2020 Report to the

21st Century Energy Policy Development Task Force

Indiana Utility Regulatory Commission

August 14, 2020

ACKNOWLEDGEMENTS

Following the passage of House Enrolled Act 1278 (2019), the Commission contracted with three organizations to assist in its study for the 21st Century Energy Policy Development Task Force. These three entities included: the State Utility Forecasting Group (SUFG), Lawrence Berkeley National Laboratory (LBNL), and Indiana University Public Policy Institute. The Commission is grateful for the work of the researchers at each organization for their work over the last several months on this initiative. Specifically, the Commission would like to thank the following:

Indiana University

- Tom Guevara, Director, Public Policy Institute
- Tim Slaper, Co-director, Indiana Business Research Center
- Sanya Carley, Professor, O'Neill School of Public and Environmental Affairs
- Matt Kinghorn, Senior Demographic Analyst, Indiana Business Research Center
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State Utility Forecasting Group (SUFG)

- Dr. Doug Gotham
- Tim Phillips
- Marco Velastegui
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- Liwei Lu
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Lawrence Berkeley National Laboratory (LBNL)[1]

- Juan Pablo Carvallo
- Joscha Mueller
- Christoph Gehbauer
- Peter H. Larsen
- Myles T. Collins
- Stephanie Bieler

In addition to the experts at the aforementioned organizations, the Commission also recognizes and appreciates the time taken by the external stakeholders in providing feedback, comments, and guidance on the issues at hand.

[1] Mr. Collins and Ms. Bieler are part of Nexant, Inc., which LBNL enlisted to help prepare their analysis.

On Aug. 22, 2019, the Commission hosted a stakeholder meeting, where Commission staff outlined the overall study requirements, and discussed scenario and sensitivity analysis. Dr. Doug Gotham from the SUFG also led a discussion regarding the group's modeling system. Following the stakeholder meeting, there was a public comment period, and the Commission asked for any feedback or comments regarding the study. The Commission received comments from the following groups: Alliance for Industrial Efficiency; Clean Grid Alliance; Citizens Action Coalition of Indiana; Duke Energy Indiana, LLC; Indiana Coal Council, Inc.; Indiana Energy Association; Indiana Industrial Energy Consumers, Inc.; Indiana Michigan Power Company; Indiana Office of Utility Consumer Counselor ; Indianapolis Power & Light Company; Midwest Cogeneration Association; Northern Indiana Public Service Company, LLC ; and Vectren Energy Delivery.

In early 2020, the Commission also posted the methodologies from each of the three groups - SUFG, LBNL and IU - and requested stakeholders to review these methodologies and provide any relevant feedback. The Commission received comments from the following groups: Citizens Action Coalition of Indiana; City Utilities of Fort Wayne; Clean Grid Alliance; Duke Energy Indiana, LLC; Indiana Electric Cooperatives; Indiana Industrial Energy Consumers, Inc.; Indiana Michigan Power Company; Indiana Office of Utility Consumer Counselor ; Indiana State Conference of the NAACP; Indianapolis Power & Light Company; Joint Comments from Citizens Action Coalition of Indiana, Hoosier Environmental Council, Energy Matters Community Coalition, Solarize Indiana, Solar United Neighbors of Indiana, Valley Watch, Hoosier Interfaith Power & Light, Indiana Distributed Energy Alliance, Sierra Club Beyond Coal, Carmel Green Initiative, and Earth Charter Indiana; Joint Comments from Midwest Cogeneration Association, Heat is Power Association, and the Combined Heat & Power Alliance; Northern Indiana Public Service Company, LLC; and Sierra Club.

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I. EXECUTIVE SUMMARY

Assigned Task and Background

House Enrolled Act 1278 (2019) (Indiana Code § 8-1-8.5-3.1(b)) directed the Indiana Utility Regulatory Commission (IURC or Commission) to conduct a comprehensive study of the statewide impacts, both in the near term and on a long term basis, of:

(1) transitions in the fuel sources and other resources used to generate electricity by electric utilities; and
(2) new and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure;

on electric generation capacity, system reliability, system resilience, and the cost of electric service for consumers. In conducting the study required, the Commission shall consider the likely timelines for the transitions in fuel sources and other resources described in subdivision (1) and for the implementation of new and emerging technologies described in subdivision (2).

To inform the required analysis of these changes, the Commission enlisted the expertise of three entities:

1. The State Utility Forecasting Group (SUFG) provided information regarding the implications of different future outcomes of a variety of parameters, including the retirement of coal-fired generators, natural gas prices, energy efficiency, and customer self-generation, which were used to develop a reference scenario and six alternative scenarios. The SUFG modeling system links electricity costs, prices, and sales on a utility-by-utility basis under the different modeled scenarios.

2. Lawrence Berkley National Laboratory (LBNL) provided a detailed analysis of emerging technologies and their impacts on generation capacity, reliability, resilience, and rates from the perspective of the electric utility distribution system. The study framework measures both the economic value and the reliability impact of distributed energy resources (DER). The analysis was designed to answer three primary questions:

    - What is the economic impact of more widespread deployment of DER within the investor-owned utility service territories?
    - Do these emerging technologies lead to increased voltage violations and line losses and, if so, how can these impacts be mitigated?
    - Do any of these technologies provide reliability and/or resilience benefits?

    The LBNL analysis was limited to the following DERs: rooftop PV, electric vehicle charging, and battery storage.

3. A team of Indiana University (IU) researchers—from the IU Public Policy Institute, the Indiana Business Research Center (IBRC), and the Paul H. O'Neill School of

Public and Environmental Affairs at Indiana University—prepared an analysis of the local economic, fiscal, and social impacts of the transition in generation resources, particularly on rural communities. The report provides state and local policymakers information about the potential impact of retiring coal-fired generation and how building replacement generation will affect local communities and regions. These impacts are important to state policymakers, state and local economic development, workforce development, and other civic leaders as they craft community, regional, and state responses.

The electric utility industry is characterized by high levels of capital-intensive, long-lived physical infrastructure, with lifespans generally measured in decades. The implication is that much of the electric utility system costs are fixed, regardless of the level of electricity consumption, and are also recovered from customers over a period of decades. The result is that significant drivers of today's rates are generation-related resource decisions, often made decades earlier. Indiana, along with the rest of the Midwest, is experiencing significant changes in generation resource portfolios. The speed of change depends on the specific circumstances of a given company, but the evolution is clear: greater diversification of generation portfolios, including greater incorporation of renewables and gas-fired generation facilities, and reduced reliance on coal-fired generation.

The trends are similar across Indiana generating utilities, as the impetus for change is the same across the industry—generally, a combination of changed economics, unit age, and environmental compliance investments. These changes are evident in the recent integrated resource plans (IRPs) of Indiana utilities. Importantly, IRPs evolve to address uncertainties inherent in the resource planning process. In other words, IRPs are meant to change as circumstances may warrant. IRPs focus on two sets of time horizons: a short-term outlook (3-5 years) and a long-term outlook (20 years). For example, coal-fired units being retired in the 2022 to 2023 time period generally have specific required environmental investments that are cost prohibitive when compared to alternative resources.[2] Resource decisions beyond that time period, however, are subject to reevaluation as each utility is required to update its IRP at least once every three years.[3] The result is that resource decisions projected to occur later in the decade are not set in stone and will benefit from more of today's future being realized as these plans are reviewed, perhaps twice more, before the utility makes specific commitments.

Reliability and Resilience

Before we can discuss how reliability, resilience, and the cost effectiveness of alternative resource commitments are evaluated in Indiana, it is necessary to understand what both reliability and resilience mean and how they differ with respect to the provision of bulk electric power service. While the focus is on the bulk power system, there will also be

[2] The ages at retirement of the coal-fired units scheduled to retire year-end 2021 through year-end 2023 ranges from 37 years old to 64 years old, with an average of 48 years.

[3] The overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible in order to respond to the unprecedented pace of change currently occurring in the production, delivery, and use of electricity.

reliability, resilience, and economic implications for distribution system planning and operations.

From the utility customer perspective, reliability means that the power is there when we plug in or turn on a switch. The North American Electric Reliability Corporation (NERC) has traditionally defined reliability from an engineering perspective as "the degree to which the performance of the elements of the system results in power being delivered to consumers within accepted standards and the amount desired."[4]

Utilities build or contract with generation facilities to meet their customers' projected needs and use engineering criteria such as minimum reserve margins to provide a specified level of generation reserves. The reserve margin (RM, or sometimes referred to as the Planning Reserve Margin, or PRM) can be thought of as a "safety net" of generation capacity that is in excess of what is needed to meet peak demand. The reserve margin is necessary to allow for contingencies, such as planned and unplanned outages of generation units, extreme weather that increase the demand for electricity, and other reliability considerations.

