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Hoosier Energy
2020 Integrated Resource Plan – Public Version
Volume I: Main Report

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1 Introduction

This *2020 Integrated Resource Plan* (the Plan or the IRP) is submitted by Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy") pursuant to the requirements of Rule 170 of the Indiana Administrative Code 4-7 (hereinafter referred to as the Rule). The Plan consists of two volumes. Volume I contains the executive summary, the peak demand and energy forecasts, a description of existing resources, the selection of resources, the resource portfolios and the short-term action plan as required by the Rule. Volume II contains the technical appendices with information required under the Rule.

The IRP contains four subsections. The first section (Section 1) provides an overview of Hoosier Energy and the Hoosier Energy member systems and an executive summary. The second subsection (Section 2) summarizes the energy and demand forecasts and the methodology used to develop the forecasts. The third subsection (Section 3) describes Hoosier Energy's existing resources, both supply-side and demand-side resources. The fourth subsection (Section 4) addresses the selection of potential new resources (both supply-side and demand-side) and the screening process used, along with the development of the modeling scenarios, the portfolio optimization modeling, and the resulting Preferred Plan.

1.1 Hoosier Energy Operational Description

1.1.1 Hoosier Energy Member Systems

Hoosier Energy is comprised of seventeen member distribution cooperatives located in central and southern Indiana and one member distribution cooperative located in southeastern Illinois.
Table1 shows the member systems that comprise Hoosier Energy.

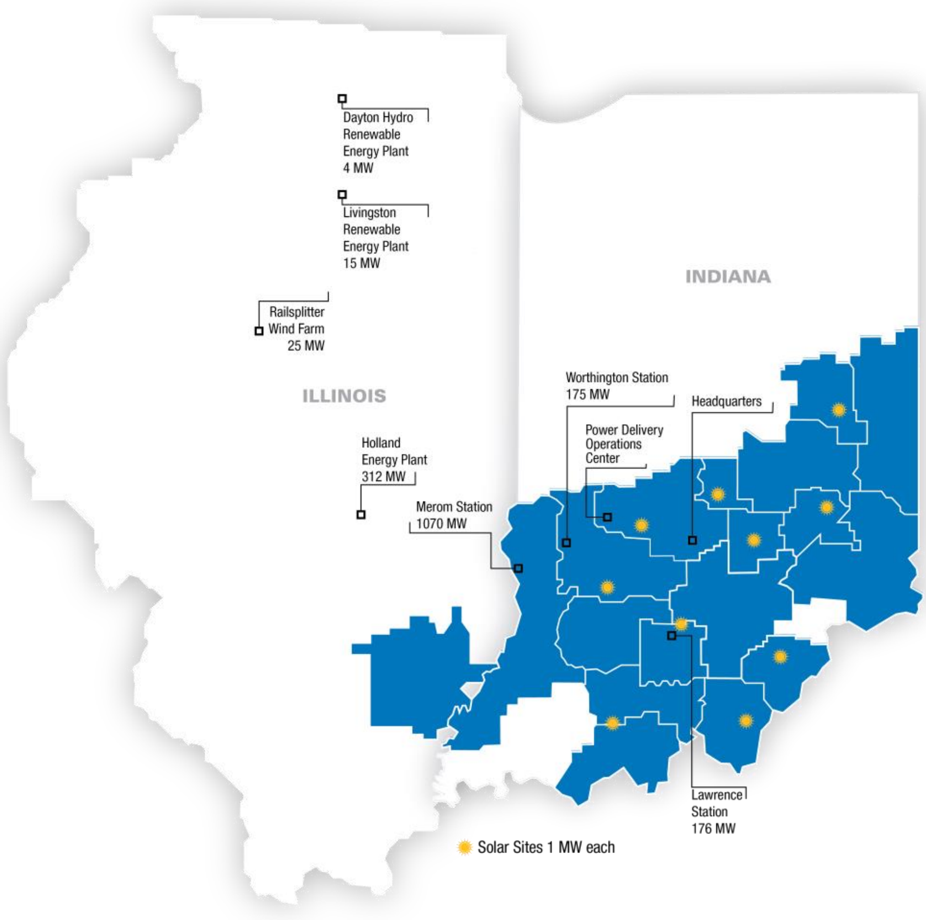
Rural Utilities Service Designation	**Name of Cooperative**	**Location of Headquarters**
Indiana 1	Utilities District of Western Indiana REMC	Bloomfield
Indiana 16	Henry County REMC	New Castle
Indiana 21	Bartholomew County REMC	Columbus
Indiana 26	Daviess-Martin County REMC	Loogootee
Indiana 27	Decatur County REMC	Greensburg
Indiana 38	JCREMC	Franklin
Indiana 47	Orange County REMC	Orleans
Indiana 52	Southeastern Indiana REMC	Osgood
Indiana 60	South Central Indiana REMC	Martinsville
Indiana 72	Clark County REMC	Sellersburg
Indiana 83	Dubois REC, Inc.	Jasper
Indiana 89	Harrison REMC	Corydon
Indiana 92	Jackson County REMC	Brownstown
Indiana 99	Southern Indiana REC, Inc.	Tell City
Indiana 109	Whitewater Valley REMC	Liberty
Indiana 110	WIN Energy REMC	Vincennes
Indiana 111	RushShelby Energy REC	Manilla
Illinois 002	Wayne-White Counties Electric Coop	Fairfield, IL

Table 1: Hoosier Energy Member Systems

1.1.2 Location and Service Territory Characteristics

Hoosier Energy's headquarters facility is located at 2501 South Cooperative Way, on the south side of Bloomington, Indiana. Hoosier Energy operates power plants in Merom, Worthington and Lawrence County, Indiana and Beecher City and Pontiac, Illinois (detailed further in Section 3.1.1) and has transmission crews stationed in Spencer, Seymour, Rushville, Worthington, Petersburg, Poseyville, Napoleon, and English.

The approximate boundaries for Hoosier Energy's member service territory are shown in the map:



Hoosier Energy's member systems serve 48 counties in rural central and southern Indiana and 11 counties in southeastern Illinois. The service territory includes portions of the suburban areas adjacent to the metropolitan cities of Indianapolis, Cincinnati, Louisville, Evansville, Terre Haute, Columbus, Bloomington and Vincennes. The major interstate highways serving these cities and Hoosier Energy's service territory are I-65, I-74, I-70, I-64 and I-69. Several major airports serve the Hoosier Energy service territory including the Indianapolis International Airport, which is located near the northern boundary of the service territory. Several railroads also cross the service area.

The terrain in Hoosier Energy's service area varies from flat to rolling farmland to heavily forested hills containing many deep ravines. This terrain is used in a variety of ways:

- Agriculture for the growing of corn, soybeans, wheat and tobacco.
- Animal husbandry for the raising of hogs, beef cattle, dairy cattle and poultry.
- Stone quarries.
- Coal mining (both strip and underground).
- Hardwood forests for logging.

Dozens of Indiana State parks, forests and fish and wildlife areas as well as portions of the Hoosier National Forest are found in Hoosier Energy's service territory. There are also three large, manmade reservoirs in the service territory, Patoka, Brookville and Monroe, which are used for recreation, water supply and flood control.

The climate in this service area is continental, with warm summers and moderately cold winters. There are four distinct seasons with an adequate growing and harvest season for most farm crops. On the northern perimeter of the service area, the monthly average temperatures range from about 28^{O}F to 75^{O}F, with record temperatures ranging from -27^{O}F to 105^{O}F.[1] The southernmost edge of the service area has monthly mean temperatures ranging from 33.0^{O}F to 78^{O}F, with extremes ranging from -23^{O}F to 108^{O}F.[2] The normal heating and cooling degree-days throughout the area vary as shown in Table 2.

City	Heating Degree Days	Cooling Degree Days
Indianapolis, IN	5,379	1,066
Louisville, KY	4,097	1,614
Evansville, IN	4,547	1,397
Cincinnati, OH	4,982	1,124

Table 2: Normal Heating and Cooling Degree-Days[3]

The normal annual precipitation for this area is approximately 42 inches per year.[4]

1.1.3 Consumer Class Breakdown[5]

The consumer mix on the Indiana portion of the Hoosier Energy system changed slightly over the 2007 - 2017 period. In 2007, 94.9 percent of the system's consumers were residential, while in 2017, 93.7 percent were residential. The number of residential consumers increased from 263,908

[1] Indianapolis Local Climatological Weather Station Reports (Midwest Regional Climate Center, average period 1981-2010, extreme period 1943-2016).
[2] Evansville Local Climatological Weather Station Reports (Midwest Regional Climate Center, average period 1981-2010, extreme period 1931-2016).
[3]Midwest Regional Climate Center (defined NOAA normal, period 1981-2010).
[4] Obtained from Midwest Regional Climate Center (Indianapolis Weather Station, period 1981-2010
[5] Historical statistics prior to 2011 do not include the addition of Wayne-White Counties Electric Cooperative.

in 2007 to 283,538 in 2017. By the year 2038, the number of residential consumers is forecast to increase 13.0 percent to 320,354. The percentage of total residential consumers served is forecast to decline slightly by the year 2038 (93.5 percent).

In 2007, 5.1 percent were Commercial and Other consumers compared to 6.3 percent in 2017. The total number of consumers in this sector grew from 14,067 to 18,979 during this period, representing a growth of 34.9 percent. The percentage of Commercial and Other sector in the year 2038 is forecast to be 6.5 percent, slightly above the present mix. The number of consumers in this class is forecast to increase 17.2 percent to 22,245 in 2038.

The total number of consumers from the Industrial sector, which is defined as loads requiring transformation greater than 1,000 kVA, increased from 190 to 213 during the 2007 through 2017 period, for a net gain of 12.1 percent. The forecast number of 231 consumers in the year 2038 indicates an increase of 8.5 percent.

The proportions of the aggregated member energy sales are different from the consumer mix. The residential class proportion of sales decreased from 63.8 percent in 2007 to 56.6 percent in 2017 due primarily to a large increase in sales to the Industrial and Other Sectors. The actual member system residential energy sales decreased 5.8 percent from 4,297 GWh in 2007 to 4,046 GWh in 2017. The year 2038 residential sales forecast is 5,020 GWh, which accounts for 59.5 percent of total sales.

Hoosier Energy experienced significant growth in sales to the Industrial classification between 2007 and 2017. Energy sales increased 36.6 percent from 1,508 GWh in 2007 to 2,060 GWh in 2017. The portion of total sales to this sector increased from 22.4 percent in 2007 to 28.8 percent in 2017. Total energy sales proportion is forecast to be 25.5 percent (2,149 GWh) for the year 2038.

The proportion of sales to the Commercial and Other sector increased slightly from 13.9 percent of total sales in 2007 to 14.6 percent in 2017. Actual sales increased from 935 GWh in 2007 to 1,045 GWh in 2017, for an overall increase of 11.8 percent. Total energy sales of this class are forecast to be 1,265 GWh in 2038, or 15.0 percent of total sales.

In aggregate, member-system energy sales increased 6.1 percent from 6,739 GWh in 2007 to 7,150 GWh in 2017. The member-system energy sales forecast of 8,434 GWh for 2038 represents an increase of 18.0 percent from the 2017 value.

1.2 Summary of the Planning Process

As described in 170 IAC 4-7, the objective of the integrated resource planning process is to give the Indiana Utility Regulatory Commission (IURC) a regulatory model to ensure that the resource initiatives considered by Hoosier Energy conform with the Indiana Legislature's policy goals. The rule requires that Hoosier Energy consider alternatives to supply-side resources when constructing its candidate resource portfolios.

In accordance with the Rule, the objective of the Hoosier Energy planning process was to develop a strategy for the planning period to afford Hoosier Energy flexibility and latitude in providing electric energy service to its customers. The first step in the IRP process was to prepare an analysis of the historical and forecast levels of peak demand and energy usage. Section 2 of the Plan presents Hoosier Energy's forecast of peak loads and energy consumption. The next step in the resource planning process was to assess the resources existing and potentially available to meet the energy and demand over the planning period. Section 3 details this resource assessment.

The final steps in the planning process were to eliminate nonviable resource alternatives through an initial screening of all future resources identified in the resource assessment and select the best combination of resources that is consistent with the objectives of the IRP. These processes are presented in Section 4.

1.3 Executive Summary of the Resource Plan

Based upon its current load forecast and existing and future resource assessment, Hoosier Energy's preferred course of action is to retire the Merom generating facility in 2023 and replace it with a combination of owned and purchased power resources, including wind, solar and natural-gas. The Preferred Plan is shown in Table 46 in Section 4.15. This Plan represents the portfolio that most economically serves members, while ensuring adequate reliability and minimizing risk.

This is very significant decision affecting both the generation resource portfolio and, more importantly, a significant number of current Hoosier Energy employees. The Board was very thorough and deliberate in making this decision and insistent that impacted employees be treated appropriately.

Hoosier Energy's Board established five criteria as most important to them in the development of the IRP. These five criteria were incorporated into a Scorecard to guide the resource planning process:

1. Limit Wholesale rates and provide a level of rate certainty over the 20-year time horizon.
2. Provide stability and predictability in portfolio costs.
3. Enhance resource diversity through the addition of new resources to meet capacity requirements.
4. Limit environmental risk.
5. Consider the impacts of a potential Merom retirement on employees.

The resource planning process resulted in a Plan that seeks to minimize member-system power supply costs and risks while maintaining a high degree of system reliability. In addition, the Plan seeks to maintain sufficient flexibility to react to changes in member system needs, load forecasts, legislative and regulatory mandates, new technologies and market price volatilities. This Plan will be reevaluated periodically to ensure that the recommended courses of action are having the desired effect and continue to be the best alternatives.

Hoosier Energy will continue to fulfill its resource requirements through a combination of company-owned resources, long-term power purchases and sales, and short-term purchases and sales. Hoosier Energy will continue to work with Member Systems to offer a menu of demand-side measures to promote the efficient use of resources. This includes the wholesale tariff, which was updated in 2019, and provides incentives for both demand response program participation and load shifting.

1.3.1 Public Policy Considerations

A major factor in the development of the Plan was the effect of potential CO_2 legislation and/or regulatory changes. For example, additional environmental restrictions have the potential to further affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions level at existing and future generating stations. The Plan considered future CO_2 legislation and was structured to be flexible enough to incorporate future restrictions.

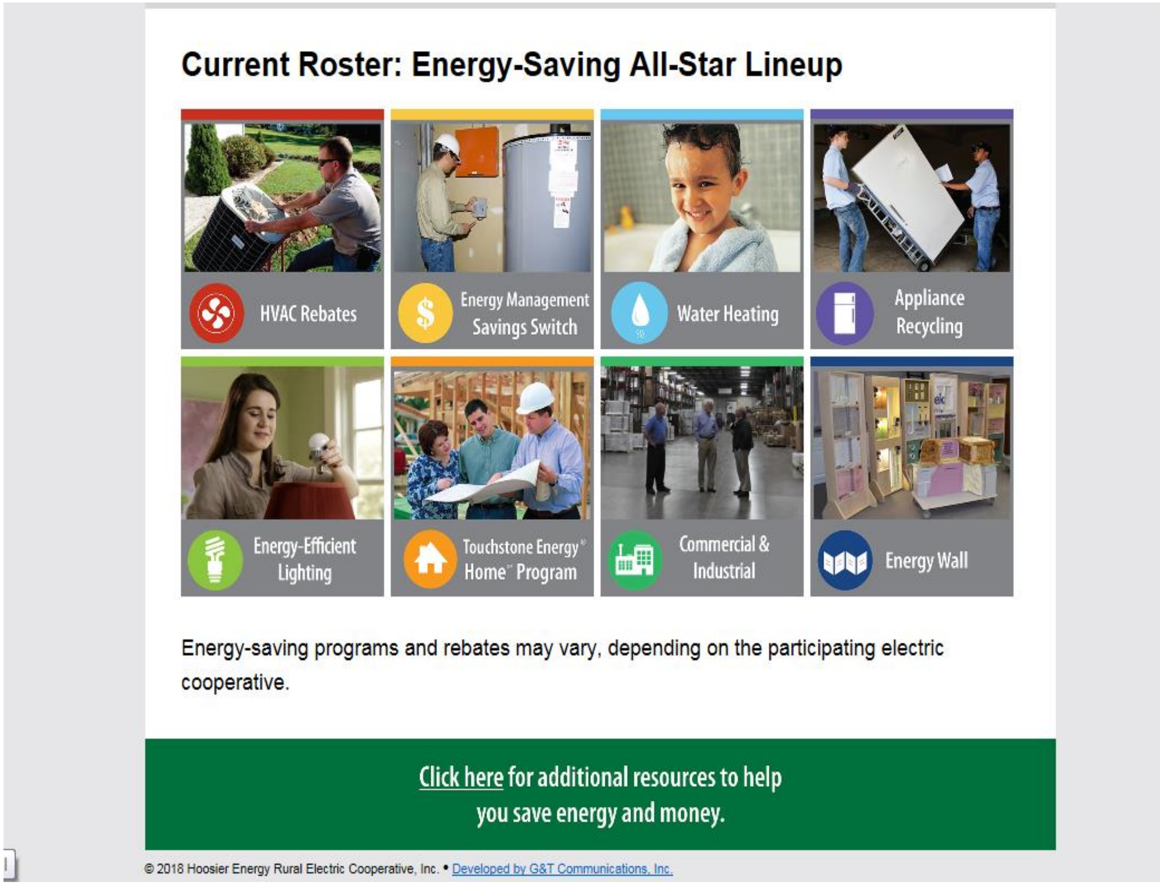
This Plan contemplates no significant changes to the current integrated retail market, which could affect Hoosier Energy's Members. However, the plan does consider the relatively high-risk environment created by customer interest in self-generation and its impact on a utility's obligation to serve retail load.

1.3.2 Supply-Side Resource Considerations

Hoosier Energy is required to adhere to specific standards regarding resource adequacy. The overall level of generation required to maintain system integrity and reliability is of paramount importance. In evaluating supply-side resources, the estimated capital cost and expected operating costs are two primary factors. However, a robust IRP must also consider additional factors, such as current and future environmental regulations, permit requirements, regulatory approvals and customer impacts. The Plan should also recognize the value of diversity – fuel, technology, resource type, ownership, location – to mitigate risks, such as operating, ownership and market risks.

1.3.3 Demand-Side Resource Considerations

As a cooperative, Hoosier Energy interests are aligned with its Members and its Members' retail customers. Hoosier Energy is committed to serving Members reliably and at the lowest possible cost. This commitment is demonstrated as Hoosier Energy and Hoosier Energy's 18 Members offer an array of energy efficiency and demand-side management programs to member-consumers. Current programs are found at the following link:
http://teamuptosave.com/



Further detail on the energy efficiency and demand response programs can be found in the 2019 Demand Side Management Report, which is included in this IRP as Appendix F. The DSM programs result from work with GDS Associates and Summit Blue Consulting to develop the Energy Efficiency & Demand Response Potential Report, which was originally constructed in 2009. The Potential Report, which was most recently updated in 2016, provides detailed descriptions and analysis of all demand-side programs considered and recommended for Hoosier Energy. The Potential Report is scheduled to be updated later in 2020.

Hoosier Energy's demand response and energy efficiency market potential study remains an integral part of the Plan. As discussed above, this study will be updated later in 2020 and its results will provide direction for Hoosier Energy's future demand-side efforts.

1.4 Hoosier Energy's Short-Term Action Plan

Section 9 of the Rule requires inclusion of a short-term action plan as part of its IRP. As discussed in more detail within this integrated resource plan, based upon the current load forecast, power and gas market expectations, known environmental regulations and supply-side and demand-side resource mix, Hoosier Energy presents the following short-term action plan:

1. Expected retirement of Merom in 2023.
2. Issue an all-source Request for Proposal (RFP) in 2020.

3. Continue to monitor and analyze potential environmental regulations.
4. Continue to monitor market economies and the impact on existing and future resources.
5. Pursue economic short-term market transactions to manage risk.
6. Continue to identify and implement cost-effective DSM resources in conjunction with 18 Member systems.

1.5 Comparison to Prior Short-Term Action Plan

In the 2017 Integrated Resource Plan filing, Hoosier Energy submitted the following short-term action plan:

1. Implementation of current and potentially new, cost-effective demand response and energy efficiency programs.
2. Pursuit of cost-effective, renewable resources that provide fuel and resource diversity and help hedge against future environmental regulation risk.
3. Management of short-term capacity and/or energy excess or needs through the wholesale power market using current market hedging mechanisms. Market interaction remains an integral part of the integrated resource plan and will continue to be an appropriate and economical complement to Hoosier Energy's existing resource mix.

Subsequent to the filing of the 2017 Plan, Hoosier Energy has continued to pursue the strategies described in its short-term action plan, including implementation of demand response and energy efficiency programs. The programs and their results are contained in the 2019 Demand Side Management Annual Report, which is attached as Appendix F to this IRP.

Hoosier Energy has continued to add cost-effective renewable resources to its resource portfolio. For example, Hoosier Energy has added 10 MW of owned solar generation and 75 MW of wind PPAs since 2015, with plans, which have been approved by the Board, to add an additional 200 MW of solar PPAs in 2022. In addition, Hoosier Energy's Preferred Plan will add a significant amount of wind and solar resources to its portfolio in the next five years. The addition of these renewable resources will add fixed price resources to the portfolio, thereby reducing market price risk.

Section 2: Energy and Demand Forecasts

2 Energy and Demand Forecasts

Pursuant to 170 IAC 4-7 Sections 4 and 5, this section presents the energy and demand forecasts for Hoosier Energy. The section is broken into eight subsections, and is supported by several appendices. As an introduction, Section 2.1 describes the Hoosier Energy forecasting process. Section 2.2 presents the methodology used to create the forecasts. Section 2.3 and Appendices A1 through A5 present the Base, High Economic, Low Economic, Base-Mild and Base-Severe forecasts. Section 2.4 presents the data used to develop the forecast. Section 2.5 and Appendix B present the load shape and electricity consumption patterns for the Hoosier Energy system. Section 2.6 discusses continuing model development. Section 2.7 discusses the impact of the COVID-19 pandemic on the load forecasts. Section 2.8 presents a summary of Hoosier Energy's forecasted peak demand and energy for the Base, High Economic and Low Economic scenarios.

2.1 Forecasting Process

Hoosier Energy compiles a *Power Requirements Study* (PRS) on a two-year cycle. The PRS meets all requirements as established in the Hoosier Energy Power Requirements Study Work Plan and the Rural Utilities Service Rule 1710, sub-part E, sections 1710.200 through 1710.210. The PRS fully documents the forecast of electric energy sales and peak demand for Hoosier Energy. The development of the PRS is a joint effort between the staff at Hoosier Energy and its member systems, with contributions and review from RUS.

The PRS provides an empirical basis for forecasting generation capacity, forecasting substation capacity and planning transmission facilities. The PRS formalizes the analysis of the need for electric energy and demand for the territory served by the Hoosier Energy member systems over a 20-year period. The PRS provides a systematic investigation of the historical growth experienced by the member systems served by Hoosier Energy. This analysis gives a better understanding of the unique features of the individual member system service areas, which allows for a better background for forecasting electrical load growth, and a more accurate perspective on the status of the member systems.

In the end, this study allows for the development of a forecast that meets three specific needs:

- Provide a basis for determining generation, transmission and distribution system modifications and capital investments;
- Develop a consistent framework for Hoosier Energy and the member systems to plan and project system-wide requirements and improvements; and
- Satisfy the requirement made by RUS that generation and transmission cooperatives provide empirical studies of each distribution cooperative that are consistent with system projections, and that reflect an understanding of the system, its loads, its member systems, and its power supply.

The approval process for the PRS includes approval of each member system's PRS by its board of directors, approval of the Hoosier Energy PRS by its board of directors, and review of the PRS by RUS. Hoosier Energy's 2020 PRS dated November 2020 was officially approved by the Hoosier Energy Board of Directors at the November 2020 meeting.

As the final 2020 PRS had not been completed at the time that CRA conducted the modeling used in the IRP studies, the preliminary PRS was used as an alternate load forecast sources. For the IRP, the numbers as presented are based upon the preliminary 2020 PRS that, as is the final PRS, a 20-year forecast of expected member system load covering the period from 2019 through 2038. There is little difference in the demand and energy forecasts provided by both versions of the PRS, with any the difference between annual growth rates considered immaterial. For purposes of the IRP, Hoosier Energy assumed Summer peak demand growth of 0.6% in 2039 and 0.7% in 2040, which is an extension of the expected growth rates from 2037 and 2038.

2.2 Methodology

This section recapitulates the basic methodology used for the Hoosier Energy demand and energy forecast development. A full explanation of the methodology can be found in the PRS.

2.2.1 Description of the Energy Models

Residential

The Hoosier Energy Residential Energy Sales Model (HERESID) is simply the summation of the results from the individual member system's econometric Residential Model (RESID). Equation (2.1) shows this summation.

$$HERES_t = \Sigma_i \ RESALES_{it} \qquad (2.1)$$

Where:

- i = A subscript representing the member system;
- t = A subscript representing annual data;
- HERES = Annual Hoosier Energy Total Member Residential Energy Sales; and,
- RESALES = Annual Individual Member System's Residential Energy Sales.

Each member system's Residential Energy Model (RESID) is represented by three equations. The values of average residential energy use per consumer per month, real average residential price of electricity, and the number of residential consumers are determined by the operation of the simultaneous solution of this system of three equations. In other words, these three variables are determined within the model, and the three-equation system will allow for the development of forecasts for all three.

The three-equation system is shown in Equations (2.2) through (2.4).

$$\ln RAUSE_{it} = a_0 + a_1 \ln RAUSE_{i,t-1} + a_2 \ln RRPE_{it} + a_3 \ln RPCI_{it} + a_4 \ln HDD_{it} + a_5 \ln CDD_{it} + a_6 XR_{it} \qquad (2.2)$$

$$\ln RRPE_{it} = b_0 + b_1 \ln RAUSE_{it} + b_2 \ln RADSK_{it} + b_3 \ln RAWPC_{it} + b_4 YR_{it} \qquad (2.3)$$

$$\ln RC7_{it} = c_0 + c_1 \ln POP_{it} + c_2 ZR_{it} \qquad (2.4)$$

Where:

i	=	A subscript representing the member system;
t	=	A subscript representing annual data;
RAUSE	=	Average electricity use per consumer per month in the residential sector;
RRPE	=	Real average price of electricity in the residential sector;
RPCI	=	Real average per capita income earned by the people living in the service area;
HDD	=	Annual value of service area heating degree-days;
CDD	=	Annual value of service area cooling degree-days;
XR	=	Other variables that influence average use, such as alternative fuel prices and agricultural production;
RADSK	=	The actual real distribution system cost to operate and maintain the distribution system excluding wholesale power costs;
RAWPC	=	The average real wholesale cost of electricity paid by the cooperative;
YR	=	Other variables that may affect price;
RC7	=	Number of residential consumers;
POP	=	Population in the service area;
ZR	=	Other variables that may affect the number of consumers.

Commercial, Industrial and Other

The Hoosier Energy Commercial, Industrial and Other Energy Sales Model (HECIO) is the summation of the individual member system's results for these classes. The HECIO is shown in Equation (2.5).

$$HECIO_t = \Sigma_i \, MCIOS_{it} \qquad (2.5)$$

Where:

i	=	A subscript representing the member system
t	=	A subscript representing annual data;
HECIO	=	Annual Hoosier Energy Total Member System Commercial/ Industrial/Other Energy Sales
MCIOS	=	Annual Individual Member System Commercial/ Industrial/Other Energy Sales

For each of the member system's Commercial, Industrial and Other class forecast, a judgmental approach was employed. The judgmental approach was selected for the following four reasons:

1. Each cooperative contributed a realistic potential growth estimate. These estimates were developed through a review of past patterns, existing and near-term developments, and expected future growth patterns.

