes for the Moderate Transition portfolio across all scenarios (blue) embedded in the range of outcomes for all portfolios across all scenarios (gray) under the three key objectives we targeted for this IRP. The costs (PVRR) of this portfolio fall near the middle of the range for all portfolios, while the market exposure (portion of total energy demand served by the market by the end of the planning period) falls near the bottom of the range, and the carbon emissions reduction (by the end of the planning period against the 2005 baseline) falls near the top of the range for all portfolios. Under the Moderate Transition portfolio, the resource mix will be diversified over time without committing to dramatic resource changes prematurely, preserving decision-making flexibility going into the 2021 IRP analysis and shielding customers from undue cost increases in the near-term. Duke Energy Indiana and its parent corporation expect to maintain strong financial positions into the future and will be able to finance the potential investments contemplated under the preferred portfolio.

Figure VI.1: Performance of Moderate Transition portfolio across all scenarios with respect to main IRP objectives (blue) within range of performance for all portfolios across all scenarios (gray)

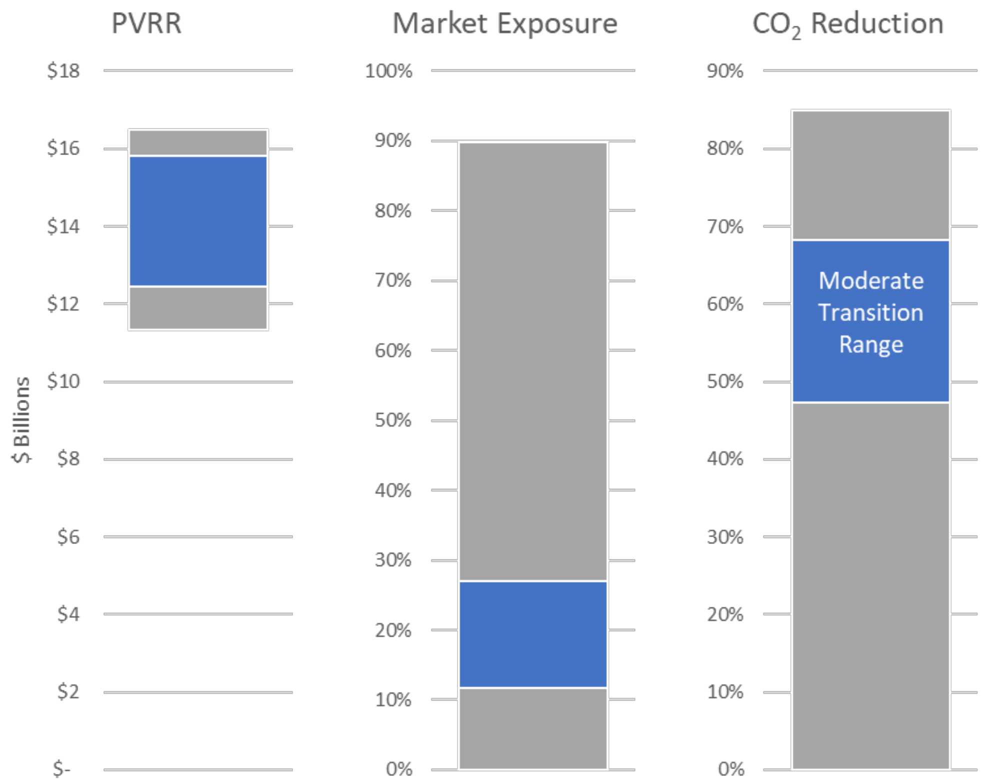


Table VI.1: Load, capacity, and reserves under preferred resource portfolio

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Load Forecast																				
DEI System Peak	6,031	6,000	6,110	6,051	6,086	6,136	6,056	6,114	6,166	6,213	6,237	6,297	6,339	6,376	6,403	6,460	6,499	6,529	6,543	6,593
Reductions to Load																				
New EE Programs	(27)	(53)	(75)	(99)	(123)	(147)	(174)	(203)	(226)	(252)	(271)	(286)	(292)	(293)	(300)	(308)	(309)	(304)	(300)	(298)
DR + IVVC	(577)	(591)	(618)	(640)	(662)	(685)	(684)	(683)	(684)	(683)	(684)	(685)	(687)	(688)	(684)	(684)	(686)	(687)	(687)	(689)
Adjusted Peak Load	**5,427**	**5,356**	**5,417**	**5,312**	**5,302**	**5,304**	**5,197**	**5,228**	**5,256**	**5,278**	**5,282**	**5,326**	**5,360**	**5,395**	**5,419**	**5,469**	**5,503**	**5,538**	**5,556**	**5,606**
System Generating Capacity (contribution to peak)																				
Retirements																				
Coal	-	-	-	-	-	(280)	-	-	(622)	-	(995)	-	-	-	-	-	(940)	-	-	-
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(264)	-	-	-
CT	-	-	-	-	-	-	-	-	-	-	(90)	-	-	-	-	-	-	-	-	-
Additions																				
CC	-	-	-	-	-	-	-	-	-	-	1,240	-	-	-	-	-	1,240	-	-	-
Solar (50% contribution to peak	-	3	1	-	-	50	75	75	75	50	50	50	50	50	50	50	50	50	50	50
Wind (13% contribution to peak	-	-	-	-	-	-	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Cogen	-	-	-	16	-	-	20	-	20	-	-	-	-	-	-	-	-	-	-	-
Contract Rolloff	-	(8)	-	-	50	-	-	-	-	-	(10)	-	-	-	-	-	-	-	(11)	-
Total System Generating Capacity	6,584	6,579	6,580	6,596	6,646	6,416	6,517	6,599	6,078	6,135	6,336	6,393	6,449	6,506	6,562	6,619	6,711	6,768	6,814	6,870
Reserve Margin (15% minimum)	**21%**	**23%**	**21%**	**24%**	**25%**	**21%**	**25%**	**26%**	**16%**	**16%**	**20%**	**20%**	**20%**	**21%**	**21%**	**21%**	**22%**	**22%**	**23%**	**23%**

B. SHORT-TERM ACTION PLAN

The preferred portfolio for the 2018 IRP calls for little change through 2021. We will implement the EE programs approved under Cause No. 43955 DSM-4, we will complete approximately 8 MW of new solar capacity that is currently in development, and a contract to purchase 8 MW of CT capacity will expire. Additionally, we will install a total of approximately 15 MW of battery energy storage systems at Crane Naval Station, the Indiana National Guard's Camp Atterbury, and a substation in Nabb, Indiana, providing grid support and backup power to critical facilities.

C. PREFERRED PORTFOLIOS ABILITY TO ADAPT TO CHANGING CONDITIONS

One of the benefits of increasing the diversity of the generating fleet is the increased flexibility that can be leveraged in the face of a changing world. Given the measured pace of transition, the company can adjust its plans accordingly. For example, if load grows more or less than expected, the plan could adjust by accelerating or slowing down implementation of the preferred portfolio. If the relative cost of a resource should change from what is being evaluated in this IRP, the company can take advantage of resources with improved economics and move away from those resources whose relative economics have worsened. This could happen due a resources capital costs, O&M costs, environmental compliance costs, or other regulatory requirements

D. VARIABLES TO MONITOR AND ONGOING IMPROVEMENTS TO IRP PROCESS

While the preferred portfolio for the 2018 IRP includes resource choices specified through 2037, it is important to remember that resource planning is an ongoing, iterative process. Every three years we reassess the state of our operating environment and adjust our plans accordingly. The IRP will be updated again in 2021, at which time we will adapt the resource selections based on new forecasts and technical, market, and political insights. Key factors to monitor ahead of the 2021 IRP will be:

- The outcome of the 2020 elections
- Renewable energy and carbon policy at the state and local levels
- The cost trends for solar, wind, and batteries
- The evolution of MISO market rules for renewables and storage

- Natural gas prices

In addition to tracking factors external to the company, we are working on improving our IRP analysis in the following ways:

- More detailed load forecasting informed by data from advanced meters
- Adoption of new modeling tools better equipped to capture the complexities of the changing power industry
- Improved cost forecasting for supply-side resources

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Appendix A:
Financial & Operating Forecasts For Preferred Portfolio

Table A.1: Production plus Capital Costs of Preferred Portfolio Under Each Scenario

Scenario: Year	Reference Case	Reference, No Carbon	High Tech Future	Slower Innovation	Current Conditions
2018	$887	$887	$890	$872	$887
2019	$899	$899	$908	$864	$899
2020	$888	$888	$899	$853	$887
2021	$868	$868	$881	$841	$866
2022	$915	$915	$926	$873	$911
2023	$947	$947	$959	$912	$943
2024	$974	$974	$983	$950	$970
2025	$1,192	$1,027	$1,316	$1,010	$1,012
2026	$1,344	$1,092	$1,448	$1,101	$1,066
2027	$1,494	$1,159	$1,585	$1,193	$1,121
2028	$1,643	$1,241	$1,687	$1,308	$1,180
2029	$1,833	$1,372	$1,844	$1,501	$1,269
2030	$1,968	$1,436	$1,974	$1,567	$1,311
2031	$2,077	$1,482	$2,067	$1,609	$1,364
2032	$2,221	$1,549	$2,188	$1,666	$1,413
2033	$2,355	$1,621	$2,314	$1,750	$1,464
2034	$2,503	$1,804	$2,388	$2,025	$1,593
2035	$2,646	$1,935	$2,501	$2,206	$1,695
2036	$2,743	$1,989	$2,560	$2,273	$1,758
2037	$2,885	$2,073	$2,680	$2,368	$1,812

Table A.2: Real Levelized PVRR (2018$/kWh) of Candidate Portfolios in Reference Case Scenario (using real discount rate of 4.56%)

Portfolio	PVRR $/kWh
Current Conditions	$0.044
Slower Innovation	$0.045
Ref NCL	$0.044
Reference	$0.044
High Tech Future	$0.046
Moderate Transition	$0.046
Aggressive Transition	$0.047
Rapid Decarbonization: CT	$0.047
Rapid Decarbonization: Batteries	$0.048

Note: IRP PVRR excludes all existing generation, transmission, and distribution rate base as well as unavoidable future expenditures. It would not be appropriate to compare these figures to market energy prices or utility rates.

Table A.3: Fuel Price Forecast by Generating Station Under Reference Case Scenario (nominal $/MMBtu)

[redacted]

Table A.4: Projected Air Emissions and Water Usage for Existing and Potential New Units Under Reference Case Scenario

	Air Emissions and Water Usage - Existing Units						Air Emissions and Water Usage - Potential New Units					
					Water						Water	
	CO2	NOx	SO2	Mercury	Consumed	Discharged	CO2	NOx	SO2	Mercury	Consumed	Discharged
Year	kTons	kTons	kTons	Pounds	Mgal	Mgal	kTons	kTons	kTons	Pounds	Mgal	Mgal
2018	27,772	12	23	96	15,954	192,634	-	-	-	-	-	-
2019	28,694	13	23	98	15,861	213,264	-	-	-	-	-	-
2020	29,228	12	23	98	15,727	218,410	-	-	-	-	-	-
2021	30,399	12	23	103	16,440	220,565	49	-	-	-	21	2
2022	28,969	9	22	95	15,490	205,307	100	-	-	-	42	5
2023	27,671	7	20	91	14,913	197,019	100	-	-	-	42	5
2024	26,753	7	19	88	14,787	184,677	157	-	-	-	66	7
2025	18,904	5	13	59	11,396	143,332	201	-	-	-	85	9
2026	15,798	4	10	47	9,568	145,105	258	-	-	-	108	12
2027	14,635	3	9	43	8,679	147,831	301	-	-	-	127	14
2028	13,129	3	9	37	8,533	123,863	2,153	0.1	-	-	1,075	301
2029	13,170	3	9	38	8,775	117,898	3,416	0.2	-	-	1,729	500
2030	13,451	3	10	38	8,829	117,925	3,428	0.2	-	-	1,738	502
2031	9,480	2	6	25	6,765	117,853	3,608	0.2	-	-	1,825	529
2032	7,726	2	4	18	5,836	117,880	3,580	0.2	-	-	1,812	525
2033	8,758	2	5	22	6,321	117,862	3,595	0.2	-	-	1,822	528
2034	5,803	1	3	12	4,821	117,856	5,649	0.3	-	-	2,862	843
2035	4,950	1	2	10	4,424	117,824	7,061	0.4	-	-	3,587	1,063
2036	3,562	1	1	7	3,869	117,749	7,179	0.4	-	-	3,634	1,077
2037	4,492	1	2	9	4,248	117,783	7,148	0.4	-	-	3,619	1,072

Table A.5: Emissions Allowances and CO_2 Price Forecasts

[redacted]

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Appendix B: Load Forecast

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. Please contact Kelley Karn at 317-837-2461 for more information.

Section 12. 17 IAC 4-7-5 Energy and Demand Forecasts

Figure B.1: Annual Load Shapes

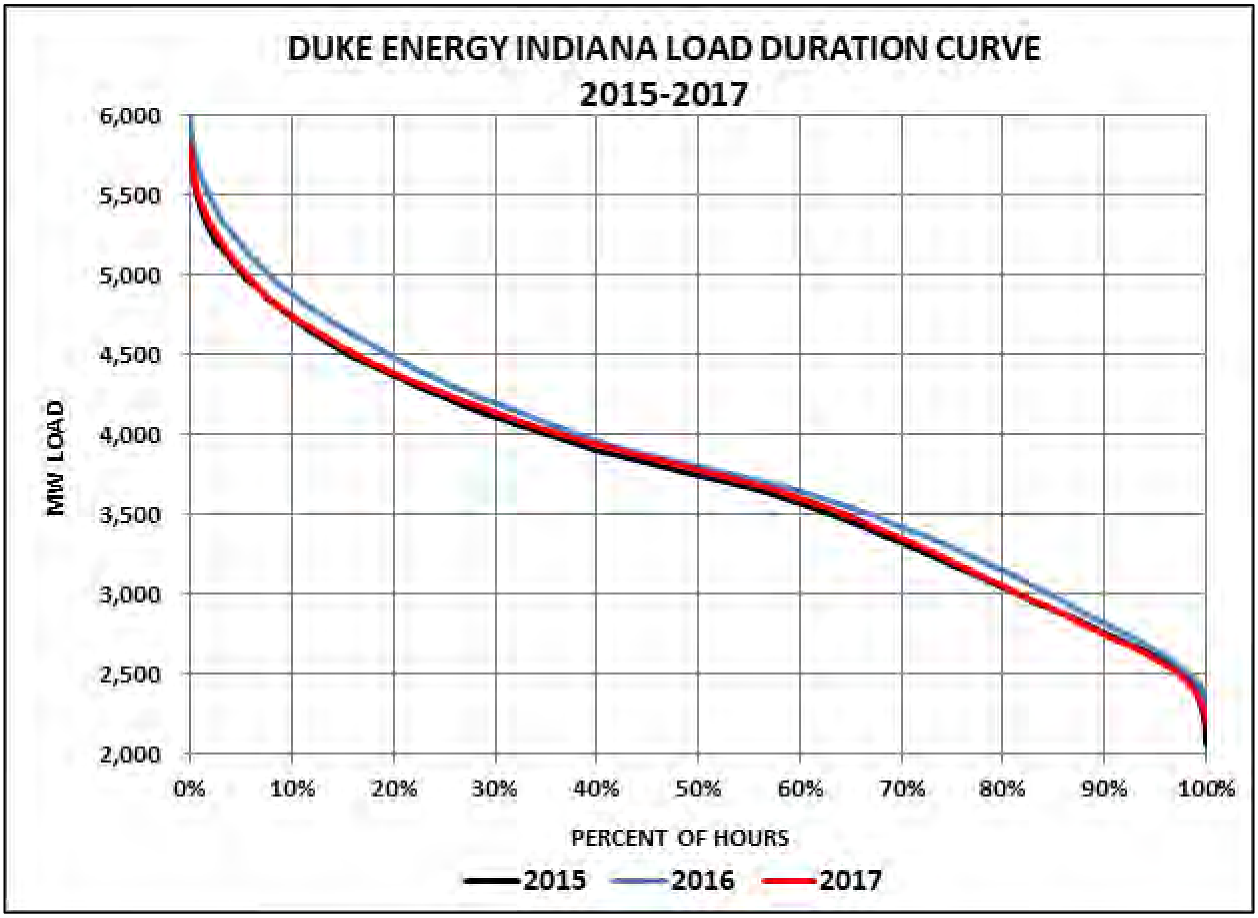
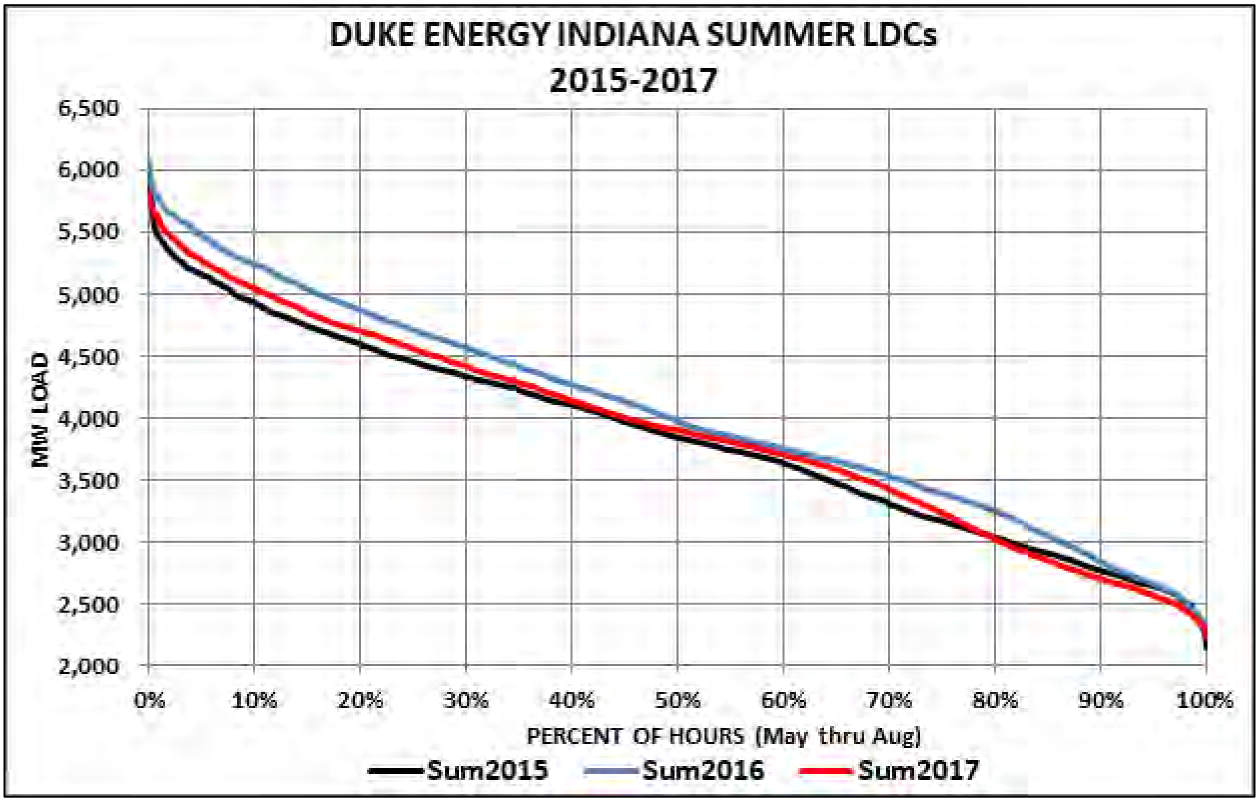