State and Commission Oversight of Utility Resource Decisions
As the electric utility industry changes, what has not changed is Indiana utilities' ongoing obligation to provide sufficient generation, transmission, and distribution capability to safely, reliably, and cost-effectively serve Indiana's retail customers, as well as the Commission's role in effective regulation of this obligation through these changing times.

Until recently, load growth drove utility resource acquisition decisions. But load growth has slowed markedly over the last decade and is generally projected to increase slowly or decrease slowly depending on the circumstances of the specific utility forecast. This is the case for Indiana utilities and across the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM) multi-state regions. In this circumstance, the driver of changing resource portfolios is changing economics and technology.

A common theme in the IRPs is the need for a managed transition; meaning the utility and Commission must evaluate how quickly the company can change its generation resource portfolio in response to competitive market economic signals while maintaining the capability to provide reliable and resilient electric service at the lowest reasonable costs to the retail customer. The progression of a managed transition is dependent on how comfortable the industry and policymakers are with the ability to accommodate an increasingly diverse range of resources with different economic and performance characteristics into a coherent package.

[4] NERC is the Electric Reliability organization certified by the Federal Energy Regulatory Commission to develop and enforce reliability standards that provide an adequate level of reliability for reliable operation of the bulk power system and must assess the reliability and adequacy of the system.

Under Indiana law and Commission administrative rules, the best process to evaluate utility resource commitments to provide reliable and resilient cost-effective electric service is the regular development of IRPs by utilities. Currently, each of the eight Indiana utilities required to submit IRPs do so on a staggered three-year cycle.[5] IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum optionality or flexibility to address resource requirements.

Key Takeaways from the SUFG, LBNL, and IU Reports

The results of analysis performed by the SUFG provide support for regular development of IRPs by Indiana utilities. The SUFG's analysis highlighted the critical impact that some variables, such as natural gas prices, renewables costs, and a price on carbon emissions, can have on the timing and type of resource commitments necessary to provide reliable and cost-effective electric service. The inability to predict with precision how these key variables will change over a 20-year planning period means that maintaining optionality is critical.

Indiana utility IRPs increasingly recognize that increased reliance on intermittent renewable energy resources means that the impact of any utility resource acquisition decision on the provision of reliable and resilient service at reasonable cost is dependent on interactions with broader changes throughout the MISO[6] and PJM footprints.[7] Regional transmission organizations (RTOs) alone are equipped to collect the information and perform the complex analysis required to understand how increased reliance on intermittent renewable resources across a multi-state region affects the reliability and resilience of cost-effective electric service to utility retail customers.

Ultimately, Indiana is not an island. Electric resource decisions by Indiana utilities will affect the performance of the electric system throughout a multistate region and the same is true for utilities in other states. Within this environment, it is incumbent that Indiana utilities and the RTOs share and effectively use the information each has to offer. The Commission, with direction from policymakers, can continue to highlight the importance of this relationship and seek out ways to make it more effective.

Much of the Commission analysis and discussion focused on the bulk power system. However, the nature of electric power system interconnectivity means that actions taken at any system component (generation, transmission, or distribution) will have the ability to

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[5] Or as conditions warrant, a utility may conclude the IRP is no longer reflective of current conditions which may necessitate preparing a revised IRP. With the rapid transformation of the resource mix, the Commission expects that there will be more out of cycle IRPs.

[6] Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. The fifteen states include all or portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin.

[7] PJM Interconnection, LLC (PJM), is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

impact the overall system. The scale of individual actions and the specific location of those actions can reasonably be expected to impact various components of the power system differently. The LBNL study focused on customer-scale actions at the distribution level. The LBNL study presents insights into the impacts of the type and pace of DER expansion that identifies the ability of the distribution system to accommodate various futures and the modeled cost to do so. Customer self-generation, storage, and automotive electrification are growing, but still very nascent, trends. Proper utility planning and regulatory oversight will ensure the electric system is prepared to support and serve both participants and non-participants moving forward.

Lastly, Indiana University researchers prepared an analysis of the local economic, fiscal, and social impacts of the transition in generation resources, particularly on rural communities. The study focused on the effects of anticipated 2021 to 2028 closures or partial closures of the Schahfer, Michigan City, Petersburg, and Rockport coal-fired generating plants, and was informed by an extensive review of literature on the transition and closing of power plants in other communities across the U.S. These closures are expected to have considerable impacts on the communities in which the plants are located. The IU study concluded, in part, that immediate job losses are more localized than any new jobs that will be created by the expected expansion in alternative energy resources. Also, the jobs created by alternative energy resources will only partially offset the job losses associated with anticipated coal-fired closures, although there is some uncertainty surrounding the potential size of these impacts. It was thought that the job loss could potentially be mitigated by tight labor markets and open positions in the regions surrounding each of the plants, but this perspective was prepared largely before the COVID-19 pandemic impacted Indiana and national economies. There is no consensus about the duration of the current economic impacts or any long-lasting effects resulting from it; therefore, the timing and long-term effects of plant closures or changes in operations may be different than those presented in this report.

II. EVOLVING UTILITY RESOURCE PORTFOLIOS

Changing Resource Portfolio of Electric Industry

The electric utility industry is characterized by high levels of capital-intensive, long-lived physical infrastructure, with lifespans generally measured in decades. The implication is that much of the electric utility system costs are fixed, regardless of the level of electricity consumption, and are also recovered from customers over a period of decades. The result is that significant drivers of today's rates are generation-related resource decisions, often made decades earlier. Additionally, the economic and engineering performance of these generation resources operate in a significantly different environment than that which existed when those resource decisions were made. The focus of this study and the transformation impacts it seeks to understand are the generation resources that provide electricity. The timing differences between long-lived generation resources and rapid technology change creates the tension that this study explores. As circumstances change, a utility needs to evaluate the ability of these legacy resources to contribute to a resource portfolio capable of cost effectively meeting changing customer loads while maintaining a high degree of reliability and resiliency.

The cost-effective replacement of expensive long-lived legacy generation resources in response to changing economics involves complex decision-making and can only be accomplished over multiple decades. This is the case with generation units today, especially coal-fired and nuclear facilities. Utilities across the country, including Indiana utilities, are often reliant upon generation facilities built in the 1960s, 1970s, and 1980s, and even in some circumstances in the 1950s. Unit age, however, is often less of a factor in decisions to retire generation resources, especially in the face of changing economic market pressures. Older generation facilities often have more recent environmental compliance investments that enable these units to continue commercial operation with lower combined operating and investment cost going forward when compared to newer units built in the late 1970s and 1980s equipped with older environmental compliance facilities that need to be replaced. This is but one factor that must be considered for future generation planning. However, it is an example of how legacy investments in generation facilities affect the timing of changes in the generation portfolio both today and into the next decade. The industry has seen a significant shift in the generation portfolio composition in response to changing economics over the last decade, and the portfolio is anticipated to continue to change significantly over the next decade.

The Midcontinent Independent System Operator (MISO), for example, has seen a significant change in its regional resource mix over the last 15 years. Coal capacity was 54% of total MISO generation capacity in 2006 and had decreased to 32% by the 2019 planning year. While gas fired capacity increased from 28% to 33%, the biggest increase occurred in demand-based resources and utility scale wind. Wind was 10% of capacity in 2019 and energy efficiency, demand resources, behind-the-meter-generation, and external resources made up as much as 11% of the MISO resource mix.[8] *(MISO 2020 Interconnection Queue Outlook)*

FIGURE 1 – Changing resource mix due to increased renewables and greater use of demand response and external resources