2. The erratic nature of the historical data and the composition of the varied types of loads in this class make it difficult to explain the growth in sales for the Commercial, Industrial and Other class accurately using an econometric model.
3. The growth in the Commercial, Industrial and Other class is highly dependent upon new business developments rather than past patterns of growth.
4. Growth of the Commercial, Industrial and Other class can be best estimated by those most familiar with the area, such as the REMC Managers and Hoosier Energy's representatives. Therefore, even if an econometric model were used, the results would be largely dependent upon information regarding new businesses and industries locating in the service area.

The strategy used in developing forecasts for the Commercial, Industrial, and Other sectors included three steps:

1. Request each REMC Manager or PRS representative to review current and expected sales and consumers conditions for each of these classifications. In addition, staff persons from each member system compiled industrial data to allow completion of Hoosier Energy's RUS Form 345[6].
2. Meet individually with each member system to exchange ideas and information. Historical growth patterns of the Commercial, Industrial, and Other sectors were examined in detail to develop future expected growth potential for each member system.
3. The final step was to compile the expected growth potential values, calculate the future values, and determine if these values represent a realistic future of these sectors. The industrial sector forecast is specifically developed from individual consumer forecasts assigned to this sector. The values for the individual member system's Commercial, Industrial and Other classifications were reviewed by each member system for final approval.

2.2.2 Description of the Demand Models

Hoosier Energy System Demand

To develop a Hoosier Energy demand forecast, information from each member system was combined with Hoosier Energy information. This information includes:

1. Member system non-coincidental peak—winter season,
2. Member system non-coincidental peak—summer season,
3. Member system coincident peak—winter season,
4. Member system coincident peak—summer season,
5. Hoosier Energy actual 30-minute coincident demands,
6. Hoosier Energy actual 60-minute coincident demands without losses, and
7. Hoosier Energy actual 60-minute coincident demands with losses.

[6] These forms were developed for all accounts having a transformation greater than 1,000 kVA.

Once the collection of these variables is completed, the Hoosier Energy demand forecasts can be developed. First, the member system demands are aggregated. Next, the total is adjusted by the Hoosier Energy estimated demand loss factor and the Hoosier Energy 60-minute to 30-minute time ratio adjustment factor (the 60/30 time factor ratio). Equations (2.6) through (2.9) were used to aggregate the member systems' forecast 30-minute demands.

$$HENWP_t = \Sigma_i\ FWINPEAk_{it} \qquad (2.6)$$

$$HENSP_t = \Sigma_i\ FSUMPEAK_{it} \qquad (2.7)$$

$$HECWP_t = \Sigma_i\ FCWINPEAK_{it} \qquad (2.8)$$

$$HECSP_t = \Sigma_i\ FCSUMPEAK_{it} \qquad (2.9)$$

Where:

i	=	A subscript representing the member systems;
t	=	A subscript representing annual data;
FWINPEAK	=	Member system winter season non-coincident peak;
FSUMPEAK	=	Member system summer season non-coincident peak;
FCWINPEAK	=	Member system winter season coincident peak;
FCSUMPEAK	=	Member system summer season coincident peak;
HENWP	=	Hoosier Energy winter season 30-minute non-coincident peak without losses;
HENSP	=	Hoosier Energy summer season 30-minute non-coincident peak without losses;
HECWP	=	Hoosier Energy winter season 30-minute coincident peak without losses; and
HECSP	=	Hoosier Energy summer season 30-minute coincident peak without losses.

Once the aggregation of the member systems' coincident demands is completed, the historical Hoosier Energy 60/30 time factor ratio is developed using Equation (2.10).

$$HETIME_t = ACT60HE_t \div ACT30HE_t \qquad (2.10)$$

Where:

t	=	A subscript representing annual data;
HETIME	=	Hoosier Energy 60-minute to 30-minute time ratio adjustment factor;
ACT60HE	=	Actual Hoosier Energy 60-minute metered coincident demand without losses;
ACT30HE	=	Actual Hoosier Energy 30-minute metered coincident demand without losses.

Through a judgmental process and analysis of the historical Hoosier Energy 60/30 time factor ratio, a value for this ratio is projected for the forecast years and applied to the aggregated member systems' future 30-minute demand values. This process yields a 60-minute Hoosier Energy coincident and non-coincident demand value without transmission losses. These demands are developed using Equations (2.11) through (2.14).

$$HE60NWP_t = HETIME_t * HENWP_t \quad (2.11)$$

$$HE60NSP_t = HETIME_t * HENSP_t \quad (2.12)$$

$$HE60CWP_t = HETIME_t * HECWP_t \quad (2.13)$$

$$HE60CSP_t = HETIME_t * HECSP_t \quad (2.14)$$

Where:

t	=	A subscript representing annual data;
HE60NWP	=	Hoosier Energy winter season NCP without losses;
HE60NSP	=	Hoosier Energy summer season NCP without losses;
HE60CWP	=	Hoosier Energy winter season CP without losses;
HE60CSP	=	Hoosier Energy summer season CP without losses.

Next, a future annual demand loss factor is predicted through examination of the historical annual demand loss factors. Historical demand loss factors represent the annual average demand loss factors which occurred, calculated as the annual average of the monthly demand losses experienced. Monthly demand loss factors are determined by dividing the difference between the 60-minute demands with losses and actual 60-minute demands without losses by the actual 60-minute demands with losses. After the 60-minute demand values without losses are calculated and a demand loss factor is determined, the final Hoosier Energy 60-minute peak demand with losses included is determined by applying Equation (2.15).

$$HEFPEAK_{xt} = HEPEAK_{xt} * [1/(1 - HELOSS_t)] \quad (2.15)$$

Where:

t	=	A subscript representing annual data;
x	=	A subscript representing the various types of demands. When: x = 1 it represents the non-coincident winter season; x = 2 it represents the non-coincident summer season; x = 3 it represents the coincident winter season; and, x = 4 it represents the coincident summer season;
HEPEAK	=	The various peak values developed via aggregation without losses included (example dependent upon "x", HE60NWP, HE60NSP, HE60CWP or HE60CSP);
HELOSS	=	Hoosier Energy demand loss factor due to member system load;
HEFPEAK	=	Hoosier Energy 60-minute peak demand with losses included.

The equations (2.6) through (2.15) are also used to forecast Hoosier Energy peak seasonal demands created by single temperature extremes. The forecast Hoosier Energy peak seasonal demands created by single temperature extremes represent the "Extreme Case" demand forecast. In contrast, the forecast Hoosier Energy peak seasonal demands created by expected, or normal, temperatures represent the "Normal Case" demand forecast.

Individual System Demands

To develop a peak demand forecast for each member system, relevant historical information was collected for the years 1975 to 2018. This information was used to determine the relationship between kWh sales and kW demands. The analysis included the following information:

- Non-coincident peak winter season (October through March);
- Non-coincident peak summer season (April through September);
- Coincident peak winter season (October through March);
- Coincident peak summer season (April through September); and
- Total annual electric energy sales.

Non-coincident peak is the sum of the maximum demand recorded at each substation. Coincident peak is the member systems' contribution to Hoosier Energy's peak demand. Accordingly, coincident peak demand is the sum of demands recorded at each of the member system substations during the same hour of Hoosier Energy's peak. This data was applied in the calculation of the coincident factor analysis.

The first step in the coincident factor analysis is to calculate the member systems' historical load factors, which are found by using Equation (2.16).

$$ALF = [TP / (PEAK * HRS)] * 100 \qquad (2.16)$$

Where:

ALF	=	Annual load factor;
TP	=	Total member system energy purchases;
PEAK	=	Annual non-coincident member system peak kW; and
HRS	=	Number of hours in the year.

The second step is to determine the relative seasonal adjustment factor, which is the percentage of summer peak value to winter peak. The relative seasonal factor is found by using Equation (2.17).

$$RSF = (SUMPEAK/WINPEAK) * 100 \qquad (2.17)$$

Where:

RSF	=	Member systems' relative seasonal factor;
SUMPEAK	=	Member systems' summer seasonal non-coincident peak value (April through September in year t);
WINPEAK	=	Member systems' winter seasonal non-coincident peak value (October in year t-1 through March in year t).

The third step is calculation of the historical coincident factor, which is found by using Equation (2.18).

$$CF_i = (CPEAK_i/NCPEAK_i) * 100 \qquad (2.18)$$

Where:

i	=	Season (winter or summer);
CF	=	Coincident factor;
CPEAK	=	Member systems' coincidental peak in the month of Hoosier Energy's coincidental peak;
NCPEAK	=	Member systems' non-coincidental peak in the month of Hoosier Energy's coincidental peak.

The load factor, the seasonal adjustment factor, and the coincident factors are used as a basis to forecast the system peak demand for each member system. The system peak demand values are based upon the historical patterns seen in these variables in conjunction with information provided by the REMC/REC representative.

The first step in determining the member systems' forecast system peak demand values is to project the future system winter seasonal non-coincidental peak. Equation (2.19) is used to determine the future system winter seasonal non-coincidental peak by applying future annual load factors and energy purchases.

$$FWINPEAK = FTP / [(FALF/100) * HRS] \qquad (2.19)$$

Where:

FWINPEAK	=	Forecast member system winter season non-coincident peak;
FTP	=	Forecast member system total energy purchases;
FALF	=	Forecast member system annual load factor, based on the interpretation of historical trends;
HRS	=	Number of hours in the year.

The next step is calculating the future summer seasonal non-coincident peak demand for each system using a forecast relative seasonal factor and the estimated non-coincident winter peak demand from Equation (2.19). Equation (2.20) shows this formula.

$$FSUMPEAK = FWINPEAK * (FRSF/100) \qquad (2.20)$$

Where:

FSUMPEAK	=	Forecast member system summer seasonal non-coincident peak;
FRSF	=	Forecast relative seasonal factor input based on expected future trends;
FWINPEAK	=	As defined above.

Finally, the coincident seasonal peaks are found by applying the summer and winter coincident factors to the calculated non-coincident peaks. These formulas are listed below as Equations (2.21) and (2.22).

$$FCWINPEAK = CF_w * FWINPEAK \quad (2.21)$$

$$FCSUMPEAK = CF_s * FSUMPEAK \quad (2.22)$$

Where:

FCWINPEAK	=	Forecast member system coincident winter seasonal peak;
CF_i	=	Member system coincident factor when: i=w denotes winter i=s denotes summer
FCSUMPEAK	=	Forecast coincident summer seasonal peak;
FWINPEAK	=	As defined above;
FSUMPEAK	=	As defined above.

2.2.3 Alternative Forecast Scenarios

As a part of Hoosier Energy's forecasting process (the PRS), the forecast process is "ranged based", rather than based upon a single value forecast. Several forecast scenarios are then developed allowing for review of the model's sensitivity to different economic and weather input assumptions. For the most recent PRS, Hoosier Energy developed five alternative energy forecasts: *Base, Base-Severe, Base-Mild, Low Economic and High Economic Cases*. For the residential sector, the scenarios are differentiated based upon fluctuation of population, real per capita income, fuel prices, and weather. For the commercial and industrial sectors, the scenarios were differentiated based upon variation in the number of consumers and energy growth rates.

The following factors were considered in order to determine the magnitude of changes to the variables to produce the alternative cases:

- The observed change in the variables over the historical period that the forecast is based;
- The range of variation that exists for the variable;
- The elasticity of the driving variables in the models (i.e., the size of the coefficient compared with the coefficient of the other variables included in the model).

Hoosier Energy's ultimate goal in making changes to the variable assumptions was to establish alternative scenarios that represent conditions that could realistically occur. This pragmatic approach was also used in determining the magnitude of fluctuation for the commercial and industrial classes' alternative scenarios.

The most probable energy case is called the *Base Case*. The Base Case was developed using the most likely input assumptions. These assumptions are based on extensive research involving the member systems' knowledge of the area, utility operational databases and forecasts for variables provided by many external sources. After the Base Case is completed, the alternative scenario cases are developed.

The first alternative scenario, the *Low Economic Case*, represents the forecast under poor economic development conditions. The Low Case scenario was developed for the residential sector by a) reducing the real per capita income and fuel price growth rates by 1 percent and b) assuming the population growth to be 0.5 percent lower than under the Base Case. To determine the Low Case scenario forecast for the commercial class, the base case growth rates for both the number of consumers and energy growth were reduced by 0.5 percent with a lower bound to be zero. To determine the Low Case scenario forecast for the industrial class, the number of consumers for each system was reduced by one for the entire forecast period, with a lower bound to be zero. Under this scenario the energy for the industrial class was decreased in the initial year using a step function. The energy was decreased by an amount equal to the average industrial consumer's energy use in the calibration year. In addition, the energy was decreased by 0.5 percent annually over the remaining forecast period.

The *High Economic Case* scenario represents robust economic development conditions and is a mirror image of the Low Case. In the High Case, the residential sector was forecast assuming the real per capita income and fuel price growth rates increased by a full percentage point greater than the Base Case and the population growth was 0.5 percent greater than under the Base Case. For the commercial class High Case scenario, the number of consumers and energy growth were increased by 0.5 percent over the Base Case. For the industrial class High Case scenario, the number of consumers for each system was increased by one for the entire forecast period. The energy for the industrial class was increased in the initial year using a step function.

Base-Severe and *Base-Mild scenarios* represent the economic Base Case conditions under varying weather conditions. The Base-Severe case represents the economic Base Case conditions under extreme cold and hot weather conditions. The Base-Severe Case was developed through use of the maximum annual heating and cooling degree-day values recorded during the historical period for the service area. The Base-Mild Case was created using the economic base conditions under mild weather conditions. Mild weather conditions were defined as the annual minimum heating and cooling degree-day values for the service area during the historical period. The primary benefit of seven different scenarios is the allowance for both economic and weather model sensitivity analyses.

For each energy scenario, two demand scenarios are examined. These are based upon historical average and extreme annual system load factors. The demand scenarios represent the effects of typical weather and extreme single temperature weather conditions on the system under the various energy scenarios established. As with the energy forecasts, the variety of demand scenarios allows weather sensitivity analysis of the system demand.

2.2.4 Evaluation of Model Performance

Having the models backcast the period from which they were developed validates how well the residential energy models perform. Once developed, the backcast and the actual data are plotted and visually examined. This analysis assists in determination of whether the model can replicate historical patterns. Examining the model R^2 values and performing a root mean square percent error (RMSPE) analysis then statistically validates the residential energy model. The R^2 for each model reflects the variation in the dependent variable explained by the independent variables being used. This reflects the goodness of fit of the regression models. The RMSPE gives a summary of how close the model's predicted values are to the actual, assuming no error in the input assumptions. The RMSPE is calculated using the Equation (2.23).

$$RMSPE = \{(1/n) \Sigma_i [(Y_i - Y_i')^2 / Y_i^2]\}^{(½)} \qquad (2.23)$$

Where:

n = The number of observations;

Y_i = The actual value of the variable projected under the modeling framework, i=1, . . . , n;

Y_i' = The predicted value.

RMSPE was calculated for the historical period from which the econometric models are developed. The RMSPE in Table 3 illustrates the average performance range of the various individual regional econometric models.

	Within Sample Period (1975-2018)		
Region 1	2.08%	to	4.24%
Region 2	3.28%	to	6.23%
Region 3	3.42%	to	4.72%
Region 4	2.40%	to	2.52%
Region 5	2.28%	to	4.81%
Overall Average	3.56%		

Table 3: Average Estimated Root Mean Square Percent Error

The methodology employed to forecast the Commercial, Industrial and Other Sectors relies on individual member system growth rates, and empirical evidence supplied by the member systems. As such, the methodology does not lend itself to verification of the method's performance. However, Hoosier Energy does have confidence in the Commercial, Industrial and Other Sector forecasting method. The veracity of the approach is confirmed through the comparison of the RUS Form 7 energy and demand breakdowns. Historically, the Hoosier Energy forecast has fallen well between the High and the Low Scenarios.

2.2.5 Justification of Forecasting Approach

Hoosier Energy prefers an econometric modeling approach to forecast the Member Systems' residential energy sales. Other forecast modeling methodologies, such as trend-line analysis, time series models, and end-use models, have strengths and weaknesses. Trend-line and time series methods are entirely based on past trends of electric energy sales. As such, these approaches do not incorporate the impact of changing population and/or changing average incomes, in influencing these trends. End-use models are theoretically appealing because they focus on appliance use at the consumer level. However, end-use models require an extensive investment in consumer surveys over several years. Once these sizable databases have been developed, an understanding of the appliance usage patterns and events shaping them is necessary before an accurate forecasting model can be developed.

An econometric model simultaneously considers the historical impact of certain variables on residential electric energy sales. These variables can include population, per capita income, weather, alternate fuel prices, average residential electric price, and system costs. Although the development data for an econometric model is time consuming, the information required for the econometric approach is available at low cost from published government sources and the consumer billing records.

As with all econometric models, the Residential Sub-model equations will be re-estimated to incorporate new data as it becomes available, including impacts of defined demand-side management programs. This process will involve updating the database and exploring the need to include additional variables to reflect changes in average residential use and the number of consumers. The member systems and Hoosier Energy will continue to cooperate to ensure that the PRS review, data development and revisions reflect a consensus. Hoosier Energy will also continue to evaluate possible alternative methodologies for both energy and demand forecasting.

2.2.6 Weather Normalization

Weather is a primary parameter impacting Hoosier Energy’s energy and demands, as well as a key driver contributing to future movement of these components. The incorporation of the effects of weather into the future Hoosier Energy forecast is completed within the PRS. Ultimately, the IRP results are driven by the PRS energy and demand results.

In the PRS, the effects of weather on future energy and demand are composed of two distinct processes. The first process is tied to degree day analysis as related to energy and the second being single-temperature tied to peak demands. The energy forecast is developed using econometric modeling and is accomplished on a per member system basis. Hoosier Energy forecast energy is an aggregated result of each individual system’s econometrics energy forecast. Within each system model the two important variables are heating and cooling degree-days (HDD and CDD, respectively). These variables represent the relationship, as established in the modeling process, between energy and weather for the service area being forecast.

Reaching beyond a “single-point based” long-term forecast, the methodology used within the PRS is “range based”. This methodology enhances the forecaster’s understanding of the impacts of key parameter variances such as weather on the movement of the forecast. In addition, this “range based forecast” provides the user some flexibility in selection of the final forecast values to be used in supporting subsequent analysis. Within the PRS, six alternative basic scenarios are established providing general examination of weather and economic flexibility from the established “base case”. Four of these six are alternative base scenarios demonstrating weather sensitivity on the system’s energy component.

Hoosier Energy, as with most companies, develops its Base Case forecast based upon “normal” weather conditions**.** Hoosier Energy defines “normal” weather conditions as the average weather that has occurred over a past period. This follows the general definition as established by the NOAA and published in their monthly and annual weather reports. To drive the member systems’ econometric models, “normal” HDD and “normal” CDD variables are developed for each of the service areas. This is accomplished by determining which NOAA defined weather divisions border or cover the various service areas being reviewed. Historical average HDD and CDD across the selected weather divisions are developed by using NOAA values and are then defined as the “normal” weather condition. These defined “normal” HDD and CDD values, specific to the various service areas, drive the econometric models to yield an energy forecast. The individual member system energy forecasts are then aggregated to produce a Hoosier Energy total system “normal” weather energy forecast.

Finally, to comprehend the full impact of weather sensitivity on energy and demand of the system, “Base-Severe” and “Base-Mild” scenarios are created. The Base-Severe case represents the economic Base case conditions under annual extreme cold and hot weather conditions. This is created by using the annual maximum heating and cooling degree day values which occurred over the historical study period. The Base-Mild case represents the economic Base case conditions under annual mild weather conditions. This is created by using the annual minimum heating and cooling degree days which occurred over the historical study period. Results from these scenarios provide an expanded perception of weather sensitivity, while maximizing the capability of using a “ranged based” long-term forecast.

Similarly, demand is temperature normalized. The demand temperature normalization process is completed on a per system basis and aggregated to obtain demand at the Hoosier Energy level. The demand methodology uses a combination of forecast energy values and forecast annual system load factors. Accordingly, no specific weather variable is used directly in the development of the demand value. Weather impacts are incorporated by reviewing the historical annual load factors for each system to determine a typical and an extreme load factor. Since the typical load factor represents what is most likely to happen, it also represents a “normal” weather demand. The extreme load factor represents demand conditions that may exist on the system under single-temperature, extreme weather conditions, and represents the “extreme” weather scenario. Through this method, a demand range is established representing normal and extreme demands for each case scenario.

2.3 Forecasts

The forecasts generated by the PRS can be found in Appendices A1 through A5.

Appendix A1 contains the Base scenario demand and energy forecasts for a 20-year period for the Hoosier Energy System, and for its individual member systems. These forecasts are divided based upon Hoosier Energy customer class, the member systems’ customer classes and the member systems in aggregate.

Appendices A4 and A5, respectively, contain the Base-Mild and Base-Severe Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These forecasts incorporate weather variations rather than economic and/or demographic growth variations.

Appendix A2 contains the High Economic Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These include forecasts by Hoosier Energy customer class and the member systems in aggregate.

Appendix A3 contains the Low Economic Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These include forecasts by Hoosier Energy customer class and the member systems in aggregate.

Energy values shown in Appendices A1, A2 and A3 assume normal weather conditions.

2.4 Forecasting Data

An integral part of the development of a database for the analysis of electricity sales is the construction of the demographic, economic, and weather variables for each member system's service area. Since operating statistics are already recorded for the service area, the database begins with this reliable set of historical information. The challenge is compiling the remaining variables, which are gathered from external sources (e.g., the U.S. Census Bureau) and not differentiated on the same basis (i.e., the same geographic definition) as the member system data. Rather, the auxiliary information is collected on a county, state, or weather division basis. Therefore, compilation of this information requires extensive manipulation to reflect the activity in the service area, usually a combination of sub-county regions.

The data needed to produce the forecasts can be broken down into these categories:

- Operating Statistics
- Demand-Side Management (DSM) Statistics
- Population Information
- Income Information
- Weather Data
- Fuel Prices
- Agricultural Variables
- Other Variables

Each of the following sections describes the data development in detail.

2.4.1 Operating Statistics

Operating statistics reflecting historical sales, revenues, and consumers of each member system were collected from two major sources – RUS and CFC Form 7s, and when available, the United States Department of Agriculture Rural Electrification Administration Informational Publication 201-1 (formally identified as Bulletin 1-1) entitled Annual Statistical Report, Rural Electric Borrowers. Monthly and annual data are reported on RUS Form 7 and annual figures are reported in Publication 201-1. Two sources of operating statistics allowed for the implementation of a validation methodology. If substantial differences between the two sources existed, the cooperative's records were checked to identify the reason for the discrepancy.

For previous PRS studies, each member system provided monthly kWh sales, revenues, and the number of consumers by class. The consumer categories include:

- Residential (includes year-round and seasonal residential);
- Commercial/Industrial Small (non-residential customers with transformation less than or equal to 1,000 kVA);
- Industrial (non-residential customers with transformation greater than 1,000 kVA); and,
- Other electric service (irrigation sales, public street and highway lighting sales, and other unclassified sales).

While the PRS Energy Model was estimated using annual data, the collection of monthly data was also important to allow identification of reclassifications and annexations. The monthly data also provided another source of data to check whether or not observed annual outliers represented an incorrect data entry or an unusual occurrence. In addition, RUS required this monthly data report as part of the PRS document.

Several variables reported are given in nominal dollar values, such as operating deductions, the cost of power, actual distribution system costs and revenues received from the consumer class. Nominal dollar values reflect inflation and the real change in price levels. Therefore, in all the equations, all dollar values have been deflated by the Consumer Price Index (CPI), with a base period of 1982-1984, to reflect real rather than nominal relationships.

To stay abreast of Demand-Side Management (DSM) activity, Hoosier Energy collects information per program per member system annually. This information is applied where necessary to the historical operational data streams in order to understand the DSM impacts on energy and demand, as well as to properly model historical relationships. In order to attain an accurate DSM program performance forecast for the future, Hoosier Energy uses a two-part approach. The first part requires estimating a realistic forecast on a short-term base tied to the most recent study completed by an outside consulting firm. This study incorporates data updated with actual DSM performance through the most recently completed year and the addition of new programs. The second part incorporates Hoosier Marketing Department staff meeting with each of the member systems to develop estimated forecasts, making adjustments as needed, and discussion of long-term forecast impacts.

2.4.2 Population and Real Per Capita Income

Externally obtained county level databases for both population and income have been transformed into what is known as “service area” population and income databases. For each member system, this is accomplished by multiplying county-level variables by “county weights”, then summing the result for all counties served by the member. Service area databases are developed for each of the Hoosier Energy member systems. These databases are established not only for the historical time period in review, but also for the forecast time period.

Use of county weights are necessary because each of the member systems serves only a portion of the respective counties and simply adding the total population or incomes of the served counties would not have been accurate in representing the member system consumers served. The methodology used in the creation of the county weights, along with the defined service area values, has been reviewed and previously used by the State Utility Forecasting Group (SUFG) and the Center for Econometric Model Research (CEMR) established within the Kelley School of Business at Indiana University.

County weights are the share of the county households served by the member system in a specific county. County level household estimates are obtained annually from external agencies. The number of consumers (households) served by the member distribution system in each county is obtained directly from the operating statistics of the system. The county weight for each individual county served by the member system is then established on an annual basis via the ratio of consumers served in a specific county to total consumers in that county. These calculations are performed for each historical year. The weighting in the most recent historical year is held constant and carried forward into the forecast time period.

2.4.3 Weather

Weather is one of the most significant factors in the determination of the variability of electricity sales. Therefore, heating degree-day and cooling degree-day figures are essential variables. A heating degree-day is a unit representing one degree of deviation below 65 degrees Fahrenheit in the mean temperature for one day. Similarly, a cooling degree-day reflects average temperatures above 65 degrees. These degree-day indices provide a measure of how much space heating or air conditioning would have been used over a month.

The weather data used by Hoosier Energy is a weighted average of the readings from the weather stations in the region, with the weights reflecting the average Hoosier Energy population surrounding the weather station. Data on both monthly and annual heating and cooling degree-days for the weather divisions and/or weather stations in Indiana, Kentucky, Illinois and Ohio are published by the National Oceanic and Atmospheric Administration. Weather information is required from the surrounding states since they also border several of Hoosier Energy's service areas.

2.4.4 Fuel Prices

Another important factor affecting the use of electricity is the price of alternative fuels. For example, if the price of fuel oil or LP gas is high, people who are installing new space heating systems (either replacement systems or equipment for new homes) may decide to heat with electricity rather than oil or gas. To capture the potential fuel substitution effects, historical data on fuel prices were collected at the national, regional and state levels. These variables in the past were collected at the specific service area region level within the state; however, these detailed values are no longer available.

The various data on fuel prices are obtained from publications produced by the Energy Information Administration and U.S. Department of Energy. The data in the PRS database included the average prices of:

1. Total energy by residential consumers (primary energy and electricity)
2. Coal
3. Natural gas

4. Petroleum products
5. Distillate fuel
6. Kerosene, liquid petroleum gas, and ethane.

2.4.5 Agricultural Variables

Twelve agricultural variables were collected for the database to reflect the use of electricity on the farms served by the member systems. When possible, these variables were collected at the county level, with estimates developed for the service area using the county weighting procedures. In some instances, where county-level data was unavailable, state-level data was used.

Corn, milk, hay, oats, soybeans, wheat, cattle, beef cattle, milk cattle, chickens, turkeys and hogs represent major agricultural products in southern Indiana and Illinois. Data was collected on these variables from Indiana Agricultural Statistics, compiled by the Indiana Agricultural Statistics Service and from Illinois Agricultural Statistics, compiled by the Illinois Agricultural Statistics Service.