Figure B.2: Seasonal Load Shapes



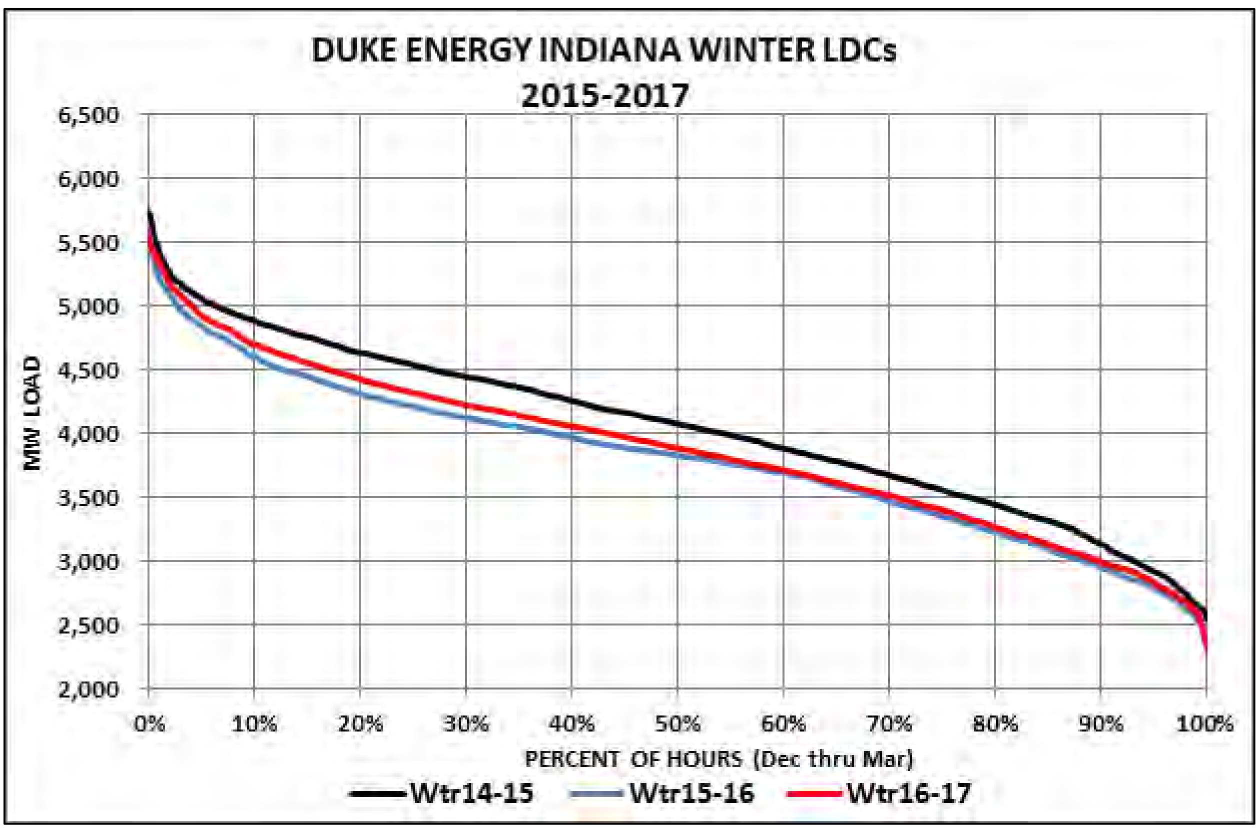
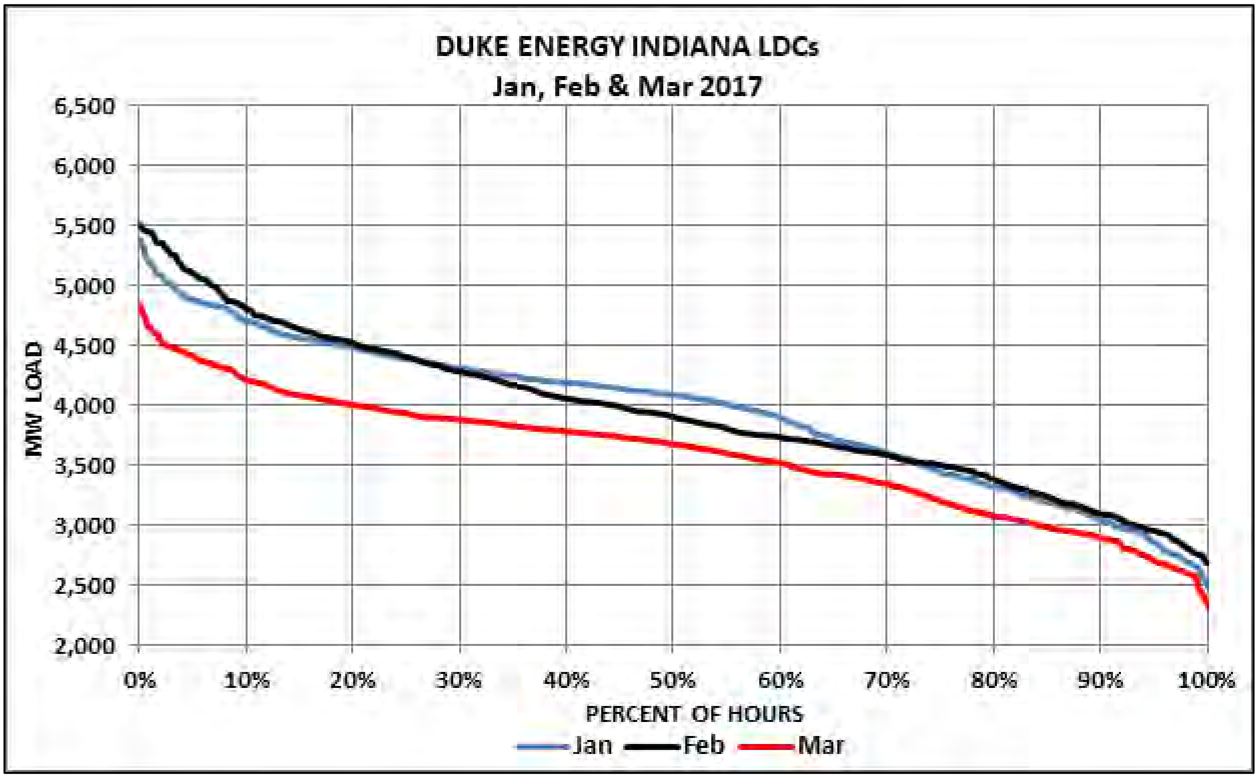


Figure B.3: Monthly Load Shapes



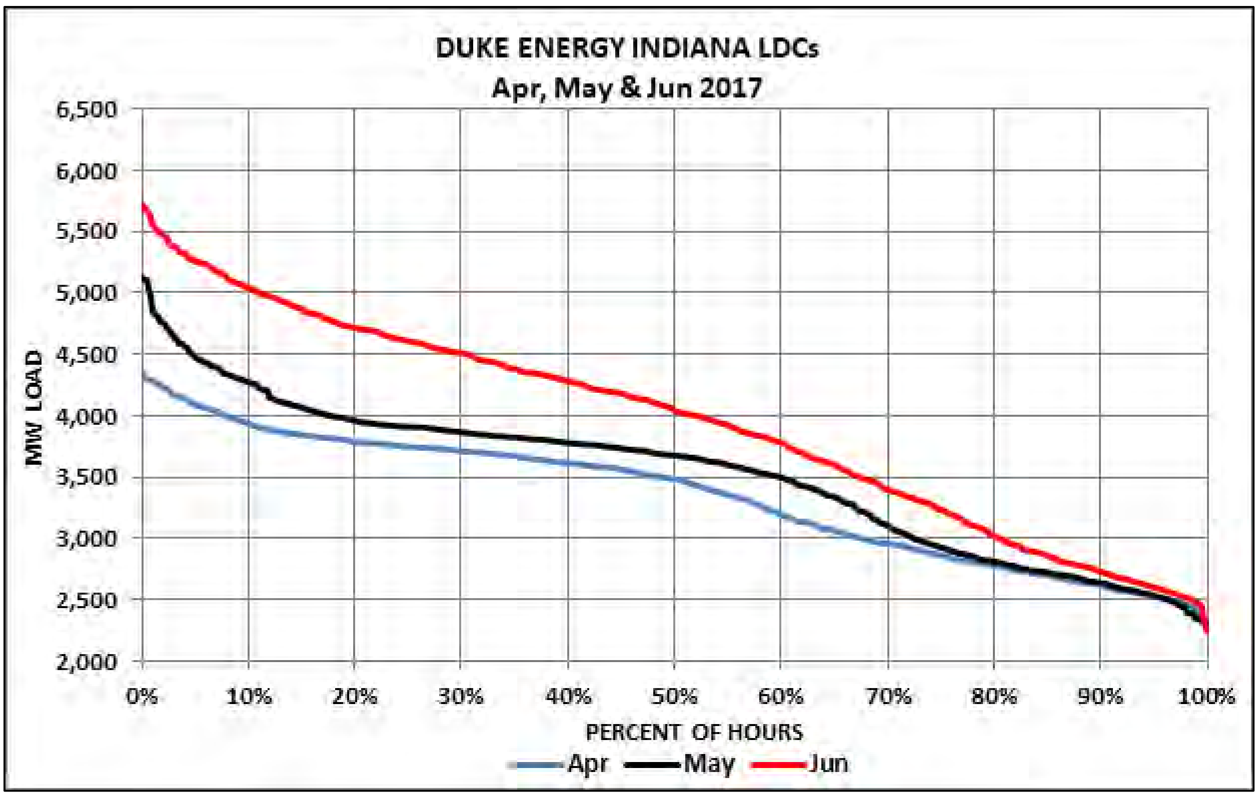
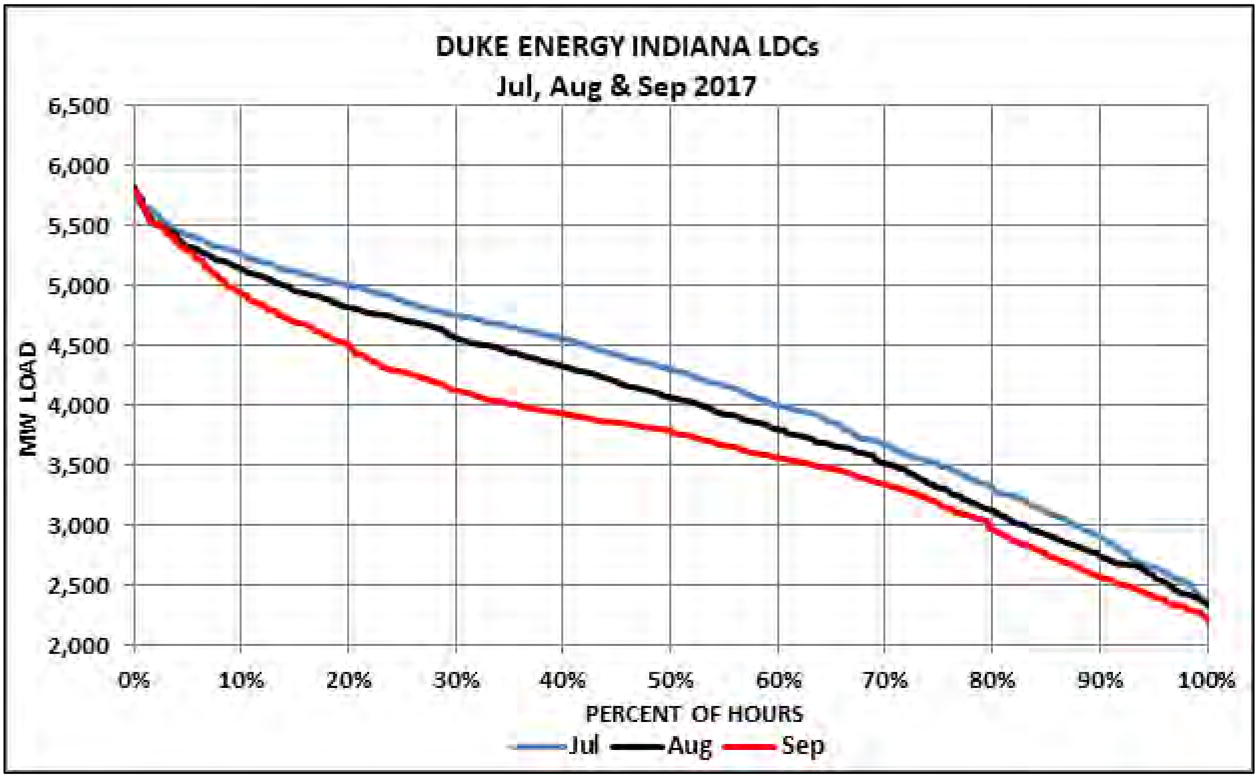


Figure B.3: Monthly Load Shapes (con't.)



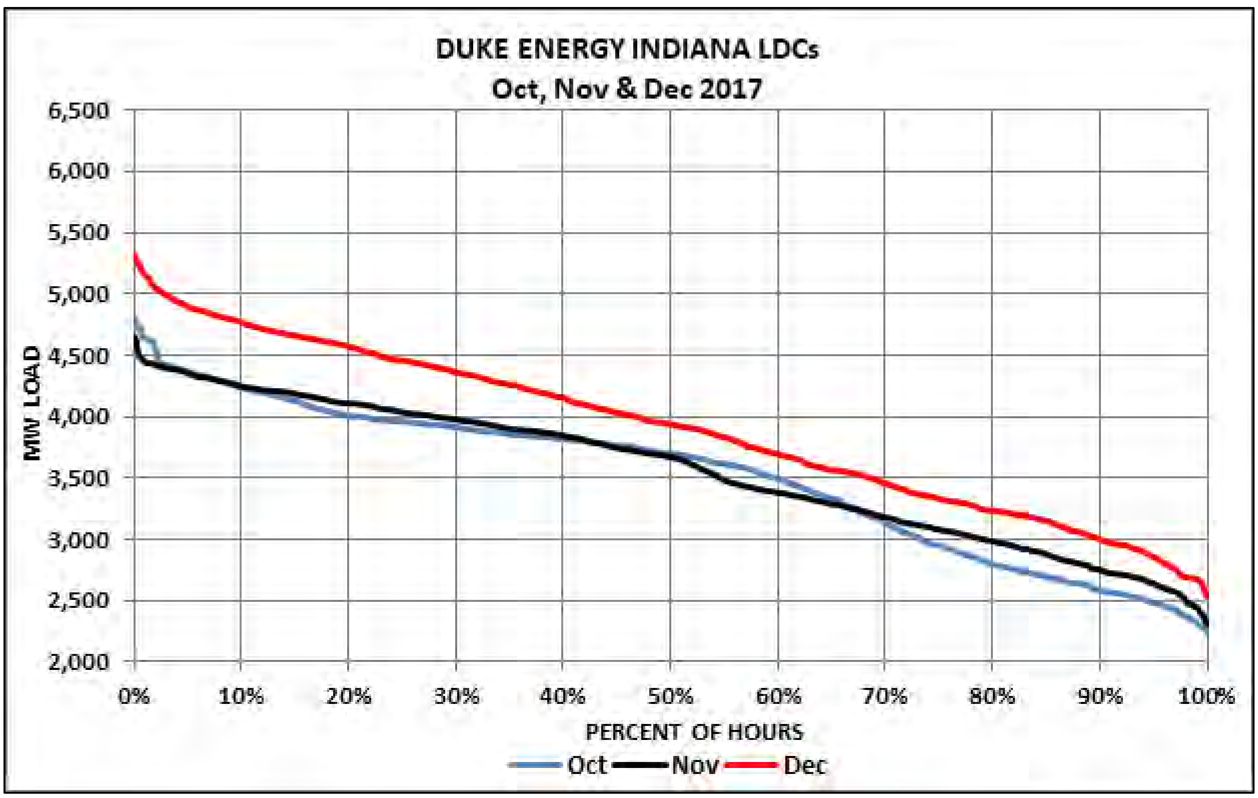
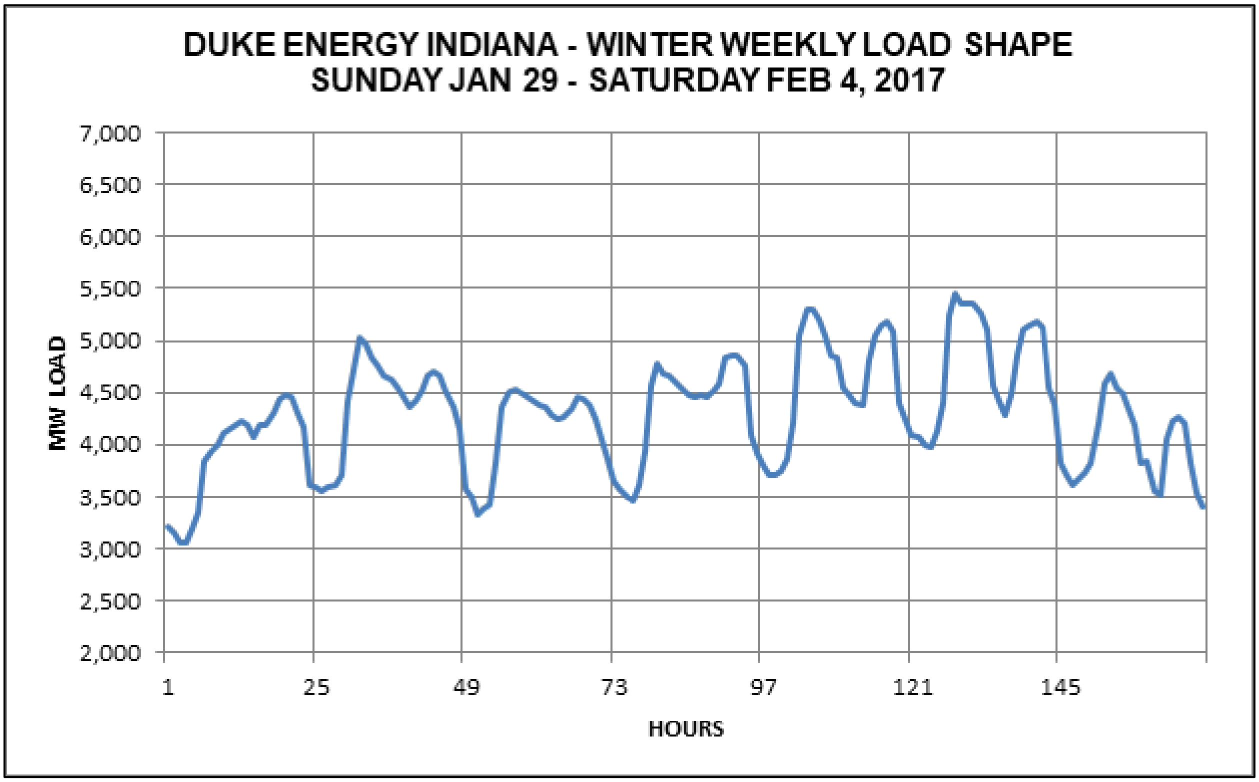