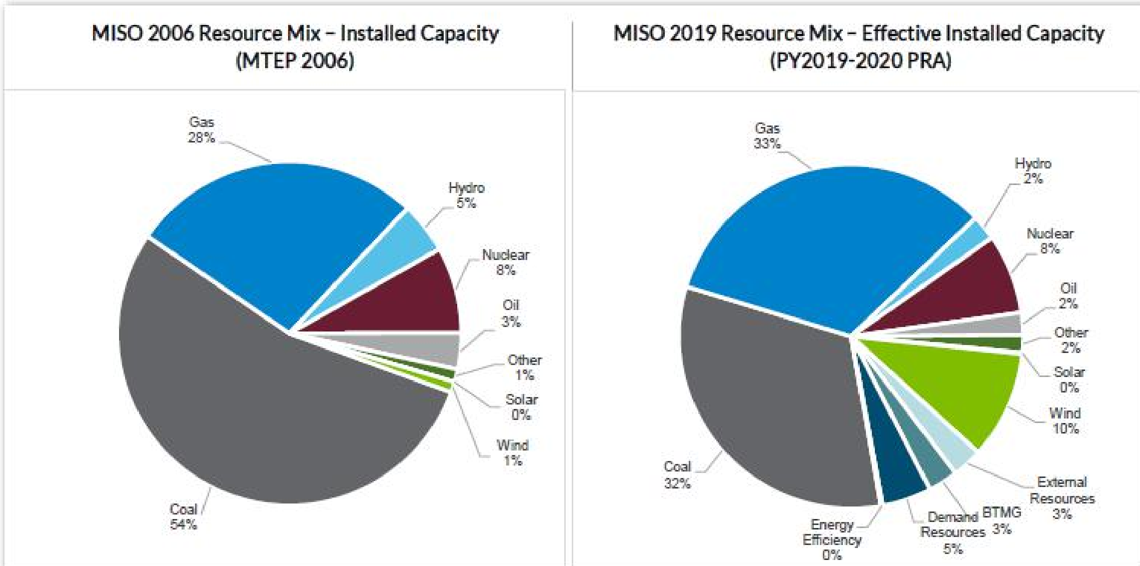
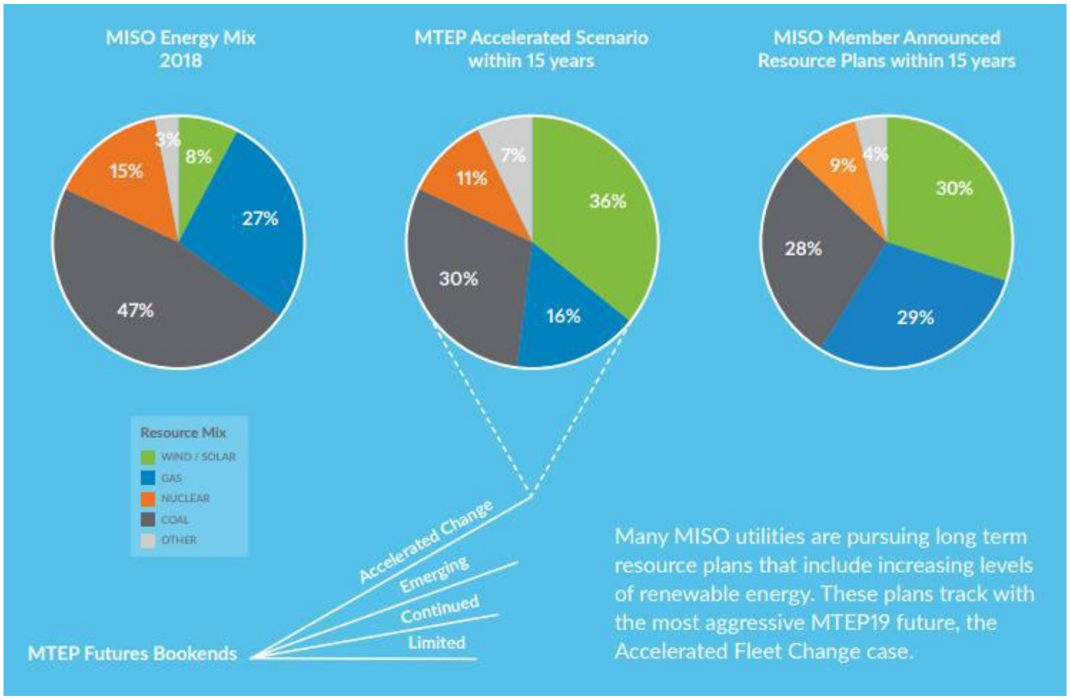


**Figure 1 from MISO 2020 Interconnection Queue Outlook*

Alternatively, the MISO energy mix in 2018 included 47% from coal, 27% gas, 15% nuclear, and 8% wind/solar. Based on MISO member announced resource plans, within 15 years, the regional generation mix is projected to be 28% coal, 29% gas, 9% nuclear, and 30% wind/solar. (*MISO Transmission Expansion Plan 2019 (MTEP 2019)*)

[8] Energy efficiency and behind-the-meter generation is generally not dispatchable.

FIGURE 2



**Page 3 of MTEP 2019*

Indiana is in a state of generation portfolio change similar to that being seen by MISO. This change is most clearly seen in the scale of retirements that have occurred since 2010 and the projected coal retirements through 2028, as seen in the most recent Indiana utility integrated resource plans (IRPs).

TABLE 1 – Coal Fleet Retirements

Retired Coal Units Since 1-1-2010					
	Coal Unit (Year In-Service)	Owner	Summer Rating (MW)	Retire Date	Age at Retire Date
1	Edwardsport Unit 7 (1949)	Duke	45	01-01-10	61
2	Edwardsport Unit 8 (1951)	Duke	75	01-01-10	59
3	Mitchell Unit 5 (1959)	NIPSCO	125	09-01-10	51
4	Mitchell Unit 6 (1959)	NIPSCO	125	09-01-10	51
5	Gallagher Unit 1 (1959)	Duke	140	01-31-12	53
6	Gallagher Unit 3 (1960)	Duke	140	01-31-12	52
7	State Line Unit 1 (1929)	Merchant	197	01-31-12	83
8	State Line Unit 2 (1929)	Merchant	318	01-31-12	83
9	Ratts Unit 2 (1970)	Hoosier	121	12-31-14	44
10	Ratts Unit 1 (1970)	Hoosier	42	03-10-15	45
11	Tanners Creek Unit 1 (1951)	I&M	145	06-01-15	64
12	Tanners Creek Unit 2 (1952)	I&M	142	06-01-15	63
13	Tanners Creek Unit 3 (1953)	I&M	195	06-01-15	62
14	Tanners Creek Unit 4 (1956)	I&M	500	06-01-15	59
15	Eagle Valley 3 (1951)	IPL	40	04-15-16	65
16	Eagle Valley 4 (1953)	IPL	55	04-15-16	63
17	Eagle Valley 5 (1955)	IPL	61	04-15-16	61
18	Eagle Valley 6 (1956)	IPL	100	04-15-16	60
19	Wabash River Unit 2 (1953)	Duke	85	04-15-16	63
20	Wabash River Unit 3 (1954)	Duke	85	04-15-16	62
21	Wabash River Unit 4 (1955)	Duke	85	04-15-16	61
22	Wabash River Unit 5 (1956)	Duke	95	04-15-16	60
23	Wabash River Unit 6 (1968)	Duke	318	04-15-16	48
24	Bailly Unit 7 (1962)	NIPSCO	160	05-31-18	56
25	Bailly Unit 8 (1968)	NIPSCO	320	05-31-18	50

TABLE 2 – Projected Coal Unit Retirements from Recent IRPs

Generating Unit	Owner	Summer Rating	Retire Date	Age at Retire Date
Petersburg 1	IPL	220	12-31-2021	54
Gallagher 2	Duke	140	12-31-2022	64
Gallagher 4	Duke	140	12-31-2022	61
Brown 1	SIGECO	245	12-31-2023	44
Brown 2	SIGECO	245	12-31-2023	37
Culley 2	SIGECO	90	12-31-2023	57
Merom 1	Hoosier	501	12-31-2023	40
Merom 2	Hoosier	482	12-31-2023	41
Petersburg 2	IPL	410	12-31-2023	54
Schafer 14	NIPSCO	431	12-31-2023	47
Schafer 15	NIPSCO	472	12-31-2023	44
Schafer 17	NIPSCO	361	12-31-2023	40
Schafer 18	NIPSCO	361	12-31-2023	37
Warrick 4 (ALCOA, 50%)	SIGECO	150	12-31-2023	53
Gibson 5	Duke	620	05-31-2026	44
Whitewater Valley Unit 1	IMPA	38	12-31-2026	71
Whitewater Valley Unit 2	IMPA	60	12-31-2026	53
Cayuga 2	Duke	495	05-31-2028	56
Cayuga 1	Duke	500	05-31-2028	58
Michigan City 12	NIPSCO	469	12-31-2028	54
Rockport 1	I&M	1300	12-31-2028	44

**Data from recent utility IRPs*

Another perspective beyond utility IRPs is the MISO Interconnection Queue for projects to be located in Indiana that are seeking to interconnect to the MISO-operated transmission system through 2023. The resources in the queue as of November 2019 are informative of the changing resource marketplace, though many of these projects may not be developed, and many that are developed will not be owned by, or under contract with Indiana utilities.