Various procedures are used in the development and analysis of these variables. These procedures include reviewing the variables through a simple sum of production in all counties served by the member systems; a county weighted production number summation representing the service area value; and the variable production magnitudes at the state level. The simple sum of production process involves the adding of the county-level production values incurred across each county for each variable. The county weight process is similar to what was described in the population and income sector of this report. This process involves applying a county weight factor to county-level information in order to develop a number more representative of the true member system service area. In addition to reviewing the number at a county and/or service area level, the variable can also be reviewed at the state level.

Theoretically, if the service area agricultural production is correlated to the state's production trends, these agricultural data are strong proxies for reflecting agricultural activity for the service area. The cost of collecting these state-level variables for the database is also much lower.

2.4.6 Other Variables

Many other variables are available for the database. These variables can provide a basis for possible future extensions of the PRS Energy Model. The Indiana University STATS INDIANA computer network and the Illinois Department of Commerce and Economic Opportunity provide excellent resources in gathering county, state and U.S. economic data. Unemployment rates, number of establishments, personal income, and number of people employed are a few examples of the type of information available to users. Future use of this data will help in understanding the characteristics of the various areas served by the Hoosier Energy member systems.

2.5 Load Shapes and Other Consumption Pattern Databases

2.5.1 Hoosier Energy Customer Databases

Hoosier Energy currently maintains a database of monthly and annual energy sales by customer class. The database was developed for use in the econometric forecast models of the Power Requirements Study and is maintained through the annual collection of member system RUS Form

7s. The customer class breakdowns in the data set are based upon the RUS Form 7 definitions, and are as follows:

1. Residential - includes year-round and seasonal residential.
2. Commercial and Small Industrial - non-residential consumers with transformation less than or equal to 1,000 kVA.
3. Industrial - non-residential consumers with transformation greater than 1,000 kVA.
4. Other - irrigation, public street and highway lighting, and other unclassified sales.

With respect to rate classes and SIC codes, data is not collected either through regulatory forms or metering, and databases of such consumption patterns have not been developed.

2.5.2 Total System Load Shapes

Appendix B contains various load shapes for the total Hoosier Energy system. These include the Hoosier Energy load duration curve, winter and summer peak day load curves, typical winter, summer, spring and fall load curves, for weekdays and weekend days. These load curves are historically based. While Hoosier Energy expects the magnitude of the loads to increase, at this time, Hoosier Energy does not expect the fundamental shape of these curves to change over the planning period.

2.5.3 Disaggregated Load Shapes

Hoosier Energy does not have the resources to disaggregate the historical total system load shape by customer class (i.e., residential, commercial, and industrial) nor by specific end-uses. However, to study the feasibility of economical DSM programs, Hoosier Energy in 1995 undertook a project to develop end-use load shapes. Hoosier Energy, in conjunction with EPRI, focused its efforts on development of 26 specific residential end-uses. These load shapes were developed from end-use metered data and studies obtained from other utilities, along with engineering models. No further activity in this area has taken place within Hoosier Energy. However, work supporting DSM program analysis by outside consultants would most likely contain similar analytical load shape data, along with engineering models.

2.5.4 Future End-Use Surveys

Hoosier Energy has conducted a residential end-use survey typically on a two-year to three-year cycle since 1979. The structure of the survey remains the same as that of the most recent survey, which was strictly an end-use and consumer characteristic survey. This research is conducted to support Hoosier Energy and its 18 member distribution cooperatives in better understanding their consumers' demographics and electricity use, as well as each members' PRS. Prior to 2009, Hoosier Energy had conducted its surveys over the telephone. However, as changing technologies have eroded the representativeness of surveying by telephone only, the survey process has evolved into a blended effort employing both telephone and internet. This in-turn, assures a more representative and expanded sample.

The residential survey total sample quotas for each of the 18 cooperatives are established such that the number of completed surveys provides for a sampling error of plus or minus 5.0% at the individual cooperative level, hence producing an overall sampling error of plus or minus 1.25% at the Hoosier Energy system level. Both sampling error magnitudes are based upon a 95% confidence level. Each survey provides a snapshot of the residential consumer's appliance saturation and characteristics at a specific time. In addition, through continuous building and maintenance of a survey database such as the one established, historical appliance and consumer characteristic trends can be examined. Through these historical observations that are valid at each individual system level, insight into the development of future appliance and consumer characteristics may be developed, along with processes to better serve and meet the needs of consumers in the distribution system.

2.6 Continuing Model Development

Modeling is a dynamic process. Each modeling exercise is a learning experience, during which possibilities for model reformulations are often uncovered. Each stage of the model development process, from database development to model estimation and validation to model simulation, brings additional insights that can be applied to the next round of development. The modeling process must be approached in terms of continual development, not only to reflect new ideas but also to incorporate changing patterns of electricity use. The estimated coefficients of an econometric model are subject to obsolescence because of periodic structural change. The values of the estimated coefficients of the independent variables are dependent upon a number of factors. Many of these factors, such as people's attitudes, beliefs, habits and perceptions are intangible, while others are tangible. All of these factors and relationships implicitly must be captured via all of the coefficients built within the model. When it becomes apparent that the variable relationships have changed significantly, causing the model to no longer adequately track electricity sales, the econometric models must be re-estimated. In order to identify when it is necessary to re-estimate the model, model performance must be continuously monitored.

The most direct strategy for monitoring model performance is to compare the predicted with actual electricity sales when new data is available. There are two possible sources of error in the forecasts. One source is inherent in the model itself, if the model specification is incorrect or if it is outdated. The actual values of the input variables will be used to run a model simulation and the predicted values will be compared with the actual. If the model predictions are considerably different from actual sales and consumers when actual historical inputs are used, a re-estimation of the model with an updated database may be warranted. Another source of error is in the predicted values of the input variables. If input projections are unrealistic, the model results based on these inputs will be unrealistic. Therefore, the model may produce relatively accurate forecasts only when the projected input values are themselves accurately reflecting future patterns.

A second procedure for monitoring model performance is to collect updated information on the projections of the input variables to the models. As time passes, organizations such as Moody's Analytics, Woods and Poole Economics, the Bureau of Economic Analysis, etc., will be publishing updated projections of population and real per capita income. These new forecasts will be incorporated into new scenarios to update the forecasts of electricity sales. Model results must be evaluated in terms of change in the system that might affect how the variables of the models interrelate. There must be a periodic assessment of the impact of system-wide changes such as DSM program positioning or rate structure modifications. These changes may affect model reliability and require an adjustment to the forecasts derived from the model. Indirect and direct consideration of items such as these have been taken into account in this forecast through the exchange of ideas and information with the member system PRS representatives and managers.

As with all econometric models, the Residential Submodel equations will need to be re-estimated to incorporate new data as it becomes available. This process will involve updating the database and exploring the need to include additional variables to reflect changes in average residential use and the number of consumers. Methodologies of incorporating the initial and long-term impact of demand side management programs on energy and demand levels will also be reviewed in the model review process. Because of a lack of information in the past, the impacts of these types of programs were analyzed only at the Hoosier Energy system level. Since 2011, they were incorporated into the member system forecasts to produce final forecasts with DSM. There will be continued dialogue between the member systems and Hoosier Energy to ensure that the PRS review, data development and revisions reflect a consensus.

The approach chosen in the PRS is one of many forecast methodologies used by electric utilities. As the electric market becomes more competitive, new DSM programs are introduced, along with the structure of the market being altered; methodologies on how to incorporate these effects of these programs into existing and/or new modeling techniques for all classifications must be explored. There will be continuing evaluation of possible alternative methodologies to be used in forecasting energy and demand values.

2.7 COVID-19 Impact

The IRP does not include any specific impacts or adjustments due to the COVID-19 virus as the forecast used in CRA's modeling was completed in mid-2019, prior to the pandemic's arrival in the United States. However, as part of its IRP, Hoosier Energy provides a Low Economic forecast that could provide insight into potential impacts of such a pandemic. The ultimate impact on Hoosier Energy's load forecast is uncertain at this time. We will continue to assess the short-term effect of the virus and will reexamine the long-term load forecast in the 2022 PRS.

2.8 Load Forecast

Hoosier Energy's forecasted peak demand and energy for the period from 2018 through 2040 is displayed in Table 4 below. Forecasted load information for the years 2018 – 2038 was taken from the PRS, while information for 2039 and 2040, which was used in CRA's modeling and highlighted in the tables below, was derived by applying the expected growth rates from the years 2037 – 2038. For purposes of this IRP, the Base scenario is used as the expected forecast as it best reflects what Hoosier Energy views as the most likely outcome. The Base forecasts include the expected impacts of Hoosier Energy's Demand Side Management and Energy Efficiency efforts. The forecasted compound average growth rates for Summer peak demand is 0.8% and for energy is 0.5% for the period. Table 5 displays Hoosier Energy's forecasted energy requirements by customer class, while Table 6 presents the forecasted annual peak demand and energy forecast for the base case, high load growth scenario and low load growth scenario. The charts that are displayed subsequent to the Tables provide forecasted demand and energy for the Base, High Economic and Low Economic cases.

Hoosier Energy REC, Inc.
Base Scenario including DSM (at Generation)[1]
For Calendar Years 2018 - 2040

	Winter Peak Demand (MW)	Winter Peak Growth (%)	Summer Peak Demand (MW)	Summer Peak Growth (%)	Energy (MWh)	Energy Growth (%)
2018	1,547		1,492		7,904,522	
2019	1,561	0.9%	1,507	1.0%	7,982,827	1.0%
2020	1,583	1.4%	1,532	1.6%	8,089,092	1.3%
2021	1,604	1.3%	1,556	1.6%	8,197,035	1.3%
2022	1,615	0.7%	1,570	0.9%	8,253,958	0.7%
2023	1,623	0.5%	1,581	0.7%	8,299,656	0.6%
2024	1,629	0.4%	1,605	1.5%	8,349,908	0.6%
2025	1,637	0.5%	1,617	0.7%	8,395,223	0.5%
2026	1,643	0.4%	1,627	0.6%	8,428,316	0.4%
2027	1,651	0.5%	1,636	0.6%	8,459,600	0.4%
2028	1,648	-0.2%	1,632	-0.3%	8,416,065	-0.5%
2029	1,653	0.3%	1,637	0.3%	8,429,186	0.2%
2030	1,668	0.9%	1,653	1.0%	8,497,658	0.8%
2031	1,684	1.0%	1,669	0.9%	8,558,138	0.7%
2032	1,695	0.7%	1,679	0.6%	8,592,293	0.4%
2033	1,697	0.1%	1,682	0.2%	8,586,544	-0.1%
2034	1,708	0.6%	1,692	0.6%	8,622,966	0.4%
2035	1,717	0.5%	1,700	0.5%	8,666,809	0.5%
2036	1,725	0.5%	1,709	0.5%	8,707,211	0.5%
2037	1,737	0.7%	1,722	0.7%	8,762,637	0.6%
2038	1,747	0.6%	1,732	0.6%	8,812,550	0.6%
2039	1,759	0.7%	1,744	0.7%	8,873,003	0.7%
2040	1,770	0.6%	1,755	0.6%	8,918,650	0.5%
CAGR %		0.6%		0.8%		0.5%

1 - Energy forecasts include forecasted Demand Side Management/Energy Eficiency impacts.

Table 4: Forecasted Demand and Energy Requirements

Breakdown of Forecasted Energy Requirements by Customer Class (MWh)[1]

	Residential	Commercial	Industrial	Other	Distribution System Losses	Transmission System Losses	Total Energy Requirements
2018	4,337,165	960,896	2,186,282	60,523	324,319	359,656	7,904,522
2019	4,372,573	969,395	2,237,077	60,520	328,096	343,262	7,982,827
2020	4,218,245	935,872	2,197,188	57,921	332,035	347,831	8,089,092
2021	4,253,071	943,930	2,253,557	57,921	336,082	352,474	8,197,035
2022	4,283,831	951,940	2,266,896	57,921	338,450	354,920	8,253,958
2023	4,313,914	959,916	2,270,717	57,921	340,304	356,885	8,299,656
2024	4,336,780	968,635	2,286,679	57,921	340,847	359,046	8,349,908
2025	4,358,874	980,751	2,293,960	57,921	342,723	360,995	8,395,223
2026	4,382,915	991,041	2,289,878	57,921	344,145	362,417	8,428,316
2027	4,412,055	1,002,626	2,277,534	57,921	345,701	363,763	8,459,600
2028	4,436,877	1,015,471	2,199,389	57,921	344,517	361,890	8,416,065
2029	4,462,268	1,028,743	2,172,940	57,921	344,859	362,455	8,429,186
2030	4,494,030	1,049,845	2,182,730	57,921	347,732	365,399	8,497,658
2031	4,527,600	1,071,590	2,182,730	57,921	350,298	367,999	8,558,138
2032	4,563,037	1,087,742	2,162,262	57,921	351,862	369,469	8,592,293
2033	4,592,806	1,098,327	2,116,213	57,921	352,055	369,222	8,586,544
2034	4,625,993	1,108,923	2,106,042	57,921	353,299	370,789	8,622,966
2035	4,670,587	1,119,618	2,090,748	57,921	355,263	372,673	8,666,809
2036	4,715,836	1,130,424	2,071,373	57,921	357,246	374,410	8,707,211
2037	4,760,622	1,141,335	2,066,279	57,921	359,687	376,794	8,762,637
2038	4,804,967	1,152,358	2,056,489	57,921	361,876	378,939	8,812,550
2039	4,838,062	1,160,396	2,070,727	57,921	364,358	381,538	8,873,003
2040	4,863,051	1,166,466	2,081,478	57,921	366,233	383,501	8,918,650

1 - Energy forecasts include forecasted Demand Side Management/Energy Efficiency impacts.

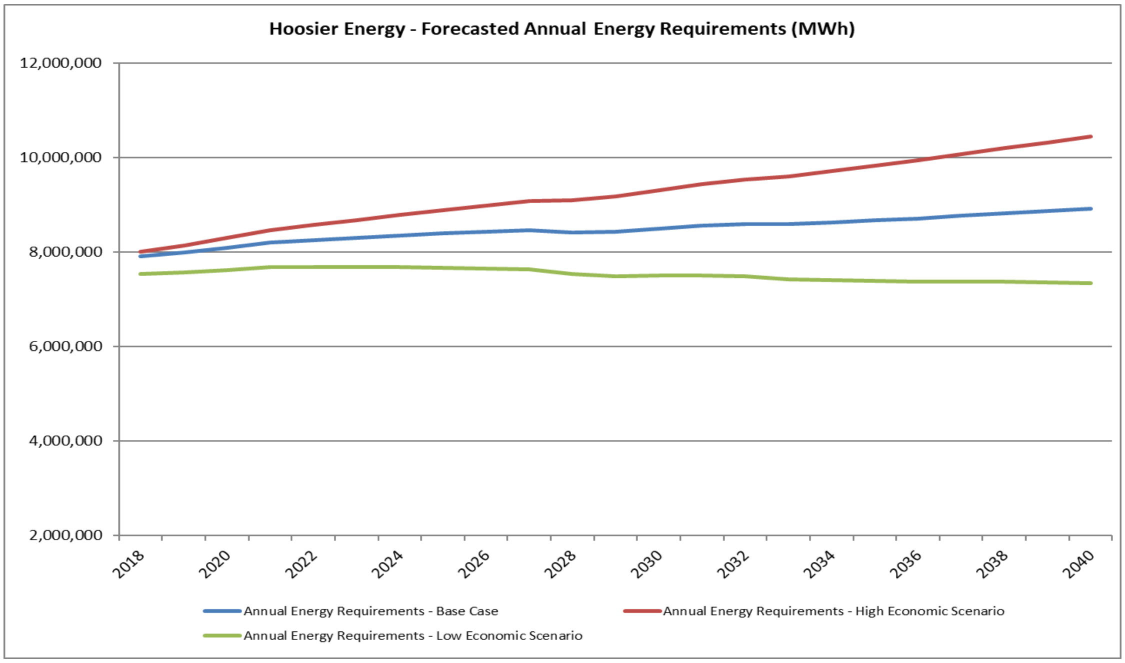
Table 5: Forecasted Energy Requirements by Customer Class

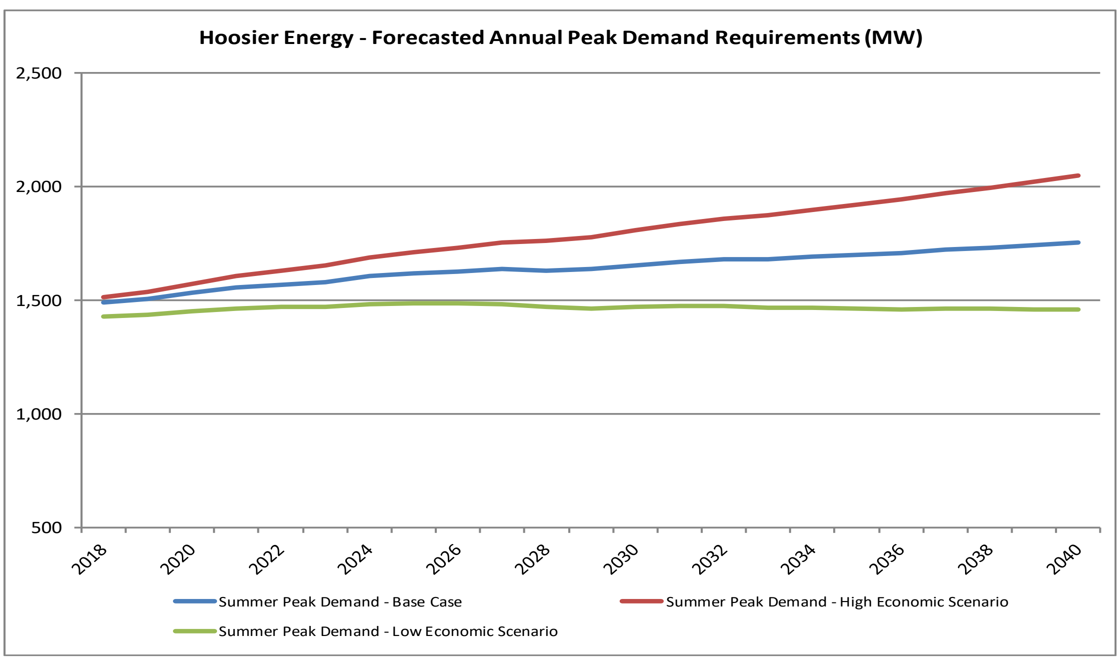
Hoosier Energy Rural Electric Cooperative, Inc.
Summary of Forecasted Demand and Energy Requirements[1]
Base Scenario, High Load Scenario and Low Load Scenario
For Calendar Years 2018 - 2040

Year	Summer Peak Demand - Base Case	Annual Energy Requirements - Base Case	Summer Peak Demand - High Economic Scenario	Annual Energy Requirements - High Economic Scenario	Summer Peak Demand - Low Economic Scenario	Annual Energy Requirements - Low Economic Scenario
2018	1,492	7,904,522	1,512	8,011,633	1,427	7,525,531
2019	1,507	7,982,827	1,537	8,138,656	1,435	7,561,228
2020	1,532	8,089,092	1,571	8,296,837	1,450	7,620,213
2021	1,556	8,197,035	1,605	8,458,852	1,465	7,678,665
2022	1,570	8,253,958	1,630	8,571,695	1,469	7,684,563
2023	1,581	8,299,656	1,652	8,674,670	1,471	7,678,372
2024	1,605	8,349,908	1,688	8,783,365	1,484	7,676,242
2025	1,617	8,395,223	1,711	8,888,372	1,486	7,668,579
2026	1,627	8,428,316	1,732	8,982,443	1,485	7,648,131
2027	1,636	8,459,600	1,754	9,076,018	1,484	7,625,346
2028	1,632	8,416,065	1,762	9,095,437	1,470	7,527,830
2029	1,637	8,429,186	1,779	9,172,345	1,464	7,486,990
2030	1,653	8,497,658	1,807	9,306,070	1,470	7,500,847
2031	1,669	8,558,138	1,836	9,433,234	1,475	7,506,140
2032	1,679	8,592,293	1,859	9,535,508	1,474	7,484,557
2033	1,682	8,586,544	1,875	9,598,464	1,466	7,423,306
2034	1,692	8,622,966	1,899	9,704,980	1,465	7,403,791
2035	1,700	8,666,809	1,921	9,820,685	1,463	7,390,891
2036	1,709	8,707,211	1,945	9,934,527	1,461	7,373,920
2037	1,722	8,762,637	1,971	10,065,154	1,462	7,371,237
2038	1,732	8,812,550	1,997	10,191,633	1,462	7,362,652
2039	1,744	8,873,003	2,023	10,313,933	1,460	7,347,927
2040	1,755	8,918,650	2,049	10,437,700	1,458	7,333,231

1 - Demand and Energy Forecasts include forecasted Demand Side Management/Energy Efficiency impacts.

Table 6: Summary of Forecasted Demand and Energy Requirements


Hoosier Energy - Forecasted Annual Energy Requirements (MWh)
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Annual Energy Requirements - Base Case
Annual Energy Requirements - High Economic Scenario
Annual Energy Requirements - Low Economic Scenario


Hoosier Energy - Forecasted Annual Peak Demand Requirements (MW)
2,500
2,000
1,500
1,000
500
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Summer Peak Demand - Base Case
Summer Peak Demand - High Economic Scenario
Summer Peak Demand - Low Economic Scenario

Section 3: Resource Assessment

3 Resource Assessment

As required by 170 IAC 4-7-6, Section 3 of this IRP describes Hoosier Energy's existing resources, including generation, transmission, rate design and demand-side management. Future Resource Assessments are presented in Section 4 of this IRP.

The 2020 Hoosier Energy Integrated Resource Plan was developed to enable Hoosier Energy to seek the lowest power supply cost possible for member distribution systems for a targeted level of low market and business risk, while maintaining a high degree of generation and transmission reliability. Through this IRP, Hoosier Energy has attempted to include all economic and reliable resources, both traditional supply-side resources and demand-side resources, to meet future electric service requirements.

3.1 Existing Resource Assessment

Hoosier Energy's portfolio has seen significant changes over the past decade. Over the past 10 years, Hoosier Energy has made a number of changes to its resource portfolio demonstrating a commitment to an "all of the above" power supply strategy. Hoosier Energy has added resources fueled by natural gas, landfill gas, wind, solar, hydro as well as continued energy efficiency and demand response efforts.

- Implementation and update of new wholesale tariff options to support demand response efforts.
- Multiple updates of an extensive analysis of member consumer energy usage to develop and implement appropriate energy efficiency and demand-side management programs.
- Purchase of 3.6 MW of generation from Dayton Hydro facility in Dayton, IL through a PPA.
- Purchase of the 15 MW Livingston Renewable Energy Plant in Pontiac, IL.
- Purchase of 25 MW of wind generation from the Rail Splitter Wind Farm in central Illinois through a PPA.
- Development of a 10 MW regional solar program throughout southern Indiana.
- Purchase of 75 MW of wind generation from the Meadow Lake Wind Farm in White County, Indiana through a PPA.
- Purchase of 200 MW of solar generation from the Riverstart Solar Park in Randolph County, Indiana through a PPA beginning in 2022.

The above resource changes have continued the diversification of Hoosier Energy's resource mix with the primary goal of maintaining reliable and affordable energy for consumers.

3.1.1 Generation Facilities – Owned Resources

Hoosier Energy operates generating stations with a total Summer net demonstrated production capacity of approximately 1,680 MW. This capacity consists of 990 MW of coal-fired capacity, 650 MW of natural gas-fired capacity and 40 MW of renewable resource capacity.

The Merom Generating Station is a two-unit, coal-fired steam generating facility located in Sullivan County. Unit One became operational in 1983 and Unit Two became operational in 1982. The plant is equipped with electrostatic precipitators for fly ash removal, a flue gas desulfurization system, or scrubber, to remove sulfur dioxide, selective catalytic reduction technology to remove nitrogen oxide and SBS technology to control SO3 (acid aerosol) emissions. Mercury control systems were added in 2015.

The Worthington facility consists of four General Electric LM6000s with a net summer demonstrated capacity of 170 MW. The LM6000 combustion turbines are more efficient than "frame-type" combustion turbines with a heat rate of approximately 10,000 Btu per kWh. LM6000s also have quick start capability and their relatively small individual size allows significant scheduling and ramping flexibility.

The Lawrence generation facility became operational in 2005. Lawrence consists of six General Electric LM6000s combustion turbines with a net summer capacity rating of 258 MW. Hoosier Energy owns two-thirds of the facility and the output while Wabash Valley Power Association owns one-third. The CTs have a heat rate of approximately 10,000 Btu per kWh and have quick start capability.

Hoosier Energy owns 50% of the Holland generation facility. Holland is a gas-fired, combined cycle facility located in Effingham County, Illinois. Holland is a 2x1 CC with two GE 7FA combustion turbine generators and a single Toshiba steam turbine generator. The facility is also equipped with two Nooter/Eriksen Heat Recovery Steam Generators with NO_x selective catalytic reduction (SCR) and 75 MW duct burners for each HRSG. Total plant heat rate is approximately 7,500 Btu per kWh. Hoosier Energy performed gas turbine compressor upgrades for both Holland Units 1 and 2 during their 2017 and 2018 outages. The compressor upgrades improve blade damage tolerance, reduce inspection requirements and increase reliability and availability.

The 15 MW Livingston Renewable Energy Plant, located near Pontiac, Illinois, is a baseload, landfill methane-gas facility. This facility was acquired by Hoosier Energy in November 2011 and has been refurbished and began operations in October 2013. The plant consists of three turbine engines fueled by landfill methane gas, which is sourced from the 460-acre Livingston Landfill. Energy from the Livingston plant is delivered to the grid through an interconnection with ComEd.

The 16-megawatt Orchard Hills facility near Rockford, Illinois is Hoosier Energy's other landfill gas generation facility. This resource began commercial operations in 2019. The facility is powered by six 620 GE Jenbacher engines.

Beginning in 2015, Hoosier Energy commenced a 10 MW regional solar program. The program consists of construction and operation of ten different 1 megawatt solar arrays located along highly visible roadways across southern Indiana. Each array provides benefits for both the nearby local cooperatives as well as all 18 member systems. The cost for generating solar power through a utility-scale program is significantly less per kilowatt hour when compared with individual, smaller scale systems. Collectively, the ten solar sites provide approximately 18,000 MWh of energy annually.

Table 7 summarizes Hoosier Energy's owned generation facilities.

Resource	Type	Net Demonstrated Capacity (MW)	ISO/RTO Unforced Capacity (MW)
Merom 1	Coal	496	477
Merom 2	Coal	495	451
Holland	Gas	307	307
Worthington	Gas	170	169
Lawrence	Gas	172	166
Livingston	Landfill Gas	13	8
Orchard Hills	Landfill Gas	16	8
Solar Units	Solar	10	7

Table 7: Hoosier Energy's Owned Generation

3.1.2 Power Purchases

In addition to owned generation resources, Hoosier Energy uses a mix of long-term and short-term power purchases to provide reliable and least-cost service to member systems.

Hoosier Energy purchases 150 MW from Duke Energy Indiana under two separate, cost-based, long-term purchase agreements. The first agreement is for 100 MW and runs through 2023, while the second agreement is for 50 MW and runs through 2025. These slice-of-system purchases provide better diversity and less operating risk than an owned resource.

Hoosier Energy also purchases capacity, energy and renewable energy credits from resources through a number of purchased power agreements.

A 20-year purchased power agreement for electricity produced by the Dayton Hydro facility. This project is a 3.6 MW hydroelectric facility near Dayton, IL. The plant produces about 18,000 megawatt-hours annually,

The Rail Splitter facility is a 100 MW facility located near Lincoln, Illinois. In 2014, Hoosier Energy entered into a 15-year agreement with EDP Renewables to purchase 25 MW from the facility. Energy purchases under the PPA began in December 2014 and continue through the end of 2029. In addition to capacity and renewable energy credits, Hoosier Energy receives approximately 70,000 MWh of energy annually from the facility.