Figure B.4: Selected Weekly Load Shapes



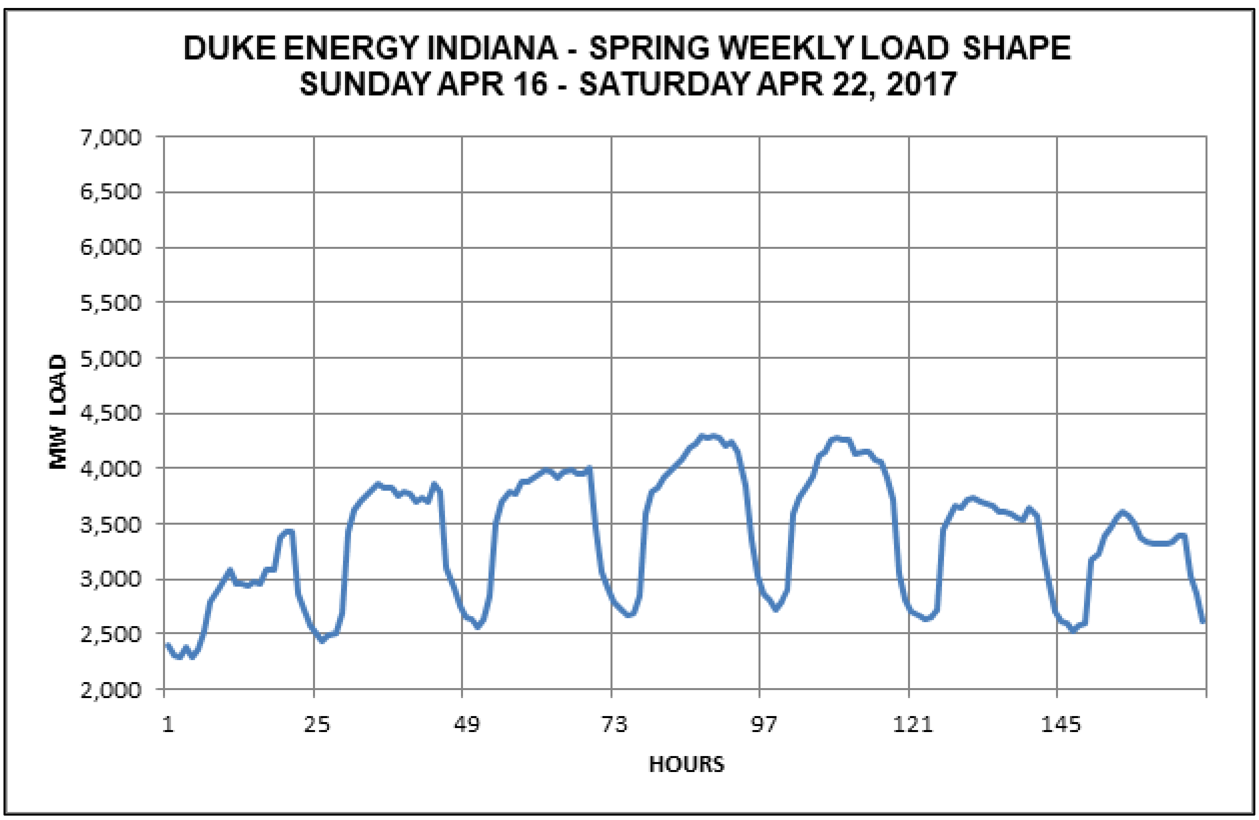
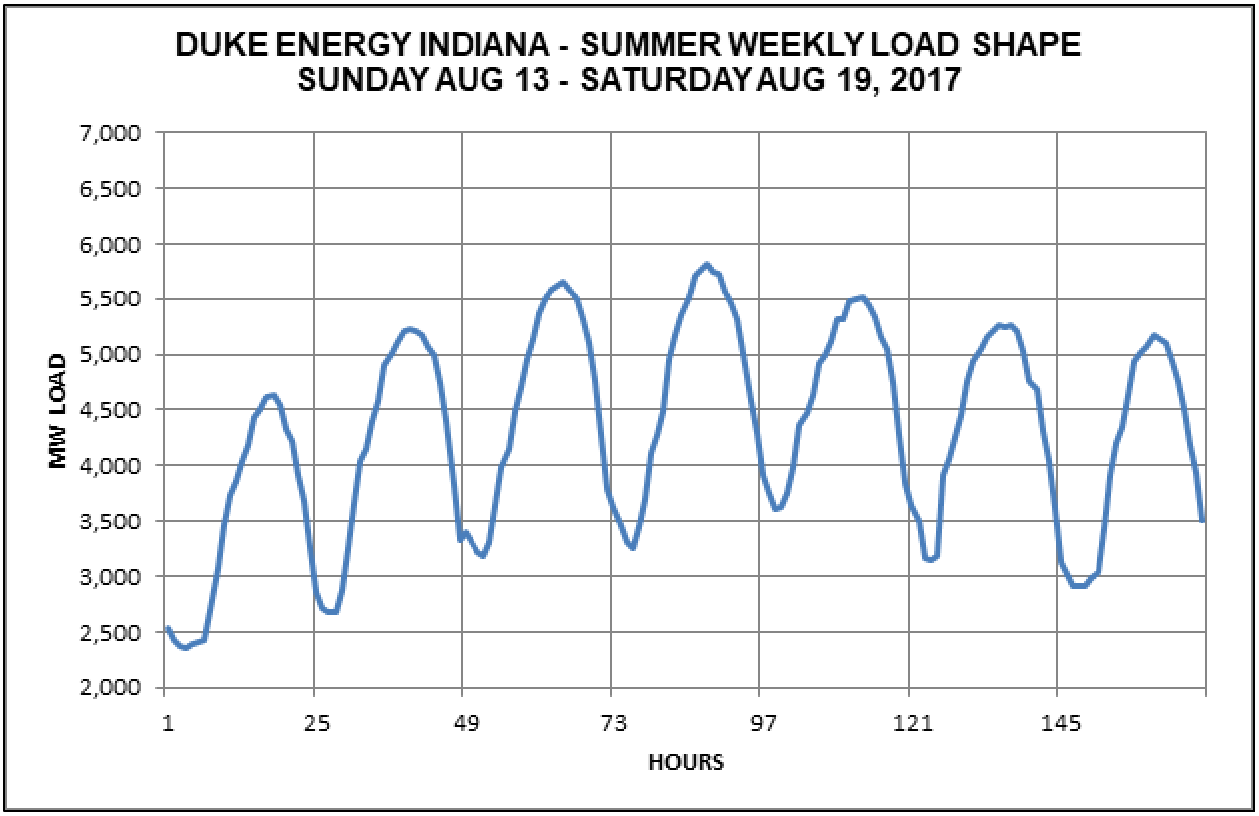


Figure B.4: Selected Weekly Load Shapes (con't.)



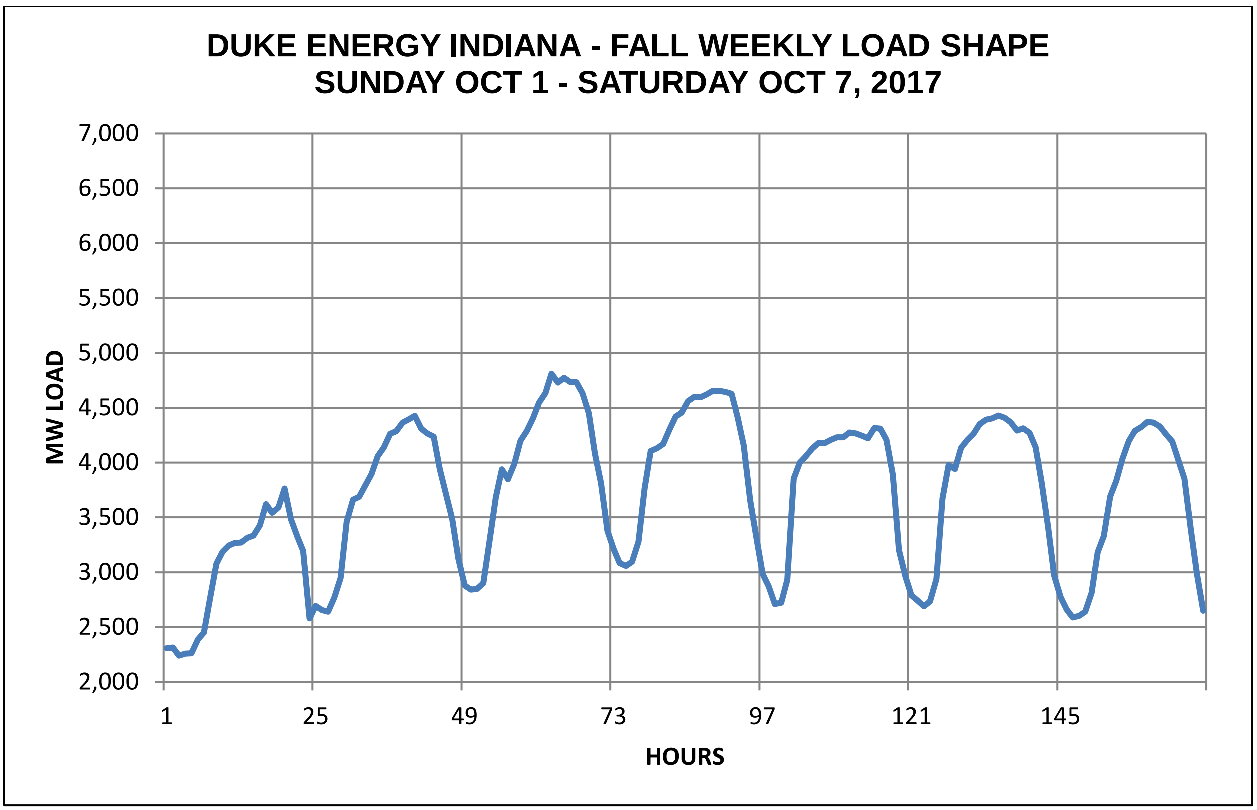
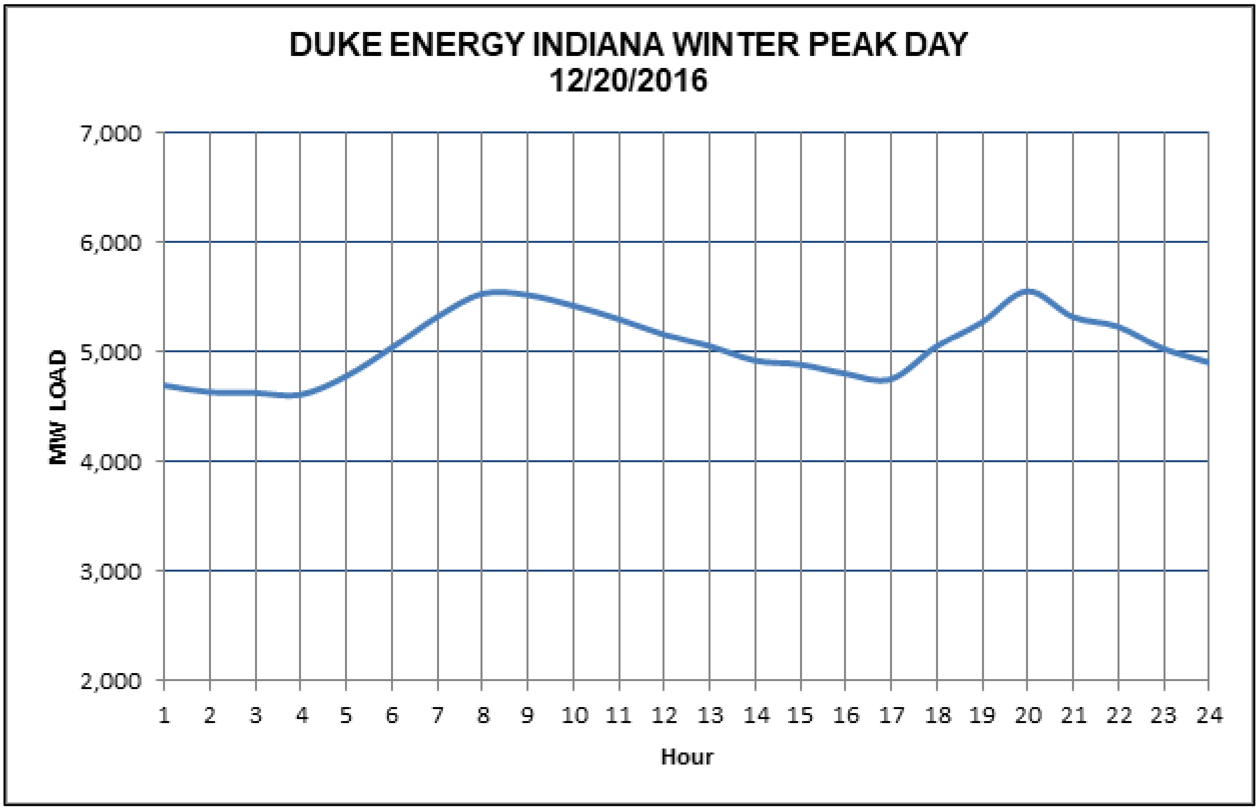


Figure B.5: Selected Daily Load Shapes – Winter Peak Day, Summer Peak Day



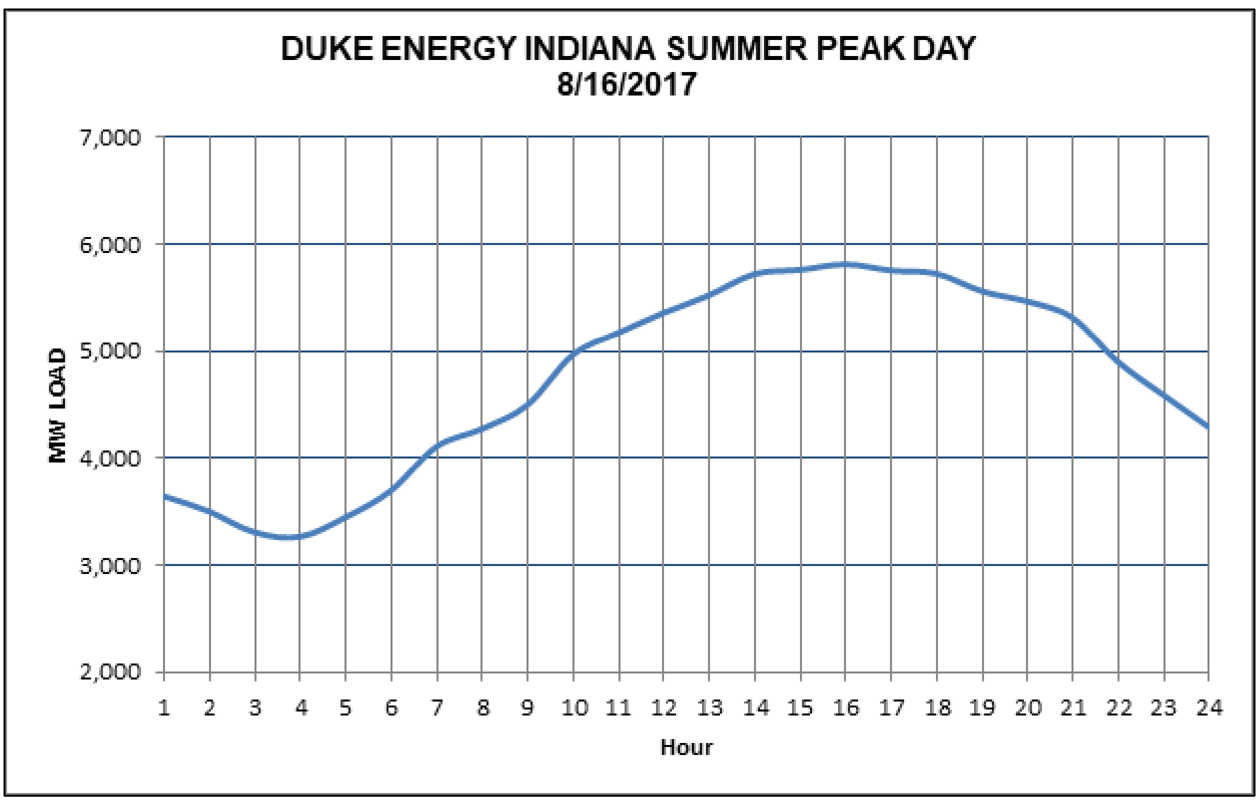
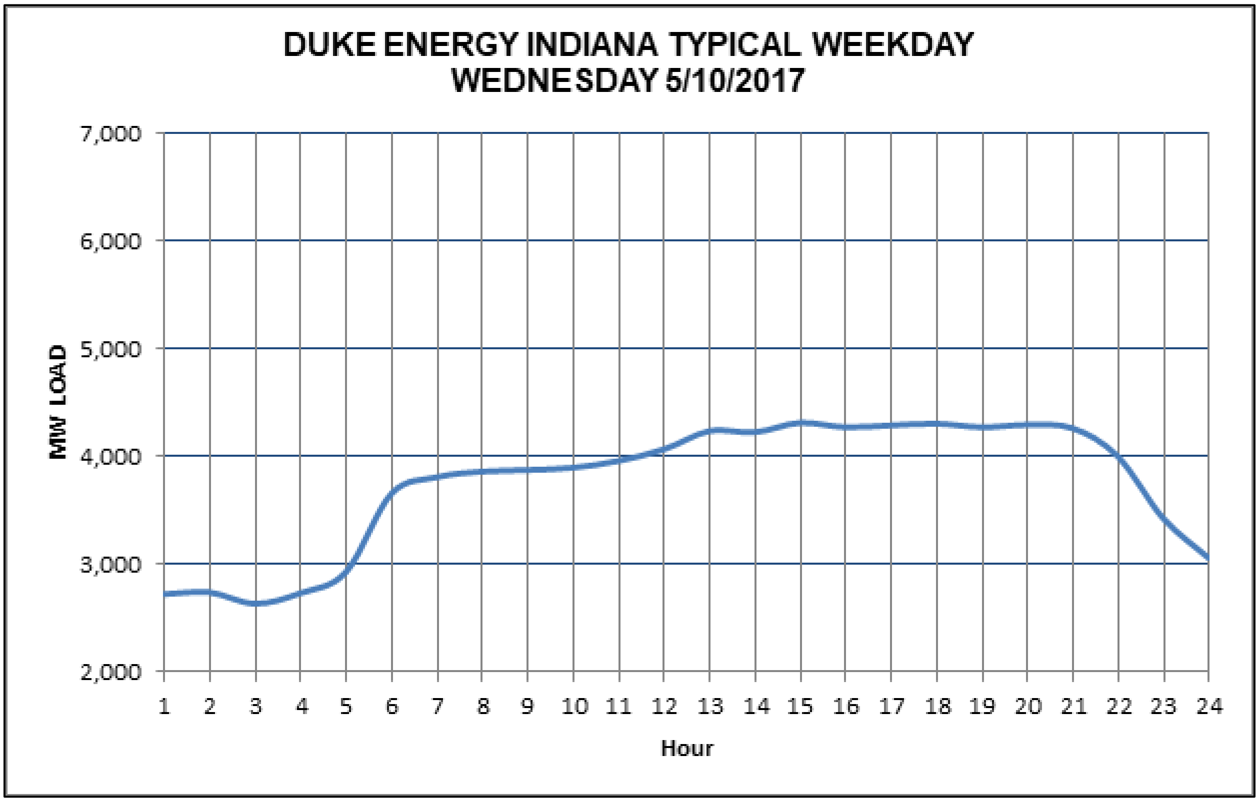


Figure B.6: Selected Daily Load Shapes – Typical Weekday, Typical Weekend



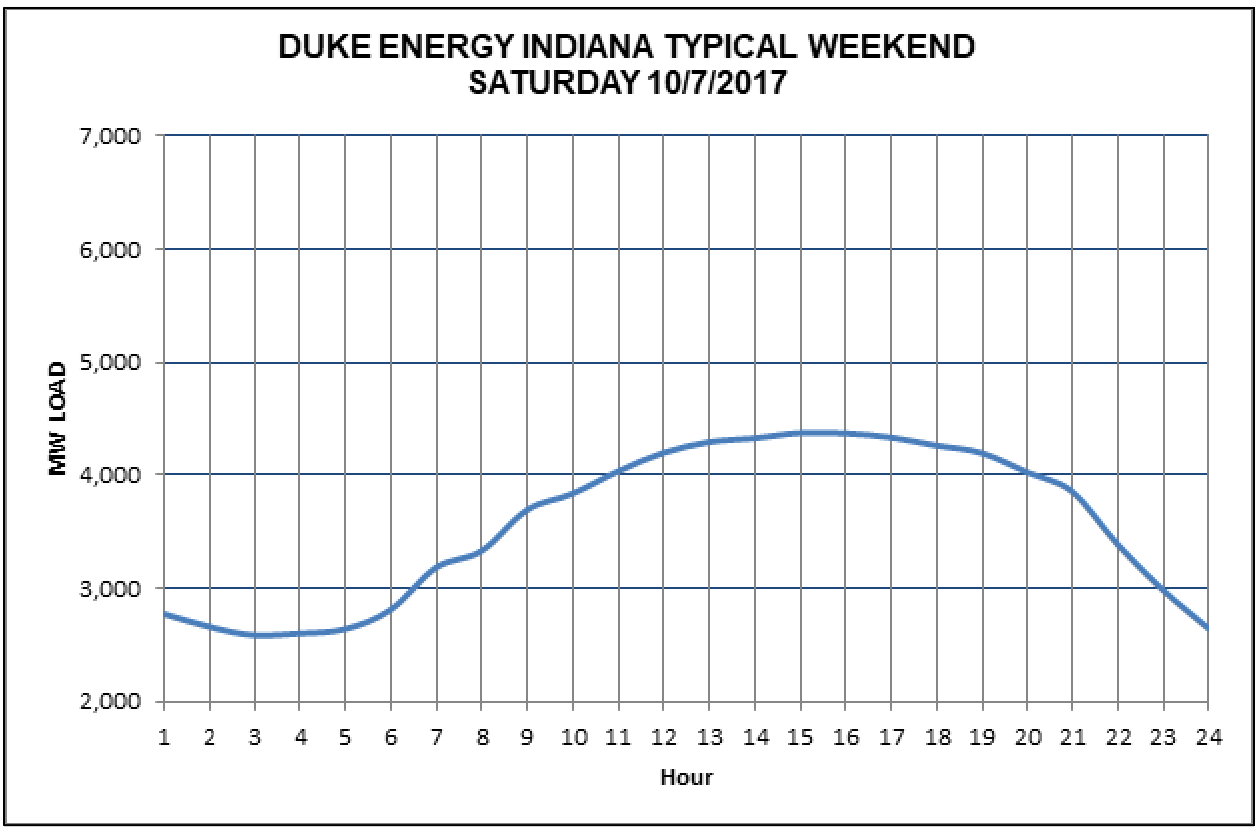


Table B.1:

Sec 5(a)(2)(A) Disaggregation of historical and forecast energy and customer data by customer class

Year	Residential GWh	Commercial GWh	Industrial GWh	Other GWh	Retail GWh	Residential Custs	Commercial Custs	Industrial Custs	Other Custs	Retail Custs
History:										
2008	9,313	6,274	10,807	2,339	28,733	673,414	89,544	2,842	10,847	776,647
2009	8,884	6,007	9,029	2,312	26,232	672,740	89,410	2,814	11,180	776,144
2010	9,648	6,219	10,097	2,308	28,272	677,998	89,554	2,790	11,477	781,819
2011	9,182	6,135	10,167	2,247	27,731	679,348	89,493	2,754	11,700	783,295
2012	8,941	6,173	10,449	2,223	27,787	683,335	89,861	2,734	11,691	787,621
2013	9,232	6,203	10,449	2,224	28,109	688,302	89,973	2,726	11,754	792,756
2014	9,285	6,197	10,643	2,216	28,341	693,006	90,117	2,708	11,749	797,579
2015	8,924	6,245	10,505	2,147	27,821	699,940	90,381	2,707	11,794	804,822
2016	9,036	6,322	10,565	2,136	28,058	707,782	90,688	2,721	11,795	812,986
2017	8,645	6,146	10,599	2,107	27,496	714,024	91,018	2,718	11,808	819,569
Forecast:										
2018	8,890	6,155	10,705	2,108	27,858	720,140	91,308	2,721	11,835	826,004
2019	8,855	6,177	10,844	2,112	27,988	726,125	91,502	2,721	11,858	832,205
2020	8,854	6,217	10,997	2,130	28,198	731,987	91,652	2,720	11,878	838,237
2021	8,792	6,218	11,091	2,136	28,236	737,663	91,804	2,718	11,898	844,082
2022	8,764	6,248	11,165	2,140	28,318	743,472	92,001	2,716	11,915	850,104
2023	8,744	6,292	11,202	2,144	28,381	749,294	92,210	2,712	11,931	856,147
2024	8,778	6,371	11,297	2,152	28,599	755,191	92,420	2,708	11,946	862,265
2025	8,768	6,409	11,337	2,155	28,669	760,893	92,630	2,703	11,960	868,185
2026	8,796	6,455	11,389	2,158	28,798	766,611	92,839	2,696	11,972	874,118
2027	8,832	6,510	11,439	2,161	28,941	772,359	93,042	2,688	11,984	880,072
2028	8,909	6,594	11,533	2,168	29,203	778,345	93,238	2,678	11,994	886,255
2029	8,922	6,627	11,595	2,174	29,319	784,375	93,427	2,666	12,004	892,473
2030	8,952	6,647	11,661	2,183	29,443	790,361	93,614	2,654	12,012	898,642
2031	9,032	6,693	11,735	2,193	29,653	796,298	93,797	2,644	12,020	904,760
2032	9,133	6,749	11,828	2,200	29,910	802,049	93,977	2,636	12,028	910,690
2033	9,205	6,785	11,897	2,205	30,092	807,843	94,154	2,630	12,035	916,662
2034	9,315	6,849	11,965	2,213	30,343	813,723	94,327	2,626	12,041	922,717
2035	9,438	6,924	12,049	2,222	30,633	819,260	94,499	2,624	12,047	928,429
2036	9,581	7,021	12,157	2,234	30,992	824,261	94,668	2,624	12,052	933,605
2037	9,717	7,094	12,231	2,244	31,285	832,009	94,832	2,624	12,057	941,522
2038	9,838	7,184	12,324	2,255	31,600	836,480	94,991	2,624	12,061	946,156

Table B.2: Actual and weather normalized energy and demand

Year	Energy Actual GWh	Energy W/Normal GWh	Summer Actual MW	Summer W/Normal MW
History:				
2008	33,623	33,747	6,243	6,493
2009	31,025	31,366	6,037	6,194
2010	33,101	34,104	6,476	6,491
2011	32,060	31,726	6,749	6,490
2012	32,129	32,001	6,494	6,510
2013	32,315	32,265	6,229	6,461
2014	32,094	32,036	5,830	6,084
2015	31,530	31,545	5,863	6,008
2016	32,189	31,962	6,079	6,180
2017	31,445	31,676	5,838	5,988

Sec 5(a)(4) A discussion of methods and processes used to weather normalize

DEI weather normalizes weather sensitive energy sales and peak demands to an average 30-year condition using the Indianapolis Airport weather station. This normal weather series is updated every year by adding the latest complete new year and dropping the earliest complete year. When a forecast is developed and released with a specific 30-Year normal, every new actual energy and peak data points thereafter will be normalized to the "normal" weather it was projected with.

The DEI weather normalization of energy sales applies a daily modeling procedure that incorporates daily DEI Load research data by class. This procedure, which is also the basis for class load profiles, selects weather variables (degree day base temperature) that best explains historical weather variation. Day-of-week variables capture non-weather variation as well. Each model's weather variable coefficient is multiplied by the difference between actual and normal series and summed by month to determine the weather adjustment. The difference between actual and normal weather conditions is multiplied by the specific weather variable's model coefficient. This results in a weather adjustment to energy.

The DEI weather normalization of peak demand is very similar but the weather in question deals with the weather on each monthly peak day. Normal monthly peak weather is a 30-year average of extreme (hot and cold) degree days in each month. For Summer and Winter peak, typically January and July, a 30-year seasonal extreme is developed to account for the monthly variability of the seasonal peak. Again, the difference between actual weather and normal projected) weather is applied to a peak model weather coefficient.

Table B.3:

Sec 5(a)(5) A twenty (20) year period for peak demand and energy usage forecast.

Year	System Annual Peak MW	Retail Annual Peak MW	Wholesale Annual Peak MW	System Annual MWH	Retail Annual MWH	Wholesale Annual MWH	System Load Factor
2018	6,021	5,400	621	33,539,361	30,123,326	3,416,035	63.6%
2019	5,973	5,439	534	33,222,158	30,263,689	2,958,469	63.5%
2020	6,061	5,497	565	33,631,956	30,490,927	3,141,029	63.2%
2021	5,977	5,514	463	33,427,403	30,531,882	2,895,522	63.8%
2022	5,987	5,525	463	33,305,712	30,619,749	2,685,963	63.5%
2023	6,013	5,550	463	33,374,031	30,688,088	2,685,943	63.4%
2024	5,907	5,565	342	33,035,850	30,923,219	2,112,631	63.7%
2025	5,941	5,583	358	33,104,261	30,999,107	2,105,155	63.6%
2026	5,969	5,606	363	33,243,368	31,138,213	2,105,155	63.6%
2027	5,994	5,633	361	33,398,689	31,293,534	2,105,155	63.6%
2028	6,000	5,658	342	33,689,229	31,576,598	2,112,631	63.9%
2029	6,045	5,688	358	33,806,869	31,701,714	2,105,155	63.8%
2030	6,077	5,714	363	33,940,819	31,835,665	2,105,155	63.8%
2031	6,108	5,747	361	34,167,168	32,062,014	2,105,155	63.9%
2032	6,134	5,792	342	34,452,625	32,339,994	2,112,631	63.9%
2033	6,188	5,830	358	34,641,749	32,536,595	2,105,155	63.9%
2034	6,229	5,865	363	34,912,378	32,807,223	2,105,155	64.0%
2035	6,265	5,904	361	35,225,885	33,120,730	2,105,155	64.2%
2036	6,283	5,941	342	35,621,870	33,509,239	2,112,631	64.5%
2037	6,340	5,983	358	35,930,847	33,825,693	2,105,155	64.7%
2038	6,385	6,022	363	36,271,042	34,165,888	2,105,155	64.9%

Sec 5(a)(6-9) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years.

Any evaluation of the performance of peak demand and energy usage over the last ten years has to include the impact of the Great Recession. The economic collapse of 2009 and the painfully slow economic rebound created by imbalances in the U.S. financial system was only exceeded by the Great Depression of 1929-1938. The destruction of wealth and jobs set utility growth rates in customer growth and energy usage back several years. Only recently has normal levels of basic economic growth stimulated any semblance of growth in energy sales and customer growth for DEI.

A second industry event occurring over the last ten years that must be mentioned is the availability of merchant generation. Cheap natural gas (central station or customer self-service) generation and subsidized renewable generation has resulted in low-cost generation options for Sales for Resale or wholesale service municipals and cooperatives. DEI has gone through a material drop in Sales for Resale.

A third factor impacting the level of growth in DEI peak and energy sales is the adoption of federally mandated highly efficient residential and commercial sector appliances and utility sponsored programs offered to help spur more efficient use of electricity. DEI has observed that the residential and commercial classes are more likely to participate in utility energy efficiency programs with the current legislative landscape in Indiana for large industrial customers enabled to opt-out of EE programs. Industrial customers are able to implement their own cost saving efforts, measures which result in reducing both, kWh usage and billing demand charges.

Each of these events have worked to reduce electric energy sales growth and even shrink the average annual kWh use per residential customer for several years. It forced DEI to move to the Itron SAE (Statistically Adjusted End-use) forecast methodology. We have found this approach to best capture the changing levels of more efficient appliances saturating through the residential households and commercial class end-uses.

While DEI has been projecting impacts of roof-top solar and electric vehicles upon the energy and peak demand projections for several years, there are improvements in the works applying actual (more local) solar load shapes and EV “charging time” data to improve our understand these influences upon class hourly load shapes.

Sec 5(b)(1-3) An evaluation of plausible risk boundaries or alternative forecasts of peak demand and energy use.

DEI will often perform a High-Low scenario around a Base Case. All three projections were centered around three economic scenarios developed in January 2018 by Moody’s Analytics. The publishing address for Moody’s Analytics is 121 North Walnut Street, West Chester, PA 19380.

The source title for all scenarios is **Moody’s Analytics US Forecast Database** and the **Indiana State Forecast Database**. Their **Consensus (“CF”) scenario** was used for the DEI base case projection. This scenario is designed to incorporate the central tendency of a range of baseline forecasts produced by various institutions. Since the result is itself a baseline, by definition, the probability that the economy will perform better than this consensus is equal to the probability that it will perform worse. A high case or **Stronger Near-Term Growth ("S1") Scenario** is designed so that there is a 10% probability that the economy will perform better than in this scenario, broadly speaking, and a 90% probability that it will perform worse. This scenario assumes that the better than expected increase in the stock market and growth in corporate earnings in 2018 lift business sentiment more than anticipated, leading to a greater than expected rise in business investment. Further, the policies of the Trump administration support faster than expected growth without triggering a trade war.

The low case or, **Moderate Recession (“S3”) Scenario,** there is a 90% probability that the economy will perform better, broadly speaking, and a 10% probability that it will perform worse. were applied for high-Low energy and peak projections. In this scenario, the stock market sells off because of the belief that it was overvalued and that the policies of the Trump administration, particularly regarding international trade, immigration and healthcare, will weaken the U.S. economy. The reduction in wealth causes consumer spending to decline.

Table B.:

Sec 5(b)(1-3) Low - Base - High Energy & Peak Scenarios

Annual System Requirements (MWH)						Annual System Peak (MW)					
Year	Low		Base		High	Year	Low		Base		High
2018	33,110,064	*-1.3%*	33,539,361	*0.3%*	33,650,983	2018	5,932	*-1.5%*	6,021	*0.4%*	6,044
2019	32,103,505	*-3.4%*	33,222,158	*0.9%*	33,513,261	2019	5,768	*-3.4%*	5,973	*0.9%*	6,028
2020	32,630,633	*-3 0%*	33,631,956	*1.0%*	33,974,686	2020	5,885	*-2.9%*	6,061	*1.0%*	6,125
2021	32,604,637	*-2.5%*	33,427,403	*1.1%*	33,809,855	2021	5,831	*-2.4%*	5,977	*1.2%*	6,048
2022	32,505,611	*-2.4%*	33,305,712	*1.2%*	33,720,074	2022	5,844	*-2.4%*	5,987	*1.3%*	6,064
2023	32,564,919	*-2.4%*	33,374,031	*1.3%*	33,805,313	2023	5,868	*-2.4%*	6,013	*1.3%*	6,092
2024	32,188,762	*-2.6%*	33,035,850	*1.4%*	33,492,186	2024	5,755	*-2.6%*	5,907	*1.4%*	5,991
2025	32,228,469	*-2.6%*	33,104,261	*1.5%*	33,591,467	2025	5,783	*-2.7%*	5,941	*1.5%*	6,031
2026	32,343,278	*-2.7%*	33,243,368	*1.5%*	33,751,774	2026	5,807	*-2.7%*	5,969	*1.6%*	6,063
2027	32,477,272	*-2 8%*	33,398,689	*1.6%*	33,923,472	2027	5,828	*-2.8%*	5,994	*1.6%*	6,091
2028	32,745,050	*-2 8%*	33,689,229	*1.6%*	34,231,612	2028	5,830	*-2.8%*	6,000	*1.7%*	6,101
2029	32,847,699	*-2 8%*	33,806,869	*1.7%*	34,365,140	2029	5,874	*-2.8%*	6,045	*1.7%*	6,148
2030	32,967,855	*-2.9%*	33,940,819	*1.7%*	34,508,326	2030	5,903	*-2.9%*	6,077	*1.7%*	6,182
2031	33,179,930	*-2.9%*	34,167,168	*1.7%*	34,750,009	2031	5,931	*-2.9%*	6,108	*1.8%*	6,216
2032	33,450,809	*-2.9%*	34,452,625	*1.7%*	35,054,600	2032	5,954	*-2.9%*	6,134	*1.8%*	6,244
2033	33,623,841	*-2.9%*	34,641,749	*1.8%*	35,256,586	2033	6,004	*-3.0%*	6,188	*1.8%*	6,301
2034	33,878,385	*-3 0%*	34,912,378	*1.8%*	35,540,762	2034	6,042	*-3.0%*	6,229	*1.9%*	6,344
2035	34,175,361	*-3 0%*	35,225,885	*1.8%*	35,869,840	2035	6,075	*-3.0%*	6,265	*1.9%*	6,384
2036	34,550,822	*-3 0%*	35,621,870	*1.8%*	36,279,141	2036	6,089	*-3.1%*	6,283	*1.9%*	6,404
2037	34,841,657	*-3 0%*	35,930,847	*1.9%*	36,600,702	2037	6,143	*-3.1%*	6,340	*2.0%*	6,465
2038	35,162,682	*-3.1%*	36,271,042	*1.9%*	36,956,508	2038	6,184	*-3.1%*	6,385	*2.0%*	6,513
CAGR:						**CAGR:**					
2018-38	*0.3%*		*0.4%*		*0.5%*	2018-38	*0.2%*		*0.3%*		*0.4%*

The scenario results above reflect the application of each scenario's specific economic input series into the base case model.

The Duke Energy Indiana Updated 2018 Integrated Resource Plan

March 23, 2020

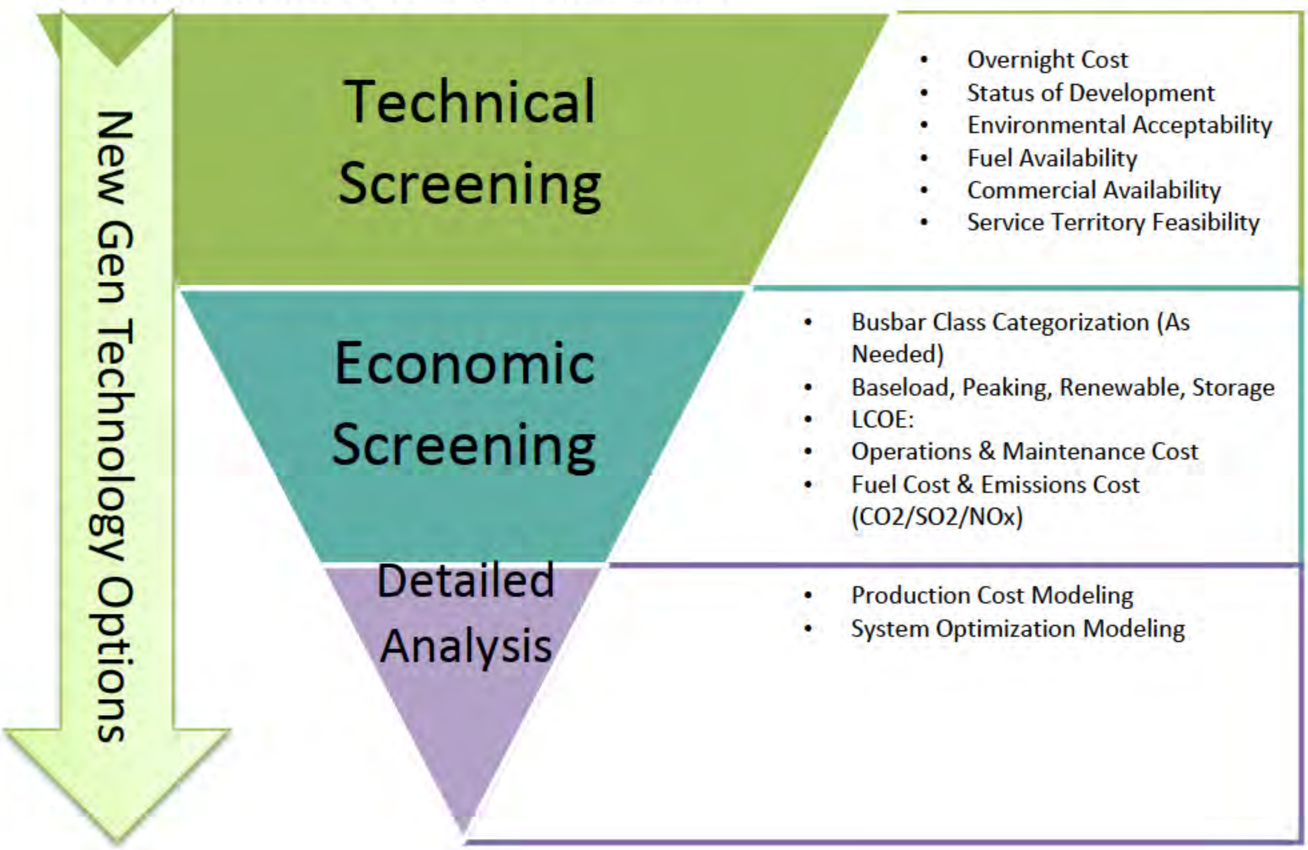
Appendix C: Supply-Side Resources

1. INTRODUCTION

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective and an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues and feasibility in the Duke Energy Indiana service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

Figure C.1: New Generation Technologies Screening Process

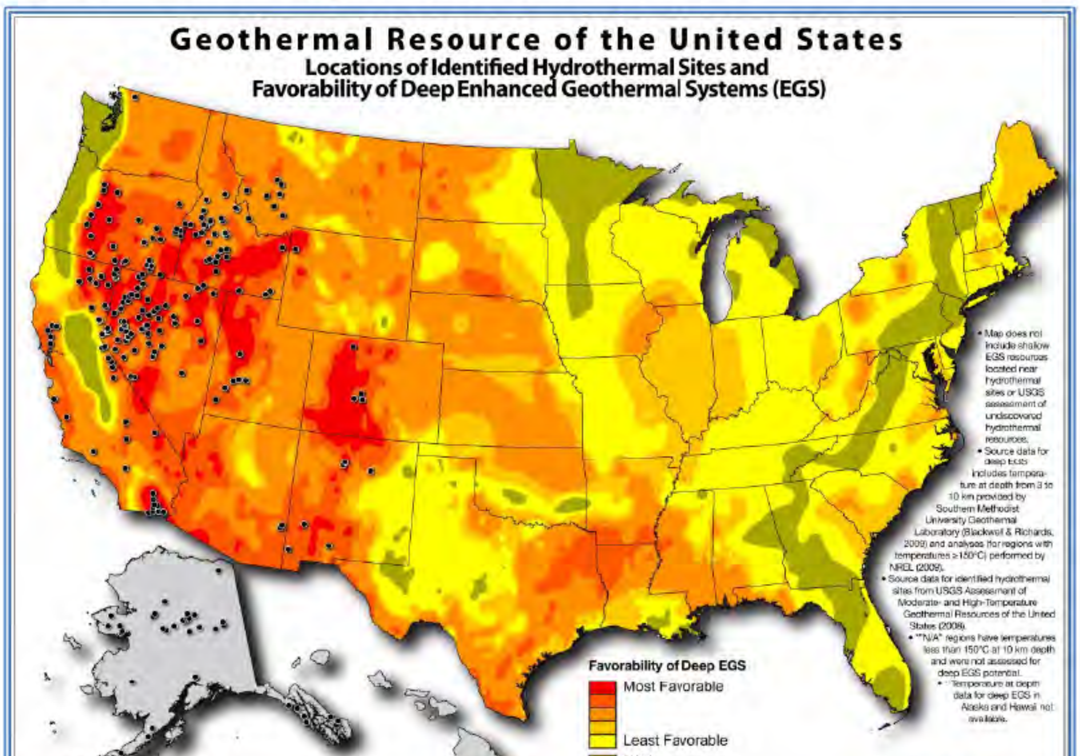


2. TECHNICAL SCREENING

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 cannot feasibly serve 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.