FIGURE 3 – MISO Generation Queue for Indiana Projects

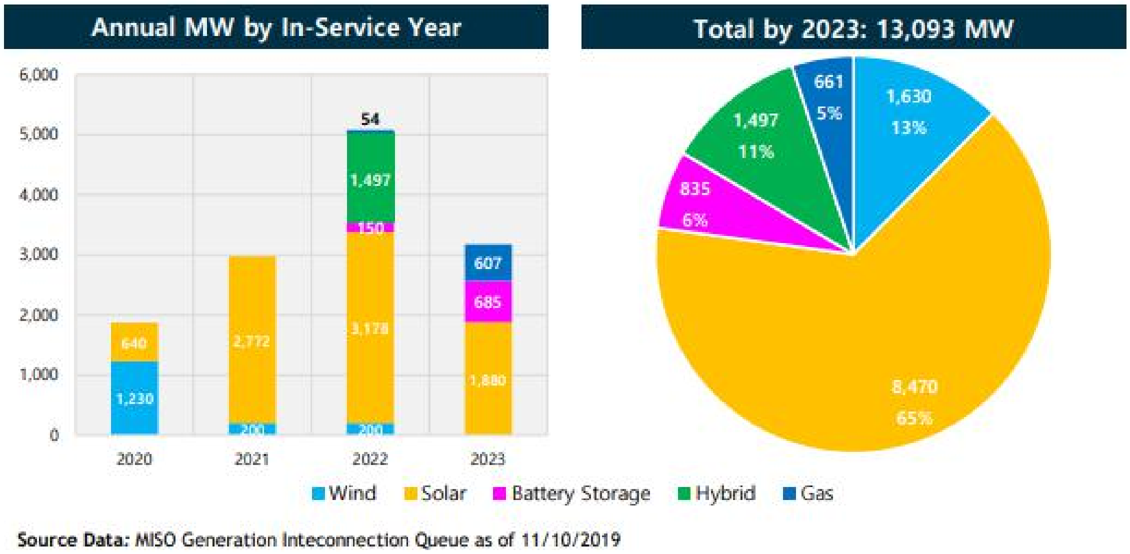


**Figure 7.20 from page 142 of IPL's IRP*

Utility IRP Projected Changes in Resource Portfolio

The following discussion is based on utility specific IRPs and highlights the changing generation portfolios each utility anticipates developing over the next 20 years. The trends are similar across the individual companies as the impetus for change is the same across the industry. While the speed of change depends on the specific circumstances of a given company, the evolution is clear: greater diversification of generation portfolios, including greater incorporation of renewables and gas-fired generation facilities, and reduced reliance on coal-fired generation. Importantly, IRPs evolve to address uncertainties inherent in the resource planning process. In other words, IRPs are meant to change as circumstances may warrant. IRPs focus on two sets of time horizons: a short-term (3-5 years) outlook and a long-term (20 years) outlook. For example, coal-fired units being retired in the 2022 to 2023 time period generally have specific required environmental investments that are cost prohibitive when compared to alternative resources, while closures projected beyond 2023 represent current plans that could be revised in future IRPs as the industry landscape changes. Resource decisions—especially decisions beyond a three-year time period—are subject to reevaluation as each utility is required to update its IRP at least once every three years. The result is that resource decisions projected to occur further into the future are not set in stone and will benefit from more of the future being known as these decisions are reviewed and as time progresses, before the utility makes specific commitments.

The specific portfolio discussed for each utility is the "preferred portfolio" resulting from a utility's most recent IRP, unless otherwise noted. "Preferred resource portfolio" means the utility has selected a long-term supply-side and demand-side resource mix that, based on what is known today, will safely, reliably, efficiently, and cost-effectively meet the projected electric system demand, taking cost, risk, and uncertainty into consideration. Resource planning will be discussed further below, but there is no guarantee that one plan will be the most cost-effective. Utility IRPs should focus on outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation. In an uncertain world, making several smaller resource decisions over time and maintaining decision optionality as long as practical can be beneficial, particularly compared to making fewer larger commitments that foreclose opportunities to adapt to changing industry circumstances.

Duke Energy Indiana (Duke)

As of July 2019, the total installed net summer generation capability owned or purchased by Duke was 6,630 megawatts (MW).[9] This capacity consisted of 4,097 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 264 MW of natural gas-fired combined cycle (CC) capacity, 45 MW of hydroelectric capacity, 1,585 MW of natural gas-fired peaking capacity, 10 MW of oil-fired peaking capacity, and 17 MW (8.5 MW contribution to peak) of owned solar photovoltaic capacity. Also included are power purchase agreements with Benton County Wind Farm totaling 100 MW (13 MW contribution to peak) and five solar facilities totaling 24 MW (12 MW contribution to peak).[10] In addition to the 6,630 MW of generation capacity, Duke had available approximately 576 MW of demand response resources.

FIGURE 4 – 2018 Duke Energy Indiana Capacity and Energy Mixes

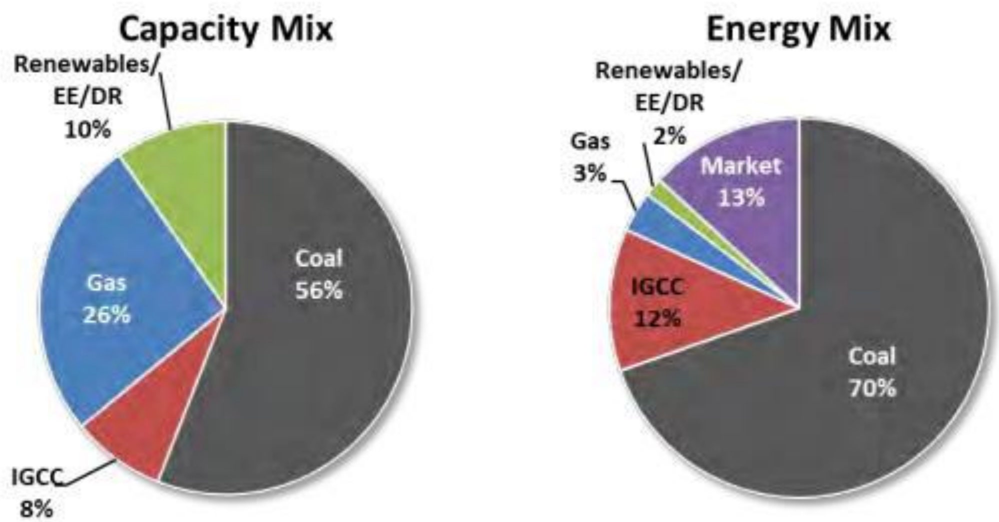


**Figure III.5 from page 39 of Duke's IRP*

Through 2037, Duke's preferred portfolio retires over 2,800 MW of coal-fired generation and adds 1,650 MW of utility scale solar, 700 MW of wind, and 2,480 MW of gas-fired combined cycle capacity, 40 MW of combined heat and power, and approximately 300 MW of energy efficiency (EE).

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[9] Utilities plan to meet their highest hour of electric demand, which normally occurs in the summer for the majority of utilities.

[10] The 6,630 MW of generation capacity includes the contribution to system peak requirements of the intermittent solar and wind resources.

FIGURE 5 – Capacity Mix: Moderate Transition Portfolio

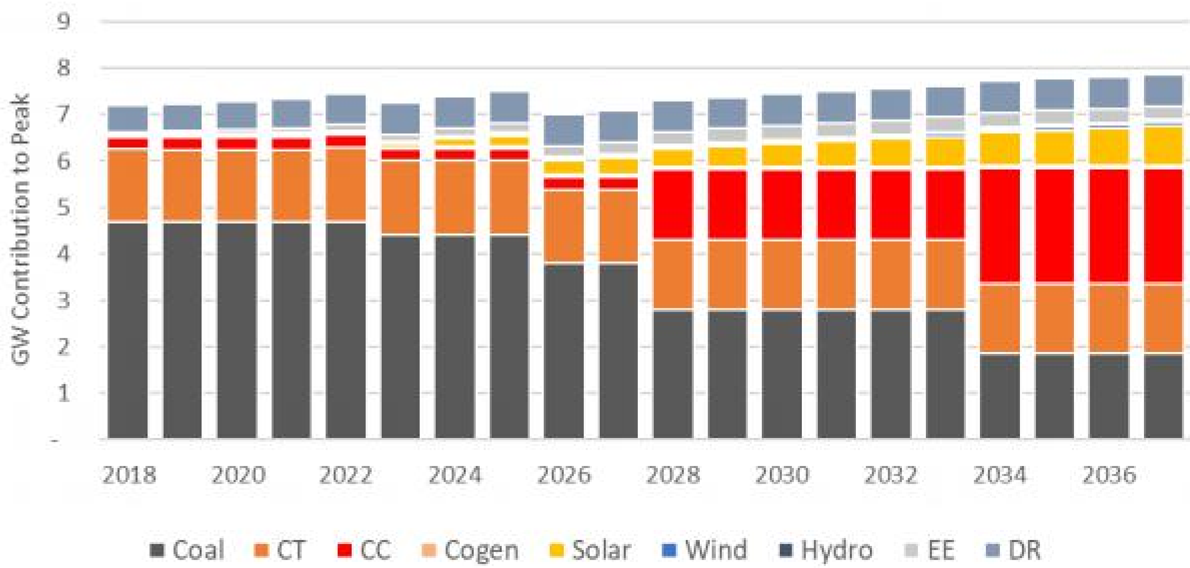


**Figure from page 15 of Duke's IRP*

Indiana Michigan Power Company (I&M)

I&M's resource mix will be highly dependent on a decision regarding the Rockport generating units and its resource alternatives. The Rockport Generating Station (Rockport), located in Spencer County, consists of two 1,300 MW coal-fired generating units.[11] The figure below shows I&M's "going-in" capacity position (meaning before resource replacements or other additions) over the planning period 2019 to 2038. In 2023, I&M expects the lease for Rockport Unit 2 to expire, creating a capacity shortfall of approximately 484 MW. The shortfall grows to 1,762 MW in 2028 with the retirement of Rockport Unit 1. The shortfall increases to 4,060 MW with the retirement of Cook Unit 1 in 2034 and Cook Unit 2 in 2038.