Hoosier Energy's Board approved a PPA with developer EDP on a wind project in White County in northwest Indiana. The PPA includes the purchase of 75 MW from the Meadow Lake V project. The Meadow Lake V project represents an expansion of the existing 500 MW wind farm that has been in service for a number of years. Hoosier Energy purchased 75 MW beginning in January 2020 for a 20-year term. The expected capacity factor of the resource is 36%.

In November 2017, Hoosier Energy's Board approved a Resolution authorizing a long term PPA for energy and capacity from a 200 MW solar array. The array will be built in Hoosier Energy's service territory and interconnected to the PJM regional transmission organization. The PPA calls for 200 MW of installed capacity, and an expected 340,000 MWh of energy, annually beginning July 1, 2022. The PPA extends through December 31, 2039. The energy price is fixed throughout the term. In addition, Hoosier Energy will receive Renewable Energy Credits (RECs) as part of this transaction. No capital investment will be required by Hoosier Energy. The agreement also protects Hoosier Energy from exposure to negative LMP prices and includes provisions guaranteeing delivery of 75% of expected annual energy from the array.

Table 8 summarizes Hoosier Energy's existing contracted power purchases.

Resource	Type	Expires	Contracted Capacity (MW)	ISO/RTO Unforced Capacity (MW)
Duke Indiana	Slice of System	2023	100	100
Duke Indiana	Slice of System	2025	50	50
Dayton Hydro	Hydro	2031	4	3
Rail Splitter	Wind	2029	25	2
Meadow Lake	Wind	2037	25	4
Meadow Lake	Wind	2039	50	8
Riverstart[1]	Solar	2039	100	60
Riverstart[1]	Solar	2039	100	60

1 - Contract begins in 2022

Table 8: Hoosier Energy's Power Purchases

3.2 Demand-Side Resource Assessment

DSM is generally defined as utility action or policy that reduces energy consumption or curtails end-use equipment or processes. DSM includes programs that are focused and immediate such as the brief curtailment of energy-intensive processes (demand response). In addition, DSM includes programs that are broad and less immediate such as the promotion of energy-efficient lighting, equipment and devices.

3.2.1 DSM Programs

Hoosier Energy and its member distribution cooperatives have developed a number of demand response and energy efficiency programs. Appendix F is the 2019 Demand Side Management

Annual Report, which provides detail on the impact by member system. The Annual Report also provides demand and energy savings and economic benefit projections by program.

Hoosier Energy has developed a website to provide member consumers with online access to information on each of the available DSM programs, including how to sign up for each program. Member consumers can also purchase energy-efficient lighting through the website. A link to Hoosier Energy's DSM website is below.

Source: http://teamuptosave.com

3.2.1.1 Residential Lighting Program

Retail cooperative members have access to high quality, energy efficient light emitting diode (LED) products through an online store. Lamps come with an instant rebate and free shipping to make it more affordable to replace inefficient lighting with long lasting, low wattage LEDs. The online store also offers easy, self-install products such as weather stripping, outlet and wall switch gaskets, LED nightlights, and refrigerator/freezer thermometers at low cost and with free shipping.

Agricultural and smaller commercial consumers can also benefit from cooperative membership with additional pricing discounts for bulk quantities ordered through the online store. In 2019, more than 25,000 high-efficiency lamps were ordered through the cooperative online store increasing the overall total to 1.9 million lights since the program began in 2009.

3.2.1.2 LED Security Lighting

By using LED models to replace older and more maintenance intensive mercury vapor or high-pressure sodium security lights, cooperative members can improve lighting output, reduce maintenance costs and reduce energy requirements for those fixtures by as much as 70 percent. Over 4,600 security lights were replaced with high-efficiency dusk-to-dawn LED fixtures in 2019.

3.2.1.3 Residential HVAC Rebates

The residential heating, ventilation and air conditioning (HVAC) program provides incentives to homeowners to upgrade to more efficient systems. More than 1,600 HVAC, attic insulation and duct sealing rebates were paid in 2019 to consumers who installed qualifying equipment. Since 2009, the Residential HVAC program has resulted in energy savings of 57,000 MWh and a 14.02 MW reduction in Summer peak demand. Program results are projected to reduce lifetime energy costs for participating businesses by more than $30 million.

3.2.1.4 Commercial and Industrial Programs

Commercial and Industrial (C&I) program incentives are designed to assist businesses in reducing electric demand in their facilities by purchasing and installing energy-efficient equipment, including lighting, HVAC systems, motors and compressed air systems. Through the C&I program, Hoosier Energy assisted member systems in providing incentives for 90 projects in 2019. Since 2009, the C&I program has resulted in energy savings of 130,000 MWh and a 21.68 MW reduction in Summer peak demand. Program results are projected to reduce lifetime energy costs for participating businesses by more than $98 million.

3.2.1.5 Energy Management Savings Switch Program

In conjunction with Member Systems, an energy management switch program is offered. This load control or demand response program is designed to alleviate demand increases by briefly cycling the retail customer's air conditioners, water heaters, pool pumps and irrigation systems. Activation of switches during peak demand periods by Hoosier Energy helps reduce the need for more expensive generation or purchased power. Member System participation is encouraged through price signals from the Standard Wholesale Tariff and Member Systems may also provide incentives to retail customers through bill credits or rebates. All Member Systems have installed advanced metering infrastructure or AMI and some use this to technology to implement this program.

3.2.2 Wholesale Tariffs

Hoosier Energy wholesale tariffs are designed to encourage demand response participation by the member systems and to introduce time-of-use energy pricing. The tariffs were reviewed and rates updated by Hoosier Energy in 2017 for implementation in April 2019. Below is a description of the Standard Wholesale Tariff:

> Production Demand Charge - To support residential control programs, the Standard Wholesale Tariff aligns the G&T tariff and system capacity costs through higher seasonal demand charges that more accurately reflect the greater cost of capacity in summer and winter peak months. Production Demand charges are billed on the Hoosier Energy coincident peak at the time of a load control event in the peak summer months of June, July

and August and the peak winter months of December, January and February. The off-peak months of September – November are billed on the average coincident peak for the three previous summer months. Similarly, the off-peak months of March – May are billed on the average coincident peak for the three previous winter months. This better ensures that the members are able to earn a return on their load control investment. The Standard Wholesale Tariff supports load control by reducing the number of months in which load must be controlled to achieve savings, increases the number of months in which members benefit from peak load reductions, restricts control to months when reductions will most likely produce system benefits, mitigates impacts on consumers, and provides additional protection from cost shifting to members that don't participate in load control programs.

Although not explicitly referenced in the new Standard Wholesale Tariff, the proposed load control program is controlled by Hoosier Energy. Control criteria is primarily based upon reduction in Hoosier Energy system peaks demands, but load control will also be operated for purposes of emergency demand response within MISO. Load control protocols also consider the impact on consumer satisfaction.

Transmission Demand Charge – The charges are based upon system coincident demand (CP) or the 60-minute clock hour during the month between 7:00 a.m. and 11:00 p.m. (EST) in which total system demand reaches its highest point. The transmission charge recovers costs associated with system-wide transmission facilities and MISO costs.

Substation/Radial Line Demand Charge – Billed on the non-coincident peak (NCP) for a 30-minute clock interval, this charge recovers the substation and local line costs for each meter point.

Energy Charge - The Standard Wholesale Tariff includes both on-peak and off-peak energy charges, with the on-peak charges set higher than the off-peak energy charges. On-peak periods for energy charges are narrowly defined as including six hours per day on summer weekdays and two, three-hour periods on winter weekdays. All weekend days and all days in "valley" months of March through May and September through November are defined as off-peak for energy charges. The differentiation between on and off-peak energy charges is intended to recover energy costs in a manner more consistent with the market price signals. In addition, this differentiation provides an incentive to members and end consumers to shift load to off-peak periods.

Optional Wholesale Tariffs

Hoosier Energy offers wholesale tariffs that are intended to provide consumers with options to manage energy costs. The tariffs are also designed to provide the G&T with tools to better manage costs during periods of high demand and market prices and to promote consumer-owned distributed generation, including the purchase of consumer power by Hoosier Energy. While not required by the Energy Policy Act of 2005, the provisions of these tariffs are consistent with key principles of that legislation. The tariffs reflect the G&T's continuing effort to develop efficiency and demand response/demand-side management (DSM) options for consumers. Tariff provisions are summarized below.

Interruptible Power Tariff No. 2

- 500 kW minimum demand and 500 kW minimum interruptible demand

- Customer contracts for "firm" load; remainder subject to interruption
- No buy-through provision
- Interrupt from 7:00 to 11:00 p.m. daily, 1-hour notice, 500 hours per year

Schedule CPP – Avoided Rates for Qualifying Facilities and Distributed Generation Resources
- Customer-owned power production resources between 50 kW and 20,000 kW
- Purchases from Qualifying Facilities paid in accordance with formulae are found at 170 IAC 4-4.1-8 and 4-4.1-9.
- Purchases from Distributed Generation resources shall be negotiated on a case-by-case basis but shall not exceed the rates for purchases of energy and capacity from Qualifying Facilities.

Voluntary Curtailment Rider
- Available to IPT and Industrial Power Transmission Service customers; annual enrollment
- Customer voluntarily agrees to curtail or reduce demand upon request
- Proposed levels are $0.10, $0.15 and $0.25 per kWh
- One hour notice for up to 12 hours of curtailment
- No penalties for non-participation

Standby Service Rider to Industrial Power Tariff (IPT)
- Service option and rates for back-up, supplemental, or standby service
- Requires minimum annual contract demand

3.3 Significant Issues Affecting Resources

3.3.1 Environmental Factors

Environmental Rules and Regulations

In recent years, the U.S. Environmental Protection Agency (EPA) has issued numerous regulations intended to reduce harmful air emissions and wastewater contaminants. Due to challenges from the past and current Administration, the potential impact and timing of these regulations to Hoosier Energy remains unclear in some instances. However, coal generation continues to be a target for new rules and tightening regulations.

Effluent Limitations Guidelines

In 2015, the EPA published the Final Rule for technology-based effluent limitations guidelines and standards (ELGs) to strengthen controls on water discharges from steam electric power plants. The rule established new or additional requirements for wastewater streams from steam electric power plants utilizing coal or other fossil-type fuel. The rule applies to waste streams at coal fired electrical power plants associated with: FGD, fly ash transport, bottom ash transport, combustion residual leachate, and flue gas mercury controls.

Hoosier Energy will need to comply with the bottom ash transport and FGD wastewater sections of the rule. Subsequent to its issuance, the EPA announced that it will reconsider and administratively stay future deadlines of the final rule. Hoosier Energy submitted a request to IDEM for an alternative applicability date of December 31, 2023 and received approval from IDEM for the alternative applicability date.

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

Section 316(b) of the Clean Water Act requires EPA to issue regulations on the design and operation of intake structures, in order to minimize adverse environmental impacts. The final rule applies to facilities that each withdraw at least two million gallons per day of cooling water from waters of the U.S and requires that existing facilities that withdraw at least 25% of their water from an adjacent waterbody exclusively for cooling purposes reduce fish impingement. The final rule also requires that existing facilities that withdraw more than 125 million gallons per day of water conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms affected by cooling water systems. Hoosier Energy submitted its study data to IDEM and is awaiting its review. Until IDEM completes their review of all the study data, it is unknown at this time what will be needed for compliance.

Solid Waste Disposal

Annually, Hoosier Energy files Form EIA 923 with the United States Department of Energy Information Administration. On page 2 of Form 923, the Coal Combustion By-Products (CCBP) quantities generated for the year are listed. The quantity of CCBP generated in a given year is a function of the amount of coal burned and its quality.

2016 Data	**Merom**
Fly Ash Generated (Tons)	219,700
Bottom Ash Generated (Tons)	24,100
FGD Sludge Generated (Tons)	437,700
Stabilizing Additive Used	0
Total CCBP (Tons)	681,500

Table 9: Hoosier Energy By-Products Summary

The majority of CCBP is disposed of in the onsite landfill, which is regulated by IDEM. However, due to increasing market demand for CCBP, approximately 20% is now sold and that percentage is expected to increase in the future. The current active disposal area, as designed, is capable of providing volumetric capacity for 15 years of station operation without consideration of CCBP, but could last longer depending on CCBP sales volume going forward.

The most significant environmental effect associated with onsite disposal of CCBP is the potential for groundwater contamination. This risk is mitigated through engineering controls including low density polyethylene liners for existing and new landfill cells, and a groundwater-monitoring program which has been in service for over 30 years. The groundwater-monitoring program will remain in service for a prescribed period defined in the solid waste permit after disposal of CCBP is discontinued. Thus far, there has been no indication of off-site groundwater contamination.

NOX Emission Reduction Requirements under CSAPR

Hoosier Energy is required to comply with the Cross-State Air Pollution Rule (CSAPR) ozone season program. This program addresses the summertime (May – September) transport of ozone pollution in the eastern United States that crosses state lines. This rule adopts federal implementation plans (FIPs) for all 22 states, updating the existing CSAPR NOx ozone season emission budgets for each state's power generating units. States are allowed to replace the FIPs by submitting state plans that adopt the CSAPR update trading program budgets. Hoosier Energy must maintain the selective catalytic reduction systems in order to comply.

Ozone National Ambient Air Quality Standards

The National Ambient Air Quality Standard (NAAQS) for ground-level ozone is an outdoor air regulation established by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act. Ground-level ozone is a gas that occurs both naturally and forms due to chemical reactions between nitrogen oxides and volatile organic compounds, which are emitted from industrial facilities, power plants, vehicle exhaust, and chemical solvents. The EPA has adopted the ozone NAAQS standard at 70 parts per billion.

Clean Air Act 111 (d) Existing Plant Rulemaking

In 2015, President Obama announced EPA's issuance of its final rules for reducing carbon emissions from new, modified or reconstructed units (111(b)) and existing units (typically referred to as the Clean Power Plan or 111(d)) along with a proposed Federal Implementation Plan (FIP). Overall, the final rule for the Clean Power Plan (CPP) calls for a 32% reduction in power plant CO2 emissions by 2030 from 2005 levels. States more dependent on coal face greater emissions reductions. Indiana is required to reduce CO2 emission by 39% from EPA's 2012 baseline by 2030. In 2016, the U.S. Supreme Court issued a stay of the CPP. The stay freezes implementation of the rule until the judicial review process for the rule is complete. Subsequently, President Trump requested that the U.S. Court of Appeals for the District of Columbia halt its review of the legality of the CPP. He also signed an Executive Order directing the EPA to review the CPP, with the focus upon potentially dismantling the plan. The Affordable Clean Energy Rule, announced in 2018, repeals and replaces the CPP. However, litigation is still ongoing over the CPP and its repeal and Hoosier Energy will monitor these events.

Affordable Clean Energy Rule

In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, which repeals and replaces the CPP. The final rule was issued by the EPA in June 2019. The ACE rule establishes emission guidelines for states to use when developing plans to limit carbon dioxide (CO2) at their coal-fired electric generating units and empowers states to develop their own plans to reduce Green House Gas. The ACE rule directs States to establish performance standards for power plants based solely on heat rate improvements and includes a list of "candidate technologies" for improving heat-rate efficiency that states can use to establish standards of performance for individual power plants. IDEM is currently developing the state plan.

The ACE rule and repeal of the CPP has been challenged by more than two dozen states and numerous interest groups in the U.S. Court of Appeals for the District of Columbia. The ongoing court battles over the CPP, its repeal, and the ACE rule will perpetuate the uncertainty around emissions limitations for coal-fired power plants. At this time, it is unclear whether the D.C. Circuit will dismiss the CPP litigation as moot while the challenge to its repeal is pending.

3.3.2 Economic Factors

Fuel Prices and Fuel Practices

Hoosier Energy fuel and commodity procurement activities are essentially made up of the following material acquisitions:

- Coal
- Natural gas
- Lime (for flue gas desulfurization sludge stabilization)
- Limestone (a reagent for SO_2 removal)
- Fuel oil (for unit start up)
- Chemical additives for FGD
- Ammonia for SCRs
- Soda Ash for sulfuric acid emission mitigation

The program scope for coal includes procurement of both fuel and transportation. Historically, Merom Station has burned 3,000,000 tons of Illinois Basin high sulfur coal each year. This number has declined in recent years as more economic resources move Merom higher in the MISO stack. Hoosier Energy acquires all of its annual coal requirements under a blend of short-term and longer-term contracts. Historically, a limited percentage of annual requirements have been acquired on the spot market. Hoosier Energy has the option of receiving coal shipments either by rail or truck at the Merom generating facility.

Coal is Hoosier Energy's primary fuel supply and represents one of its largest expenses. Hoosier seeks to maintain a low risk profile regarding available supply and price stability. Medium to long-term contracts, employing price re-openers, and maintaining adequate inventory levels generally support this goal. Spot purchases and short-term contracts also supplement contracts as market or operating circumstances warrant. Merom inventory levels target a 35-day supply (350,000 tons). Table 10 shows Hoosier Energy's recent historical coal costs.

Fuel Cost ($ per MWh)	2017	2018	2019
Merom	18.56	19.32	25.04

Table 10: Merom's Recent Historical Fuel Costs

Natural Gas and Transportation

Hoosier Energy and Wabash Valley Power are joint owners of the Holland facility and are responsible for procuring natural gas and gas transportation. Currently, the parties have a contract with Tenaska Marketing Ventures to supply natural gas and transportation to Holland via the NGPL pipeline. Tenaska is a reliable and appropriate service provider.

Transportation of supply to Worthington Generation is provided through agreements with Texas Gas Transmission. Hoosier administers an Hourly Overrun Transportation (HOT) and Park & Loan (PAL) Service Agreements with Texas Gas to satisfy the supply needs of all four units.

Hoosier Energy also has a supply agreement with Citizens Energy Group to connect the Worthington generating facility to their supply system. This has provided both reliability and fuel diversity by establishing access to multiple major interstate pipelines as well as Citizens' natural gas storage field.

Transportation of supply to Lawrence County is provided through a marketing agreement with Sequent Energy, Hoosier Energy, and ANR Pipelines. This agreement provides Lawrence County with greater flexibility in transportation and more competitive pricing, thereby creating increased efficiencies and reduced cost to satisfy the supply needs of all six units.

Avoided Cost Calculation

As defined in 170 IAC 4-7-1 (b), "avoided cost" means the incremental or marginal cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility's IRP. Table 11 presents Hoosier Energy's calculation of the avoided Demand and Energy costs for the years 2021 through 2040 in nominal dollars per kW-month and dollars per MWh. These rates are based upon the cost of a generic Combustion Turbine and have been developed consistent with the IURC's QF calculation. The annual costs have been escalated by a percentage rate consistent with the annual increase in the capacity and energy cost assumptions employed by CRA in the IRP modeling. Hoosier Energy included the potential avoided transmission cost in the evaluation of DSM resources.

	Avoided Fixed Cost ($/kW-mo)	Avoided On-Peak Energy Cost ($/MWh)	Avoided Off-Peak Energy Cost ($/MWh)
2021	$ 4.80	$ 32.90	$ 23.96
2022	$ 4.15	$ 31.64	$ 23.83
2023	$ 4.74	$ 31.20	$ 23.77
2024	$ 5.34	$ 32.00	$ 24.21
2025	$ 6.32	$ 32.30	$ 24.73
2026	$ 5.76	$ 33.28	$ 25.62
2027	$ 7.18	$ 34.25	$ 26.66
2028	$ 7.28	$ 35.22	$ 27.63
2029	$ 7.73	$ 36.98	$ 29.26
2030	$ 8.86	$ 38.74	$ 30.69
2031	$ 9.24	$ 40.41	$ 32.21
2032	$ 9.56	$ 42.19	$ 33.67
2033	$ 9.70	$ 43.65	$ 35.02
2034	$ 9.70	$ 45.25	$ 36.66
2035	$ 10.06	$ 47.10	$ 38.28
2036	$ 10.48	$ 49.17	$ 39.89
2037	$ 10.58	$ 51.36	$ 41.83
2038	$ 10.08	$ 53.60	$ 43.76
2039	$ 10.27	$ 56.14	$ 45.89
2040	$ 10.55	$ 58.51	$ 47.99

Table 111: Summary of Avoided Costs

3.3.3 Transmission Resources

Analysis of Existing Utility Transmission System

Hoosier Energy cooperates with all utilities within the Midcontinent ISO as well as our regional reliability council, ReliabilityFirst Corporation (RFC), to ensure that system changes are compatible with an orderly, economic and reliable development of the entire grid.

Hoosier Energy currently has physical interconnections with the following utilities:

- Big Rivers Electric Corp. (Big Rivers)
- Duke Energy Indiana
- Vectren
- Indianapolis Power & Light Company (IPL)
- Ameren
- Indiana & Michigan Power (I&M)

- Louisville Gas & Electric (LGE)

Hoosier Energy's transmission system consists of more than 1,700 miles of transmission line at 69 kilovolts (kV), 138 kV, 161 kV, and 345 kV. Approximately 59 percent of the member systems' power requirements are delivered to Hoosier Energy substations and delivery points using the transmission facilities of Duke Energy Indiana, Vectren, IPL, LGE, I&M and Ameren. The remainder is delivered through Hoosier Energy's transmission facilities.

Hoosier Energy's system presently includes twenty-five primary substations and approximately 315 distribution substations/delivery points. The distribution substations that serve the member systems are owned in part by Hoosier Energy and the member system. Hoosier Energy owns all the high voltage equipment, transformers, regulators, metering, the low voltage bus disconnect, all associated structures, the property and all in-ground fixtures (foundations, grounding, fencing, etc.). The member systems own the low voltage equipment and structures used for the service to the distribution circuits. Hoosier Energy performs the required maintenance on the entire substation and is responsible for upgrading of the transformer, etc., to meet increased requirements.

Hoosier Energy must coordinate any maintenance outages, expansions or upgrades on its bulk transmission system with the MISO and report these improvements to Reliability First (RF). Hoosier Energy personnel and contractors actively participate in various MISO and RF committees and work groups. Hoosier Energy complies with NERC standards that are enforceable under FERC Order 693 (reliability) and FERC Order 706 (cyber). Hoosier Energy was audited by Reliability First in 2018 (reliability) and 2019 (cyber). The next reliability audit will occur in 2021. RF is one of eight regions that enforce NERC reliability standards. Significant man-hours, documentation procedures and maintenance tracking software has been added in an effort to adequately comply with such reliability standards under Hoosier Energy's Internal Compliance Program, Administrative Bulletin 28 and Board Policy 3-7. The compliance effort extends throughout the company and continues to expand to involve facilities at the Merom Station.

Transmission Access

Member system loads and power purchases from outside Hoosier Energy have costs associated with them for transmission access, either through agreement with the specific utility involved, or the MISO. The MISO transmission expansion cost allocation methodology requires Hoosier Energy to bear some cost of regional transmission projects. MISO continues efforts to reduce congestion throughout the footprint and recently begun an analysis that could lead to significant expansion of the bulk transmission system.

Capital Asset Management

Capital asset management is focused on ensuring that required maintenance is performed and necessary investments are made to economically maintain the long-term safety, security, adequacy, and reliability of these power delivery assets. A critical element of asset health that must be considered in the long-term planning process is the aging infrastructure of Hoosier Energy's transmission system; the majority of which was built more than 50 years ago. The current rate of asset replacement will eventually become insufficient to maintain reliability as those assets exceed the end of their serviceable lives. Hoosier Energy performs comprehensive asset inspections to determine which assets require replacement before substantial degradation or failure affects reliability. Ongoing comprehensive inspections, which began in 2015, will continue to guide sustainable asset replacement strategies.

In addition to replacing aging infrastructure, Hoosier Energy's expected future transmission investment depends, in part, on the development of the Preferred Plan. Table 12 displays Hoosier Energy's expected future transmission investment through 2029.

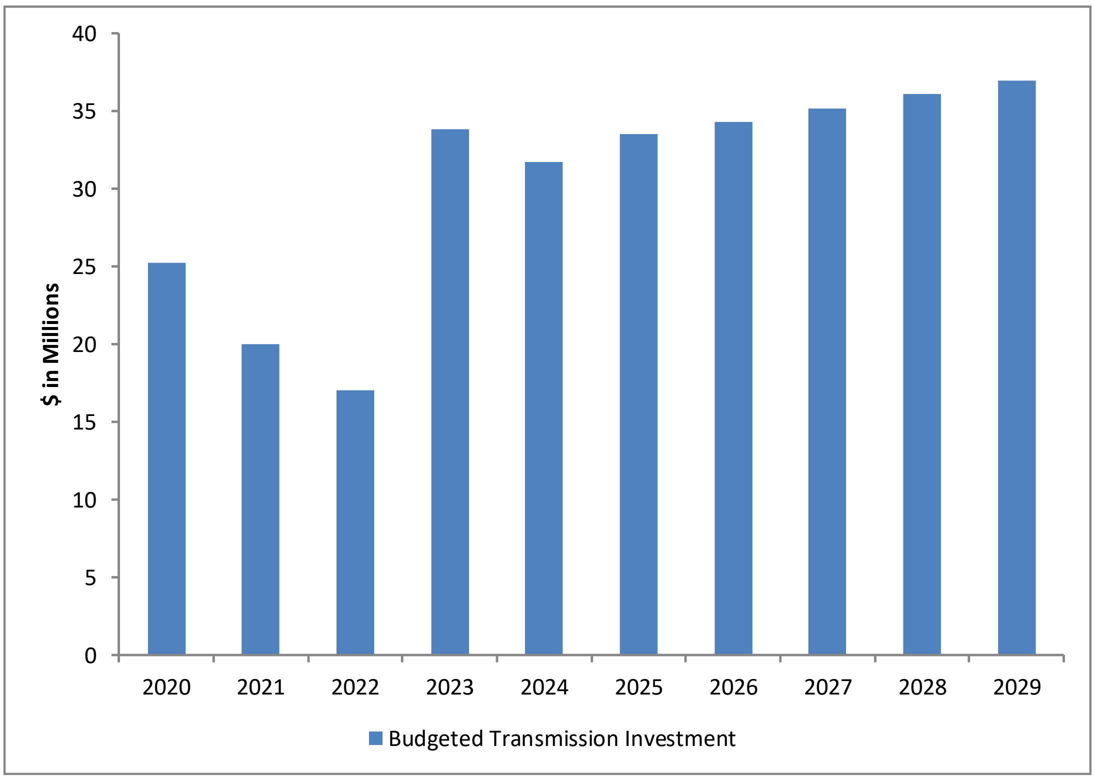


Table 12: Budgeted Transmission Investment

Operations & Maintenance

The operations and maintenance (O&M) function drives the development and execution of maintenance planning practices. These practices are designed to identify equipment maintenance tasks based on the health of equipment assets. Equipment asset health is determined through periodic inspections, monitoring, calibration, evaluation, testing, and repair. The purpose of the maintenance program is to ensure equipment asset health is sustained to ensure the highest level of reliability in a cost effective manner that protects and prolongs asset life.

As described in Section 1.1.2, Hoosier Energy has transmission crews stationed in Spencer, Seymour, Rushville, Worthington, Petersburg, Poseyville, Napoleon, and English The operations and maintenance functions serve to collect and report data points for maintenance planning as well as to construct, repair and replace equipment assets. Equipment assets include substations, transmission lines, communications equipment, and all equipment related to these major assets. In addition to equipment assets, property assets such as rights-of-way (easements) and real property are maintained under a vegetation management program. This program is generally governed by a Transmission Vegetation Management Program (TVMP) which develops the guidelines used to effectively manage vegetation on Hoosier Energy's property assets and undergoes continual improvement as methodologies and equipment evolve and within the scope of current and evolving NERC/RF requirements. The operations and maintenance functions serve as the executing entity for all transmission system maintenance plans, TVMP, and capital improvement projects including oversight of select contractors.