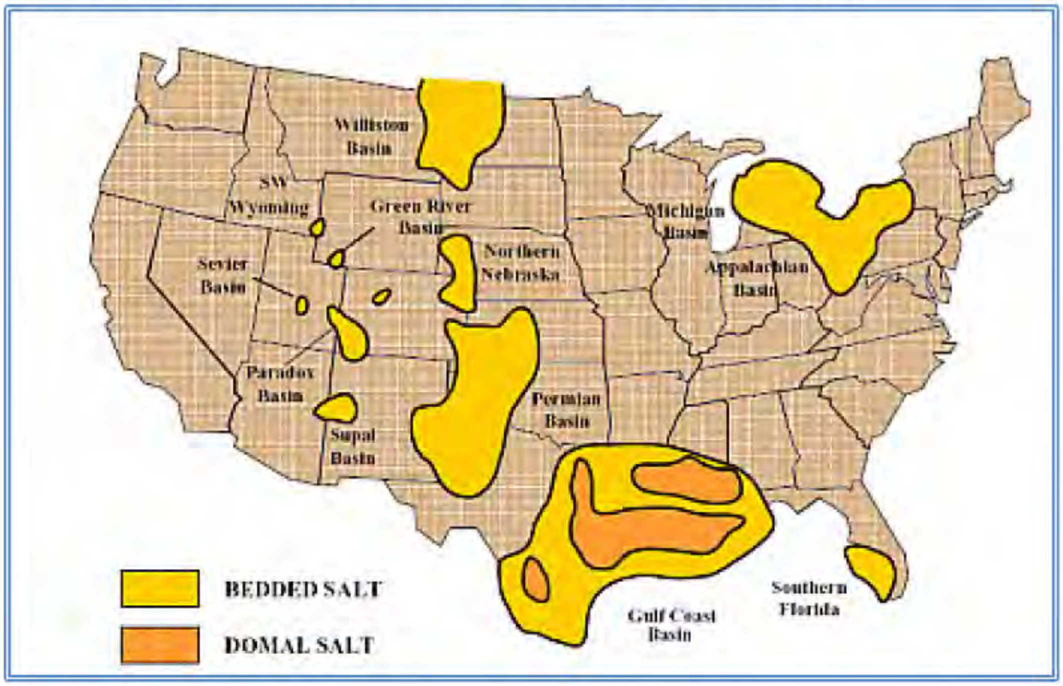
Figure C.2: Geothermal Map of the US (Source: NREL)



- **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir. When the electric grid needs more electricity and when electricity prices are higher, water is released from the upper reservoir. As the water flows from the upper reservoir to the lower reservoir, it goes through a hydroelectric turbine to generate electricity. Many operational pumped storage hydropower plants are providing electric reliability and reserves for the electric grid in high demand situations. PSH can provide a high amount of power because its only limitation is the capacity of the upper reservoir. Typically, these plants can be as large as 4,000 MW and have an efficiency of 76% - 85% (EPRI, 2012). Therefore, this technology is effective at meeting electric demand and transmission overload by shifting, storing, and producing electricity. This is important because an increasing supply of intermittent renewable energy generation such as solar will cause challenges to the electric grid. PSH installations are greatly dependent on regional geography and face several challenges including: environmental impact concerns, a long permitting process, and a relatively high initial capital cost. There are no suitable sites for PSH in the Duke Energy Indiana service territory.

- **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. Traditional systems require a suitable storage site, commonly underground where the compressed air is used to boost the output of a gas turbine. 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, especially in the Indiana. However, above-ground compressed air energy storage (AGCAES) technologies are under development but at a much smaller scale, approximately 0.5 - 20MW. Several companies have attempted to develop cost effective CAES systems using above ground storage tanks. Most attempts to date have not been commercially successful, but their development is being monitored.

Figure C.3: CAES Potential US Salt Cavern Site Depiction (Source: NETL)



- **Liquid Air Energy Storage (LAES)** uses electricity to cool air until it liquefies, stores the liquid air in a tank, brings the liquid air back to a gaseous state (by exposure to ambient air or with waste heat from an industrial process) and uses that gas to turn a turbine and generate electricity. Although demonstrated through several pilot projects, the scaling of this technology and the resultant economics is not yet completely understood. As research and pilots continues with LAES, Duke Energy will continue to monitor as the technology offers bulk energy storage without the need for reservoir construction.

- **Small Modular Nuclear Reactors (SMR)** are generally defined as having capabilities of less than 300 MW per reactor and possessing the ability for the major nuclear island components to be fully manufactured in a facility, thus reducing onsite construction costs. A SMR vendor is undergoing the process to obtain a *Design Certification* with the NRC while several other vendors perform *Pre-Application* work. A vendor has successfully received a reduction in the Emergency Planning Zone (EPZ) area, which greatly reduces the land and subsequent security requirement to support operation. Several *Early Site Permits* are under evaluation by the NRC for SMR development, one in Idaho and another in Tennessee. Duke Energy will be monitoring the progress of these SMR projects for potential consideration and evaluation for future resource plans as they provide an emission free source of fuel diverse, flexible generation.

- **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 viable/available for utility-scale application.

- **Supercritical CO_2 Brayton Cycle**, an advanced heat recovery system that utilizes liquid carbon dioxide to obtain much higher efficiencies than the traditional Rankine Cycle used in power conversion systems, is of increasing interest. However, the technology is not mature or ready for commercialization. Several pilots are underway and Duke Energy will continue to monitor their development as a potential source of future generation needs.

- **Offshore Wind** was eliminated because there are no suitable offshore locations for Indiana.

- **Solar Steam Augmentation** systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. This technology, although attractive, has several hurdles yet to clear, including a clean operating history and initial capital cost reductions. This technology is very site-specific and Duke Energy will continue to monitor developments in the area of steam augmentation.

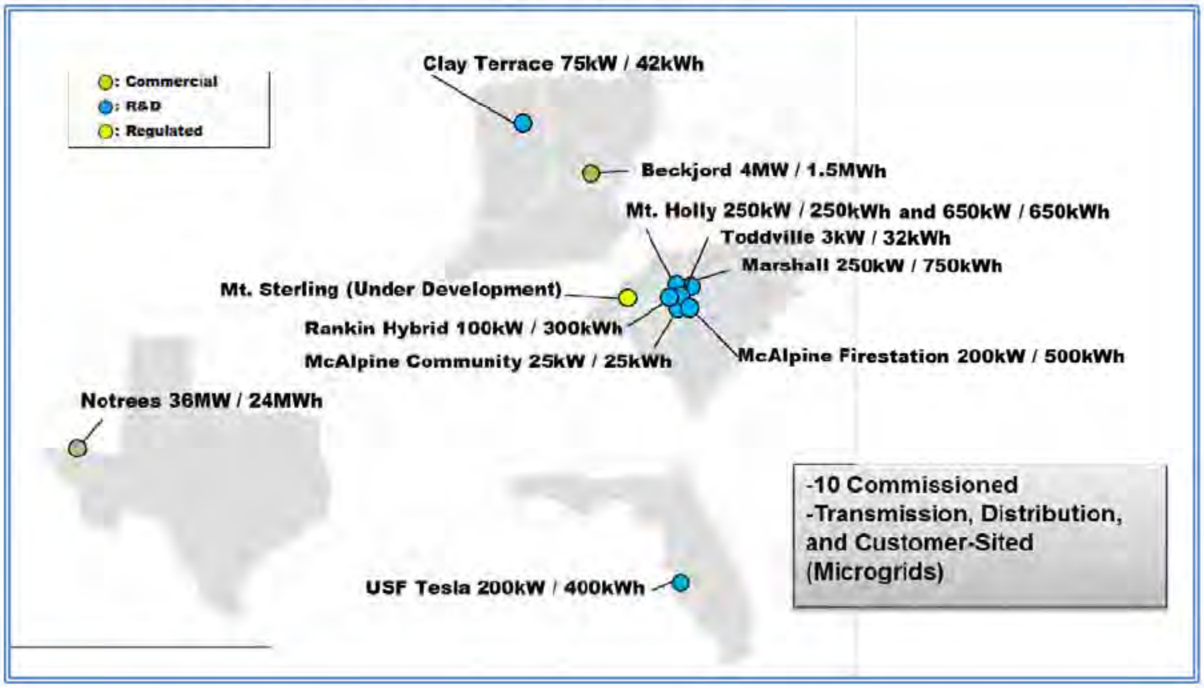
A brief explanation of the technology additions for 2018 and the basis for their inclusion follows:

- **Addition of Battery Storage Options to the IRP**

  Energy storage solutions are becoming a viable tool in support of grid stability at peak demand times and in support of energy shifting and smoothing from renewable sources. Energy Storage in the form of battery storage is becoming more feasible with the advances in battery technology (Tesla 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). In order to generically evaluate the potential value of a generation-connected battery storage system an unencumbered battery dedicated to capacity and energy services will be utilized for screening purposes. *Encumbrances* to the battery are other uses which may limit, or even completely eliminate the battery system's ability to provide capacity and energy storage services. These encumbrances may include (but are not limited to) frequency response, asset deferral, back-up power, black start, ancillary services, etc. Duke Energy recognizes the potential benefits that battery connected systems can provide, especially at the transmission and distribution (T&D) levels, which reside outside the scope of this IRP. Evaluation of potential T&D benefits, along with other uses that can be "stacked" with these T&D benefits, are being assessed on a case-by-case basis at this time through pilot projects.

  Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array.

Figure C.4: Existing, Operational Duke Energy Battery Storage Assets



These examples are only a few in support of a growing trend of coupling Battery Storage with an intermittent renewable energy source such as solar or wind in an effort to stabilize output and increase a facility's (renewable plus storage) net capacity factor.

Battery Briefing:

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharging. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed “flow,” “conventional,” and “high temperature” battery designs. Each battery type has unique features yielding specific advantages compared to one another.

A **conventional battery** contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharging, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current.

Batteries are designated by the electro-chemicals utilized within the cell; the most popular conventional batteries are lead acid and lithium ion type batteries.

Lead acid batteries are the most mature and commercially accessible battery technology, as their design has undergone considerable development since conceptualized in the late 1800s. The Department of Energy (DOE) estimates there is approximately 110 MW of lead acid battery storage currently installed worldwide. Although lead acid batteries require relatively low capital cost, this technology also has inherently high maintenance costs and handling issues associated with toxicity as well as low energy density (yields higher land and civil work requirements). Lead acid batteries also have a relatively short life cycle at 5 to 10 years, especially when used in high cycling applications.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Many Li-ion manufacturers currently offer 15-year warranties or performance guarantees. Consequently, Li- ion has gained traction in several markets including the utility and automotive industries.

Li-ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-ion batteries are anticipated to expand their reach in the utility market sector. At present, Li-ion Battery Technology is the only battery technology considered for the 2018 IRP based are market maturity and ease of commercialization.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane. The charge-inducing chemical reaction occurs in liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

High temperature batteries operate similarly to conventional batteries, but they utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level. The most popular and technically developed high temperature option is the Sodium Sulfur (NaS) battery. Japan-based NGK Insulators, the largest NaS battery manufacturer, recently installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project’s inception in the 1980s.

The NaS battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium. The melting points of sodium and sulfur are approximately 98^{o}C and 113^{o}C, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300^{o}C, which results in a higher self-discharge rate of 14 percent to 18 percent. For this reason, these systems are usually designed for use in high-cycling applications and longer discharge durations.

NaS systems are expected to have an operable life of around 15 years and are one of the most developed chemical energy storage technologies. However, unlike other battery types, costs of NaS systems have historically held, making other options more commercially viable at present.

Generation Flexibility

As more intermittent generation becomes associated with the system, there may be a greater need for generation that has rapid load changing capabilities. This generation would need to be dispatchable, possess desirable capacity/energy, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or have the potential to in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

Tables C.1: 12x24 Energy Production Profiles for Wind and Solar Resources

SOLAR	Hour End																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0%	0%	0%	0%	0%	0%	0%	0%	6%	28%	36%	34%	34%	35%	38%	45%	30%	6%	0%	0%	0%	0%	0%	0%
February	0%	0%	0%	0%	0%	0%	0%	1%	21%	48%	50%	46%	44%	48%	54%	64%	62%	25%	1%	0%	0%	0%	0%	0%
March	0%	0%	0%	0%	0%	0%	0%	1%	17%	47%	54%	63%	65%	64%	62%	60%	55%	44%	26%	4%	0%	0%	0%	0%
April	0%	0%	0%	0%	0%	0%	0%	3%	35%	64%	66%	70%	71%	72%	74%	70%	66%	62%	52%	16%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	0%	13%	43%	58%	62%	68%	73%	73%	75%	72%	69%	61%	47%	25%	2%	0%	0%	0%
June	0%	0%	0%	0%	0%	0%	1%	14%	38%	56%	67%	72%	77%	78%	78%	77%	76%	74%	64%	33%	8%	0%	0%	0%
July	0%	0%	0%	0%	0%	0%	0%	14%	49%	64%	74%	76%	79%	78%	80%	79%	76%	72%	58%	37%	6%	0%	0%	0%
August	0%	0%	0%	0%	0%	0%	0%	7%	36%	69%	77%	81%	81%	80%	79%	76%	76%	71%	55%	22%	2%	0%	0%	0%
September	0%	0%	0%	0%	0%	0%	0%	2%	22%	56%	68%	69%	68%	67%	68%	69%	70%	64%	35%	7%	0%	0%	0%	0%
October	0%	0%	0%	0%	0%	0%	0%	0%	8%	45%	60%	61%	59%	58%	57%	58%	55%	44%	10%	0%	0%	0%	0%	0%
November	0%	0%	0%	0%	0%	0%	0%	0%	14%	39%	44%	44%	45%	45%	46%	44%	21%	2%	0%	0%	0%	0%	0%	0%
December	0%	0%	0%	0%	0%	0%	0%	0%	5%	22%	31%	31%	31%	32%	35%	36%	16%	0%	0%	0%	0%	0%	0%	0%

WIND	Hour End																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	55%	53%	52%	52%	52%	51%	51%	52%	51%	48%	44%	44%	43%	43%	44%	46%	44%	46%	47%	50%	52%	56%	56%	57%
February	58%	53%	47%	46%	49%	53%	56%	54%	54%	50%	47%	45%	42%	46%	48%	49%	49%	47%	50%	54%	55%	53%	49%	52%
March	50%	49%	47%	48%	53%	51%	53%	47%	40%	43%	44%	44%	47%	46%	44%	40%	42%	44%	43%	43%	43%	47%	48%	45%
April	44%	39%	36%	44%	46%	43%	40%	32%	27%	27%	27%	30%	32%	36%	37%	37%	38%	35%	31%	31%	33%	36%	43%	44%
May	29%	27%	30%	29%	28%	25%	22%	16%	17%	22%	24%	21%	21%	24%	28%	26%	32%	26%	23%	24%	23%	27%	26%	28%
June	33%	33%	30%	28%	31%	31%	26%	18%	11%	11%	12%	15%	15%	15%	18%	19%	19%	19%	19%	19%	21%	26%	28%	27%
July	27%	24%	24%	23%	24%	24%	20%	14%	5%	5%	7%	8%	11%	10%	11%	12%	14%	13%	8%	11%	19%	22%	24%	28%
August	33%	35%	32%	30%	29%	25%	23%	18%	5%	4%	7%	9%	9%	14%	15%	16%	16%	17%	15%	22%	29%	36%	37%	38%
September	50%	54%	50%	52%	51%	52%	50%	50%	37%	37%	41%	44%	42%	41%	45%	46%	43%	43%	42%	46%	50%	49%	46%	49%
October	62%	59%	60%	60%	59%	55%	54%	54%	53%	40%	36%	34%	37%	38%	38%	37%	39%	43%	47%	54%	59%	61%	65%	66%
November	55%	57%	54%	55%	60%	59%	56%	55%	55%	52%	49%	46%	48%	47%	45%	47%	46%	46%	50%	52%	55%	60%	59%	57%
December	62%	59%	56%	61%	58%	54%	50%	47%	49%	48%	46%	45%	45%	43%	43%	46%	46%	49%	51%	54%	61%	64%	65%	64%

3. ECONOMIC SCREENING

The Company selected the technologies listed below for the screening analysis in System Optimizer (SO) for the Duke Energy Indiana territory. While regulation may effectively preclude new coal-fired generation, Duke Energy Indiana has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for base load analysis consistent with the potential federal regulation standards. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix F. 2018 additions include Combined Heat & Power (CHP) as a base load technology and Lithium ion Battery Storage as a renewable technology.

Dispatchable

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units
- Base load – 1,239 MW – 2x2x1 Advanced Combined Cycle (CC) (Fired)

- Base load – 16 MW – Combined Heat & Power (CHP, CT driven)
- Peaking/Intermediate – 202 MW, 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 858 MW 4 x F-Frame Combustion Turbines (CTs)
- Renewable – 2 MW Solar PV plus 2MW / 8MWh Li-ion Battery

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 150 MW Solar PV - Fixed Tilt
- Renewable – 5 MW / 20 MWh Li-ion Battery

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 internal Departments: Duke Energy's Project Management & Construction, Emerging Technologies, and Corporate & Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, from other sources such as those mentioned above, or a combination of the two. 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 capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas as well as NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A).

4. CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs, but the costs of all generation technologies technically screened in. The Technology Forecast Factors were sourced from the EIA's Annual Energy Outlook (AEO) 2017 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2018 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2016, July 2017)

From *NEMS Model Documentation 2016, July 2017*:

"*Uncertainty about investment costs for new technologies is captured in the Electric Capacity Planning module of NEMS (ECP) using technological optimism and learning factors.*

- *The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*
- *Learning factors represent reductions in capital costs due to learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

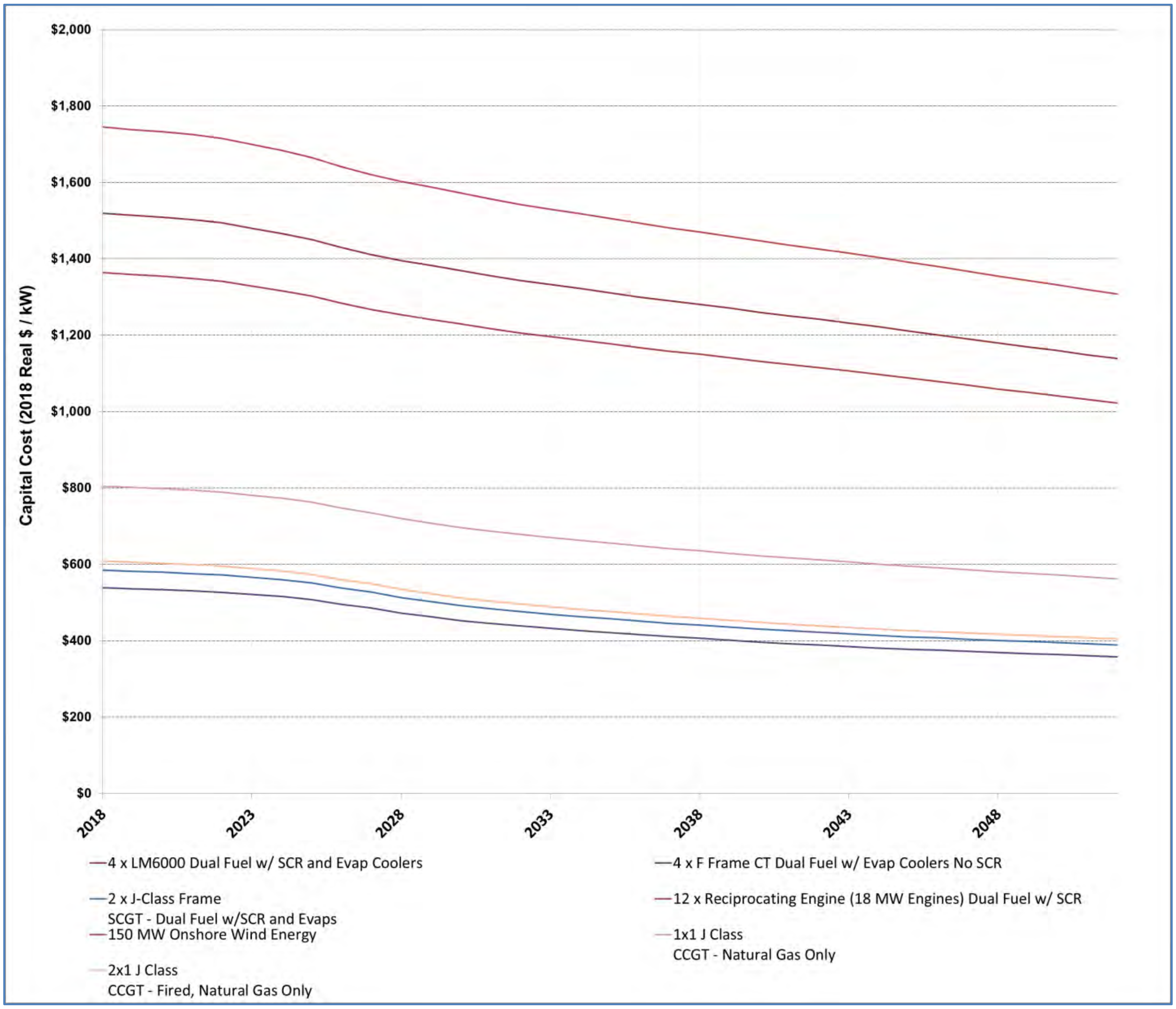
The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table C.2.