[11] I&M owns 50% of Rockport Unit 1 and leases 50% of Rockport Unit 2 under a sale and leaseback arrangement. I&M also purchases 35% of the capacity and energy of Rockport 1 and 2 from AEP Generating Company under a FERC filed Unit Power Agreement. In total, through these arrangements 2,227 MWs of the combined 2,620 MWs of the Rockport Plant are available to serve I&M customers.

FIGURE 6 – I&M's "Going-In" Position

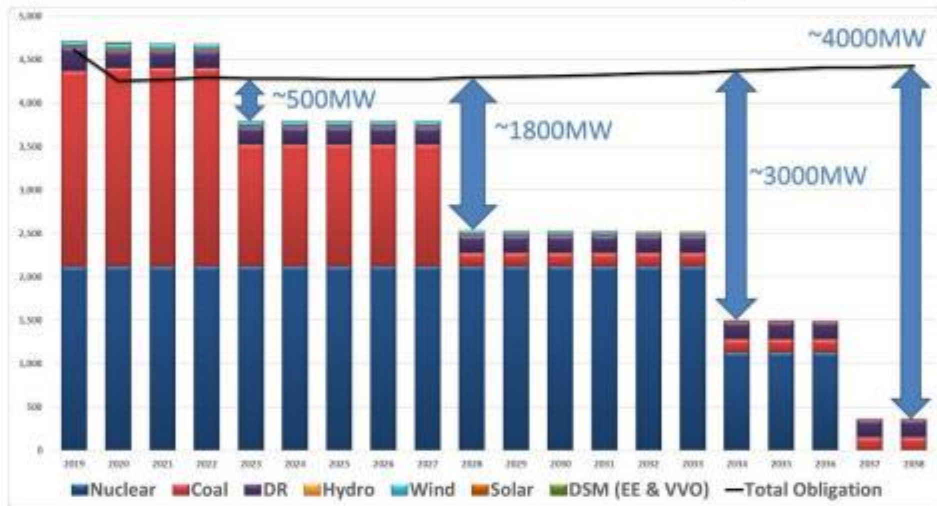


**Figure 34 from page 142 of I&M's IRP*

Important components of I&M's Preferred Plan include the following:

a. Continuing to operate the Cook nuclear units through the remainder of their current license periods.
b. The Rockport Unit 2 lease expires at year end 2022 and retire Rockport Unit 1 at year end 2028.
c. Adding 2,700 MW of natural gas combined cycle including 770 MW in 2028 to replace Rockport capacity, 770 MW in 2034 to replace Cook Unit 1, and 1,155 in 2037 to replace Cook Unit 2.
d. Adding 1,700 MW of utility scale solar and 1,950 MW of wind over the period 2022 – 2038.

TABLE 3 – Preferred Plan Cumulative Additions from 2019 to 2038 (MW)

	Commodity Pricing	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Case 9 (Preferred)	BASE	New Solar Firm				76	153	153	229	305	381	458	559	661	737	814	865	865	865	865	865	865
		New Solar				*150*	*300*	*300*	*450*	*600*	*750*	*900*	*1100*	*1300*	*1450*	*1600*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
		New CT																				
		New DSM		*19*	*36*	*50*	*62*	*71*	*81*	*89*	*97*	*105*	*96*	*102*	*101*	*101*	*101*	*100*	*102*	*97*	*61*	*86*
		New VVO															9	9	9	9	9	9
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC										770	770	770	770	770	770	1540	1540	1540	2695	2695
		New STMP					150	150				200	100									
		New DR															14	29	43	58	72	86

**Table ES-2 from page ES-6 of I&M's IRP*

FIGURE 7 – Existing and New Capacity Additions – Firm (MW)

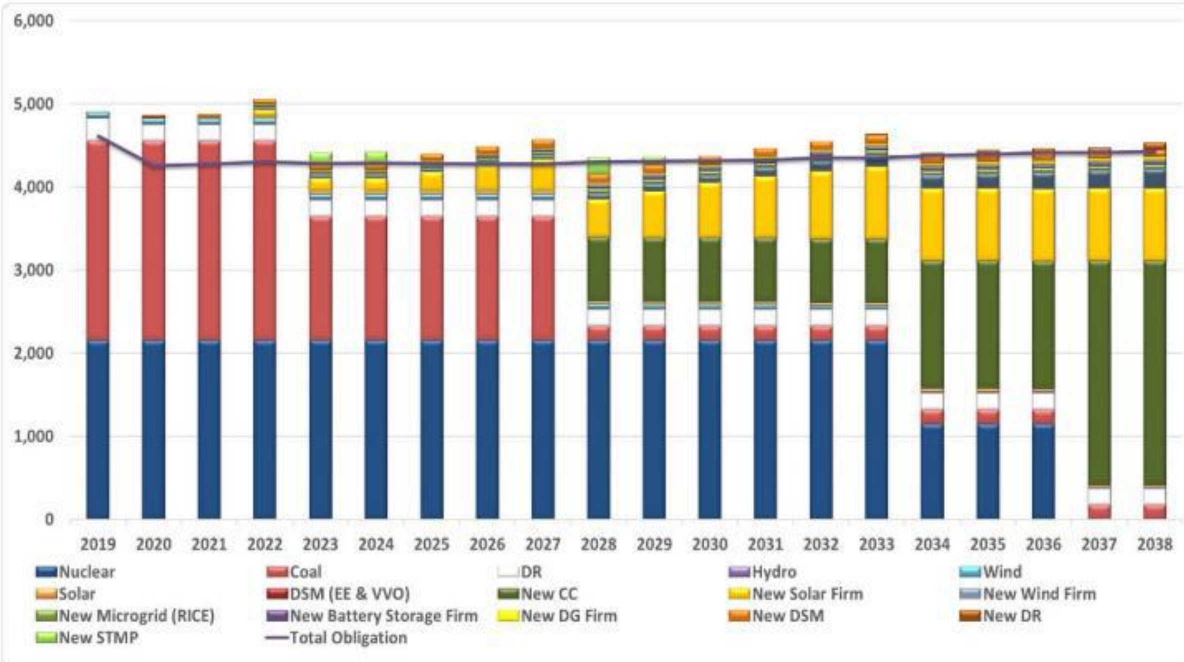


**Figure ES-3 from page ES-7 of I&M's IRP*

<u>Indianapolis Power and Light Company (IPL)</u>
IPL's total generation capacity consists of 1,706 MW of coal-fired capacity at the Petersburg Plant; 1,725 MW of gas-fired capacity with 671 MW in natural gas combined cycle capacity at Eagle Valley, 442 MW of combustion turbine (CT) capacity; 612 MW of steam turbine capacity, 396 MW of renewables with 300 MW of wind purchase power agreements and 96 MW of solar.

IPL concentrated on the decisions to be made through year-end 2023 in its 2019 IRP. Of importance is the determination to retire 630 MW of coal-fired capacity by year-end 2023, which includes the retirement of Petersburg Unit 1 by the end of 2021 and Petersburg Unit 2 in 2023. IPL has issued a request for proposal (RFP) to acquire up to 200 MW of replacement resources in 2023. IPL's preferred plan through 2039 includes the addition of 550 MW of wind, 1,450 MW of solar, 440 MW of battery storage, 325 MW natural gas combined cycle, and 293 MW of demand-side management (DSM).