FERC Form 715

Historically, Hoosier Energy has performed an annual analysis of its transmission network to determine whether the system can reliably support the loads and resources placed upon the network. Beginning with the 2014 filing, this analysis, FERC Form 715 Annual Transmission Planning and Evaluation Report (FERC Form 715), has been filed by the Midcontinent ISO as part of the Regional FERC Form 715 filing made on behalf of the Transmission Owning members of MISO. All power flow studies and dynamic simulations incorporated into the FERC Form 715 filing were performed by MISO as part of its MISO Transmission Planning Process (MTEP) and are not specific to Hoosier Energy. MISO's annual MTEP plan assesses transmission requirements and proposes projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. FERC Form 715 is considered to be Critical Energy Infrastructure Information (CEII).

Hoosier Energy periodically prepares a long-range plan (Plan) as a guide for developing the system to meet present and future needs of its consumers. The purpose of the Plan is to study the current system, including asset health projections, identify system shortfalls and develop system mitigation measures that will provide the most practical and economical means of serving future loads.

The Plan was developed to examine the ability of the Hoosier Energy system to serve the projected load levels for the near term (year 0 to year 5) and longer term (year 10) planning horizons. This Plan included additional study models to align with NERC TPL001-4 Standards. Hoosier Energy is a winter peaking system, therefore, the summer peak, light load and winter peak loading conditions were evaluated. In addition to the ability to serve projected load, the health of existing assets is considered in the Plan.

Results from the most recent transmission studies, which were conducted in 2017, show that there was no loading in the base case above 100%. Overloads were observed during certain single contingency conditions. The overloads can be mitigated with operational procedures, so other mitigation measures are not required for the long-range plan.

Low voltage issues were observed during base case (N-0) analysis. The low voltage issues during the base case scenario can be mitigated by either adding capacitor banks to the low voltage areas or upgrading the system to increase voltages. This study used capacitor banks to mitigate low voltage issues.

Low and high voltage issues were also observed during the single contingency (N-1) analysis. In addition to the capacitor banks to be added for the base case low voltage issues, current operating guides, either performed by Hoosier Energy or MISO, were identified to address voltage violations as the preferred approach as opposed to adding additional capacitor banks.

Section 4: Selection of Future Resources and Resource Integration

4 Selection of Future Resources

Pursuant to 170 IAC 4-7 Section 7, this section presents the process that Hoosier Energy uses to select future resources. Through discussion and collaboration with the Hoosier Energy portfolio team, CRA provided potential resource options to be evaluated. For the resource screening, the capacity alternatives were evaluated based on cost, reliability, availability and the maturity of technology. Table 13 lists the resources that were considered for use in the IRP.

Considered	Why?
Natural Gas Combined Cycle	Efficient thermal baseload
Natural Gas Peaking (Frame, Aero, Recip)	Flexible peaking capacity
Merom Repowering (Unit 2)	Peaking capacity alternative
Solar PV	Low cost carbon-free energy during daytime
Wind Turbine	Widely available and low cost carbon-free energy
Battery Storage	Flexible energy resource with peaking capacity
Market Purchases	Cheap resources available in MISO market

Not Considered	Why Not?
Nuclear	Expensive & out of scale
Biomass / Landfill Gas	Limited opportunities to develop projects at scale
Solar Thermal	High cost and poorly demonstrated
Hydro	Resource not available
Geothermal	Resource not available

Table 13: Potential Resource Options

4.1 Demand-Side Resources

In 2009, Hoosier Energy completed an extensive analysis of energy efficiency and demand-side management programs. This work has been performed by GDS Associates and Summit Blue Consulting and has been updated several times, most recently in 2016, and is scheduled to be updated again later in 2020. The individual measures recommended by the analysis, and approved through a collaboration with Hoosier Energy's Member Systems, are then offered to customers through the DSM program. An effort is made to offer a menu of programs to ensure all customers the opportunity to participate. The demand and energy savings and economic benefits of each measure are included in Hoosier Energy's 2019 Demand Side Management Annual Report, which is provided as Appendix F. The DSM Report provides a description and estimated performance through 2019 and also describes changes for the future.

With direction from the DSM Sub-Committee, which is a subcommittee of the Managers Association, and approval of the Managers Association, Hoosier Energy has made the following additions to the DSM program portfolio for 2021 and beyond:

New Programming (effective Jan. 1, 2021):

- Residential HVAC Tune-Up incentive pilot
- Indoor Horticulture/Load Growth incentive pilot

- Electric Lawn Equipment incentive pilot
- Smart Thermostat with Demand Response capability pilot expansion

It is anticipated that Hoosier Energy's future Demand Response/DSM programs will be based heavily on the introduction of a new/revised wholesale rate structure, which is currently under discussion, as well as a push for load growth within its beneficial electrification initiatives with emerging technologies.

4.2 Supply-Side Resources

4.2.1 Market Power Purchases

The wholesale power market has developed standard products that are commonly traded in increments of 50 MW for specific hours of the day or week, such as on-peak hours (5x16), around-the-clock hours (7x24), and wrap hours (weekend 2x16 + off peak 7x8). The two most common products are forwards and options. Forward contracts are take-or-pay and, over the period of one month or more, amount to a capacity factor of approximately 45%. Option contracts are generally day-ahead whereas the buyer provides day-ahead notice to take energy. With the MISO LMP market, the industry has transitioned to financial products as primary risk management tools.

Hoosier Energy actively participates in the wholesale market to serve member load and maximize the value of resources. Hoosier Energy is a member of ACES, which acts as Hoosier Energy's agent for wholesale transactions. ACES is owned by and is the market broker for 21 cooperative members and has a working knowledge of the power market. ACES uses this market knowledge to develop proprietary market pricing information. Hoosier Energy uses information from ACES and other sources to make resource decisions.

4.2.2 Long-Term Power Purchases

Long-Term power purchases are generally at least one year in length and up to 20-30 years. Long-Term purchases may allow for a more diverse portfolio of generation assets, can reduce operating risk, unit contingent risk, and diversify fuel and power supplies. Long-Term Purchases also provide the opportunity to add a resource without taking on construction and operating risk.

Hoosier Energy recognizes the value of purchases as part of a diverse portfolio of generation resources. Hoosier Energy will continue to seek power purchases as not simply an alternative but also as a complimentary component to owned generation assets.

4.2.3 Natural Gas Peaking - Combustion Turbines

Combustion turbines (CT) are generally used for peaking needs and to satisfy capacity requirements. The primary fuel for CT is natural gas with some potential for diesel as a back-up fuel. The key characteristics of CTs include low capital costs, quick start capability, short construction time and somewhat high variable cost. A shorter decision-making lead-time of for procurement, licensing and construction make CTs an attractive option from a flexibility standpoint. Hoosier Energy monitors the capacity and variable costs of the CT resources based upon quotes from vendors and consultants, as well as industry publications.

4.2.4 Natural Gas Combined Cycle Generation

Natural Gas Combined Cycle (NGCC) capacity is preferred for providing intermediate to baseload energy needs. While variable operating costs are generally lower than CTs due to greater efficiency, capital costs are higher. NGCCs require a larger footprint and usually greater amounts of water for cooling. Due to efficiency degradation if cycled, in order to recoup higher fixed costs, NGCCs are likely to be economical with annual capacity factors above 25-30%.

New NGCCs have traditionally been at a disadvantage in the Midcontinent region versus existing coal-fired, baseload resources. The incremental cost of the older coal facilities tended to drive the forward market and supply the region's baseload and intermediate energy needs. However, due to environmental regulations and natural gas price decreases due to improvements in extraction technology, NGCCs are increasingly on the margin in the spot and forward markets of the Midcontinent region. Future environmental regulations are likely to improve the economics of natural gas-fired combined-cycle facilities due to the CO2 emission advantage versus coal generation.

4.2.5 Wind Generation

Energy from wind resources has become a prominent component of most resource plans as cost reductions due to technology improvements allow wind to be more competitive. The problem with wind generation remains the intermittent nature of the resource, which means the value is significantly lower due to the intermittent and unpredictable nature. Another hurdle for wind resources is the availability and expense of sufficient transmission infrastructure to move the wind energy from producing regions to load centers.

The installed cost of wind ranges from $1,200 - $1,700 per kW ($2019), depending upon the size of the installation.[7] For purposes of the IRP, Hoosier Energy modeled assumed wind PPAs in 50 MW blocks, with a maximum of 500 MW available in any particular year. The PPAs were assumed to be acquired as a 20-year fixed-price transaction, with prices reflected in Appendix D.

4.2.6 Solar Generation

Due to decreasing costs of photovoltaic panels, solar energy generation is becoming more economically competitive relative to other supply-side resources. The intermittent nature of solar generation tends to limit its value unless paired with energy storage. The cost for generating solar power through a utility-scale program is significantly less per kilowatt hour when compared with individual, smaller scale systems.

The installed cost of Solar PV ranges from $1,300 - $2,300 per kW ($2019) for a utility-scale PV installation[3]. For purposes of the IRP, a 50 MW Solar PPA was used as a proxy to model solar generation, up to a maximum of 500 MW allowable in any year. This PPA has a 20-year term and uses an assumed energy rate based upon the prices shown in Appendix D.

[7] U.S. Energy Information Administration; Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies; February 2020

4.2.7 Battery Storage

Battery storage falls in the broad category of energy storage and is now in the deployment phase of the technology continuum for electrical generation. Frequency regulation and grid support are primary drivers of commercial deployments for battery storage however, as battery costs continue to decrease, a shift towards multiple services such as capacity, ramping support and ancillary services is expected. At the end of 2018, 869 megawatts (MW) of power capacity, representing 1,236 MWh of energy capacity, of large-scale battery storage was in operation in the United States, including 39 MW in MISO[8].

There is a variety of battery technologies available including metal air, flow, sodium chemistries, lead acid and lithium ion. While lead acid is the most mature, lithium ion is the most widely selected technology by utilities, and in fact is the only battery technology that has advanced from grid support to the bulk-energy management level. Sodium sulfur batteries offer high density and efficiency, and are used for grid support but have experienced some safety concerns throughout the industry. Hoosier Energy is considering applications within its power network for battery storage, and closely following technology advancements, as well as costs. Installed costs for lithium ion technologies, range from $650/kW to $1,500/kW depending on duty (frequency regulation, grid support, bulk storage) and scale, with average installed costs falling below $1,000/kW in recent years. Potential applications include co-location of a battery storage facility with a consumer solar PV array, or storage located at an existing base load plant to offset auxiliary power during on peak hours.

4.2.8 Merom Repowering

As an alternative to building or purchasing peaking capacity, and also to prolong economic and useful operations of the Merom generating units, Hoosier Energy considered repowering Unit 2 of the Merom facility. The repowering would be achieved through a coal-to-gas conversion of the Unit. Hoosier retained Burns & McDonnell (BMcD) to provide a high-level estimate of the costs associated with repowering. As part of its analysis, BMcD provided information regarding capital and operating costs, along with required modifications to repower the Unit.

4.2.9 Other Renewable Resources

Other resources considered renewable are technologies fueled by landfill gas, coalbed methane and biomass. These technologies can be promising as continued technological advances increase efficiencies and experience reduces the development and operating risk. However, in order to be cost effective versus other resources, these technologies generally require a specific need, such as a requirement to find an alternate method to dispose of waste. In addition, in order to be cost competitive these technologies generally require a sufficient, reliable and economically advantageous fuel source.

Other alternative energy projects, such as cogeneration and coal waste technologies, may or may not qualify as renewable energy but could prove economic and provide supply-side diversification. Hoosier Energy has analyzed a number of these proposals and has demonstrated a commitment to considering all economically viable renewable energy resources.

[8] Battery Storage in the United States: An Update on Market Trends, U.S. Energy Information Administration, July 2020

4.2.10 Distributed Generation

Options for distributed generation include both fossil and renewable sources. On the fossil side, the cost of distributed generating capacity for diesel or gas turbines is estimated to be greater than $1,000 per kW. The actual cost is highly dependent upon a number of factors, including the type of engine (diesel reciprocating engine or gas turbine), size, manufacturer, emission level, efficiency, etc. Given the higher capital cost, the economics of distributed generation does not compare favorably to central station power without a customer specific need for increased reliability and/or an economically advantageous fuel source.

Reciprocating internal combustion engine (RICE) is a mature technology that has grown in popularity for use in the electric power generation sector. Historically, RICE was not considered for power generation due to economies of scale; however, utilities have increased interest in RICE because of flexibility, completive life cycle costs and operating characteristics including:

- Flexibility – fast start and fast ramping
- Modularity – increments of 1 to 20 MW
- Fuel Diversity – biogas, hydrogen, natural gas, landfill gas and diesel
- Low Emissions – clean burning requiring minimal water usage
- Low capital cost – comparable to NGCCs from $900 to $1500 per unit

An internal Hoosier Energy team continues to analyze and valuate RICE system configurations and technology applications for potential projects. The group monitors new installed project costs, unit performance updates, and technology applications. Hoosier Energy also participates with the Electric Power Research Institute (EPRI) RICE interest group to monitor and understand the evolving market for these quick-start resources.

4.2.11 Non-Utility Generation

Commercial and industrial (C&I) consumers served by Hoosier Energy members have expressed growing interest in developing renewable energy resources adjacent to their facilities. Hoosier Energy and the cooperative member staff have met with several C&I consumers interested in on-site generation to discuss projects ranging from a few hundred kW up to 10 megawatts of capacity with most projects averaging 1 MW. Interest is motivated by multiple factors including corporate sustainability policies and goals, support for marketing programs based on green attributes, pressure from customers who encourage or offer incentives to suppliers to use renewable energy, and interest in locking in a portion of energy costs at a fixed price. Recruiting employees was cited by one business that thought a solar array might help attract new graduates to the company.

C&I interest in on-site renewable generation may accelerate as the cost of solar drops further, as a result of tax credit extensions, as momentum builds at business groups that encourage renewable energy, and as a result of increased marketing by solar vendors. Some companies, including large data centers, are also beginning to include “renewable friendly policies” at utilities in their site selection process.

In response, Hoosier Energy changed Board Policy to provide member systems and the G&T with new tools and renewable generation options that members can offer these consumers. The change authorizes Hoosier Energy to work with member cooperatives, end consumers and developers to build on-site generation at C&I locations, largely through purchase power agreements (PPA’s), and pass contractual obligations and costs through the distribution co-op to the C&I consumer via “take or pay” agreements. This is a significant step to better facilitate retail customer interest in on-site renewable energy technologies.

In addition, Hoosier Energy also created a C&I Renewable Energy Credit (REC) program to help companies meet their renewable and carbon goals in a cost effective way without having to build new renewable generation at their facility. The current program allows C&I members to purchase RECs directly from Hoosier Energy’s renewable portfolio and currently has several companies signed up to meet internal goals ranging from 25% - 100% renewable.

Hoosier Energy’s Member systems have 423 distributed solar and 19 distributed wind generation customers. These customers installations have a nameplate capacity of 3.9 MW of solar and 0.1 MW of wind. Hoosier Energy and the majority of its Members have adopted a consistent compensation mechanism applicable to all installations of less than 50kW. The rate is based upon Hoosier Energy’s projected variable production cost from the G&T’s Budget and provided to the members in October for the upcoming budget year.

For customer-owned generation qualifying facilities greater than 50kW (and less than 20MW), Hoosier Energy and its Member Cooperatives have adopted a policy that requires excess energy to be purchased by Hoosier Energy under Schedule CPP. Schedule CPP is consistent with the IURC’s QF rules and includes the following compensation amounts:

If the qualifying facility meets the requirements of Schedule CPP, Hoosier Energy will purchase energy at the following rates:

For all on-peak energy supplied	$0.03668 per kWh
For all off-peak energy supplied	$0.02541 per kWh.

Hoosier Energy may also purchase capacity supplied from the QF in accordance with the conditions and limitations of the contract at the following minimum rate:

Unadjusted rate for Capacity	$3.40 per kW-month.

There are currently no customers with qualifying generation facilities taking service under Schedule CPP.

4.2.12 Emerging Technologies

Hoosier Energy monitors mature and emergent generation technologies as potential options to provide low cost, reliable generation. Variable demand power markets, environmental regulations and economic conditions have caused a heightened interest in novel cycle technologies that accommodate intermittent cycles from renewable generation as well as for adding smaller blocks of incremental capacity.

- Adaptive Generation Resources - Certain technologies that convert mechanical work to electrical energy have been in existence for some time now, and have been increasingly incorporated into the bulk electric system. Increasing intermittent generation requires flexible power sources for voltage regulation, grid stabilization and load balancing. Base load and intermediate load facilities cannot easily accommodate the increased penetration of variable generation seen on the electric grid due to thermal cycles and slow ramp rates. As a result, non-conventional sources of generation are finding a place in bulk electric generation.

- Compressed Air Energy Storage - CAES uses off peak electricity to compress air into an underground reservoir, surface vessel or air storage system and when electricity is needed, or prices are high is released. The air is withdrawn, heated with fuel and passed through an expansion turbine to generate electricity. Advantages of CAES is that plants burn 1/3 of the fuel of a CT and corresponding reduction in pollutants. While there are a few, full-scale CAES plants in operation; the technology is relatively immature, requires favorable geologic-geographic conditions and has a relatively poor heat rate.

- Pumped Hydro - Pumped Hydro is a mature technology that is utilized in geographic area where conditions for reservoir storage capacity and elevation changes are favorable. While Hoosier Energy's physical service territory is not well suited for pumped hydro, it is a storage option that is mature and available.

- Flywheel Energy Storage - Flywheel energy storage is primarily used for powering UPS, frequency regulation, wind generation stabilization and power quality. While there are flywheel plants in operation, the technology is relatively immature and not widely used.

Advanced Engine Concepts

Recognizing the growing need for scalable, modular and packaged generation, power generation equipment suppliers are developing novel technologies with the goal of further improving the efficiency of engine based systems. Engine fuel cell hybrid, supercritical CO2 bottoming cycle and direct carbon injection are technologies in the demonstration and commercial stages that could potentially help Hoosier Energy meet its resource needs in the future. These technologies are discussed further below:

- Engine Fuel Cell Hybrid - Solid oxide fuel cell (SOFC) engines exist at the commercial level and are used with RICE forms of generation achieveing 60 to 65% electrical efficiency. The process is known as "fuel cell – combined cycle" where natural gas is supplied to a fuel cell that produces electricity from the fuel cell process, and the tail gas from this process is fed to a reciprocating engine. While this equipment is marketed as distribution level equipment, combining individual engines could result in the production of electricity at the bulk electric system level. Further, existing RICE can be retrofitted with the fuel cell component thus increasing the output and efficiency of the unit.

- Direct Injection Carbon Engine - Direct injection carbon injection (DICE) is a diesel engine modified to enable combustion of waster based slurry of micronized refined carbon (MRC) fuel. DICE is a mature technology but not widely used. Engine technology and coal water system advancements are enabling renewed interest in DICE technology. Emissions may be lower for DICE due to combustion temperatures and the use of hydro desulfurization. A DICE power plant can have reliabilities exceeding 99 percent, due to multiple, modular units ranging in size from 20 MW to no more than 100 MW. The small size of the units would allow a G&T cooperative to add small increments of generation when needed. DICE technology is suited for baseload, peaking and backup duties. The first commercial DICE power plant is expected to be deployed in the early to mid- 2020s. DICE is an attractive technology as it utilizes coal, which is an abundant, domestic fuel, but is also clean burning and claims of 30% to 40% lower carbon capture cost than pulverized coal.

- Fuel Cells - A fuel cell is a device that converts the chemical energy in natural gas or hydrogen into electricity and water through an electrochemical reaction with oxygen. No combustion of fuel takes place during the process, which makes the technology environmentally attractive. Fuel cells are similar to batteries in structure, except they rely upon an external fuel source instead of stored chemical reactants. While there are different types of fuel cells, each is made up of three layers: an anode, an electrolyte, and a cathode.

  Fuel cells are an emerging technology and there are very few commercial applications. Fuel cells have a great deal of technical challenges to overcome before successful commercialization takes place. One challenge in particular is the development of a cost-effective fuel reformer that converts the fossil fuel into hydrogen. While research looks promising, the fuel reformer is not perfect and sometimes fails and poisons the fuel cell by passing carbon monoxide and carbon dioxide through the electrolyte.

  Another significant challenge is cost. Fuel cells require expensive and sometimes rare earth metals such as yttrium and zirconium. Furthermore, fuel cells are difficult and time-consuming to manufacture. While costs may decline in the future as research continues, fuel cells remain an expensive technology for most applications.

At this time, it is not prudent for Hoosier Energy to commit a significant amount of financial resources on technologies that are not “mature.”

4.2.13 Transmission Facilities

Hoosier Energy prepares a Long-Range Transmission Plan to serve as a guide for developing its system to meet present and future needs of its consumers. This Plan is updated on a 5-year cycle or as the result of a significant change to the transmission system, whichever is sooner. As described in Section 3.3.3, the purpose of the Plan is to study the current system, including asset health projections, identify system shortfalls and develop system mitigation measures that will provide the most practical and economical means of serving future loads.

Additionally, as a member of MISO, Hoosier Energy participates in the MISO Transmission Expansion Plan (MTEP) process, which is an annual assessment of the regional transmission system reliability. This process identifies long-term regional transmission requirements and develops a portfolio of projects designed to maintain grid reliability and address congestion issues.

4.3 Wholesale Rate Design

The current tariffs, as described in Section 3.2.2, were reviewed with the member systems through the Members’ Managers Association and rates updated by Hoosier Energy in 2017. The structure of the wholesale tariffs were confirmed, and rates updated, for implementation in April 2019. The wholesale tariffs are designed to encourage demand response participation by the member systems and to introduce time-of-use energy pricing. Hoosier Energy periodically reviews and updates its rate design for reasonableness and applicability to current market conditions. In addition, Hoosier Energy is currently assessing the reasonableness of its wholesale rate structure.

4.4 Future Resource Planning Criteria

4.4.1 Reserve Margin

Reserve margin is likely the most common reliability measure. Reserves are a necessary addition to the resource requirement plan and are used to offset the effects of contingencies that arise either because of generation unavailability or changes in load (e.g. weather effects, customer mix and usage). Reserve margin is defined as follows:

$$\text{Reserve Margin} = \frac{(\text{Total Resources} - \text{Total Load})}{\text{Total Load}}$$

As a member of ReliabilityFirst (RFC), Hoosier Energy is required to adhere to specific standards regarding resource adequacy. Specifically, RFC requires the calculation of a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year being equal to 0.1. This is commonly referred to as a Loss of Load Expectation (LOLE) analysis based upon a one day in 10 years criterion.[9] MISO serves as the Planning Coordinator for RFC and is responsible for annually calculating the appropriate planning reserve margin. The required reserve margin for MISO's 2020 – 21 Planning Year is 8.90%.

This figure is not based upon unforced generation capacity values but rather on forced generation capacity. That is, each generation resource maximum capacity value must be adjusted based upon either:

a) The unit's historical forced outage rate as supported by GADS data; or if GADS data is not available,
b) The historical forced outage rate from a similar proxy group of generators as supported by GADS data calculated by the Midcontinent ISO.

The reserve margin requirement is therefore subject to change in the future due to modifications to either the Midcontinent ISO's LOLE analysis and/or to the historical forced outage rates of the generation resources. The capacity figures found in Table 47 reflect values for the planning year beginning June 2020.

4.4.2 Environmental Analysis

A key component of any future comprehensive national energy policy will likely be the establishment of a long-term strategy for addressing climate change with particular focus on electric power generation. In the face of a challenging operating environment, including uncertain energy demand, competition from alternative energy sources and aging power infrastructure, electric utilities need a clear understanding of future emission reduction obligations in order to make the right investment decisions. This includes further reductions of air emissions as well as future regulatory restrictions on carbon, particulate and other pollutants.

If a new generation facility is selected through the integrated resource planning process and then proposed, Hoosier Energy will comply with all then-current state and federal environmental regulations.

[9] ReliabilityFirst standard BAL-502-RF-03

4.4.3 Risk

The preferred plan seeks to position Hoosier Energy in a low market and business risk profile. Risk is broadly defined in three categories: financial, business, and market risk. Financial risk is a consequence of Hoosier Energy's highly leveraged capital structure. Thus, changes in interest rates, for example, can have significant financial impacts. Business risk, that is risk associated with a stable revenue stream, is relatively low as Hoosier Energy, through its member cooperatives, has defined franchised service territories. Taken together, Hoosier Energy's higher financial risk profile has been balanced by its overall lower business risk.

One objective of Hoosier Energy's preferred plan is to lessen overall risk by using a strategy of owned resources, long-term purchases and sales and short-term power market purchases and sales. Market transactions can provide economic opportunities that allow Hoosier Energy to lower its overall cost to serve load. The addition of wind and solar resources in MISO in recent years, along with low natural gas prices, have reduced market energy costs making exposure to the market preferable during some periods. The Preferred Plan reflects Hoosier Energy's desire to increase its market exposure levels and take advantage of these lower available energy costs.

Hoosier Energy has traditionally emphasized resource ownership as a method of reducing risk, preferring to limit its reliance on PPAs. This strategy worked well during periods when power market prices were stable and allowed large baseload units to generate at full capacity. However, as market prices have declined, many larger units have become underutilized and unable to recover all of their fixed costs. In adopting the Preferred Plan, Hoosier Energy has emphasized resource diversity in size, resource type and method of power procurement to reduce its overall risk. Rather than resource ownership, Hoosier Energy has made the decision to lower its price and operating risk by acquiring a significant portion of its contracted power through intermediate and long-term PPAs. It is anticipated that these PPAs will have terms ranging from 5 to 20 years, with staggered terms, which in the future will allow Hoosier Energy to replace a smaller portion of its power requirements at a single time.

Hoosier Energy recognizes that it faces a changing environment. A principal goal for this IRP is to develop a plan that will provide the best service and price, using technologies currently available. Whenever possible, the Hoosier Energy resource screening process recognized these effects and evaluated their impact though various scenario analyses.

4.4.4 Transmission Analysis

From a reliability perspective, Hoosier Energy's preference is to interconnect any new supply-side resource to the Hoosier Energy transmission system. Hoosier would be required to follow Midcontinent ISO rules for generation interconnections. The Midcontinent ISO tariff includes rules for both large and small generation interconnection projects.

From a market perspective, Hoosier Energy's preference is to interconnect any new supply-side resource to the Hoosier Energy transmission system to lessen LMP risk (i.e, resources located near load generally reduces LMP risk). Membership in the Midcontinent ISO allows consideration of supply-side options that are within the Midcontinent ISO footprint, with emphasis on options that are both economical and correlated with the locational marginal prices of Hoosier Energy's loads.

Hoosier Energy continues to expand the bulk transmission network to meet local and regional system needs as well as changing RFC criteria. Any bulk expansion plans require review and approval of the Midcontinent ISO through its MTEP process.

Hoosier Energy continuously monitors the need for additional transmission facilities. At the time the need for additional facilities is identified, the timing, type and approximate costs of additional facilities will be developed.

4.4.5 Reliability Analysis

At this time, Hoosier Energy has not evaluated the impact of each potential resource on system-wide reliability, either transmission or generation. It is clear that resources have varying impacts on system reliability. Generation resources may be used for voltage control and reactive support, spinning reserves, and quick and/or black-start capabilities. In addition, properly sited and operated generation resources are more capable of enhancing or increasing available transfer capability (ATC) or total transfer capability (TTC) than purchased power. Ultimately, the responsibility for system reliability belongs to MISO as planning coordinator. As a MISO market participant, Hoosier Energy works with MISO to ensure that system reliability is maintained.

4.4.6 Market Analysis

The ability to access the Midcontinent ISO market as a resource for potential capacity and energy purchases or sales allows Hoosier Energy to balance its needs in the short-to-intermediate term. This mitigates the impacts of market price and load volatility. In this IRP, Hoosier Energy has included market exposure tolerance levels of 20 percent above and below member load in its analyses. Hoosier Energy is also an active participant in many of the Midcontinent ISO committees and working groups. Hoosier Energy will continue to monitor the LMP market and its potential impact on resource planning.