Table C.2: Excerpt from Forecast Factor Table by Technology (Source: EIA-AEO 2017)

Year	Aero CT	F Class Frame CT	J Class Frame CT	RICE	Onshore Wind	1x1 J Class Combined Cycle	2x1 J Class Combined Cycle
2018	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2019	0.996	0.995	0.995	0.996	0.996	0 995	0 995
2020	0.993	0.990	0.990	0.993	0.993	0.991	0 990
2021	0.989	0.984	0.984	0.989	0.989	0.986	0 984
2022	0.983	0.978	0.978	0.983	0.983	0.980	0.978
2023	0.974	0.967	0.967	0.974	0.974	0.970	0.967
2024	0.965	0.957	0.957	0.965	0.965	0.960	0.957
2025	0.954	0.942	0.942	0.954	0.954	0.947	0.942
2026	0.941	0.920	0.920	0.941	0.941	0.928	0.920
2027	0.928	0.902	0.902	0.928	0.928	0.913	0.902
2028	0.918	0.877	0.877	0.918	0.918	0.894	0.877
2029	0.910	0.859	0.859	0.910	0.910	0.879	0.859
2030	0.901	0.840	0.840	0.901	0.901	0.864	0.840
2031	0.892	0.827	0.827	0.892	0.892	0.853	0.827
2032	0.884	0.815	0.815	0.884	0.884	0.842	0.815

These forecast factors were blended with additional third-party capital cost projections for more rapidly developing technologies (i.e. Solar PV, Battery Storage) in order to provide a consistent forecast through the planning period for all technologies evaluated. The resulting Capital Cost changes for the technologies shown in Table C.1 are depicted below in Figure C.5.

Figure C.5: Capital Cost Forecasts for Select Technologies (Source: EIA-AEO 2017)



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 Kelley Karn at (317) 838-2461 for more information.

The Duke Energy Indiana Updated 2018 Integrated Resource Plan

March 23, 2020

Appendix D:
Demand Side Resources

ENERGY EFFICIENCY RESOURCES

A. INTRODUCTION

As part of the IRP, Duke Energy Indiana analyzes the impacts associated with new Energy Efficiency (EE) or Demand Response (DR) programs and any changes to existing EE or DR measures/programs. The portfolio of existing and future EE and DR measures/programs is evaluated within the IRP to examine the impact on the generation plan if the current set of measures/programs were to continue and proposed programs were added. Additionally, all proposed and current EE and DR programs are evaluated in the IRP modeling process to determine if a given measure/program should be included in the IRP. The projected load impacts of all measures/programs selected by the IRP model 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 societal perspective.

C. CURRENT ENERGY EFFICIENCY PROGRAMS

Duke Energy Indiana's current EE program portfolio was approved by the Commission in Cause No. 43955 – DSM4 for the periods 2017-19.

1. Residential Programs

The following programs are currently approved to be offered in 2018 and 2019

Smart $aver® Residential

HVAC Equipment

Program objectives include promoting energy savings and increased customer satisfaction through offering prescriptive incentives to residential customers for the purchase and installation of energy efficient measures designed to help customers improve the efficiency of their HVAC system, building shell, in-ground swimming pool filtration, and water heating.

The HVAC Equipment program offers prescriptive incentives to residential customers for the purchase and installation of energy efficient measures designed to help customers improve the efficiency of their HVAC. As a result of increased federal energy efficiency standards for baseline (SEER rating) and higher cost for energy efficient equipment, the Company will implement modifications to its current program to offer a cost-effective Program. Modifications include a tiered incentive structure for HVAC equipment, an optional add-on measure, and a new referral channel component for eligible trade allies. Two incentive levels will be made available for customers replacing HVAC equipment, based on the efficiency rating of the new unit installed, along with an add-on optional efficiency measure for a smart thermostat. Customers can choose to combine the optional smart thermostat measure with the HVAC equipment replacement that will further improve the efficiency of the HVAC system. The smart thermostat is a programmable Wi-Fi enabled thermostat to help customers monitor and manage their HVAC from their smart device, and must be purchased and programmed as part of the HVAC equipment installation.

Attic Insulation and Air 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 home's 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.

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.

Heat Pump Water Heater

Program incentives are provided to encourage the adoption and installation of high efficiency heat pump water heaters in 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. Duke Energy program personnel establish relationships with 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.

Variable-Speed Pool Pump

Program 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. Duke Energy program personnel establish relationships with 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.

Referral Channel

The referral component of the Program is a new delivery channel that provides a free referral service to customers to enhance program awareness and participation. The service simplifies the customer's decision-making around energy efficiency purchases and takes the guesswork out of finding reliable, qualified contractors with competitive offers. This delivery channel supports the Company’s role as an energy efficiency program administrator while building trusted partnerships with customers and HVAC and home performance contractors as well as home builders (“Trade Allies”) who interface directly with residential customers.

The Referral Channel offers high achieving Trade Allies in the Program the ability to receive referral services. The Referral Channel establishes designations between registered Trade Allies as referred or non-referred. As part of the Program, the Company will generate leads for qualified, referred Trade Allies by identifying prospective customers with interest in eligible incentivized energy efficiency upgrades and/or subsequent non-incentivized services.

Duke Energy will continue to pay the customers of the referred and non-referred Trade Allies an energy efficiency incentive for qualifying eligible measures.

<u>Free LED Program</u>

The Free LED program is designed to increase the energy efficiency of residential customers by offering customers LEDs to install in high-use fixtures within their homes. The LEDs are offered through an on-demand ordering platform, enabling eligible customers to request LEDs and have them shipped directly to their homes. Eligibility and participation limits are based on past participation in the CFL program and other Duke Energy programs distributing lighting. 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 and include 9 watts dimmable LEDs.

<u>Specialty Lighting & other energy efficient products</u>

The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase a variety of energy efficient products. These products are shipped directly to customers’ homes. The Savings Store offers a variety of products such as specialty Light Emitting Diodes lamps (“LEDs”) lighting, including; Reflectors, Globes, Candelabra, 3 Way, Dimmable and A-Line type bulbs, smart thermostat, smart strips, water savings products, dehumidifiers, air purifiers, & LED fixtures. Duke Energy incentive levels vary by bulb type and product, and the customer pays the difference, including shipping. The amount of products each customer can purchase is restricted by an account limit per product type, but customers may choose to order more without the Duke Energy incentive.

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 products will be installed at the accounts premise address, to participate in this program.

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 and how it compares to high efficiency alternatives.
This program provides discounted products for residential customers to help them reduce their energy usage while maintaining a comfortable atmosphere.

Retail Lighting
This upstream, buy-down retail-based lighting program works through lighting manufacturers and retailers to offer discounts to Duke Energy customers selecting incentivized LEDs and energy-efficient fixtures at the shelf for purchase at the register. Retailers, such as, but not limited to, Home Depot, Lowe’s, Sam’s Club, Walmart and Costco will be evaluated at the store level for possible 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 customers are purchasing the correct bulb for the application in order 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.

CLEAResult (formerly Ecova) is the implementation vendor for the Retail program. CLEAResult will utilize a field team to promote and monitor the program at the participating retail locations. A toll-free call center and website will be hosted by CLEAResult 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.

Save Energy and Water Kit

The Save Energy and Water Kit ("SEWK") is designed to increase the energy efficiency of residential customers by offering customers energy efficient 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 energy efficient water 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: bath and kitchen aerators, state-of-the-art shower heads and insulated pipe tape. The kit also includes directions and items to help with installation.

Low Income Neighborhood

The Low Income Neighborhood program, known as the Neighborhood Energy Saver Program, or NES, 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. Energy Efficient Bulbs - Up to 15 LED bulbs to replace incandescent bulbs.
2. Electric Water Heater Wrap and Insulation for Water Pipes.
3. Electric Water Heater Temperature Check and Adjustment.
4. Faucet Aerators - Up to three low-flow faucet aerators.
5. Showerheads - Up to two low-flow showerheads.
6. Wall Plate Thermometer –one per home.
7. HVAC Winterization Kits – Up to three winterization HVAC kits for wall/window air conditioning units 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. Refrigerator Magnet – highlighting the top 10 energy tips.
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 <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, manufactured housing 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 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

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 strategies Duke Energy may utilize to meet participation goals:

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

Agency Assistance Portal

The Agency Assistance Portal assists low-income customers in reducing energy costs through providing energy efficiency bulbs to eligible customers. Customers participating in this program will receive a package of 12 LED bulbs 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 (LIHEAP) 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 help low-income customers save energy and money on their utility bills by using energy efficient lighting. 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.

<u>Low Income Weatherization</u>

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 owner occupied, single family homes meeting income qualification levels based on DOE standards (*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.

Duke Energy will utilize the Indiana Housing and Community Development Authority (IHCDA) to administer the program, partnering with the current Indiana Community Action Association weatherization network.

This program will operate on a tier system, based on an annual KWH/sq. ft. consumption.

Tier 1 services are as follows:

- Electric Heating System Tune-up & Cleaning
- Electric Heating System repair up to $600
- Water Heater Wrap for electric water heaters
- Water Heater Pipe Wrap
- Cleaning / replacing electric dryer vents
- Energy Efficient Light Bulbs

- Water saving shower heads and aerators
- Weather-stripping doors & windows
- Energy Education

Tier Two services are all Tier One Services plus:

- Additional cost effective measures using the National Energy Audit Tool ("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, air sealing, wall insulation, crawl space insulation, floor insulation, duct sealing.
- In addition, up to $750 can be spent on a home for Health & Safety issues which may prevent them from receiving weatherization assistance. However, the Health & Safety component must average no more than $250 per home.

In addition, refrigerator replacement will be available to income-eligible customers whose refrigerators test to be inefficient or >10 years old, including renters.

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.

This program's objective is the installation energy efficient measures including:

- LED Lighting
- Kitchen Faucet Aerators*
- Bathroom Faucet Aerators*
- Showerheads*
- Hot Water Pipe wrap*

*Water measures are only available if water is heated electrically

Measures are installed by program crews during scheduled direct install visits and the crews are accompanied by property personnel. Franklin Energy installers carry tablets to keep track of what is installed in each apartment.

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.

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. This includes Program 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. Additionally, once the installation is complete the property will receive a complementary window cling highlighting the participation in the program.

Residential Energy Assessments

Residential Energy Assessments is a free in-home assessment designed to help customers reduce energy usage and energy cost. A Building Performance Institute (”BPI”) certified 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. As part of the assessment, the energy specialist reviews and provides a customized report to the customer that identifies actions the customer can take to increase energy efficiency in their home. The recommendations may range from behavioral changes to equipment modifications that can save energy and reduce cost.

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 and water measures, outlet/switch gaskets, weather stripping and energy saving tips.

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

This program targets Duke Energy residential customers that own a single-family home with at least 4 months of billing history. Program participation is primarily driven through bill inserts and targeted mailings; however, for those who elect to receive offers electronically, email marketing will be used to supplement. Additional channels include but are not limited to mass media, billboards, community events, and online awareness via the Duke Energy website as well as through online services.

My Home Energy Report

The My Home Energy Report (MyHER) program provides customers with a comparison of their energy usage to similar single-family residences in the same geographical area based upon the age, size and heating source of the home. Specific energy saving recommendations are provided to encourage energy saving behavior. The paper reports are mailed 8 times a year for single family dwellings. Multifamily dwellings receive a combination of 4 paper reports and 8 electronic reports throughout the year. MyHER Interactive, a portal, provides similar information as the printed report but also provides the ability to create a savings plan, see how energy is used in the home by end use, provides an energy expert to respond to customer questions and delivers weekly email challenges. MyHER Interactive customers also receive email versions of their reports.

The objective of this program is to generate kWh savings, increase customer satisfaction and educate customers on other Energy Efficiency offers from Duke Energy.

The paper report MyHER program is an opt out program that automatically creates and sends reports for eligible customers. The MyHER Interactive portal is an opt in program and is marketed through messages in the printed report and email marketing campaigns. Sweepstakes offers are used to encourage enrollment on the Interactive Portal.

Energy Efficiency Education Program for Schools

The Energy Efficiency Education Program for Schools is available to students enrolled in public and private schools who reside in households served by Duke Energy Indiana. The current curriculum administered by The National Theatre for Children (NTC) targets K-12 grade students. 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. Beginning in February 2019, the program also added a fun and educational game app, *Kilowatt Krush*, to the curriculum, which is available to all students who see a performance, regardless of kit eligibility.

The Program provides principals and teachers with an innovative 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 centerpiece of the curriculum is a live theatrical production focused on concepts such as energy, renewable fuels and energy efficiency performed by two professional actors. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

Students are encouraged to complete a home energy survey with their family (included in their classroom and family activity book) to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption. The kit is available at no cost to all student households at participating schools, including customers and non-customers. Program participation is driven by student households that elect to receive the Energy Efficiency Starter Kit.

The National Theatre for Children is responsible for all marketing campaigns and outreach. NTC utilizes direct mail and email sent directly to principals to market the Program.

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.

The objective of the Power Manager® program is to provide customer bill savings to customers through reducing their usage during times of high system loads or high wholesale energy prices. This program delivers direct savings to participating customers in the form of bill credits as well as reduces rates for all customers by providing a cheaper capacity option than building generation for the small number of hours that the program impacts. For the apartment complex marketplace, the program also provides property manager/owners incentives to provide apartment units that will have lower monthly operating costs for their tenants.

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.

Customers residing in single family homes participating in this Program 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.

Additionally, the Power Manager® program has a specific offer focused on customers who are tenants in apartment complexes/communities—marketed as Power Manager® for Apartments. The program is offered to property/managers/owners of individually metered apartment units that have a functional central air-conditioning unit 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 the A/C system during Power Manager® events and enroll tenants in the 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. The property manager/owners will receive a one-time enrollment incentive of $5 for each water heater switch installed.

Additionally, 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.

Power Manager® for Apartments 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.

The following Residential programs were approved in DSM-4 and the projected savings are included in the IRP forecast for 2019, however, these programs have not been implemented as of the date of this IRP.

Bring Your Own Thermostat (In development)

Bring Your Own Thermostat (BYOT) provides residential Demand Response (DR) load management using the customers' own "smart" 2-way communicating thermostats instead of traditional load control switches. It is intended for customers who already use smart thermostats, allowing the utility to avoid the costs of hardware and installation associated with traditional DR methods. The utility can verify how many thermostats are connected to the network at any given time, and determine which thermostats are participating in DR events as opposed to opting-out. Since it was first introduced in 2012, over a dozen utilities have implemented, or are planning to implement BYOT pilot programs in the United States.

The program goals are to add kW savings during peak periods by adding new customers without the time and cost of installing a traditional DR switch. In addition the program expects to reach new customers who have not traditionally participated in demand response.

The program will be marketed to customers through participating device manufacturers who offer utility branded marketing and enrollment services. One of the significant advantages of Smart Thermostats is its ability to have two way communication. Agreements with the aggregation vendor and the thermostat manufacturers include the ability to send messages to device owners inviting them to participate in their utility's DR program. Communication may include, but is not limited to messages on the unit, email and text messages. Interested customers are brought into the enrollment system, which can vary by manufacturer. In addition to the unit manufacturer communication, the company may use a number of channels including, but not limited to online marketing direct mail and social media.

<u>Energy Efficient Appliance (In development)</u>

The Energy Efficient Appliance program offers customers rebates on qualified energy efficiency appliances and devices purchased through various methods and channels. The efficiency of the units will be based on Energy Star or similar standards and may include appliances such as electric water heaters, refrigerators, clothes washers, electronics, televisions, computers and controls for water heaters, lighting and thermostats.

The goal of this program is to offer customers rebates on additional energy saving technologies beyond HVAC equipment, lighting and water saving measures to large appliances, electronics and other technologies that impact plug-in load within their homes. Through this program, customers can achieve deeper savings while at the same time receiving an incentive from Duke Energy to offset part of the cost of buying equipment designed to use less energy.

The program will be marketed through a number of channels including but not limited to retail point of sale, E-commerce online marketing, direct mail, email and social media.

<u>Manufactured Home (In development)</u>

The Manufactured Home program offers owners of manufactured housing incentives to improve the energy efficiency of their homes. Customers living in manufactured homes may receive rebates when they implement one or more of the qualifying improvements. These may include HVAC equipment and services, duct and/or thermal boundary improvements.

The program is designed to expand the opportunity for additional energy efficiency savings by including manufactured homes eligible for rebates on energy saving improvements.

The program will be marketed to builders and developers through personal outreach, training seminars and trade organization meetings.

Multi-Family Retrofit (In development)

The Multi Family Retro Fit program offers Property Managers incentives to improve the energy efficiency of their existing rental properties by performing building envelope improvements and increasing HVAC efficiency via equipment upgrades and/or services. The program may include rebates for high efficiency HVAC equipment and services as well as envelope measures to improve building thermal characteristics and seal penetrations to reduce energy consumption and improve comfort.

The objective of this program is to expand the opportunity for energy efficiency savings by including multifamily residential unit properties eligible for rebates on qualifying energy improvements.

The program will be marketed to Property Managers, Building Owners and Property Management companies using direct mail, email and direct selling techniques.

Residential New Construction (In development)

The Residential New Construction program offers incentives to builders of new single family homes and new multi-family properties constructed to higher efficiency standard than existing building codes. Builders may use a combination of construction techniques, equipment and materials to achieve the higher energy savings.

The objective of this program is to improve the efficiency of single family and multi-family building stock by building efficiency into the construction process. The program seeks to raise builders' awareness of efficient building practices and ultimately incorporate those into their standard building processes.

The program will be marketed to builders and developers through personal outreach, training seminars and trade organization meetings.

2. **Non-Residential Programs**

The Smart $aver® Non-residential Incentive Program provides incentives to commercial, industrial, and institutional 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.

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 delivered to customers through three incentive categories: Prescriptive, Custom and Performance.

Commercial, industrial, and institutional customers can have significant energy consumption, but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Smart $aver Incentive Program is designed to meet the needs of Duke Energy customers that have opportunities for electrical energy savings projects, whether the project involves common energy efficiency equipment or more complicated or alternative technologies.

The financial incentives help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Prescriptive Incentives offered in the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products, including sometimes directly providing the incentive to customers. The Custom Incentives and Performance Incentives offer options to encourage customers to implement energy efficiency measures that are not included in the list of Prescriptive Incentives.

<u>Prescriptive Incentives</u>

Prescriptive Incentives are pre-determined, fixed incentives for common energy efficiency equipment. Pre-approval is not required; eligibility requirements and incentive amounts are published on the application form posted to the Duke Energy Indiana website.

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.

Duke Energy will investigate providing a limited quantity of low-cost energy efficient equipment directly to eligible Nonresidential customers, at no cost to the customer, through this program or in partnership with other Duke Energy programs.