FIGURE 8 – IPL Resource Mix

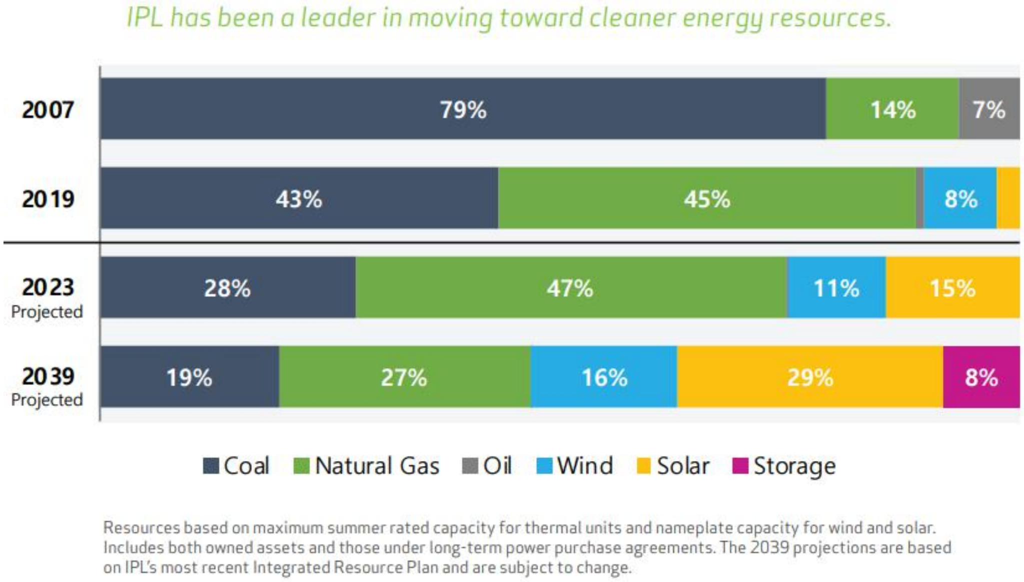


**Figure 1 from page 2 of IPL's 2019 IRP Non-Technical Summary, in Appendix 2 of 3*

Northern Indiana Public Service Company (NIPSCO)

As of NIPSCO's 2018 IRP, the total capacity of the existing generation resources is 2,925 MW across multiple sites, including R.M. Schahfer (Schahfer) (Units 14, 15, 16A, 16B, 17 and 18), Michigan City (Unit 12), Bailly (Units 10), Sugar Creek, and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). *Table 4* shows the fuel type, technology, and size of each of the generation facilities. In addition, NIPSCO had approximately 621 MW of demand response resources available.

TABLE 4 – Net Demonstrated Generation Capacity

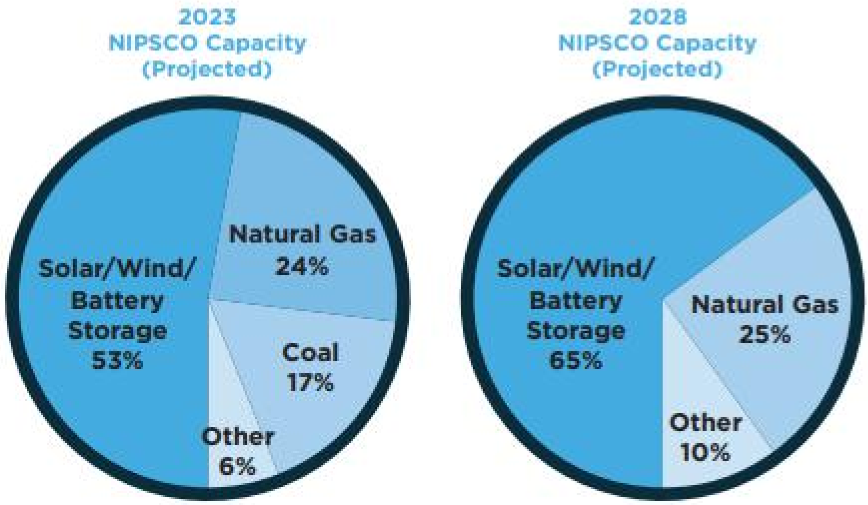
Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	14	Coal	431
	15	Coal	472
	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	1,780
Sugar Creek		NG	535
Bailly	10	NG	31
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	100
NIPSCO			2,925

NG=Natural Gas

**Table 4-1 from page 42 of NIPSCO's IRP*

NIPSCO is currently planning to retire coal-fired Schahfer Units 14, 15, 17, and 18 by the end of 2023 and coal-fired Michigan City Unit 12 by the end of 2028. *Figure 9* displays NIPSCO's projected capacity share by technology for 2023 and 2028, to reflect the changes when the four Schahfer units retire in 2023 and Michigan City Unit 12 retires in 2028. By 2028, NIPSCO plans to add 1,348 MW of solar capacity, 92 MW of solar + storage, 157 MW of wind, 50 MW of wholesale market purchases, and 239 MW of DSM.

FIGURE 9

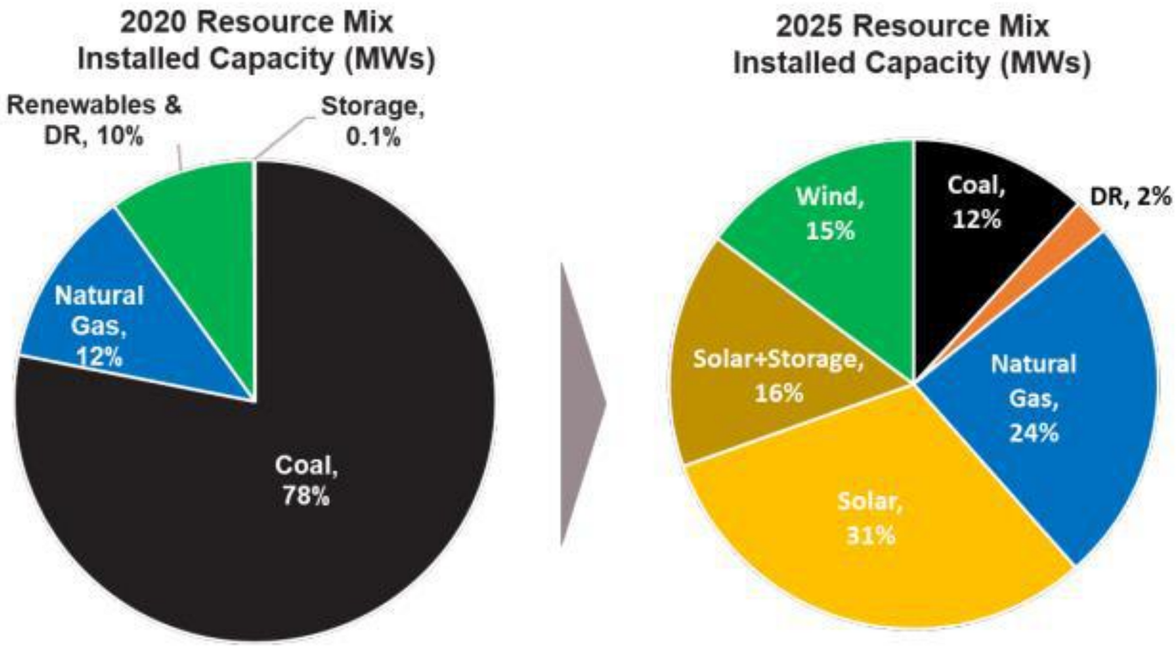


**Figures from page 6 of NIPSCO IRP Executive Summary*

<u>Southern Indiana Gas & Electric Company (SIGECO/Vectren/CenterPoint Energy)</u>
SIGECO's current resource portfolio includes approximately 1,280 MW of installed generation capacity. This capacity consists of approximately 1,000 MW of coal-fired capacity, 160 MW of gas-fired peaking capacity, 3 MW of renewable landfill gas generation, 4 MW of solar, 80 MW from wind power purchase agreements (PPAs), and a 1.5% ownership in Ohio Valley Electric Corporation generation facility.

SIGECO's preferred portfolio in the 2020 IRP includes 300 MW of wind in 2022, approximately 746 MW of solar in 2023 and 2024, paired solar + storage (400 MW of solar and 126 MW storage) in 2023, and two new 236 MW combustion turbine units in 2024 and 2025, all of which replace A.B. Brown 1 and 2, F.B. Culley 2, and Warrick 4 coal units when they retire by the end of 2023. SIGECO's preferred portfolio also includes approximately 1.25% of annual EE increments planned in the 2021 to 2023 period, 0.75% of annual EE increments in the period 2024 to 2026, and 0.50% of annual EE increments for the period 2027 to 2039.

FIGURE 10



**Figures from page 53 of Vectren's IRP*

Hoosier Energy Rural Electric Cooperative (Hoosier Energy)
As of March 2018, Hoosier Energy owned generation resources of approximately 1,780 MW consisting of the coal-fired Merom Units 1 and 2 (1,070 MW), a 50% interest in the Holland gas-fired combined cycle facility (315 MW), the Worthington and Lawrence gas-fired combustion turbines (350 MW), three landfill gas units (35 MW), and solar (10 MW). This was supplemented with purchased power agreements including 150 MW from Duke, 125 MW of wind, 200 MW of solar, and 4 MW of hydro.

On Jan. 20, 2020, Hoosier Energy's Board of Directors approved a new long-range resource plan under which Hoosier Energy expects to retire the coal-fired Merom plant in 2023 and transition to a more diverse generation mix. Merom Generating Station is Hoosier Energy's largest power plant, capable of producing approximately 1,000 MW of electricity. Hoosier Energy is expected to submit a new IRP in November 2020.