4.5 Results of Initial Screening Analysis

Based upon an initial screening analysis, the list of potential resource options were reduced to those resources that demonstrated economic viability, operational reliability and were flexible enough to meet expected, and potentially more stringent, environmental standards. These resources were then included in the portfolio modeling scenarios developed by Charles River Associates. In addition to the above supply-side resources, some member systems have expressed an interest in pursuing distributed energy resources with retail customers. These resources may be different than Hoosier Energy's current DSM offerings. Hoosier Energy has committed to assist and support members in these efforts and will incorporate those resources into the G&T's portfolio. A summary of the screening analysis results is provided below in Table 14.

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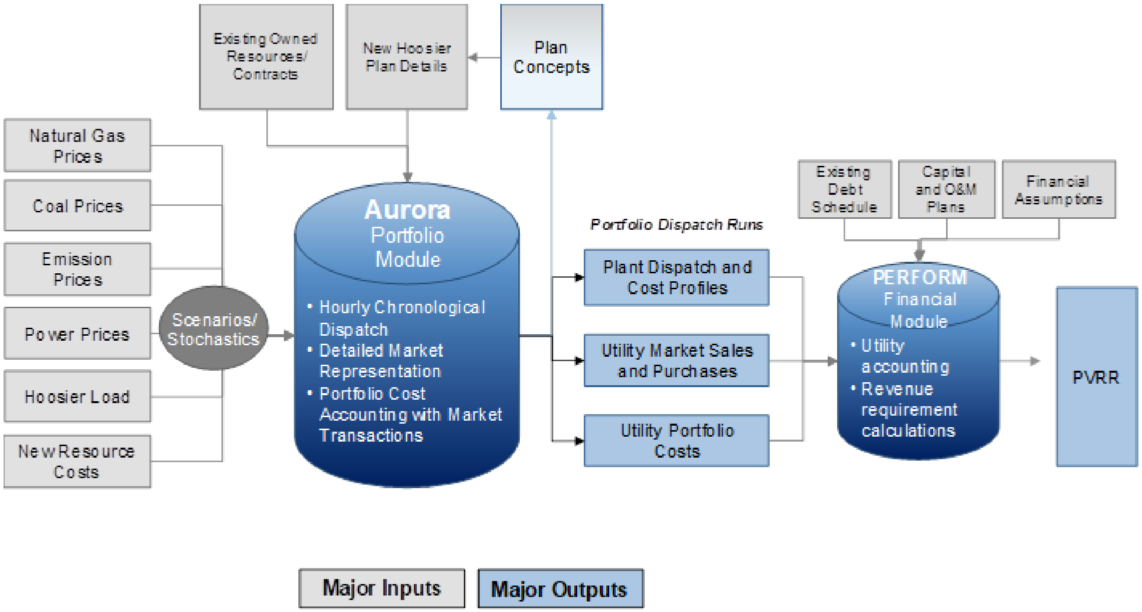
Resource/Strategy	Net Nominal Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative?	Reason why Resource was Accepted or Rejected
Nuclear	_	Nuclear	Rejected	Not cost effective
Biomass/Landfill Gas	_	Biomass	Rejected	Limited opportunities to develop projects at scale
Solar Thermal	_	Solar	Rejected	Not cost effective
Hydro	_	Hydro	Rejected	Resource not available
Geothermal	_	Geothermal	Rejected	Resource not available
Merom Repowering	495	Natural Gas	Rejected	Not cost effective
Natural Gas Peaking (1x1 7FA)	**100 MW block**	**Natural Gas**	**Accepted**	**Cost effectiveness and Reliability**
Natural Gas Peaking (LM 6000)	**53 MW block**	**Natural Gas**	**Accepted**	**Cost effectiveness and Reliability**
Combined Cycle (2x1 H Class)	**100 MW block; 300 MW maximum**	**Natural Gas**	**Accepted**	**Cost effectiveness and Reliability**
Reciprocating Internal Combustion Engine	**114 MW block**	**Natural Gas**	**Accepted**	**Cost effectiveness and Reliability**
Onshore Wind PPA	**50 MW block; 500 MW max per year**	**Wind**	**Accepted**	**Cost effectiveness and Reliability**
Solar Photovoltaic PPA	**50 MW block; 500 MW max per year**	**Solar**	**Accepted**	**Cost effectiveness and Reliability**
Battery Storage	**25 MW block; 250 MW max per year**	**Storage**	**Accepted**	**Cost effectiveness and Reliability**

Table 14: Summary of Resources Included in Portfolio Modeling

4.6 Modeling Methodology

To conduct an assessment of supply-side and demand-side resource portfolio under varying scenarios and sensitivities, CRA began with the power market models developed in AURORA. AURORA consists of a number of individual modules that are designed to perform different functions within the general model structure. These models perform an hourly, chronological dispatch of Hoosier Energy's portfolio options within the MISO power market, accounting for all variable costs of operation, all contracts or PPAs, and all economic purchases and sales with the surrounding market. AURORA produces projections of asset-level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide emissions over time and capacity and generation by fuel type. As a companion to AURORA, CRA has also used its proprietary PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed and variable operating and maintenance costs, and financial accounting of depreciation and taxes. The PERFORM model produces annual and net present value estimates of revenue requirements.

With these tools, CRA conducted an in-depth assessment of some of the key electricity market components, such as electricity price volatility, and the impact on resources dispatch into the LMP markets. Finally, CRA used internally developed portfolio optimization model to evaluate the hundreds of thousands of possible resource portfolio combinations that could reliably and economically meet the forecast needs. A high-level overview of the IRP modeling methodology is provided below.



Fundamental Market Modeling

In a competitive market, assets dispatch into the market, and the wholesale electricity price is based on the marginal costs of generation. This means prices will rise until the variable costs of the last generating unit meet the demand. The fundamentals approach reflects the economics and individual characteristics of demand and supply to find the marginal unit per zone. CRA used the AURORA Zonal Forecasting module, which provides hourly MISO market prices at a zonal level based on a fundamental dispatch of the market, to estimate the market prices. Market inputs for the AURORA model include fuel prices, emission prices, load growth, new resource costs, and capacity expansion and retirement, which are tested across a range of key uncertainties using scenarios.

In the long-term analysis, changes to MISO's capacity mix were simulated through retirements of existing and addition of new build units. In addition to publicly announced generator retirements and new builds, the decision for retirements or new builds were also based on economics and the return on investment for an investor. Using the combination of cost components and projected production and associated market revenues, the profitability of each unit was calculated and if a unit was not projected to be profitable over a defined time period, the model assumed it will retire. The opposite accounts for generic new build units which were assumed to be added to MISO if the investment can be recovered in a defined timeframe. CRA used the AURORA model in an iterative process for the long-term planning of unit retirements and new builds.

Ultimately, the AURORA modeling process yielded projected market prices for MISO Zone 6, where Hoosier Energy is located. CRA then used these market prices to develop the projected dispatch and market revenues for each owned and contracted resources, as well as future candidate resources.

Asset Dispatch Simulation

CRA used the AURORA Stochastic module to simulate each assets' dispatch that treats the prices of power and fuels stochastically. The model tests portfolio options under a full stochastic distribution of commodity price and renewable generation outcomes. The stochastic analysis relies on CRA's Monte Carlo engine, which simulates future gas and electricity prices and renewable generation based on historical data analysis and specification of key statistical parameters.

Dispatch is performed against a probability array that captures the uncertainty of future prices, i.e. the model does not assume perfect foresight of future prices, and takes into account the physical operating limitations of power generation (i.e. start time, heat rate, VOM, minimum run times, etc.). The resulting output (operations and associated revenues and variable operating costs) represents the expected value of 500 individual simulations.

Portfolio Optimization Modeling

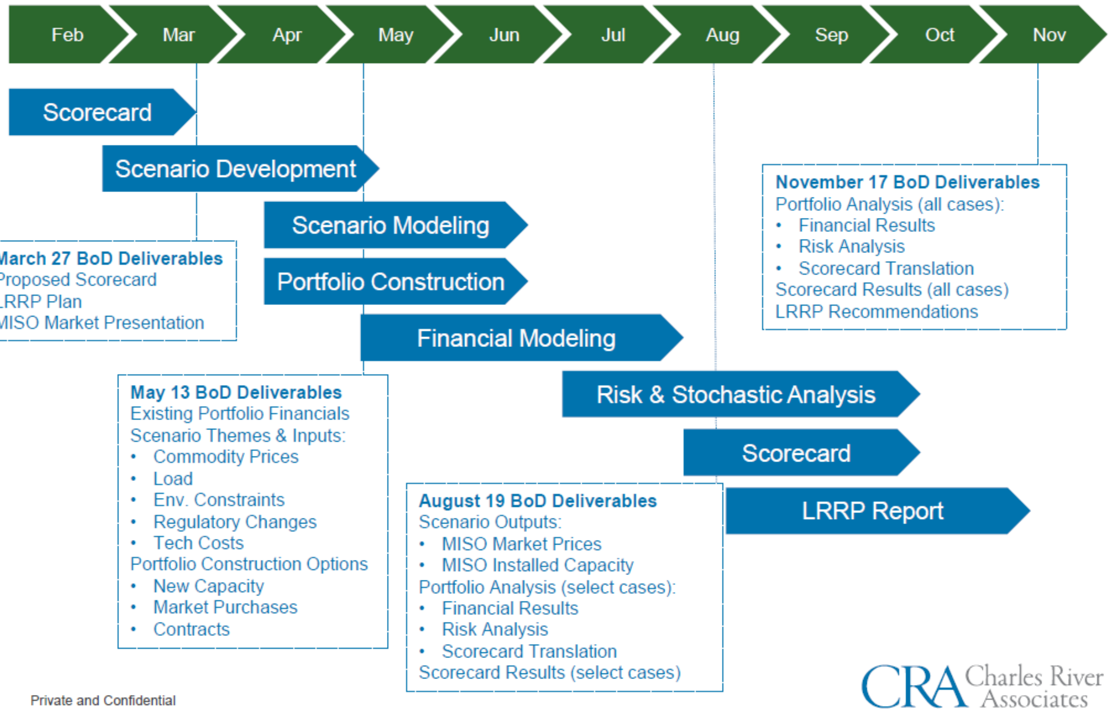
To optimize potential portfolios, CRA used the AURORA Portfolio Optimization module, which helps develop least-cost portfolio concepts under various scenarios using a variety of constraints. Both supply side and demand side resources were evaluated in the portfolio optimization framework. This model builds potential portfolios of current and future assets that will satisfy any capacity reserve requirements, as well as additional constraints related to capacity and energy exposure to the MISO energy markets.

The model was customized to consider the existing assets and power supply contracts, as well as the Member Systems' energy and capacity requirements, and calculated the supply and demand balance associated with those loads and resources. In doing so, the model calculated the capacity and energy shortfalls going forward in time, as assets retire, power supply agreements terminate, and load grows.

The optimization model then used CRA's PERFORM model to incorporate the asset revenues and energy and capacity costs to project the 20-year Net Present Value (NPV) of the power supply revenue requirements for each portfolio, including the costs to serve the Member System loads and the net revenues associated with asset dispatch into the MISO markets. The model produced the NPV associated with each supply portfolio and ranked the portfolios according to least cost NPV. These rankings were then considered for feasibility and risk profile of each portfolio.

4.7 Board Interaction Process

In the 2020 IRP, consistent with that of the Stakeholder meetings required of Indiana electric IOUs, the Board participated in the process designed to promote discussion, elicit feedback and provide ownership share in the IRP and Preferred Plan. During the February 2019 Board meeting, CRA began the process by presenting an overview of Resource Planning concepts, along with a key milestones and deliverables for the project. At subsequent Board meetings, CRA, Hoosier Energy staff and the Board collaboratively worked their way through the process of creating assumptions, performing the analysis and discussing the output provided by CRA. During each meeting, the Board was encouraged to ask detailed questions and to provide feedback. The timeline of the schedule is provided below.



4.8 Scorecard Development

Hoosier Energy's Board and Member CEOs participated in an IRP process consistent with that of the Stakeholder meetings required of Indiana electric IOUs. This process promoted discussion, elicited feedback and provided the Board with ownership of the IRP and Preferred Plan.

The initial step was to determine the significant factors important to the Board in soliciting the Board's input was to develop a list of significant factors to consider in designing Hoosier Energy's future generation resource portfolio. These factors were determined through small group discussions designed to encourage individual feedback from all Board members and Member CEOs. Below is a list of factors discussed in the small groups:

1. <u>Wholesale Rates</u> - Wholesale rates represent the total cost to serve member load. This includes capital, operating and fuel costs. The lowest cost portfolio will depend in part on expected fuel prices and may come with tradeoffs including flexibility in operating plants, exposure to drawbacks and opportunities with commodity market and the level of rate certainty.

2. <u>Rate Stability and Predictability</u> - Generating resources have different levels of sensitivity to commodity prices (fuel, energy and capacity markets). Resources that provide more stability and predictability in variable cost may have greater capital and fixed costs and vice-versa.

3. <u>Ownership of Power Supply Resources</u> - Power supply resources may be either owned by Hoosier Energy or contracted from third parties through purchase power agreements. In

addition to cost implications, the decision to own or enter into a contractual arrangement determines the types of risks that Hoosier Energy will need to manage in the future.

4. Operation of Portfolio Resources - For owned resources, Hoosier Energy may choose to operate the facilities themselves or enter into a service contract with third parties. This has direct employment implications and impacts the type and amount of risk Hoosier would need to manage in the future.

5. Construction of New Resources - Once the decision is made to develop and build a new power supply resource, Hoosier must decide whether to build the unit itself or contract with a third party to do so. In addition to the direct employment implications, the decision to construct or contract may impact new unit costs and drive the types of risks Hoosier will need to manage in the future.

6. Sustainability of the Portfolio - Supply alternative have different emissions and water consumption profiles. The environmental sustainability profile of the fleet impacts the risk of possible future costs associated with tightened environmental policies and may impact air and water quality in the Hoosier Energy service territory.

7. Resource Location - The decision to build or contract new resources and/or retire existing units within Hoosier's service territory will impact expected costs and may impact local employment, tax revenues and air quality.

8. Development of Demand-Side Resources - Development of demand side (or consumer facing) resources may reduce the need for investment in the traditional utility infrastructure (power plants, transmission and distribution lines). While these programs can lower the overall cost to serve the customer, successful implementation of these programs will require Hoosier Energy and its members to strengthen the relationship with the end consumer.

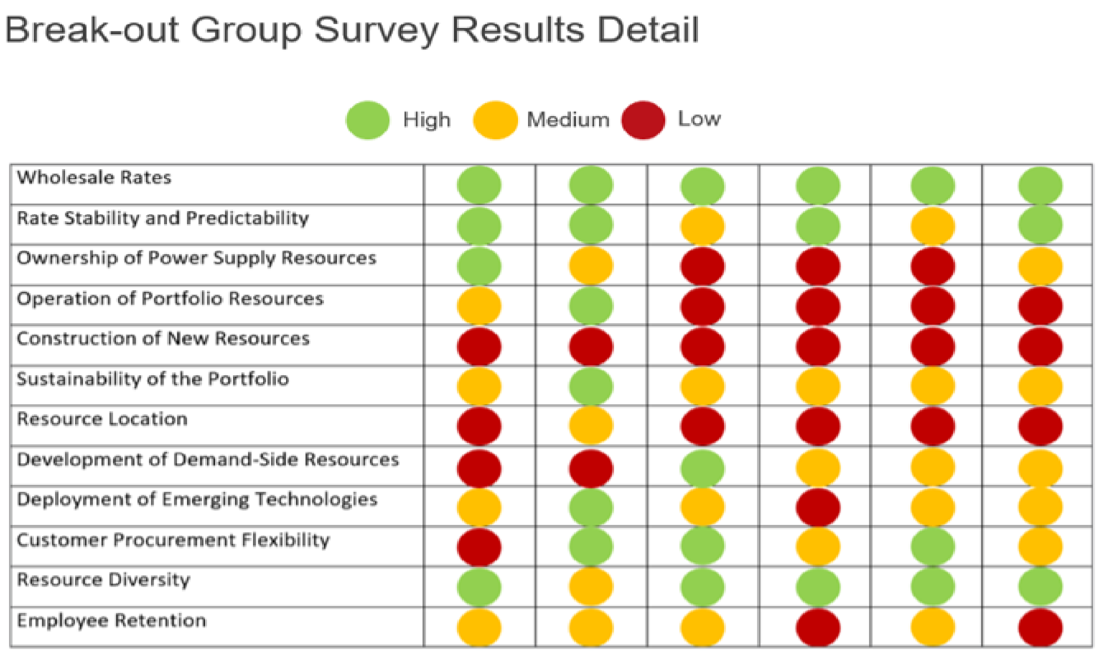
9. Deployment of Emerging Technologies - Novel technologies may offer lower costs and improved performance relative to current, well-established alternatives. Reliance on new technologies may expose Hoosier to "first of a kind" cost and performance risks. Adoption of novel technologies may require new skill set development for Hoosier staff.

10. Customer Procurement Flexibility - Some commercial and industrial customers have corporate sustainability and/or market-based energy access goals. Hoosier Energy could aggregate these requests, act on the consumer's behalf and create value through scale and ability to access resources.

11. Resource Diversity - In the event that the long-range resource plan results indicate a retirement of Merom or other existing assets, Hoosier can replace them with another similarly-sized resource or a combination of smaller units, or a combination of new resources and contracts. A more diverse set of resources may mitigate market commodity and operational risks but be less able to capitalize on low fuel costs and economies of scale.

12. Employee Retention - The decision to develop new resources and retire existing plants could have a significant impact on the need for plant operations staff and functional groups at the corporate level.

Breakout sessions were held at Hoosier Energy's March 2019 Board meeting to discuss and rank each factor in level of importance. Each Board member was assigned to one of six teams for factor discussion. Each team was instructed to rank each of the factors as high, medium or low in importance. Following the discussion, each team's votes were tallied, with the results of each group's votes as shown below.



When the Survey results were tabulated, it became apparent that the most important factors to the Board were Wholesale Rates, Rate Stability and Predictability, Sustainability of the Portfolio, and Resource Diversity. Following the meeting, Employee Impacts was added to the short list based upon feedback from the Board.

Hoosier Energy's next step was to take the five highest-scoring factors selected by the Board and establish a scorecard that will allow CRA to quantify the factors for each tested portfolio. Metrics were selected to quantify the portfolio objectives and are provided in Table 15.

Portfolio Objective	Metrics
System Costs	(1) Near-term cost difference driven by resource composition (2) Long-term cost differences driven by resource composition (3) Impact of resource decisions on customer power bills
Rate Certainty and Risk	(1) Expected cost range across scenarios (2) 25th to 75th percentile (3) Fleet tail risk in worst-case scenario
Resource Diversity	(1) The portion of Hoosier's load served by different resource types (2) The portions of Hoosier's capacity requirement met by different resource types
Sustainability	(1) Hoosier's fleet greenhouse gas emissions (2) Hoosier's fleet water emissions (3) Hoosier's fleet waste production
Employee Impact	(1) Expected impact on Hoosier Energy's plant operations staff and corporate functional levels

Table 15: Selected Quantitative Metrics

Taking into consideration the selected quantitative metrics, the resulting scorecard is shown below in Table 23:

	Low Wholesale Rates			Rate Stability & Predictability				Sustainability of Portfolio	Resource Diversity		Employee Impact
	Base Case 20-Yr NPV of Supply Cost	Average 2020-2030 Supply Cost	Average 2031-2040 Supply Cost	Lowest Expected 20-Yr NPV of Supply Cost	Highest Expected 20-Yr NPV of Supply Cost	Likely Range of 20-Year Supply Costs	Worst Case of 20-Year Supply Costs	2030 Carbon Reduction from Current Portfolio (Base Case)	Max Resource Type as % of Generation Mix	Maximum Unit Size	Criteria Rating (Low, High)
	$MM	$ / MWh	$ / MWh	$MM	$MM	-$MM +$MM	$MM	% reduction	%	MW	Rating
Current Portfolio											
Alt 1											
Alt 2											
...											

Portfolio Objective Scorecard

4.9 Scenario Development

A primary component of the resource plan is Merom's future operations and economics, including the timing and trade-offs associated with its potential retirement. Scenarios represent holistic, integrated views of the world that inform the model inputs and assumptions across many sectors. They are one-off cases that are defined by a discrete change to a specific parameter to evaluate the impact on key outputs.

CRA and the Hoosier Energy team jointly developed a set of six market scenarios that were thematically oriented around market developments in MISO and the broader US economy. First, the team developed a "Base Case" that represents the current, most likely outlook for key market drivers, such as fuel prices, load, supply technology costs, and environmental compliance pressure. The team then developed a set of alternative scenarios that test portfolio decisions under a range of conditions. These alternatives were intended to be plausible, though less likely than the Base Case, and include internally consistent combinations of uncertainties. The output of the scenario analysis will be reflected on the scorecard which will be used to support decision making and determine the preferred portfolio.

The selected scenarios were defined as follows:

1. **Base Case** – The MISO market continues to evolve based upon the current outlook for load growth, commodity prices, technology development and regulatory pressure.
2. **Stagnating Economy** – Decline in economic outlook relieves regulatory pressure and results in a low load growth environment and fewer coal retirements.
3. **U.S. Economy Decarbonizes** – A national cap on CO^2 emissions affects all sectors of the U.S economy, negatively affecting fossil generation and changing end-use demand patterns.

4. **Customers in Control** – Widespread procurement of renewable energy by large C&I customers reduces demand for central station power and impacts load shape.
5. **Challenged Gas Economy** – Restrictions on gas resource and infrastructure expansion result in high commodity prices for natural gas and reduced reliability of gas-fired units.
6. **Flat Gas** – Base case sensitivity where natural gas prices remain flat – based upon current market futures prices – and no carbon policy is enacted.

4.10 Modeling Assumptions

4.10.1 Risks Inherent in the Modeling Process

Risks are addressed through the varying assumptions associated with scenarios and sensitivity cases in the modeling process. The incorporation of different resource alternatives, market conditions, load growth and future environmental regulations into the modeling process provides a range of scenarios and outcomes. However, it is not possible to predict and capture all risks and the models are simply another tool for management to employ to make resource decisions. Hoosier Energy reviews its assumption selection process during each IRP to improve its modeling inputs and to confirm that the assumptions used in the IRP are consistent with those costs available in actual practice.

4.10.2 Quantitative Assumptions

CRA developed a set of quantitative assumptions for each of the six selected scenarios, including the Base Case scenario. A summary of the assumptions used in each of the scenarios is provided below in Table 16, while discussion of the individual assumptions follows.

Category	Driver	Base Case	Flat Gas Sensitivity	Stagnating Economy	US Economy Decarbonizes	Customers in Control	Challenged Gas Economy
Fuel Prices	Natural Gas Price	CRA Base	CRA Flat	CRA Base	CRA High	CRA Low	CRA High
	Coal Price	CRA Base	CRA Base	CRA Base	CRA Low	CRA Base	CRA Base
Load	MISO Load Growth	MTEP CFC	MTEP CFC	MTEP LFC	MTEP AFC	MTEP CFC	MISO CFC
	MISO Load Shape	MTEP Base	MTEP Base	MTEP Base	MTEP DET	MTEP Base	MTEP Base
Generator Costs	Solar Costs	CRA Base	CRA Base	CRA High	CRA Low	CRA Low	CRA Base
	Wind Costs	CRA Base	CRA Base	CRA High	CRA Low	CRA Base	CRA Base
	Battery Costs	CRA Base	CRA Base	CRA High	CRA Low	CRA Base	CRA Base
Regulatory	MISO Emissions	Base CO_2 Price	No Carbon Price	No Carbon Price	High CO_2 Price	No Carbon Price	No Carbon Price
Market	MISO RM	8.9% by 2024	8.9% by 2024	7.9%	8.9% by 2024	11.4% by 2024	8.9% by 2024
	Capacity Credit	PV: 50% → 30%	PV: 50% → 30%	PV: 50% → 50%	PV: 50% → 20%	PV: 50% → 20%	PV: 50% → 30% NGCC: -15%
Market Capacity	Planned Additions	Planned / Announced	Planned / Announced	Planned / Announced	Planned / Announced	15% by 2030 & 20% by 2040 C&I load served by customer resource	Planned / Announced
	Planned Retirements	Planned / Announced	Planned / Announced	Fewer Coal Retirements	No MISO Nuclear Retirements	Planned / Announced	Planned / Announced

Table 16: Summary of Scenario Modeling Assumptions

4.10.3 Fuel Price Assumptions

Hoosier Energy provided estimates of near-term coal prices, which were assumed to remain constant during all months of each year. These prices were supplemented by long-term coal price assumptions that were developed by CRA and are reflected in the graph below. Natural gas forward prices were developed by CRA through its Natural Gas Fundamentals model and vary by month, although the charts reflect annual averages and are shown below. Detailed price projections are found in Appendix D.

Redacted

Coal Price Forecast

Redacted

Natural Gas Price Forecast

4.10.4 MISO Load Growth and Shape Assumptions

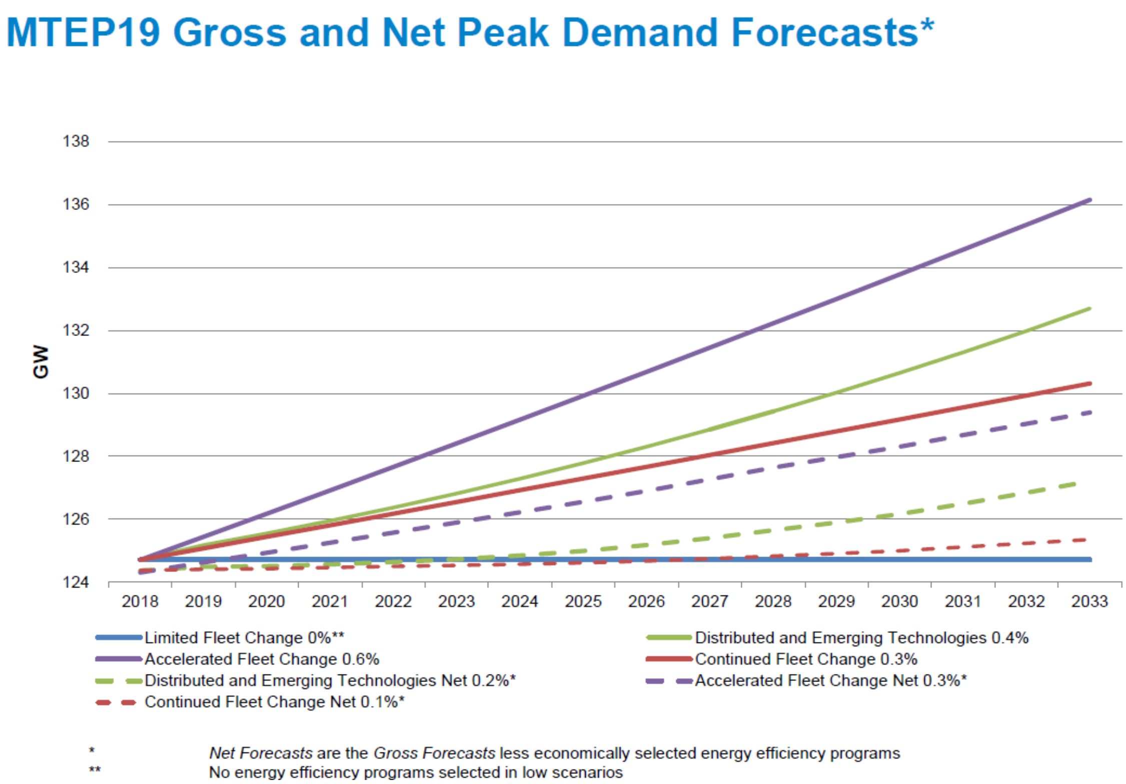
The assumptions for MISO load growth and load shape for each scenario were obtained from the 2019 MISO Transmission Expansion Plan (MTEP 19) study. MTEP is the process MISO uses to determine additional transmission requirements necessary to ensure reliability, to support state and federal energy policies, and deliver low-cost energy to customers within MISO's region. The MTEP studies are performed annually and provide an assessment of transmission operations over a range of scenarios for a 15-year forward period. The Limited Fleet Change scenario is referred to as MTEP Base in Table 24 above.