Standards continue to change and new, more efficient technologies continue to emerge in the market. The Company expects that new measures will be added to the program to increase participation and provide customers a broader suite of products.

Prescriptive Incentives are offered to customers through multiple channels, including an application form (paper and electronic), the online Energy Efficiency Store, and Midstream network. Additional channels may be added in the future, in order to reach as many customers as possible.

Custom Incentives

Unlike Prescriptive Incentive Program measures, 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 applying for Custom Incentives; Classic Custom and Custom to Go. Application documents vary slightly depending on the approach taken. The two approaches differ in terms of the method by which energy savings are calculated. Customers eligible for the Custom to Go calculations approach may elect to apply under the Classic Custom approach if that is their preference.

The following application forms are located on the Duke Energy website under Smart $aver Custom Incentives (Business and Large Business tabs). These forms may be completed and returned to the program via e-mail or through use of the Online Application Portal.

- Custom Application – Administrative Information
- Energy Savings Calculations & Basis
    - Classic Custom Approach (> 700,000 kWh or no applicable Custom to Go calculator)
        - Variable Frequency Drives
        - Energy Management Systems (HVAC)
        - Compressed Air Systems
        - Lighting
        - General (for technologies not listed above)
    - Custom to Go Calculators (< 700,000 kWh unless otherwise noted and applicable Custom to Go calculator)
        - Variable Frequency Drives (Fans & Pumps)
        - HVAC/Energy Management Systems
        - Compressed Air Systems
        - Lighting (> 700,000 kWh is supported)

The Smart $aver Custom Incentive team continues to explore additional program enhancements designed to increase program participation.

During 2019, the software-based Custom-to-Go calculation tools will transition to a web-based environment and marketed as the "Smart Saver Tools". Lighting and HVAC tools have already been transitioned.

Performance Incentives

Duke Energy Indiana's $mart Saver Performance Incentive provides a mechanism to encourage the installation of high efficiency measures not eligible for Smart $aver Prescriptive or Custom Incentive payments. $mart Saver Performance Incentive has been designed to complement the Company's Smart $aver Prescriptive and Custom measures, and would encourage the implementation of energy conservation measures which are characterized, at the time of conception, by a degree of uncertainty associated with the end result. The types of measures that will be covered by $mart Saver Performance Incentive will include some combination of unknown building conditions or system constraints, coupled with uncertain operating, occupancy, or production schedules. The specific type of measures will be included in the contract with the Customer.

In order to receive payment under this program, the customer must submit an application and receive approval before making a decision to implement the project. An estimated total project savings will be calculated and agreed to by the applicant and the Company. Program incentives will be based on the published incentive rate schedule. Incentives paid under Performance Incentive may be divided into multiple payments. When applicable, the initial incentive payment will be made upon completion of the project, and following a review and approval by the company. This initial payment will be based on a portion of the initial estimated total savings for the project that will be achieved with a high degree of confidence subsequent and, ultimately, final measured incentive payment(s) will be made as savings are confirmed and will be equal to the applicable incentive rate multiplied by the verified savings amount. The percentage of payment made for the initial incentive versus the verified incentive payment amount will be made on a project-by-project basis according to the measure of uncertainty assigned to the project.

Performance Incentives will leverage the application materials and processing channels established in the Smart Saver Custom program as well as the same promotional channels.

Due to the different types of projects, and the range of variables involved with these different categories of energy efficiency measures, the program Evaluation, Measurement & Verification will be performed separately for Prescriptive, Custom and Performance measures.

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 could affect the amount of energy efficiency opportunities 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.

Small Business Energy Saver

The purpose of Duke Energy's Small Business Energy Saver (SBES) program is to reduce energy usage through the direct installation of energy efficiency measures within qualifying small and medium non-residential customer facilities. SBES is designed to offer a convenient, turn-key process for non-residential customers to make facility energy efficiency improvements. Many small and medium business owners lack the time, upfront capital, or technical expertise to facilitate the retrofit or replacement of older equipment within their facilities. The SBES 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. Participants may be in owner-occupied or tenant facilities with owner permission.

All aspects of SBES are managed by a Duke Energy-authorized program vendor. Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy. Upon receiving the results of the energy assessment, if the customer decides to move forward with the proposed energy efficiency project, the customer makes the final determination of which measures will be installed. The energy efficiency measure installation is then scheduled at a convenient time for the customer and the measures are installed by a Duke Energy-authorized vendor electrical subcontractor.

The SBES program incentive amount is 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 address major end-uses in lighting, refrigeration, and heating ventilation and air conditioning (HVAC) applications. Lighting measures such as interior and exterior light emitting diode (LED) fixtures, screw-in LED lamps, LED tubes and LED retrofit kits; LED exit signs; and occupancy sensors may be offered. All lighting measures offered are 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 provides 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.

Duke Energy Indiana's incentive payment for any installed measures will be paid directly to the program vendor upon verification that the energy efficiency measure(s) have been installed. The program vendor is only compensated by Duke Energy Indiana for energy savings produced through the installation of energy efficiency measures. 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. The program vendor will offer interest-free extended payment options to the customer, to further minimize any financial barriers to participation.

The objective of the Small Business Energy Saver (SBES) program is to enable the direct installation of high efficiency equipment in existing small and medium non-residential facilities by removing common barriers to energy efficiency program 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.

<u>Power Manager® for Business</u>

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.

The objective of the Power Manager® for Business program is to provide customer bill savings to customers through reducing their usage during times of high system loads or high wholesale energy prices. This program delivers direct savings to participating customers in the form of bill credits as well as reduces rates for all customers by providing a cheaper capacity option than building generation for the small number of hours that the program impacts. In addition, this program is reaching a subset of the customer base that previously has not been well-served by similar demand response programs (too small for PowerShare® and not eligible for the residential Power Manager® program).

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. Direct sales via doo-to-door outreach will also be evaluated for potential inclusion as a future marketing channel.

3. Demand Response Programs

In addition to the programs approved in Cause 43955 – DSM4, 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 20-year planning horizon from 2018 through 2037 as options for consideration in the IRP analytical process. In preparing the projected impact options available for selection in this IRP, the Company developed 150 sub-portfolios of EE programs (also referred to as "bundles").

These bundles were designed to be treated as demand-side resource options for selection by the IRP process and EE measures were grouped together in these bundles based on the hourly shape of the savings contributed by these measures. For each of these hourly shapes, three different levels of customer participation, a Base Case, a High Case, and an Extra-High Case, were created.

The participation included in these three cases were provided by either the currently approved EE Portfolio (2018-2020) or the Market Potential Study (2021-37). These bundles were also created for various time periods based on the timing of incremental new additions of EE measures as explained below.

In order to reduce the amount of time required for analyzing the overall portfolio of bundles, the Company further consolidated the 150 bundles into a final group of 70 bundles. The consolidation was done by combining together the Base, High and Extra-High cases for certain bundles of hourly shapes where the incremental amounts of the High and Extra-High cases were not large compared to the Base Case.

The annual megawatt-hours and costs for the final group of 70 bundles were used to calculate a levelized cost in $/MWh for each bundle. The levelized cost and hourly MWh for each bundle was loaded into the IRP models as discrete resource options for selection. This process enabled the EE programs to compete for selection against traditional generating resources to serve projected customer load.

2018-2020

For the first 3-year bundle (2018-20), the IRP model was required to select all Base bundles. These bundles represent the currently approved 2017-19 Portfolio as submitted along with an assumption that the portfolio in 2020 would be an extension of the same programs approved in 2019 with the exception of the reduction in the size of the “Old Behavior” bundle to reflect the application of the recent M&V performed in 2018. High and Extra-High bundles were not available in the 2018-20 period because the bundles were required to match the existing approved portfolio.

2021-2037

For all subsequent bundles, the recommended EE portfolio includes those bundles selected by the IRP model but also includes the Residential Old Behavior bundle (adjusted for the 2018 M&V).

The current behavior program is an important part of the existing EE portfolio because it provides customers with an awareness of their usage and provides them information that they can use to reduce their monthly electric bill, including information about other EE measures available to them through the Duke Energy Indiana Residential EE Portfolio. Because this is an established platform for distributing the normative comparisons and EE tips and recommendations, this program continues to be a critical base program to encourage customers savings and provide customers with usage information.

In order to provide the model with increased granularity in the near term, a set of bundles was analyzed with a duration of 3 years for the periods 2021-23 and 2024-26. In order to reduce the amount of analytical burden in the overall IRP process, the next two sets of bundles were analyzed with a duration of 5 years and 6 years for the periods 2027-31 and 2032-37.

Table D.1 below provides the potential projected annual Gross MWh impacts (includes Free Riders) from the EE programs in the Moderate Transition Portfolio, as selected by the IRP model.

Table D.1

Year	Cumulative Gross MWh Impacts, at generation
2018	191,488
2019	389,131
2020	574,180
2021	760,133
2022	949,752
2023	1,144,707
2024	1,369,903
2025	1,583,768
2026	1,788,931
2027	2,002,767
2028	2,208,604
2029	2,406,450
2030	2,598,518
2031	2,784,799
2032	2,969,625
2033	3,151,029
2034	3,331,744
2035	3,510,214
2036	3,685,712
2037	3,856,752

Please note that the table above reflects the projected impacts for 2018 based on the portfolio approved in DSM-4 due to the timing of the IRP analysis. Actual results for 2018 were approximately 233,000 MWh at generation (approximately 215,000 MWh at meter).

Table D.2 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 D.2 MW LOAD IMPACTS OF DR PROGRAMS[5]

	Demand Response Program Load Impacts			
	MW			
Year	PowerShare	Power Manager	Interruptible	Total DR
2018	311	69	197	576
2019	316	76	197	588
2020	324	82	197	603
2021	332	86	197	615
2022	341	90	197	628
2023	349	95	197	640
2024	349	95	197	640
2025	349	95	197	640
2026	349	95	197	640
2027	349	95	197	640
2028	349	95	197	640
2029	349	95	197	640
2030	349	95	197	640
2031	349	95	197	640
2032	349	95	197	640
2033	349	95	197	640
2034	349	95	197	640
2035	349	95	197	640
2036	349	95	197	640
2037	349	95	197	640

[5] DR MWs for Power Manager includes MWs from Power Manager, Power Manager Water Heaters, Power Manager for Apartments, and 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. 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. INTEGRATED VOLT-VAR CONTROL (IVVC)

Duke Energy is implementing 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. This IVVC program is projected to reduce future distribution-only system peak needs by approximately 0.215% in 2020, 0.38% in 2021, 0.53% 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.

1. Avoided Cost for EE Screening

The avoided costs used in screening the EE and DR programs in the Market Potential Study to determine the Economic Potential were based on information in the New Portfolio Program filing (Cause No. 43955 – DSM4) 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 Kelley Karn at (317) 838-2461 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 Kelley Karn at (317) 838-2461 for more information.

Table D.4 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

Table D.5 Projected Program Expenditures.

	Total Cost / Cost Recovery 2018	Total Cost / Cost Recovery 2019
Residential		
Energy Efficiency		
Agency Assistance Portal	$ 186,146	$ 154,020
Energy Efficient Appliances	$ -	$ 45,729
Energy Efficiency Education Program for Schools	$ 590,100	$ 646,766
Low Income Neighborhood	$ 598,419	$ 641,232
Low Income Weatherization	$ 1,857,418	$ 1,832,345
Manufactured Home Retrofit	$ -	$ 68,586
Multi-Family EE Products & Services	$ 100,167	$ 176,398
Multifamily Retrofit	$ -	$ 124,206
My Home Energy Report	$ 3,403,395	$ 3,414,052
Residential Energy Assessments	$ 858,371	$ 917,952
Residential New Construction	$ -	$ 723,648
Smart $aver® Residential	$ 8,895,062	$ 8,664,252
Energy Efficiency Total	**$ 16,489,079**	**$ 17,409,186**
Demand Response		
Bring Your Own Thermostat	$ 445,968	$ 677,684
Power Manager®	$ 2,861,337	$ 3,012,174
Demand Response Total	**$ 3,307,305**	**$ 3,689,859**
Non-Residential		
Energy Efficiency		
Small Business Energy Saver	$ 5,216,213	$ 5,263,080
Smart $aver® Non-Residential	$ 8,896,828	$ 9,484,159
Energy Efficiency Total	**$ 14,113,041**	**$ 14,747,239**
Demand Response		
Power Manager® for Business	$ 740,366	$ 1,117,843
Demand Response Total	**$ 740,366**	**$ 1,117,843**
TOTAL Indiana Portfolio	**$ 34,649,791**	**$ 36,964,126**

Please note that the table above reflects the projected costs for 2018 based on the portfolio approved in DSM-4 due to the timing of the IRP analysis. Actual costs for 2018 were approximately $31MM.

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Appendix E: Transmission Planning

1. TRANSMISSION EXECUTIVE SUMMARY

A. System Description

The Duke Energy Indiana bulk transmission system is comprised of the 345 kilovolt (kV), 230 kV, and 138 kV systems. The Duke Energy Indiana transmission system serves primarily to deliver bulk power into and/or across Duke Energy Indiana 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 Indiana has with neighboring local balancing areas, the Duke Energy Indiana 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 2018, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 852 circuit miles of 345 kV lines, 777 of 230 kV, and 1446 of 138 kV. Duke Energy Indiana, Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Alliance (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.

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 Indiana bulk transmission system is comprised of 138 kV, 230 kV, and 345 kV systems. The 345 kV system distributes power from Duke Energy Indiana's large generating units, and interconnects the Duke Energy Indiana system with other systems. 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 Indiana'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 Indiana 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 Indiana'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 Indiana 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.

Table E.1: Transmission System Voltage Limits

Nominal Voltage (kV)	Normal Voltage Limits Minimum	Maximum	Emergency Voltage Limits 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 Indiana 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. <u>System-Wide Reliability Measure</u>

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

D. <u>Evaluation of Adequacy for Load Growth</u>

The transmission system of Duke Energy Indiana 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. Duke Energy Indiana'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 Indiana transmission system would be required.

E. <u>Economic/Loss Evaluation</u>

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 Indiana 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 Indiana 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 18 assessed the Duke Energy Indiana transmission system for the period 2018 through 2028 with simulations for years 2020, 2023 and 2028. 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. <u>Transmission Project Descriptions</u>

The following planned transmission projects include new substation transformers, transmission capacitors, transmission circuits, and upgrades of existing circuits and substations.

Sugar Creek to Ameren Kansas 345 kV line consist of construction of 1.5 miles of 345 kV line. The new line will be routed from the Duke Energy Indiana Sugar Creek Substation to the state line between Indiana and Illinois state line. The remaining section to will be built by Ameren. This project will relief congestion for the Kansas area and promote access to renewable generation.

Lafayette South East to Concord Road Junction 138 kV reconductor project. Included in project, adding a 138 kV breaker in the Lafayette South East Substation ring bus and tapping another line between Lafayette South and Concord Road. The project will reduce 138 kV line exposure and reduce outage minutes to Lafayette industrial customers.

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 2019 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.

H. Economic Projects Comments

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.

I. Short Term Implementation Plan - 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.

Table E.2: STATUS UPDATES AND CHANGES FROM PREVIOUS REPORT DUKE ENERGY INDIANA TRANSMISSION PROJECTS

				CASH FLOWS ($000)*		
PROJECT NAME	**MILES or MVA**	**kV**	**PROGRESS/ COMPLETION DATE**	**2015**	**2016**	**2017**
Westpoint 230 kV Switching Station	-	230	12/31/15 Canceled 6-18-2014 (Note 1)			
Lafayette 230 kV Sub Breaker Repl with Ring Bus Phase 1	-	230	12/31/2014 Completed 12/31/14	$11	$2652	$0

Table E.3: CURRENT DUKE ENERGY INDIANA MAJOR TRANSMISSION PROJECTS

				CASH FLOWS ($000)*		
PROJECT NAME	**MILES or MVA**	**kV**	**PROGRESS/ COMPLETION DATE**	**2018**	**2019**	**2020**
Sugar Creek to Ameren Kansas	1.5	345	6/5/2019	$9,348	$5,986	$0
Laf SE Conc Rd. Jct 138kV Line (Note 2)	3.6	138	1/15/2020	$3,205	$116	$0
Speed to Jeffersonville 138 kV line (Note 2)	2.5	138	3/26/2019	$1,861	$3,998	$923

*Excluding AFUDC

Anticipated Project Milestones – update as needed

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 – Wind developer requested project to be canceled.
Note 2 – Project will be partially funded by IMPA as part of their obligations as joint owner of the Duke Energy Indiana transmission system.

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Appendix F: Environmental Compliance

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 Section B. Risks associated with anticipated and potential changes to environmental regulations are discussed in Section C.

B. COMPLIANCE PLANNING – EXISTING LAWS AND REGULATIONS

1. Ozone National Ambient Air Quality Standards ("NAAQS")

On October 1, 2015, EPA finalized a rule lowering the ozone standard from 75 to 70 ppb. The EPA finalized attainment designations in 2017, based on actual 2014-2016 ozone air quality data. EPA designated several Indiana counties as non-attainment including Lake and Porter Counties (Chicago area), and Clark and Floyd Counties (Louisville area). These counties were all classified as "marginal" non-attainment, which does not require Indiana to adopt any further emission controls at facilities in the affected counties provided that the areas achieve attainment during the first planning period (by 2021). Indiana filed a Good Neighbor plan on November 2, 2018 which addresses potential significant impact from Indiana sources on downwind areas in other states that are non-attainment for the 2015 ozone standard. No further requirements are anticipated at this time.

2. Sulfur Dioxide Ambient Air Quality Standard

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 as 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 were retired in April 2016 in response to the EPA's Mercury and Air Toxics Standards ("MATS") rule. Wabash River Unit 6 was also retired, after a decision not to switch fuels to natural gas, also in response to the MATS rule. EPA has proposed to redesignate Vigo county to attainment in the May 3, 2019 Federal Register. All other areas of Indiana where Duke Energy Indiana facilities are located have been classified as attaining the SO_2 NAAQS, and no further SO_2 controls or restrictions are anticipated at these facilities as a result of the SO_2 NAAQS.

3. <u>Interstate Transport – Ozone</u>

Phase I of the Cross State Air Pollution Rule ("CSAPR") took effect on January 1, 2015 and Phase II of CSAPR took effect on January 1, 2017 for the annual NOx and SO_2 programs. EPA promulgated a "CSAPR Update Rule" in September 2016 which set a more stringent cap on ozone season NOx emissions, and those more stringent requirements became effective May 1, 2017. The additional reductions required have been achieved through enhanced utilization of Selective Catalytic Reduction ("SCR") systems installed at Cayuga and Gibson Stations. For Cayuga Units 1&2, this enhanced utilization includes operating the SCRs with ammonia injection during the ozone season to control NOx. Those SCR systems were installed to promote oxidation and capture of mercury to meet MATS requirements, which does not require ammonia injection.

On November 16, 2016, the State of Maryland submitted a petition to the EPA under Section 126 of the Clean Air Act ("CAA"), requesting that EPA impose stringent, short-term NOx emissions limits on a number of electric utility units that Maryland claimed were having a significant impact on ozone attainment in Maryland. The sources listed in the petition included Gibson Unit 3 and Unit 5. EPA formally denied the petition on October 15, 2018, but the Maryland has filed litigation to appeal EPA's decision. Duke Energy Indiana has filed with the Court as an intervenor in support of EPA's determination. On March 12, 2018, the State of New York filed a similar Section 126 petition, which alleged that sources including all of the units at Cayuga, Edwardsport, Gallagher and Gibson Stations were significantly impacting ozone attainment in New York. On May 20, 2019, EPA published a proposal for comment that it intended to deny the New York petition. It is possible that New York would likewise challenge EPA in court if a final decision is made to deny the New York petition. If either of these Section 126 petitions were granted, Duke Energy Indiana would be required to comply with the more stringent limits within three months of a final decision, or up to three years if EPA allowed for extensions provided under the CAA. Duke Energy Indiana would need to evaluate enhancements to existing NOx control systems on any affected units at Cayuga, Gallagher, and Gibson Stations to determine what additional steps, including potential operating restrictions, would be required to meet the limits. No impact would be expected at Edwardsport because of the inherently low emissions rate from those units.

4. MATS

On June 29, 2015 the Supreme Court found that EPA should have considered costs as part of its determination of whether the regulation of hazardous air pollutants ("HAPs") from power plants was appropriate and necessary, and remanded the case to the D.C. Circuit Court 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. Duke Energy Indiana cannot predict the outcome of the court proceedings or how it might affect the MATS requirements. However, Duke Energy Indiana's coal fired units are complying with all requirements of the MATS rule.