Indiana Municipal Power Agency (IMPA)
As of Feb. 1, 2018, IMPA's resources included:

- Joint ownership interests in Gibson Station #5 (156 MW), Trimble County Station #1 & #2 (162 MW) and Prairie State Energy Campus #1 and #2 (206 MW);
- Operation and maintenance responsibility of Whitewater Valley Station #1 & #2 (91 MW);
- Seven combustion turbines wholly owned by IMPA;
- Generating capacity owned by one (1) IMPA member;
- 17 Solar Parks located in member communities

- Long term power purchases from:
    - I&M
    - Duke
    - Crystal Lake Wind, LLC (expires 12/31/2018)
- Short term contracts with market participants in MISO and/or PJM Interconnection, LLC (PJM);
- The IMPA Energy Efficiency Program

IMPA's Preferred Plan called for IMPA to cover capacity shortfalls by engaging in bilateral capacity transactions and market energy hedges through approximately 2025. The Preferred Plan also had the Whitewater Valley Station (WVS) retiring in 2026 when carbon emission legislation was assumed to begin. Since IMPA was projected to be long on capacity in PJM, no additional capacity needs were anticipated to make up for this retirement. Even though WVS is shown as being retired in the Preferred Plan, no definitive retirement studies or decisions had been made.

IMPA's Preferred Plan for the period 2018 to 2037 is shown in the following table.

TABLE 5 – 2017 IRP Expansion Plan – Base Case Plan

Year	Capacity Losses MW Lost	Resource	Capacity Additions MW Added	Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (21-25)	12
2022			12	Solar	12
2023			12	Solar	12
2024			12	Solar	12
2025			12	Solar	12
2026	(90) (200)	WWVS Retires Bilateral Capacity Expires	12 200 50	Solar Advanced CC Wind PPA	(28)
2027			12	Solar	12
2028			12	Solar	12
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	260	Advanced CC	70
2035					
2036					
2037					
Total	(780)		992		212

**Table 1 from page 1-13 of IMPA's IRP*

IMPA is expected to submit a new IRP in November 2020.

<u>Wabash Valley Power Authority (WVPA)</u>
As of January 2018, WVPA owned 1,094 MW of generation capacity consisting of 239 MW of coal-fired capacity split between Gibson Unit 5 and Prairie State, 315 MW of gas-fired combined cycle capacity, 486 MW of other gas-fired capacity, 54 MW of landfill gas, and 1.6 MW of solar. WVPA also had numerous wholesale purchase agreements shown in the following table.

Table 6 – Wabash Valley's Power Purchase Summary

Wabash Valley's Power Purchases Summary				
Supplier	**Type**	**Expires**	**MW**	**Comments**
AEP	Firm	2033	160	Load Following
Duke Indiana	Firm	2032	70	85% Min. Capacity Factor
Duke Indiana	Unit Peaking	2021	50	
Duke Indiana	Firm	2031	150-180	65% Min. Capacity Factor; 180 MW beginning in 2020
Duke Indiana	Firm	2025	55	50% Min. Capacity Factor
Story Wind	Wind Turbine	2019	21	
NextEra	Firm	2017	50	Fixed Price
NextEra	Firm	2017-2018	100	Fixed Price
Macquarie	Firm	2017-2018	50	Fixed Price
BP Energy	Firm	2018	50	Fixed Price
Mercuria	Firm	2019-2023	100	Fixed Price
Morgan Stanley	Firm	2018-2025	100	Fixed Price
Morgan Stanley	Firm	2019-2022	100	Fixed Price
NextEra	Firm	2021-2030	50	Fixed Price
NextEra	Firm	2024-2032	50	Fixed Price
Morgan Stanley	Firm	2024-2035	50	Fixed Price
Agriwind	Wind Turbine	2018	8	
Pioneer Trail Wind Farm	Wind Turbine	2030	10	
Windy Ridge	Digester	2020	1.4	1 year auto renewals after 2020
County Line	Landfill Gas	2039	4	
Meadow Lake Wind V	Wind Turbine	2037	25	Expected to begin commercial operation in Q1 2018
Meadow Lake Wind VI	Wind Turbine	2038	75	Expected to begin commercial operation in Q1 2019
Illinois Wind Project	Wind Turbine	2039	100	Expected to begin commercial operation in Q1 2020
Various Suppliers	Short-Term	Various	Various	Usually 1-2 years in duration

**Table 2-8 from page 18 of WVPA's IRP*

WVPA's 2017 IRP resource portfolio showed that WVPA needed additional capacity to meet projected demand requirements in 2018. From 2018 to 2020, the base resource plan recommended that WVPA purchase incremental capacity from the market. Past 2020, the base resource plan recommended the addition of 576 MW of baseload combined cycle resources and 336 MW of peaking combustion turbine resources along with some incremental market capacity purchases in certain years. Additionally, the base resource plan included an additional 50 MW of EE.

Table 7 – Power Supply Expansion Plan

Year	Power Supply Requirements MW (1)	Existing Owned & Contracted Power Resources (MW) (2)	Planned Additions (MW) (2)	Capacity Needs (MW) (2)	Capacity Market (2)	CC (NG) (2)	CT (NG) (2)	EE (2)
2018	1,843	1,512	3	328	337	0	0	0
2019	1,748	1,521	10	217	218	0	0	0
2020	1,900	1,538	20	342	354	0	0	0
2021	1,762	1,502	20	240	48	0	192	0
2022	1,773	1,490	20	263	70	0	192	1
2023	1,786	1,491	20	275	0	96	192	1
2024	1,801	1,492	20	289	0	96	192	2
2025	1,814	1,469	20	325	34	96	192	3
2026	1,829	1,438	20	371	0	192	192	4
2027	1,847	1,439	20	388	0	192	192	9
2028	1,832	1,433	20	379	0	192	192	14
2029	1,852	1,420	20	412	10	192	192	19
2030	1,868	1,413	20	435	0	192	240	24
2031	1,885	1,333	20	532	71	192	240	29
2032	1,902	1,201	20	681	0	384	288	33
2033	1,920	1,162	20	738	29	384	288	38
2034	1,950	993	20	937	0	576	336	42
2035	1,969	993	20	956	0	576	336	46
2036	1,988	991	20	977	16	576	336	50

**Table 4-5 from page 69 of WVPA's IRP*

WVPA is expected to submit a new IRP in November 2020.

A Statewide Perspective

Individual utilities, under Indiana law, are responsible for providing safe and reliable electric service at a reasonable cost. These utilities are also obligated to develop plans to best adapt to the changing economic and technological resource options available in the market place, subject to Indiana Utility Regulatory Commission (IURC or Commission) review. IRPs provide detailed perspectives for each utility.

While utility-specific IRPs provide important information, a broader statewide perspective is also helpful. The State Utility Forecasting Group (SUFG) is responsible under Indiana law with developing and keeping current a methodology for forecasting the probable future growth of the use of electricity within Indiana. The SUFG has both the tools and expertise to review Indiana electricity resource requirements over a multi-year planning period. A later section, *Summary* of *the State Utility Forecasting Group's Long-Term Resource Analysis,* provides an overview of the work performed by the SUFG to inform the discussion of the evolving resource portfolio from a statewide perspective.

Interpretation of IRP Results and Trends

Until recently, load growth drove utility resource acquisition decisions. But load growth has slowed markedly over the last decade and is generally projected to increase slowly or decrease slowly depending on the circumstances of the specific utility forecast. This is the case for Indiana utilities and across the MISO and PJM multi-state regions. Within this circumstance, the driver of changing resource portfolios is changing economics and technology.

The implications of the long-lived nature of coal-fired generation portfolios is amply demonstrated in the individual Indiana utility IRPs. The generation resource portfolios are evolving for all eight utilities in response to changing economics and technology, but the speed of change varies depending on utility-specific circumstances. Regardless, current plans indicate that the portfolios will continue to change well into the 2030s with increasingly less reliance on coal-fired generation under a wide range of potential futures.

A common theme in the IRPs is the need for a managed transition; meaning the utility and Commission must evaluate how quickly it can change its generation resource portfolio in response to economic signals while maintaining the capability to provide reliable and resilient electric service at the lowest reasonable cost to the retail customer. The progression of a managed transition is dependent on how comfortable the industry and policymakers are with the ability to accommodate an increasingly diverse range of resources with very different economic and performance characteristics into a coherent package.

III. EVALUATION OF RELIABILITY, RESILIENCE, AND COST EFFECTIVENESS OF RESOURCE PORTFOLIOS IN INDIANA

Before we can discuss how reliability, resilience, and the cost effectiveness of alternative resource commitments are evaluated in Indiana, it is necessary to understand what reliability and resilience each mean and how they differ with respect to the provision of bulk electric system (BES). Everyone has an intuitive understanding of the concept of reliability, but the electric industry has a specific definition that is embedded in resource planning activities and system operations.