The four MTEP19 scenarios for which assumptions are provided are:

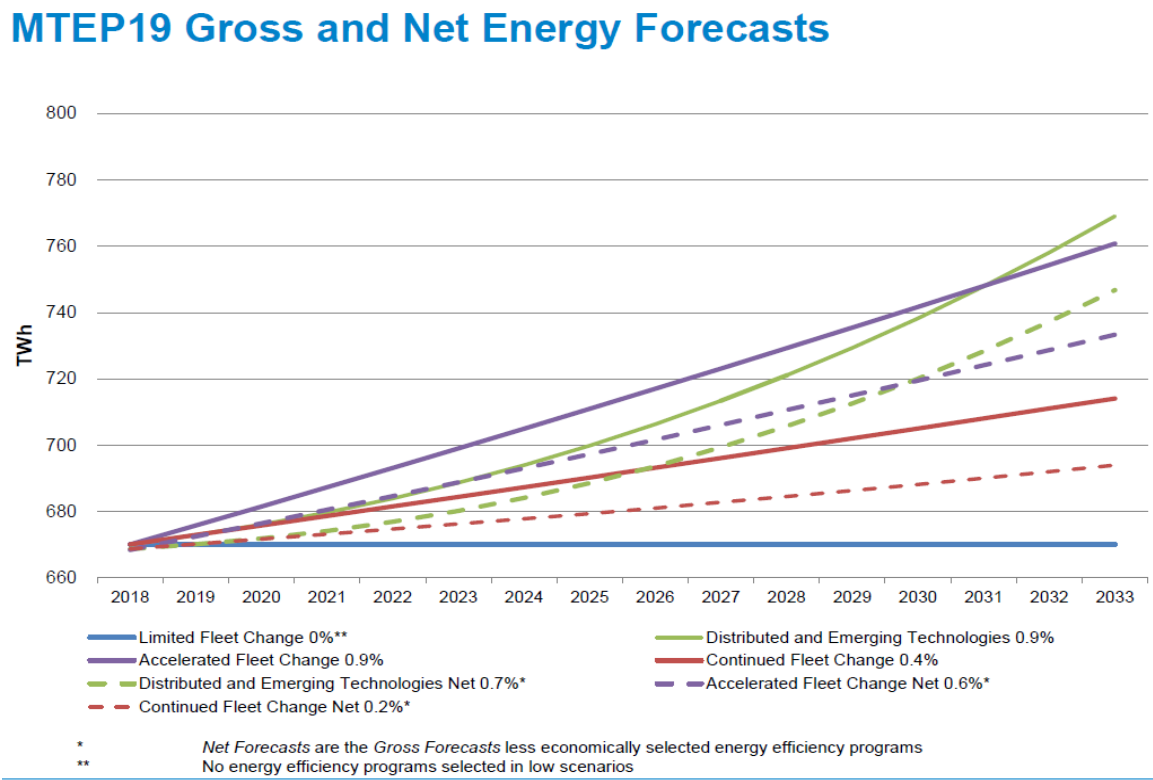
1. Limited Fleet Change (LFC) - assumes all current policies and trends in place at the time of futures development continue, unchanged, throughout the duration of the study period. No carbon regulations are modeled, though reductions are expected due to age-related retirements and modest renewable additions driven primarily by existing Renewable Portfolio Standards (RPS) and goals. Natural gas prices remain low due to lower demand, increased well productivity and supply chain efficiencies. Low natural gas prices and static economic growth reduce the economic viability of alternative technologies so capital costs for wind and solar mature more slowly. Based on stakeholders' feedback, the 2033 renewable energy levels were increased by 5% from MTEP18 Futures.
2. Continued Fleet Change (CFC) - captures the effects of current economic growth with base gas prices. Renewable energy levels continue to grow above and beyond what is required by state RPS. Renewable energy is modeled to serve 20% of MISO energy by 2033, 5% higher than MTEP18 CFC.

3. Accelerated Fleet Change (AFC) - captures a robust economy that drives technological advancement and economies of scale, resulting in a greater potential for demand response, energy efficiency, and distributed generation as well as lower capital costs for renewables reflected in the maturity cost curves. To capture the potential effects of future national or state-level carbon regulations or a general continued decline in emissions, a 20% aggregate MISO fleet CO2 reduction from current emission levels is modeled. Renewable energy is modeled to serve 35% of MISO energy by 2033, 5% higher than the MTEP18 AFC future.
4. Distributed and Emerging Technologies (DET) - captures the effects of a mid-high economic growth rate reflecting broader-scale adoption of electric vehicles, especially later in the study period. Fleet evolution trends continue, primarily driven by local policies and emerging technology adoption. State-level policies reflect desires for local reliability and optionality. Renewable energy is modeled to serve 25% of MISO energy by 2033 with 5% coming from solar photovoltaic (PV).

Forecasted demand and energy growth under each MTEP scenario are provided in the graphs below.



MISO MTEP19 Demand Forecasts



MISO MTEP19 Energy Forecasts

4.10.5 Generator Cost Assumptions

CRA provided capital cost estimates for solar, wind and battery storage resources, which are provided in the graphs below.

Redacted

Solar Capital Cost Assumptions ($/kW)

Redacted

Wind Capital Cost Assumptions ($/kW)

Redacted

Battery Storage Capital Cost Assumptions ($/kW)

4.10.6 Carbon Price Projections

Carbon price assumptions were included in the Base Case and U.S. Economy Decarbonizes scenarios and were developed by CRA. These assumptions are shown below and provided in Appendix D. Both the Base Case and the U.S. Economy Decarbonizes scenario assume that a carbon tax is implemented beginning in 2028.

Redacted

Carbon Price Assumptions

4.10.7 Market and Associated Price Projections

CRA developed annual all-hours market energy price projections for Zone 6 through 2040 for each scenario, which are shown below. The complete summary of power prices is provided in Appendix D.

Redacted

All-Hours Energy Prices

Hoosier Energy's tolerance for market demand and energy exposure also impacts the timing and economics of the optimal compliance plan. CRA worked with Hoosier Energy to define an appropriate risk tolerance level and conduct analysis using tolerance bands. For purposes of this IRP, modeling was conducted assuming a tolerance band of +/- 15% above forecasted member load for demand and +/- 20% for energy.

4.10.8 Future Resource Options

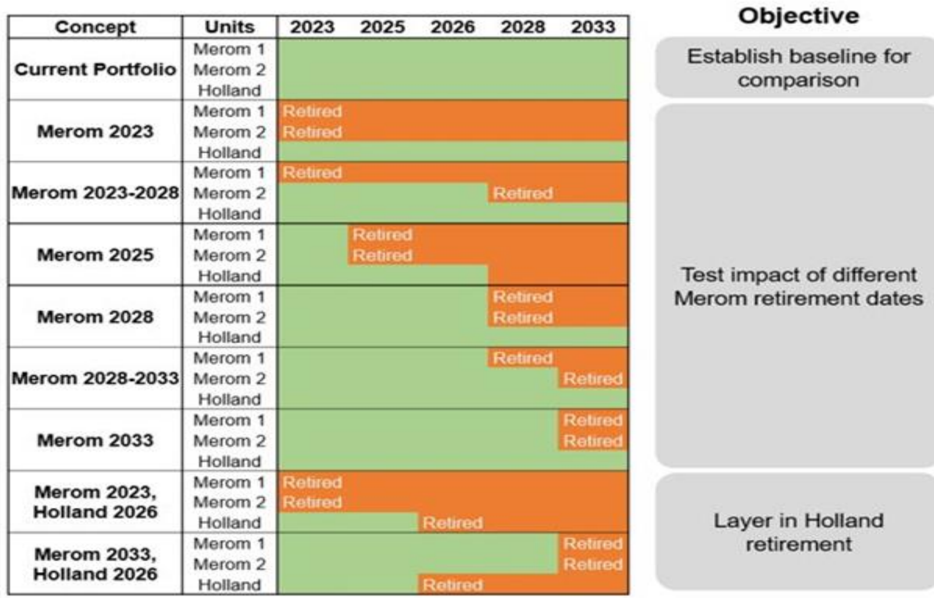
In conducting its initial analysis, CRA assessed a number of supply-side options with respect to Merom's long-term operational and economic feasibility. The cost and performance characteristics for each of these potential supply-side alternatives are included in Appendix C. The supply-side resources considered were produced through a collaborative effort between Hoosier Energy and CRA. As described in Section 4.5, these resources passed the screening analysis and were the best future resource options available. The options considered were:

Replacement Option	Technology Specifications	Modeling Assumptions
Combined Cycle	GE 7HA.02 2x1 6,295 Btu/kWh heat Rate	100 MW block size, 300 MW max per year (2023-2028)
Frame GT	GE 7HA 02 1x0 9,221 Btu/kWh heat Rate	100 MW block size (2023-2040)
Gas Aeroderivative	GE LM60000 PF+ 1x0 9,520 Btu/kWh heat Rate	53 MW block size (2023-2040)
Reciprocating Engine	Wartsila 50SG 18V 6-engine 7,930 Btu/kWh heat Rate	114 MW block size (2023-2040)
Solar	24.2% capacity factor; 0.8% degradation in capacity per year	50 MW block size, 500 MW max per year (2023-2040)
Wind	39.9% capacity factor	50 MW block size, 500 MW max per year (2021-2040)
Storage	Unpaired battery storage	25 MW block size, 200 MW max per year (2023-2040)
Capacity Purchase	Short-term capacity for resource adequacy at MISO Zone 6 prices	10 MW block size, 15% peak load max in 2020s, drops to 5% in 2030s

Summary of Future Resource Options

4.11 Examination of Early Retirement Concepts

The Hoosier Energy team and CRA collaboratively examined a number of alternative early retirement cases versus the Current Portfolio to determine if retirement of any of Hoosier Energy's resources before the end of their book lives was economically advantageous. To conduct the analysis, Hoosier and CRA identified eight specific retirement concepts to test, using a combination of prospective early retirement at Merom Unit 1, Merom Unit 2 and Holland. The concepts were modeled using Base Case assumptions. Individual potential resource retirement years tested were 2023, 2025, 2026, 2028 and 2033. The modeled concepts are shown in the following graphic.



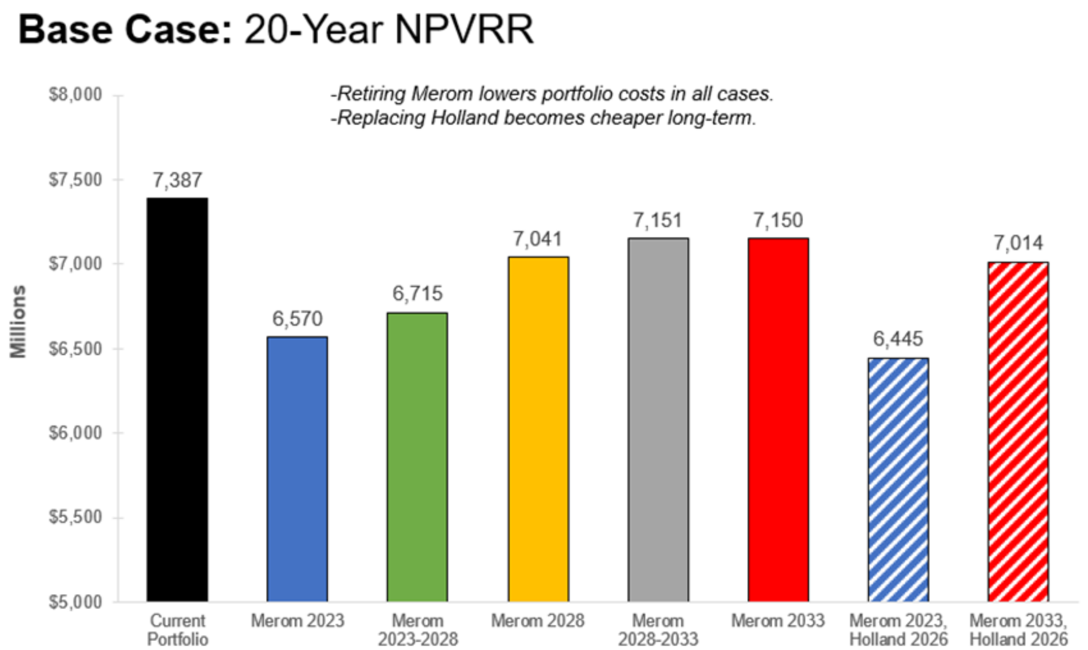
Summary of Early Retirement Concepts Tested

For each of the retirement concepts, indicative replacement options were identified to fill the gap left behind by the resource retirement. These resources help to assess whether an early retirement is appropriate by evaluating economic options for replacing the lost energy and capacity. The indicative replacements used to fill a particular capacity gap reflect the most economic capacity option at the time. For initial modeling purposes, replacement resources considered for each of the retirement concepts were limited to the following:

1. Wind
2. Solar
3. Paired Solar plus Storage
4. Natural Gas Combined Cycle
5. Frame Natural Gas Peaker

The 20-year NPVRR results for the concepts are provided in the chart below. The analysis of Base Case shows that:

1. Early retirement of Merom in 2023 provides substantial savings versus retaining the current portfolio through the study period.
2. Staggered retirement of Merom units in 2023/28 also offers significant savings and potentially more operational flexibility, but this option would incur more costs at the coal plant and potentially miss the lowest-cost renewable resource opportunities.
3. Retiring Merom after 2028 provides more limited savings versus the current portfolio.
4. Early retirement of Holland offers opportunity for additional savings by swapping out low-cost capacity for low-cost energy.



	Current Portfolio	Merom 2023	Merom 2023-2028	Merom 2028	Merom 2028-2033	Merom 2033	Merom 2023, Holland 2026	Merom 2033, Holland 2026
Delta ($M)	-	-$817	-$672	-$346	-$236	-$237	-$942	-$373
Delta (%)	-	-11.1%	-9.1%	-4.7%	-3.2%	-3.2%	-12.8%	-5.0%

20-Year Net Present Value for Early Retirement Concepts

4.12 Initial Portfolio Modeling

Following review of the initial early retirement results, Hoosier Energy eliminated four retirement concepts from consideration, leaving four concepts for further analysis. These concepts represent the Current Portfolio plus the three concepts with the lowest NPVRR from the initial round of modeling. The concepts remaining under consideration were:

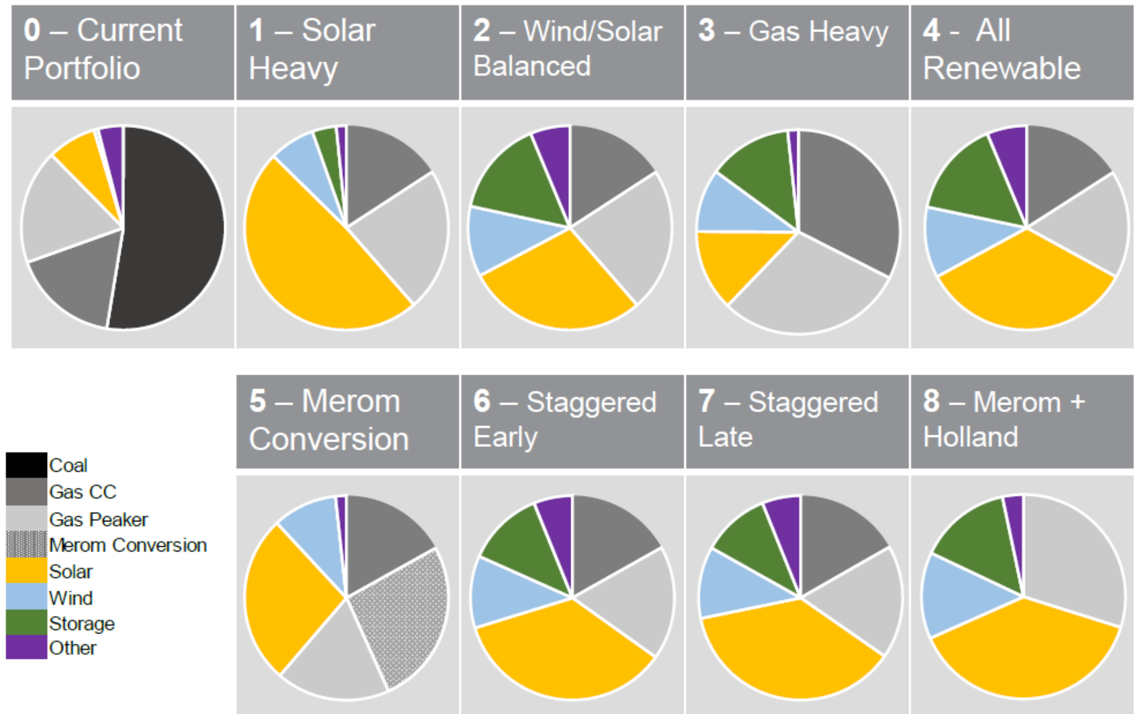
1. Current Portfolio
2. Merom 2023 retirement
3. Merom 2023 – 2028 retirement
4. Merom 2023, Holland 2026 retirement

The remaining concepts were tested against a group of portfolios with varying coal retirement dates and a broad range of resource alternatives within the portfolios, with the purpose of the modeling to determine which resource retirement dates and replacement options worked best together. A description of each of the portfolios is provided in the following graphic.

#	Portfolio	Description
0	Current Portfolio	No changes to existing portfolio, solar is added to meet load growth
1	Solar Heavy	2023 Merom retirement with solar heavy replacement mix. (Portfolio optimized using annual constraints only)
2	Wind/Solar Balanced	2023 Merom retirement with more balanced wind and solar replacement mix. (Portfolio optimized using monthly peak constraints)
2a	Merom Energy Complex	Portfolio 2 with owned peaking capacity at Merom Energy Complex. (Will not differ in energy performance but will study ownership impact)
3	Gas Focused	2023 Merom retirement replaced with combined cycle and gas peaking capacity and wind heavy renewable mix
4	All Renewable	2023 Merom retirement replaced entirely with solar, wind storage, and capacity purchases.
5	Merom Conversion	2023 Merom retirement with Unit 2 coal-to-gas conversion and even split of wind and solar for energy generation.
6	Staggered Early	Merom 1 retired in 2023 and Merom 2 retired in 2025.
7	Staggered Late	Merom 1 retired in 2023 and Merom 2 retired in 2028.
8	Merom + Holland	2023 Merom retirement and 2026 Holland retirement.

Summary of Early Retirement Options Tested

A preliminary view of capacity in 2030 for each portfolio outcome is shown on the next page. With the exception of the Current Portfolio, a movement toward wind, solar and natural gas-fired capacity is seen in the portfolios. Wind and solar resource options are the most cost-effective under Base Case market conditions and provide the majority of the energy in all portfolios. Beyond renewable resource additions, most capacity needs are met by a combination of market purchases, gas peakers, and battery storage. The “Other” category in the graphs in Table XX refer to required net market purchases under each of the scenarios.



2030 UCAP Summary Based on Initial Portfolio Optimization

4.13 Final Portfolio Modeling

Following a review of the initial portfolio optimization runs and prior to conducting the final round of portfolio optimization modeling, CRA made a number of changes to the assumptions:

1. Based upon MISO discussions to implement a seasonal Resource Adequacy construct during the 2022 – 2023 Planning Year, CRA changed the capacity modeling assumptions to include capacity requirements for both a Summer and Winter season.
    a. Winter capacity prices are discounted by 40% starting in 2022 and trend to parity by 2030 as solar penetration increases and winter supply and demand become tighter.
    b. Any excess capacity in summer assumed to be sold through bilateral transaction or MISO auction at 75% of prevailing summer capacity price.
    c. The seasonal capacity modeling assumed a MISO Planning Reserve Margin of 7.9% for the Winter season.
2. Because Holland's early retirement benefits do not begin to be seen until the late 2020's, Holland early retirement was removed as an option to be considered.
3. The staggered 2023/2028 Merom early retirement option was replaced with a Merom 2025 early retirement option.

The revised assumptions leave Hoosier with the following early retirement options to be modeled against the replacement portfolios:

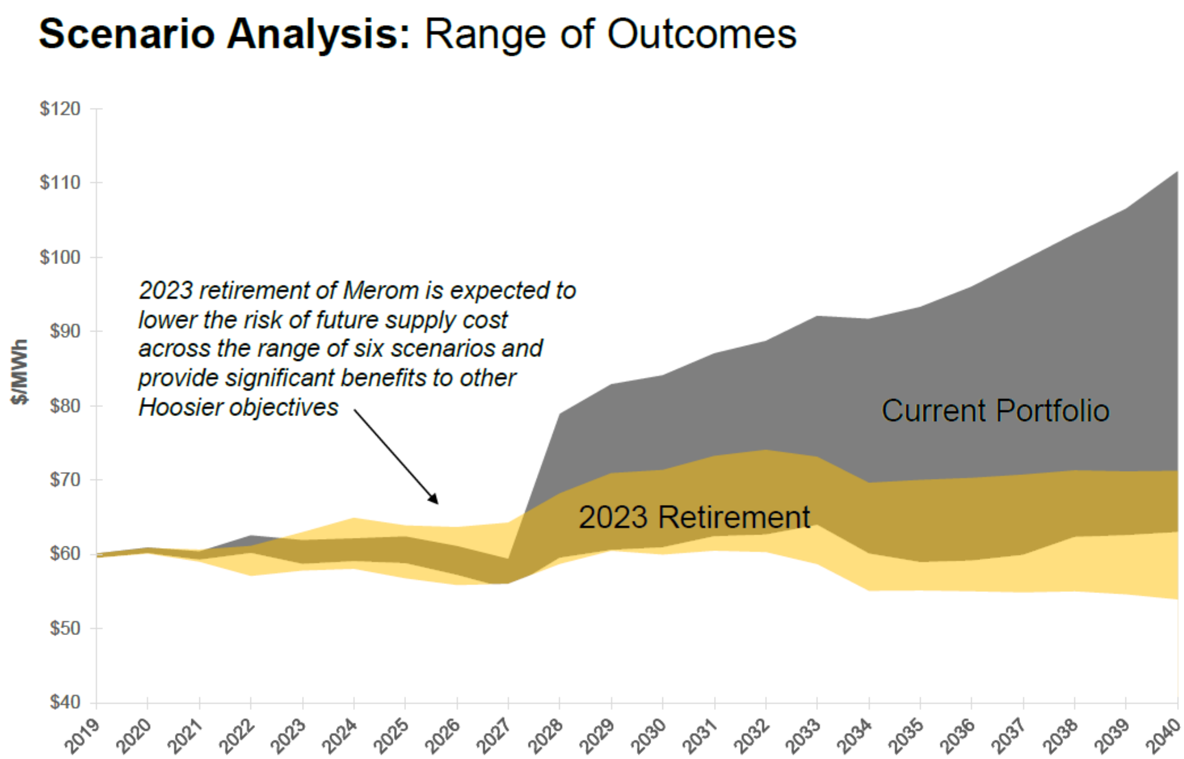
1. Merom 2023 retirement
2. Merom 2025 retirement

The final group of portfolios were developed based on a combination of least cost analysis throughout the modeling process and consideration of other scorecard objectives. As in the earlier model runs, the alternative portfolios were compared to the Current Portfolio to determine if early retirement was warranted and, if so, which retirement dates and replacement portfolios were preferred. A list of the objectives that were modeled is provided in Table 17.

#	Portfolio	Description
0	Current Portfolio	Existing portfolio with solar and storage added to meet load growth
1	Least Constrained	2023 Merom retirement with replacement mix dominated by solar - Significant capacity purchases needed to meet winter obligation
2a	No CC, Annual Balance	2023 Merom retirement - More solar energy than wind, plus balanced gas peaker and storage for capacity
2b	No CC, Monthly Balance	2023 Merom retirement - More wind energy than solar, plus balanced gas peaker and storage for capacity
3a	Small CC, Annual Balance	2023 Merom retirement replaced with 300 MW combined cycle plus gas peaker and storage - More solar energy than wind
3b	Small CC, Monthly Balance	2023 Merom retirement replaced with 300 MW combined cycle plus gas peaker and storage - More wind energy than solar
4	Large CC	2023 Merom retirement replaced with 600 MW combined cycle plus storage; Moderate wind and small solar
5	Less Storage	Portfolio 3b (Small CC, Monthly Balance) with no battery storage before 2035; batteries replaced by gas peakers
6	All Renewable	2023 Merom retirement with all renewable/storage replacement
7	2025 No CC, Monthly Balance	Concept 2b with 2025 Merom retirement (no early renewables)
8	2025 Small CC, Monthly Balance	Concept 3b with 2025 Merom retirement (no early renewables)
9	2025 All Renewable	Concept 6 with 2025 Merom retirement (no early renewables)

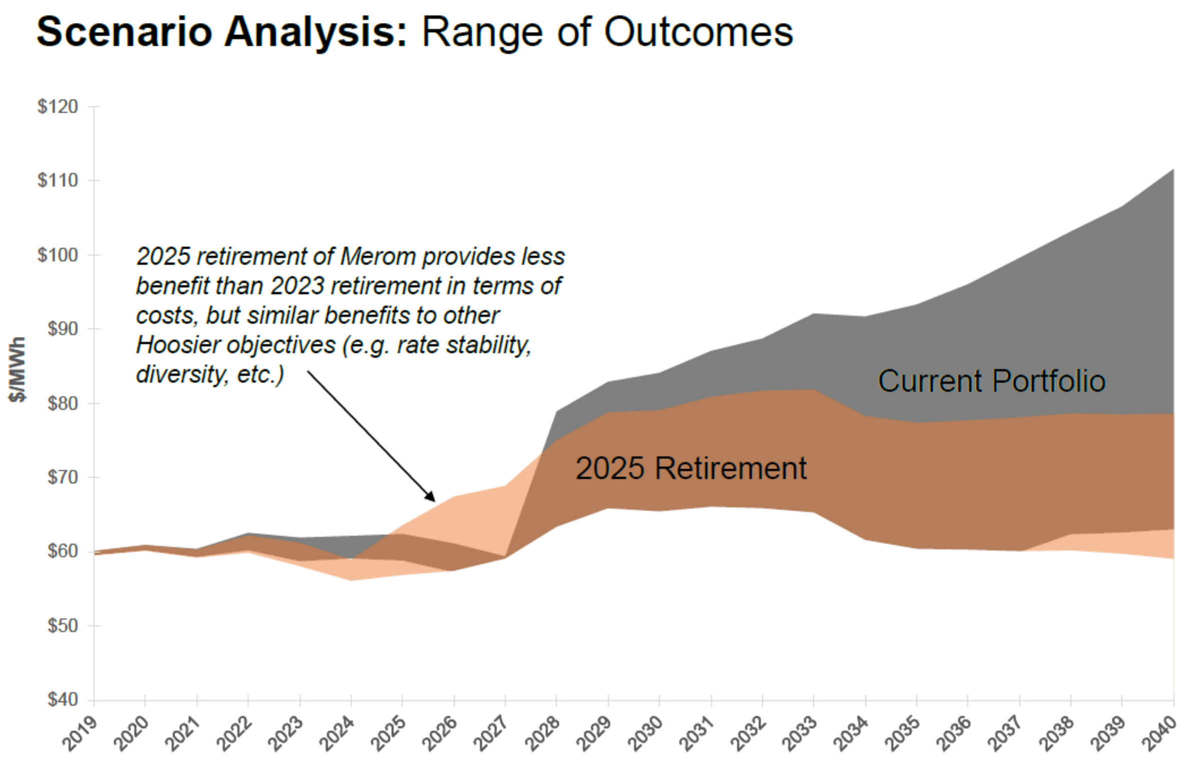
Table 17: Summary of Final Portfolios Tested

The comparison of Revenue Requirements for the Current Portfolio versus each of the alternative Portfolios under a Merom 2023 retirement option is presented on the following chart. The modeling results show that retiring Merom in 2023 provides a lower range of prospective supply costs across all portfolios, and thereby lower risk, than does the Current Portfolio.