In February 2019, EPA proposed several actions related to the MATS Rule. In response to the ongoing litigation of the MATS rule, EPA proposed to revoke its 2016 Supplemental Finding which addressed the Supreme Court's remand; however, it also proposed to keep the existing MATS rule in place. EPA also proposed a combined Residual Risk and Technology Review ("RTR"), which is required within 8 years of adopting a standard (such as MATS) under Section 112 of the Clean Air Act. In the RTR, EPA proposed to find that any residual risks are below any threshold of regulatory concern and that there are no developments in practices, processes, and control technologies that warrant revisions of the current MATS standards and no additional restrictions are anticipated at this time.

5. Steam Electric Effluent Limitation Guidelines

EPA signed the final revisions to the Steam Electric Effluent Limitations Guidelines ("ELG") on September 30, 2015. The new limitations are incorporated into a station's National Pollutant Discharge Elimination System ("NPDES") permit upon renewal. The rule requires the new limitations for some waste streams to apply based on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 but no later than December

31, 2023. For flue gas desulfurization ("FGD") and Bottom Ash Transport Water ("BATW"), the EPA issued a final rule on September 18, 2017 to postpone the initial deadline to November 1, 2020, but no later than December 31, 2023. Furthermore, Best Available Technology ("BAT") for the FGD and BATW wastestreams will be subject to a proposed rulemaking during 2019 that is scheduled to be finalized during 2020. For coal combustion residuals ("CCR") leachate, the limits are effective immediately upon issuance of the permit after the effective date of the rule; however, this was vacated and remanded to the EPA for further consideration on April 12, 2019 by the Fifth Circuit United States Court of Appeals. The compliance dates determined by IDEM will be dependent on the site specific-modifications necessary. Duke Energy Indiana has installed wastewater treatment that is believed to be compliant with the rule, as appropriate for a specific DEI facility, including dry fly and bottom ash systems, and plant process wastewater management systems.

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

The latest 316(b) rule revision 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 NPDES discharge permit.

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 submitted 316(b) study reports for Gibson during 2019. The Gallagher reports will be submitted no later than July 30, 2019 and the Cayuga reports will be submitted no later than April 30, 2020. Any required intake modification would be anticipated to occur during the 2021 to 2023 timeframe, depending on the NPDES compliance schedule developed by IDEM. At this time, we believe that DEI facilities are compliant with the 316(b) rule; however, installation of new fish friendly traveling screens ("modified Ristroph") may be required at Cayuga.

C. ENVIRONMENTAL RISK/REGULATORY IMPACTS

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. 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.

2. Coal Combustion Residuals

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 ("RCRA"). This is the first federal regulation of CCRs. The effective date of the rule was October 19, 2015, starting with the obligation 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 all existing surface impoundments used to store or dispose of CCRs and treat non-CCR wastewaters. The closure of surface impoundments lead to dry handling of fly ash and bottom ash and the need for additional landfill capacity. It has also result in a need for alternative wastewater treatment for the non-CCR wastewaters in smaller lined ponds. The regulatory deadlines that have factored into 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 filed with the IDEM in December 2016 closure plans to either close in place or excavate impoundments at all facilities. At this time IDEM has not approved any of our proposed closure plans.

3. Greenhouse Gas Regulation

In June 2019, EPA finalized the Affordable Clean Energy ("ACE") rule to replace the previous Clean Power Plan. The ACE rule will require CO_2 emissions reductions from existing coal-fired electric generating units by requiring states to develop implementation plans based on efficiency improvements that can be adopted "inside the fence" at existing power plants. The EPA Administrator signed the final ACE rule on June 19, 2019. The rule will become effective after it is published in the Federal Register. The final ACE lists seven measures for efficiency improvements that states should consider for application at individual units[6]. States will have three years to develop implementation plans. The implementation plans must include enforceable emissions performance standards for each coal-fired unit, in terms of pounds of CO_2 per MWH of electricity produced. Compliance will be required within two years after state plan approval by EPA, or roughly in the 2024-2025 timeframe.

Duke Energy Indiana's Gibson and Cayuga coal-fired units have already installed the most significant of the measures identified in the final ACE rule. That includes stream turbine blade path upgrades, and variable frequency drives on induced draft fans. Gibson Station also has operating neural networks on its units. The economizers on the Gibson and Cayuga units have also already been replaced, having been optimized for heat recovery while balancing the required gas temperatures for proper operation of SCR catalyst for NOx control. The remaining measures are generally smaller in scope and cost to implement.

[6]The seven measures EPA lists in the ACE rule are neural networks/intelligent sootblowers; boiler feed pump upgrades; air heater and duct leakage control; variable frequency drives; steam turbine blade path upgrades; redesign/replace economizer; and improved operating and maintenance practices.

On August 3, 2015, EPA finalized a rule that established CO_2 emission standards for new, modified, and reconstructed fossil-fuel power plants, the Greenhouse Gas New Source Performance Standards ("NSPS"). This final rule would have prevented Duke Energy Indiana from developing any new coal-fired power plants that are not equipped with carbon capture and storage technology. On December 6, 2018, EPA proposed to revise the CO_2 emissions standards for new-modified, and reconstructed fossil fuel-fired power plants. This proposal would replace the 2015 rule with one that requires new large coal units to meet an emission rate reflective of supercritical operation (1,900 lb CO_2/MWhr).

D. ENVIRONMENTAL COMPLIANCE PLAN

The current modeling analysis primarily focused on compliance with the 316(b) rule requirements. For CCR and ELG compliance, conversion to dry ash handling and waste water treatment projects are already complete; ongoing future landfill construction costs were included in the analysis. 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.

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
    - Ongoing Future 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
    - The unit compliance timeframes were based off of each facility's NPDES permit renewal schedule per the proposed rule.

The balance of all 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. Modeling Assumptions

For this analysis, Duke Energy Indiana utilized a similar analytical modeling process to past compliance planning activities. Forecasts used in planning included fuel price forecasts from IHS Markit, ABB's PROMOD model for forecasting future MISO power prices, and observable market curves and extrapolation for emission allowance prices. Duke Energy Indiana's internal Engineering Screening Model provided input to the modeling process as described in paragraph 2 below.

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 pre-screen environmental compliance options. As some generating units have already been committed to retirement and others are already well controlled, no specific screening activity was performed for this IRP. The Engineering Screening Model was used to support this IRP by organizing modeling information and providing some modeling characteristic data for future compliance costs to the System Optimizer and Planning and Risk models. The model is considered proprietary confidential and competitive information by Duke Energy Indiana.

3. System Optimizer / Planning and Risk Results

The modeled costs associated with CCR, ELG, and 316(b) were passed to the System Optimizer and Planning and Risk models from the Engineering Screening Model. The costs associated with operations utilizing these emissions controls were reflected in unit operating costs and considered in the integration step of this IRP in conjunction with energy efficiency and various supply-side alternatives.

E. EMISSION ALLOWANCE MANAGEMENT

Table F.1 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 2019 through 2022 control periods. Tables F.2 and F.3 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 2019 through 2022 control periods. Beginning with control period 2023, the state of Indiana has an approved

State Implementation Plan to administer the CSAPR program. As a result, allowances that Duke Energy Indiana receives beginning in 2023 may differ somewhat from the allocations that would have been received under the federal program. The change to allocations is anticipated to be minor and have minimal impact to compliance strategies.

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). The market pricing for annual SO_2 and NOx allowances has seen a significant drop since 2015 (when the CSAPR program went into effect) due to substantial decreases in regional annual SO_2 and NOx emissions, resulting in low demand for allowances. Those emissions decreases have been driven largely by retirement of many older, uncontrolled coal-fired units and enhanced operation of controls on operating coal-fired units in response to the MATS rule. This causes low projected emission allowance prices for annual 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. There remains a demand for ozone season NOx allowances due to additional limitations on NOx emissions as a result of the 2016 revised CSAPR ozone season rule. However, even considering the higher cost of ozone season allowance as compared to annual NOx allowances, the pricing of allowances is still typically below the variable cost of control and is not a significant factor in longer term environmental compliance strategy. Allowance pricing for ozone season NOx does play into shorter-term decisions relative to dispatch and short -term operations and maintenance costs.

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.

Table F.1: SO_2 Allowances (tons) Allocated to Duke Energy Indiana Units

Station	Unit	Percent Ownership	2019	2020	2021	2022
Cayuga	1	100	4084	4084	4084	4084
Cayuga	2	100	4027	4027	4027	4027
Edwardsport	6-1	100	1	0	0	0
Edwardsport	7-1	100	139	0	0	0
Edwardsport	7-2	100	119	0	0	0
Edwardsport	8-1	100	143	0	0	0
R Gallagher	2	100	948	948	948	948
R Gallagher	4	100	907	907	907	907
Gibson	1	100	5694	5694	5694	5694
Gibson	2	100	5624	5624	5624	5624
Gibson	3	100	6082	6082	6082	6082
Gibson	4	100	5615	5615	5615	5615
Gibson	5	50.05	4825	4825	4825	4825
Wabash River Gen Station	2	100	751	751	0	0
Wabash River Gen Station	3	100	727	727	0	0
Wabash River Gen Station	4	100	840	840	0	0
Wabash River Gen Station	5	100	770	770	0	0
Wabash River Gen Station	6	100	2857	2857	2857	2857

Table F.2: NOx Annual Allowances (tons) Allocated to Duke Energy Indiana Units

Station	Unit	Percent Ownership	2019	2020	2021	2022
Cayuga	1	100	2738	2738	2738	2738
Cayuga	2	100	2700	2700	2700	2700
Edwardsport	6-1	100	1	0	0	0
Edwardsport	7-1	100	93	0	0	0
Edwardsport	7-2	100	80	0	0	0
Edwardsport	8-1	100	96	0	0	0
R Gallagher	1	100	563	0	0	0
R Gallagher	2	100	635	635	635	635
R Gallagher	3	100	595	0	0	0
R Gallagher	4	100	608	608	608	608
Gibson	1	100	3818	3818	3818	3818
Gibson	2	100	3771	3771	3771	3771
Gibson	3	100	4078	4078	4078	4078
Gibson	4	100	3765	3765	3765	3765
Gibson	5	50.05	3235	3235	3235	3235
Henry County Generating Station	1	100	16	16	16	16
Henry County Generating Station	2	100	16	16	16	16
Henry County Generating Station	3	100	17	17	17	17
Noblesville Repowering	1-3	100	246	246	246	246
Duke Energy Vermillion, II LLC	1	62.50	5	5	5	5
Duke Energy Vermillion, II LLC	2	62.50	5	5	5	5
Duke Energy Vermillion, II LLC	3	62.50	4	4	4	4
Duke Energy Vermillion, II LLC	4	62.50	4	4	4	4
Duke Energy Vermillion, II LLC	5	62.50	5	5	5	5
Duke Energy Vermillion, II LLC	6	62.50	4	4	4	4
Duke Energy Vermillion, II LLC	7	62.50	4	4	4	4
Duke Energy Vermillion, II LLC	8	62.50	4	4	4	4
Wabash River Gen Station	2	100	504	504	0	0
Wabash River Gen Station	3	100	487	487	0	0
Wabash River Gen Station	4	100	563	563	0	0
Wabash River Gen Station	5	100	516	516	0	0
Wabash River Gen Station	6	100	1915	1915	1915	1915
Wheatland Generating Facility LLC	1	100	12	12	12	12
Wheatland Generating Facility LLC	2	100	11	11	11	11
Wheatland Generating Facility LLC	3	100	9	9	9	9
Wheatland Generating Facility LLC	4	100	10	10	10	10

Table F.3: NOx Seasonal Allowances (tons) Allocated to Duke Energy Indiana Units

Station	Unit	Percent Ownership	2019	2020	2021	2022
Cayuga	1	100	640	640	640	640
Cayuga	2	100	574	574	574	574
Edwardsport	CTG1	100	159	159	159	159
Edwardsport	CTG2	100	184	184	184	184
R Gallagher	1	100	42	42	0	0
R Gallagher	2	100	68	68	68	68
R Gallagher	3	100	51	51	0	0
R Gallagher	4	100	59	59	59	59
Gibson	1	100	788	788	788	788
Gibson	2	100	789	789	789	789
Gibson	3	100	768	768	768	768
Gibson	4	100	665	665	665	665
Gibson	5	50.05	684	684	684	684
Henry County Generating Station	1	100	11	11	11	11
Henry County Generating Station	2	100	11	11	11	11
Henry County Generating Station	3	100	11	11	11	11
Noblesville Repowering	1-3	100	25	25	25	25
Duke Energy Vermillion, II LLC	1	62.5	3	3	3	3
Duke Energy Vermillion, II LLC	2	62.5	2	2	2	2
Duke Energy Vermillion, II LLC	3	62.5	2	2	2	2
Duke Energy Vermillion, II LLC	4	62.5	2	2	2	2
Duke Energy Vermillion, II LLC	5	62.5	2	2	2	2
Duke Energy Vermillion, II LLC	6	62.5	2	2	2	2
Duke Energy Vermillion, II LLC	7	62.5	2	2	2	2
Duke Energy Vermillion, II LLC	8	62.5	2	2	2	2
Wabash River Gen Station	2	100	59	59	0	0
Wabash River Gen Station	3	100	68	68	0	0
Wabash River Gen Station	4	100	73	73	0	0
Wabash River Gen Station	5	100	34	34	0	0
Wabash River Gen Station	6	100	324	324	324	324
Wheatland Generating Facility LLC	1	100	13	13	13	13
Wheatland Generating Facility LLC	2	100	9	9	9	9
Wheatland Generating Facility LLC	3	100	10	10	10	10
Wheatland Generating Facility LLC	4	100	11	11	11	11

The Duke Energy Indiana Updated 2018 Integrated Resource Plan

March 23, 2020

Appendix G:
Cross Reference to Proposed Rule

170 IAC 4-7 (Proposed 10/6/17) **Regulatory Requirement**	**Location in Duke Energy Indiana 2018 IRP Document**
Section 0.5 - Purpose and applicability	No Response Required
Section 1 - Definitions	No Response Required
Section 2. - Integrated resource plan submission	No Response Required
Section 2.1 - Confidentiality	No Response Required
Section 2.2 - Public comments and director's reports	No Response Required
Section 2.3 - Resource adequacy assessment	No Response Required
Section 2.5 - Effects of integrated resource plans in docketed proceedings	No Response Required
Section 2.6 - Public advisory process	No Response Required
Section 2.7 - Contemporary issues technical conference	No Response Required
Section 3. - Waiver or variance requests	No Response Required
Section 4. - Integrated resource plan contents	
(1) Twenty-year forecast	Section IV
(2) Analysis of historical and forecasted peak demand and energy usage	Section III.A; Section IV.A; Appendix B
(3) Alternative forecasts of peak demand and energy usage	Section IV; Appendix B
(4) Description of existing resources	Section III.B
(5) Process for selecting possible future resources	Section II
(6) Description of possible future resources	Section V.A; Appendix C
(7) Screening analysis and summary table	Section V.A; Appendix C
(8) Candidate resource portfolios	Section V
(9) Preferred resource portfolio	Section I; Section V.D; Section VI
(10) Short-term action plan	Section I; Section VI.B
(11) Inputs, methods, and definitions for load forecasts	Section II; Section IV
(12) Data sets and sources for load forecasts	Appendix B
(13) Efforts to develop a database of electricity consumption patterns	Appendix B; Appendix D
(14) Suggested methods for developing database in (13)	No Response Required
(15) Schedule for customer surveys	Section II.A
(16) Usage of AMI data	Section VI
(17) Contemporary issues designated	None designated

(18) Distributed generation	Appendix B
(19) Model structure and applicability	Section II.B
(20) Fuel inventory and procurement planning	Section II.A
(21) Emission allowance inventory and procurement planning	Appendix F
(22) Generation expansion planning criteria	Section II.D; Section V.A
(23) Consideration of compliance costs	Section IV; Appendix F
(24) Resource planning objectives	Section II.D; Section V.A
(25) Base case scenario	Section IV.A
(26) Alternative scenarios	Section IV
(27) Description of power flow models and transmission planning criteria	Appendix E
(28) List and description of methods	Section II
(29) Avoided cost calculation	The avoided cost is scenario specific and voluminous. It can be obtained contact Kelley Karn at (317) 838-2461 for more information.
(30) Summary of public advisory process	Volume 2
(31) Assessment of resources considered	Section II; Section V; Appendix C; Appendix D
Section 5. - Energy and demand forecasts	
(a)(1) Historical load shapes	Section III.A; Appendix B
(a)(2) Disaggregation of data	Section III.A; Appendix B
(a)(3) Actual and weather-normalized levels	Section III.A; Appendix B
(a)(4) Methods to weather-normalize	Appendix B
(a)(5) 20-year energy and demand forecasts	Section IV; Appendix B
(a)(6) 10-year historical analysis	Section III.A; Appendix B
(a)(7) Impact of historical DSM programs on load forecast	Appendix B
(a)(8) Justification for forecast methodology	Appendix B
(a)(9) Potential improvements for forecasting	Appendix B
(a)(10) Data sources for historical analysis	Appendix B
(b)(1) Alternative forecasts - high	Section IV; Appendix B
(b)(2) Alternative forecasts - low	Section IV; Appendix B
(b)(3) Alternative forecasts - most probable	Section IV; Appendix B
(c) Suggested inputs for most probable forecast	No Response Required
Section 6. - Description of available resources	
(a)(1) Net and gross dependable generating	Section V.A

capacity	
(a)(2) Expected changes to existing capacity	Section VI.A
(a)(3) Fuel price forecasts by existing generating unit	Appendix A
(a)(4) Environmental effects at existing fossil generating units	Appendix A; Appendix F
(a)(5) Analysis of existing transmission system	Appendix E
(a)(6) Discussion of demand-side resources	Appendix B
(b)(1) Rate design as a resource	The company's EE & DR programs can be viewed as resources that have rate design elements to them.
(b)(2)(A) Description of potential DSM resources	Appendix D
(b)(2)(B) Methods by which DSM resource characteristics are determined	Appendix D
(b)(2)(C) Customer class affected by potential DSM resources	Appendix D
(b)(2)(D) Annual and lifetime energy and savings for potential DSM resources	Appendix D
(b)(2)(E) Impact of potential DSM on load, capacity, and T&D requirements	Section V; Appendix D
(b)(2)(F) Ability of all ratepayers to participate in DSM	Appendix D
(b)(3)(A) Description of supply-side resources considered	Section V.A; Appendix C
(b)(3)(B) Description of efforts to coordinate planning with other utilities	At the time the company gets underway with a larger new resource addition, it will inquire about potential opportunities to coordinate with other utilities. This also takes place in transmission planning.
(b)(3)(C) Environmental effects of supply-side resources considered	Section V.A; Appendix A; Appendix F
(b)(4)(A) Transmission resources considered	Appendix E
(b)(4)(B) For transmission resources, timing, types, and alternatives considered	Appendix E
(b)(4)(C) Cost of expected transmission projects	Appendix E
(b)(4)(D) Value of transmission upgrades	Appendix E
(b)(4)(E) How IRP affects RTO planning and	Section II.D

RTO planning affects IRP	
Section 7. Selection of resources (screening analysis)	Appendix C
Section 8. Resource portfolios	
(a) Process for selecting candidate portfolios	Section II.E; Section II.F
(b) Candidate portfolio performance across scenarios	Section V
(c)(1) Preferred resource portfolio	Section I; Section V.D; Section VI
(c)(2) Standards of reliability	Section II.D
(c)(3) Assumptions having greatest effect on preferred resource portfolio	Section V
(c)(4) Analysis showing that supply-side and DSM have been considered on a consistent basis	Section II; Section V; Appendix D
(c)(5) Analysis showing that portfolio meets demand	Section V; Section VI.A; Appendix A; Appendix F
(c)(6) Analysis of DSM deferring T&D investment	Appendix E
(c)(7)(A) Operating and capital cost of preferred portfolio	Appendix A
(c)(7)(B) Avg. cost/kWh of future resources	Appendix A
(c)(7)(C) Avoided cost in each year for preferred port.	Not applicable - avoided cost is not used in the IRP analysis
(c)(7)(D) Ability to finance preferred portfolio	Section VI
(c)(8) How preferred port balances cost, reliability, risk	Section V; Section VI.A
(c)(9) Discussion of potential improvements	Section VI.D
(c)(10) Strategy for adapting to change in assumptions	Section VI.C
Section 9. Short-term action plan	Section I; Section VI