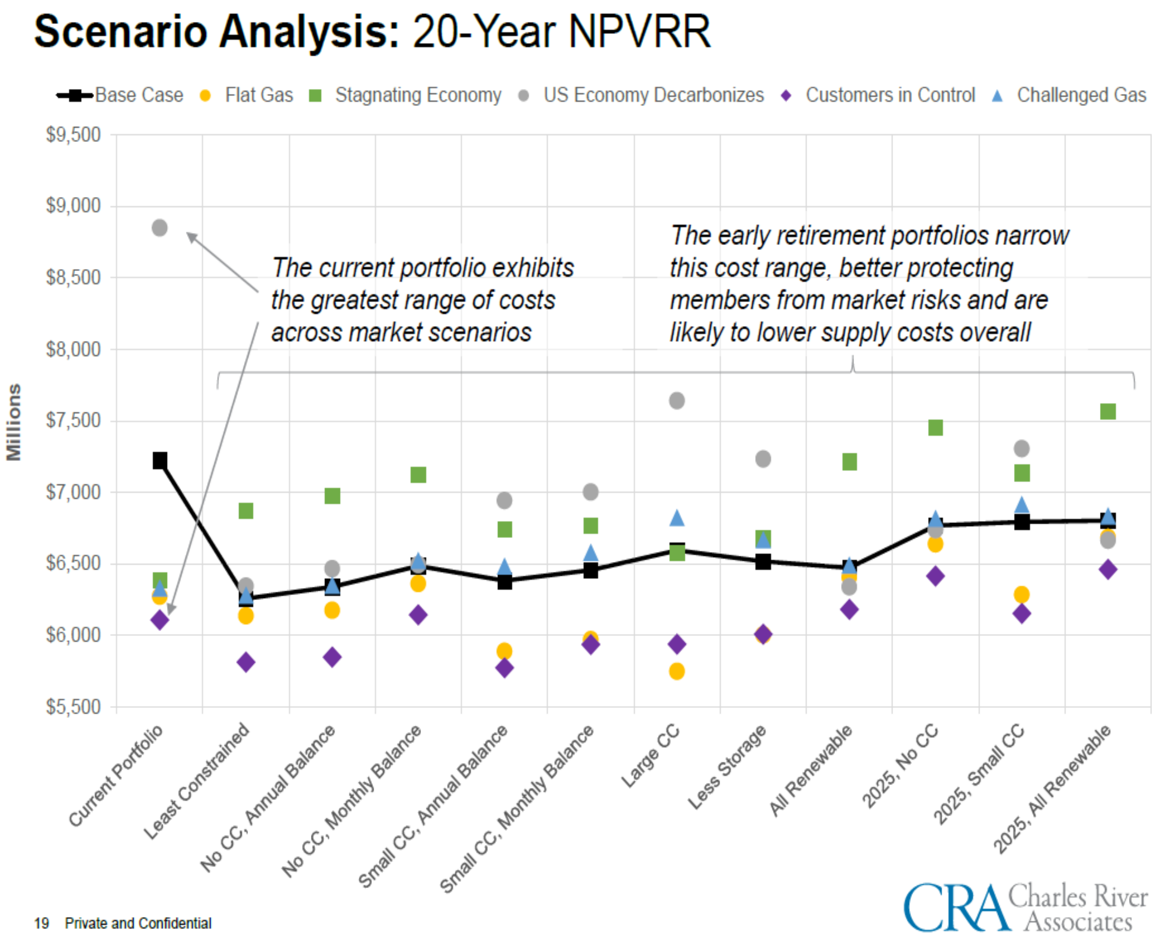
Range of Revenue Requirements – Merom 2023 Retirement

The next graphic provides a comparison of Revenue Requirements for the Current Portfolio versus each of the alternative Portfolios under a Merom 2025 retirement option. While the modeling results show that retiring Merom in 2025 provides a lower range of prospective supply costs across all portfolios than the Current Portfolio, the costs under a Merom 2025 retirement option are more expensive than the same portfolios under a Merom 2023 retirement option.



Range of Revenue Requirements – Merom 2025 Retirement

A chart showing the 20-year NPVRR for each portfolio is provided below. As is evident from the chart, replacing Merom in 2023 is expected to reduce long term costs to Hoosier members under a wide range of portfolio alternatives and scenarios when compared to the Base Case. Merom can only remain competitive under conditions with no CO^2 pressure or high natural gas prices. Retiring the plant in 2025 still benefits members, but forgoes supply cost savings from tax-subsidized wind and solar resources



Scenario Analysis - 20-Year NPVRR Results

Table 18 provides a summary of the 20-Year NPVRR for each of the tested portfolios, assuming a 2023 Merom retirement timeframe. As can be seen from the table, keeping Merom (Portfolio 0) adds $600 to $900 million (20-year NPVRR) of supply cost relative to the 2023 retirement options (Portfolios 1 – 6). Retaining Merom adds $300- $400 million to expected supply costs (20-year NPV) relative to 2025 retirement (Portfolios 7-9). The NPVs were calculated using an interest rate of 5%.

Scenario Analysis: 20-Year NPVRR Table

Portfolio	Description	Base Case	Flat Gas	Stagnating Economy	US Economy Decarbonizes	Customers in Control	Challenged Gas
0	Current Portfolio	7,222	6,276	6,387	8,850	6,109	6,333
1	Least Constrained	6,259	6,122	6,875	6,345	5,814	6,283
2a	No CC, Annual Balance	6,340	6,179	6,974	6,467	5,850	6,353
2b	No CC, Monthly Balance	6,487	6,354	7,126	6,496	6,144	6,525
3a	Small CC, Annual Balance	6,384	5,889	6,739	6,943	5,775	6,485
3b	Small CC, Monthly Balance	6,457	5,962	6,768	7,003	5,938	6,581
4	Large CC	6,596	5,738	6,576	7,641	5,939	6,825
5	Less Storage	6,518	5,999	6,675	7,234	6,010	6,669
6	All Renewable	6,474	6,396	7,214	6,341	6,183	6,492
7	2025 No CC, Monthly Balance	6,769	6,640	7,452	6,739	6,416	6,819
8	2025 Small CC, Monthly Balance	6,795	6,285	7,136	7,306	6,155	6,916
9	2025 All Renewable	6,804	6,686	7,567	6,666	6,483	6,837

Less Attractive

More Attractive

Table 18: Scenario Analysis – Table of 20-Year NPVRR Results

4.14 Scorecard Finalization

4.14.1 Low Wholesale Rates

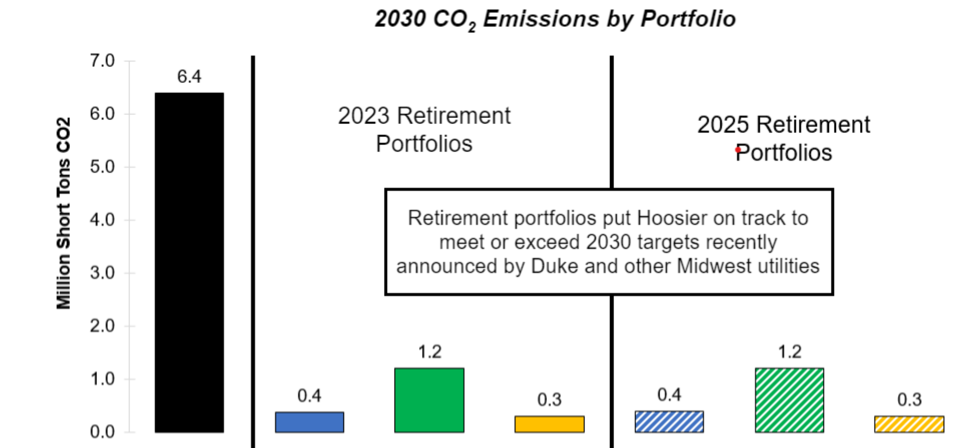
As is shown on the charts on pages 94 and 95, retiring Merom in 2023 can be expected to provide significant cost savings on an NPV basis over the 20-year time horizon of the IRP. Retiring Merom in 2025 portfolios show lower savings than 2023 due to higher renewable costs, as tax credits phase out.

4.14.2 Rate Stability and Predictability

The 2023 Small Gas CC portfolio (Portfolios 3a and 3b) reduces the range of expected supply costs under different scenarios. Additionally, fuel diversity in the 2023 replacement portfolios reduces overall risk when compared to the current portfolio.

4.14.3 Sustainability of Portfolio

By replacing Merom with a portfolio of wind, solar and natural-gas fired resources, all replacement options significantly improve the sustainability of the supply portfolio. The anticipated CO^2 reduction from replacing Merom ranges from 81% to 96% depending upon the replacement portfolio selected. The chart below reflects the projected 2030 CO_2 emissions and percentage reduction from current levels by portfolio.



Portfolio	Current Portfolio	2023 No Gas CC	2023 Small Gas CC	2023 No New Fossil	2025 No Gas CC	2025 Small Gas CC	2025 No New Fossil
% CO_2 Reduction		94%	81%	96%	94%	82%	96%

CO_2 Emissions by Portfolio

4.14.4 Resource Diversity

When compared to the current portfolio, replacement options increase fuel diversity and reduce market purchase reliance. By retiring Merom and replacing it with a number of smaller geographically diverse resources, all replacement portfolios improve Hoosier's single unit exposure relative to the current portfolio.

4.14.5 Employee Impact

All portfolios that retire Merom will have High impact on Hoosier employees. Alternatively, retaining Merom will have the lowest impact on current Hoosier employees. Merom retirement in either 2023 or 2025 will impact the timing, but not the level, of effects on employees.

4.14.6 Completed Scorecard

The completed scorecard is provided in Table 19. Costs and wholesale rates included in the scorecard are based upon the Base Case scenario modeling results. As described below, Hoosier Energy's Preferred Plan is based upon the Flat Gas scenario, which based upon CRA's modeling output, has lower expected costs than the Base Case. The Flat Gas scenario represents the planning scenario that Hoosier Energy believed has the highest probability of occurrence as compared to the Base Case and other modeled scenarios. Hoosier Energy's selection of the Flat Gas scenario was based upon recent natural gas market price trends, as well as its examination of forward NYMEX market gas prices through 2030. Should gas prices increase and the Base Case scenario ultimately proves to be more realistic, the potential 20-year NPVRR increase will be approximately $500 million, as compared to the Flat Gas scenario.

	Low Wholesale Rates			Rate Stability & Predictability				Sustain-ability of Portfolio	Resource Diversity		Employee Impact
	Base Case 20-Yr NPV of Supply Cost	Average 2020-2030 Supply Cost	Average 2031-2040 Supply Cost	Lowest Expected 20-Yr NPV of Supply Cost	Highest Expected 20-Yr NPV of Supply Cost	Likely Range of 20-Year Supply Costs	Worst Case of 20-Year Supply Costs	2030 Carbon Reduction from Current Portfolio (Base Case)	Max Resource Type as % of Generation Mix	Maximum Unit Size	Criteria Rating (Low, High)
	$MM	$ / MWh	$ / MWh	$MM	$MM	-$MM +$MM	$MM	% reduction	%	MW	Rating
Current Portfolio	7,222	64.1	82.2	6,109	8,850	-$14 +11	7,246	-	Coal 63%	500	Low
2023 Retirement Options											
No Gas CC	6,487	63.5	62.3	6,144	7,126	-$14 +14	6,520	94%	Wind 67%	200	High
Small Gas CC	6,457	62.0	64.2	5,938	7,003	-$21 +20	6,504	81%	Wind 43%	300	High
No New Fossil	6,474	63.8	61.4	6,183	7,214	-$10 +8	6,496	96%	Wind 73%	200	High
2025 Retirement Options											
No Gas CC	6,769	65.3	67.3	6,416	7,452	-$15 +16	6,810	94%	Wind 69%	200	High
Small Gas CC	6,795	64.0	70.2	6,155	7,306	-$22 +22	6,850	82%	Wind 41%	300	High
No New Fossil	6,804	65.4	67.9	6,463	7,567	-$10 +10	6,834	96%	Wind 68%	200	High

Coal / Gas / Solar / Wind / Landfill / Hydro / Market Purchases

Table 19: Hoosier Energy IRP – Fully Populated Scorecard

4.15 Discussion of Preferred Plan

Hoosier Energy's has selected the 2023 Small Gas CC Case, using the Flat Gas scenario as its Preferred Resource plan in this IRP. This scenario includes a 15% market exposure tolerance level for demand and 20% market tolerance for energy. As discussed in Section 1.3, Hoosier Energy's preferred Integrated Resource Plan meets the five critical resource planning criteria established by its Board.

1. The Plan reduces costs by over $700 million on a 20-year NPV basis compared to the current portfolio.
2. With respect to the current portfolio, Hoosier Energy's Plan provides lower risk and therefore a greater level of rate certainty to its members.
3. The Plan enhances Hoosier Energy's resource diversity by adding wind, solar and gas generation as replacements for coal-fired generation. Additionally, the Plan reduces single-site risk by substituting smaller units for a single large generating plant.
4. The Plan demonstrates portfolio sustainability in that it reduces carbon emissions by approximately 80% compared to Hoosier Energy's current portfolio.
5. The Plan takes into consideration the impacts of retiring Merom to Hoosier Energy employees.

The Preferred Plan includes the retirement of 990 MW of coal-fired generation, which is anticipated to be replaced with a mix of wind, solar, and natural-gas fired resources. The capacity expansion plan (Table 21) demonstrates sufficient capacity resources for the short-term planning horizon. A summary of the preferred resource plan resulting from the 2023 Small Gas CC Case, using the Flat Gas scenario, is provided in the following table. Although not shown in this table, Hoosier Energy, in conjunction with the Member Systems, will continue to provide cost effective demand response and energy efficiency programs.

Year	Resource Subtractions	Resource Additions
2021		New Wind (250 MW)
2022		Riverstart Solar (200 MW), New Wind (250 MW)
2023	Merom (990 MW), Duke 2 PPA (100 MW)	New Solar (500 MW), New Wind (300 MW), New CC (300 MW)
2024		New CT (200 MW)
2025	Duke 3 PPA (50 MW)	
2026		
2027		New Wind (50 MW)
2028		New Solar (200 MW), New Wind (200 MW), New CT (200 MW)
2029	Rail Splitter Wind PPA (25 MW)	
2030		New CT (200 MW)
2031	Dayton Hydro PPA (4 MW)	
2032		
2033		
2034		
2035		Generic Storage (25 MW)
2036		New Solar (150 MW)
2037	Meadow Lake 1 Wind PPA (25 MW)	Generic Storage (25 MW)
2038		New Wind (50 MW)
2039		Generic Storage (25 MW)
2040	Meadow Lake 2 Wind PPA (50 MW)	
Total MW	1,244 MW	3,125 MW

Table 20: Hoosier Energy Preferred Integrated Resource Plan

4.15.1 Capacity Expansion Plan and Energy Requirements

Table 20 presents the Capacity Expansion Plan for the period from 2021 through 2030, based upon the resources included in Hoosier Energy's Preferred Plan. This table compares the Summer Peak Demand requirements, as determined through load forecasting, to existing and planned future resources. With the exception of the proposed retirement of Merom in 2023 as discussed in Section 5, Hoosier Energy does not project any impact to other existing generation capacity as a result of additional retirements, derating, plant life extensions, repowering or refurbishment.

Table 22 compares total annual energy requirements to expected generation from existing and planned system resources. As reflected in the Table, Hoosier Energy plans to replace Merom's generation with a combination of renewables, purchased power agreements and market transactions following its retirement.

Capacity Expansion Plan - Summer Peak

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand										
Demand Forecast (1)	1,605	1,618	1,630	1,655	1,667	1,678	1,687	1,683	1,688	1,702
Demand Response/Energy Efficiency	(49)	(48)	(49)	(50)	(50)	(51)	(51)	(51)	(51)	(49)
Reserve Requirement (2)	138	140	141	143	144	145	146	145	146	147
Peak Requirement	1,694	1,710	1,722	1,748	1,761	1,772	1,782	1,777	1,783	1,800
Resources (MW)										
Merom	991	991	0	0	0	0	0	0	0	0
Power Purchase	150	150	150	50	50	0	0	0	0	0
Holland	307	307	307	307	307	307	307	307	307	307
Worthington	177	177	177	177	177	177	177	177	177	177
Lawrence	170	170	170	170	170	170	170	170	170	170
New CC	0	300	300	300	300	300	300	300	300	300
New Gas Peaker	0	0	0	200	200	200	200	400	400	600
Wind (3)	350	600	900	900	900	900	950	1,150	1,150	1,125
Solar (3)	10	210	508	504	500	496	492	688	683	677
Renewables (3)	33	33	33	33	33	33	33	33	33	33
Adj. per MISO RAR (4)	(381)	(680)	(1,021)	(1,023)	(1,022)	(1,020)	(1,060)	(1,333)	(1,330)	(1,310)
Total Resources Adjusted	1,807	2,258	1,525	1,619	1,616	1,564	1,570	1,893	1,890	2,080
Total Resources minus Peak Req.										
Excess / (Deficit)	113	549	(197)	(129)	(145)	(208)	(212)	115	108	280

1 2020 Power Requirements Study Update - Base Case Summer Peak Demand - Without Demand Response/Energy Efficiency - escalated

2 Assumed long-term Midwest ISO reserve requirement of 8.90%

3 Estimated Wind, Solar and Renewable Resources additions provided by IRP modeling

4 MISO Resource Adequacy Requirements - Based upon current MISO capacity rules and plant performance, both of which are subject to future changes.

Table 21: Summer Demand Requirements

Source: 2020 PRS and Integrated Resource Plan

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Requirements (GWh)										
Members	8,197	8,254	8,300	8,350	8,395	8,427	8,459	8,416	8,427	8,497
Spot Sales	1,426	2,276	1,869	1,399	1,397	1,100	1,036	1,727	2,154	2,280
Total Energy Required	9,623	10,529	10,170	9,749	9,791	9,527	9,494	10,143	10,581	10,777
Energy Resources (GWh)										
Merom	4,596	5,065	2,102	0	0	0	0	0	0	0
Power Purchase	947	947	947	317	316	0	0	0	0	0
Holland	397	385	401	383	384	359	355	355	338	335
Worthington	410	402	380	351	314	272	244	207	218	213
Lawrence County	287	284	273	260	233	197	180	168	178	171
Wind	788	1,662	2,632	3,123	3,111	3,101	3,203	3,676	3,979	3,916
Solar	17	410	1,046	1,455	1,450	1,433	1,423	1,667	1,818	1,802
New CC	0	0	1,497	2,567	2,569	2,576	2,562	2,576	2,574	2,572
New CT	0	0	0	340	483	502	410	649	815	1,056
Other Renewables	192	192	192	192	192	191	192	192	192	192
Spot Purchases	1,989	1,182	701	761	740	895	926	652	469	521
Total Resources	9,623	10,530	10,170	9,749	9,791	9,527	9,494	10,143	10,581	10,777

Table 22: Annual Energy Requirements 2021 – 2030

4.15.2 Cost

As displayed in Table 18, the projected 20-year NPV of Hoosier Energy's Preferred Plan (Option 3b), is $5.962 billion. This plan performed best over all scenarios and provides Hoosier Energy members with anticipated cost savings of $700 million over the 20-year IRP time horizon when compared to the current portfolio. While Table 18 presents one of the lowest cost resource plans, it is based upon the resources selected for Hoosier Energy's modeling. Ultimately, Hoosier Energy may elect to pursue other cost effective and/or advantageous resources. This could include market products, joint development of supply-side resources, power purchase agreements, renewables, and/or additional demand-side management.

A balanced portfolio of utility owned generation (baseload, peaking and intermediate), power purchases and sales, renewables, market contracts, and demand-side resources diversifies risk in the event load or market conditions change.

4.15.3 Reliability

This IRP addresses reliability in three ways. As a load-serving entity, Hoosier Energy has an obligation to serve member cooperatives. A diverse portfolio of resources assures Hoosier Energy can reliably and economically provide wholesale power to member-owned cooperatives. The IRP also accounts for planning reserves as established by RFC and the MISO and forced outage rates based upon the actual operating history of Hoosier Energy's generation resources. Reserves are a necessary addition to the resource requirement plan and are used to offset the effects of contingencies that arise either because of generation unavailability or changes in load (e.g. weather effects, customer mix and usage). Additionally, Hoosier Energy continues to invest in the transmission system to accommodate growth and ensure reliable service. Membership in the regional transmission organizations (MISO and PJM) allows reliance upon the RTOs' reliability tools, such as the state estimator, real-time contingency analysis and regional outage coordination. In addition, membership in the RTOs allows management of generation facilities that are connected to other RTO utilities but still benefit Hoosier Energy.

4.15.4 Risk

The Preferred Plan displayed a low variance across the scenarios, which indicates that the portfolio provides stability against changing economic conditions. The Plan, which includes more wind, solar and potential gas-fired generation, in combination with Hoosier Energy's current resource portfolio – a diverse mix of owned resources, long-term purchases, renewables, demand-side management and short-term power market purchases and sales – maintains a low market and business risk profile. While the current wholesale market provides short-term economic opportunities, that is unlikely to be the case for the long-term. Therefore, additional resources (PPAs or owned) will likely be required in the future. The risk mitigation technique of joint ventures for owned resources, which allow for the sharing of risks and reduce overall costs, may be an important component of future resource strategy.

4.15.5 Flexibility

As stated in the Executive Summary, the goal is to develop a Plan that is low risk, reliable and cost effective. A secondary goal is a Plan that is flexible to enable cost effective responsiveness to changing business circumstances. With the replacement of Merom with a significant amount of wind, solar and gas resources, along with an increasing market exposure, the preferred plan will enable Hoosier Energy to react to and adapt to load forecast changes, legislative and regulatory mandates, and the potential development or advancement of new technologies.

Environmental legislation and regulations are a significant driver in the development of the IRP. These regulations affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions levels of existing and future generating resources. Therefore, the IRP must not only comply with existing regulations but also allow Hoosier Energy to be flexible enough to adapt to further emission restrictions.

The ability to pursue alternative strategies depending upon regulatory and market environments is an important component of the preferred plan. The Plan use of owned resources and long and short-term purchases and sales not only reduces risk, but also provides the flexibility necessary to respond to changing market conditions.

4.15.6 Greatest Influences on the Preferred Resource Plan

A resource plan is inherently uncertain and major cost categories require risk management. The following is a list of these major categories:

- Fuel costs
- Interest rates
- Future environmental regulations
- LMP market changes
- Regional power requirements
- Member system growth
- Industrial growth
- Inflation rates
- Transmission pricing
- New technologies

Some of these are briefly discussed below.

- The variable with the prospective greatest influence on the preferred resource plan is future natural gas price expectations. The increasing reliability on wind and solar resources in the preferred plan mitigates much of that risk.
- The PRS includes five different forecasts (base, high-economic, low-economic, base-mild weather and base-extreme weather) to establish reasonable boundaries for expected load growth.
- The preferred resource plan is based on an estimated MISO reserve margin of 8.90% as its minimum standard of reliability.
- The Plan considers the potential for future environmental regulations, including restrictions on other pollutants such as carbon, wastewater and coal combustion residuals. No financial benefits are assumed because of the sale of emissions credits to other utilities.

4.15.7 The Present Value of Revenue Requirement of the Preferred Plan

As discussed in the Executive Summary, one of the primary goals of the IRP is to develop a plan that economically meets member requirements. The Net Present Value of the Preferred Plan is $5.962 billion over the 20-year IRP horizon, which is significantly lower than the expected cost of the current portfolio. The NPV was calculated using a discount rate of 5%.

4.15.8 Consideration of Non-Traditional Supply

The Preferred Plan contemplates not only the retirement of Hoosier Energy's lone coal-fired generating resource, but also the addition of over 2,200 MW of wind, solar and storage resources. This portfolio will complement Hoosier Energy's current portfolio, which includes other renewable resources and demand-side management, through both demand response and energy efficiency, and supporting non-utility generation. In the past ten years, Hoosier Energy has built and operates several landfill gas generation facilities, 10 solar facilities and entered into PPAs for both hydro and wind generation.

With respect to energy efficiency and demand response, Hoosier Energy continues to collaborate with Member Systems to provide a variety of DSM programs to their retail members. These efforts lower demand and energy consumption and reduce retail member electricity costs through these programs wherever economically feasible.

4.16 Development of the Preferred Plan

The goals of this IRP are to achieve low power supply cost for member systems while maintaining a low market and business risk profile and ensuring a high degree of reliability. This IRP considered a variety of generation options (supply-side) and consumer usage modification (demand-side) alternatives to develop an appropriate blend of resources to minimize overall system cost.

An assessment of Hoosier Energy's current generation capacity and purchased power agreements is found in Section 3.1. This section also provides additional detail on environmental, transmission and commodity forecasts. Sections 3.2 Demand-side Resource Assessment, 4.2 Future Demand-Side Resource Assessment and 4.3 Future Supply-Side Resource Assessment outline the demand and supply-side options that are available to Hoosier Energy to meet future demand. Section 4 includes the resource screening analysis for demand and supply-side options. Based on this analysis, the most economical resources were considered in the Hoosier Energy plan.

4.16.1 Effects of the Preferred Plan on Revenue Requirements

For a cooperative, the impact on revenue requirements is one of the primary considerations when determining the proper mix of resources. The CRA modeling results shows an average annual decrease in the generation component of revenue requirements of $2/MWh over the next 10 years. Average rates for the years 2031 – 2040 under the Preferred Plan are expected to approximate current rates. Hoosier Energy will continue to strive to find additional cost and operational efficiencies to minimize the impact of increasing revenue requirements.

4.16.2 Hoosier Energy's Ability to Finance New Resources

Hoosier Energy is rated A+ by Standard & Poor's and A2 by Moody's as of October 2020. Both ratings are investment grade and allow for ready access to public and private capital at market-based rates. Hoosier Energy anticipates maintaining this credit quality in the future. Therefore, adequate capital resources are available to finance the construction or acquisition of new resources recommended by this Plan.

4.17 Conclusion

Based upon the results of CRA's modeling, the most economic course for Hoosier Energy is to retire Merom in 2023. Merom's capacity is expected to be replaced with a diverse portfolio of wind, solar, and natural gas-fired generating resources, along with capacity and market purchases. Assuming forecasted load growth, Hoosier Energy has a need for additional capacity in the mid-2020s as current PPAs expire. The optimal online date for new capacity, as well as the most economic type of resource, depends upon the assumptions in the various scenarios, such as member load growth, environmental regulations and market conditions.

Hoosier Energy will pursue a plan based upon the following strategies:

1. Hoosier Energy will limit Wholesale rates and provide a level of rate certainty over the 20-year time horizon by retiring Merom in 2023 and replacing it with a diverse portfolio of resources, along with capacity and market purchases.
2. Provide stability and predictability in portfolio costs through the acquisition of a diverse portfolio of resources through fixed-price PPAs of varying lengths.
3. Enhance resource diversity through the addition of new wind, solar and natural gas-fired resources to meet capacity requirements.
4. The retirement of Merom and its replacement with wind, solar and natural gas-fired resources will allow Hoosier Energy to limit its environmental risk.
5. Hoosier Energy will continue to consider the impacts of a potential Merom retirement on employees through employee retraining and internal cross-functional opportunities.