What are Reliability and Resilience?

From the utility customer perspective, reliability means that the power is there when we turn on the switch. The North American Electric Reliability Corporation (NERC) has traditionally defined reliability from an engineering perspective as "the degree to which the performance of the elements of the system results in power being delivered to consumers within accepted standards and the amount desired."[12] This definition has two distinct pieces.

> Resource Adequacy – Having sufficient generation and transmission capacity to meet projected needs plus sufficient reserves for contingencies like forced outages of generation units and higher-than-expected demand.
>
> Security (or operating reliability) – Primarily involves the real-time operation of the power system and is defined as the ability of the BES to withstand sudden disturbances such as electric short circuits or the unanticipated loss of generation units or transmission facilities going offline.

NERC's definition of reliability encompasses aspects of resilience of the bulk power system. NERC considers resilience to embody four outcome-based, focused abilities:

a. Robustness—the ability to absorb shocks and continue operating;
b. Resourcefulness—the ability to detect and manage a crisis as it unfolds;
c. Rapid recovery—the ability to get services back as quickly as possible in a coordinated and controlled manner and taking into consideration the extent of the damage; and
d. Adaptability—the ability to incorporate lessons learned from past events to improve resilience.

[12] NERC is the Electric Reliability organization certified by the Federal Energy Regulatory Commission to develop and enforce reliability standards that provide an adequate level of reliability for reliable operation of the bulk power system and must assess the reliability and adequacy of the system.

NERC's Reliability Issues Steering Committee (RISC) goes on to say:

> Resilience is an existing part of NERC's statutory mission to assure the effective and efficient reduction of risks to the reliability and security of the grid. The RISC's examination of resilience demonstrates NERC has consistently considered aspects of resilience as part of what contributes to reliability. While a system able to withstand impacts from all risks is a difficult and costly goal to realize, it is feasible and imperative to establish an adequate level of reliability that gives due consideration to cost efficiency and effectiveness. A balance is achieved by coupling the ability to withstand impacts to certain design levels with resilience measures that are meant to mitigate risks to reliability and maintain Reliable Operation of the BPS. *(Reliability Issues Steering Committee Report on Resilience, November 8, 2018, page 12)*

Given that utilities and regional transmission organizations (RTOs) must comply with NERC reliability standards, it is reasonable to conclude that they also must comply with resilience requirements.

Responsibility for Reliability and Resilience at the Lowest Reasonable Cost
Traditionally, vertically integrated utilities, which are those that generate, transmit, and distribute electricity to retail customers, have been responsible for the provision of both the security and adequacy of the power system at the lowest reasonable cost within their monopoly service territories. The monopoly utility also was considered to be a "balancing authority," meaning the entity responsible for operating generation within its area to ensure the electricity supplied exactly matched demand second-by-second, accounting for scheduled power imports and exports. The highly interconnected nature of the power system required these vertically integrated utilities to develop a significant level of coordination and cooperation with neighboring utilities to ensure each balancing authority was operating within industry standards to maintain system reliability. The sheer number of balancing authorities across an interconnected grid created potential reliability problems because of the number of borders (or seams) over which the flow of power had to be monitored.

Utilities build or contract with generation facilities to meet their customers' projected needs and use engineering criteria such as minimum reserve margins to provide a specified level of generation reserves. The reserve margin (RM, or sometimes referred to as the Planning Reserve Margin, or PRM) can be thought of as a "safety net" of generation capacity that is in excess of what is needed to meet peak demand. The reserve margin is necessary to allow for contingencies such as planned and unplanned outages of generation units, extreme weather that increase the demand for electricity, and other reliability considerations. Utilities have numerous statistical and engineering criteria to evaluate generation resource adequacy, but these are often translated into an approximate reserve margin equivalent. Thus, a specified minimum reserve margin for planning purposes is a proxy for reliability.

Historically, utilities built transmission facilities to connect their generation facilities to load centers where the power could be delivered or distributed to their retail customers. Over time, transmission was built to connect to neighboring utilities to improve system reliability by increasing the ability to share generation while also enabling each utility to carry less generation reserves. As the transmission systems became more interconnected with neighboring utilities, utilities used transmission to buy and sell power when it was economic for them, not just to improve reliability. The build-out of transmission over decades resulted in the creation of a grid that enabled routine economic power transactions and enhanced the reliability of the electric system. The grid continues to evolve to further improve reliability and economic efficiency.

Indiana utilities have an obligation to provide sufficient generation to maintain reliable and cost-effective electric service to their customers. This is supplemented, but not replaced, by both the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM), as NERC reliability coordinators, setting minimum generation resource adequacy standards that apply throughout their broad regional wholesale markets. The RTOs set these minimums to avoid potential problems of equity and, ultimately, reliability and efficiency, as many companies are operating in different states with very different rules, all interacting in one regional power market. Individual states are still able to set higher generation resource adequacy requirements for utilities operating within their borders, but all utilities within a given RTO face the same minimum.

Transmission is regulated by both the Federal Energy Regulatory Commission (FERC) and the states.[13] Companies own, maintain, and operate the facilities with RTOs functionally operating the bulk power transmission facilities. However, planning for new or expanded transmission infrastructure, which is necessary to maintain reliability and resilience throughout the RTO footprint, is divided between the utility and the RTO. This relationship will be discussed more fully in Section V of this report.

Integrated Resource Planning – Evaluates Reliability, Resilience, and Cost-Effectiveness

By statute and rule, integrated resource planning requires each utility that owns generating facilities to prepare an Integrated Resource Plan (IRP) and make continuous improvements to its planning as part of its obligation to ensure reliable and economical power supply to Hoosiers. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans, which are always subject to continuous re-evaluation and change as the future warrants.

As discussed earlier, the overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric

[13] FERC jurisdiction extends to electric utility wholesale sales and transmission in interstate commerce, mergers and acquisitions, reliability of the interstate transmission grid through mandatory standards and the issuance of securities. Facilities used in the local distribution of electric energy are exempt from regulation by the FERC. States regulate resource planning and decisions to build or buy generation facilities.

power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible in order to respond to the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be informed by public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Flexibility is fundamental for electric service to be cost-effective in an environment characterized by rapid changes in technology, economics, commodity prices, and federal and state policies. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities employ IRPs to explore the possible implications of a variety of alternative resource decisions for the provision of economic service while meeting reliability criteria. Because of the complexities of an IRP, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting. By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolios to maintain reliable service at the lowest reasonable cost to customers.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative, as an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that affect the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

A major part of the resource planning process is the development of a long-term forecast of the demand for electricity (or energy use) by a utility's customers and the peak demand. To be resource adequate, a utility must own or have contractual control of enough resources to satisfy forecasted future loads. The IRP process focuses on developing potential resource portfolios needed to cost-effectively meet the two different types of customer needs: energy use and peak demand. Annual energy use is measured in megawatt-hours (MWh) to reflect the accumulation of electricity used over time. Annual peak demand is the measure of the highest hour of usage for the year and is measured in MW. The projected peak demand drives the aggregate amount of resource capacity needed while the level of energy consumption drives the type of resources or overall portfolio over the 20-year planning period. The IRP process considers peak load and annual energy consumption to evaluate resource choices to cost-effectively meet the projected customer load.

Utilities address system reliability and resource adequacy in the planning process by targeting an appropriate planning reserve margin (PRM) for use in the IRP models. A PRM is defined as the percentage by which the total capacity of utility system resources exceeds the forecasted peak demand. Extra capacity is necessary to ensure the supply of resources is sufficient to meet load under a variety of system conditions, such as warmer than average weather (increase in load) or an unexpected generator failure (decrease in system resources).

For most Indiana utilities, reserve requirements are set by the planning coordinator, which is MISO for most Indiana utilities. PJM sets the reserve margin for I&M and other utilities reliant on I&M's transmission system in northeast Indiana.

Coordination of Transmission Planning with IRPs

The performance of the transmission system under different resource choices is an important factor in maintaining utility reliability by ensuring energy delivery from generation to the customer. As a general rule, transmission system performance analysis is not part of the IRP model optimization, so the impact of different potential resources being located directly on the utility's transmission system, versus someplace else, is not directly evaluated. But, that does not mean the transmission aspects of resource acquisition are ignored.

It is important to evaluate transmission system limitations to ensure reliability and cost-effectiveness when analyzing different resource portfolios. One method is to evaluate the capability of the utility's transmission system to import and export power under different conditions. A transmission study can show, for example, the maximum import capability of the existing transmission system. If the import capability is inadequate for a future resource plan, additional transmission upgrades will be needed to maintain reliability. A utility must also evaluate the ability of the system to provide necessary ancillary services if reliability and resilience are to be maintained under different resource portfolios. Important ancillary services include reactive power and voltage control, short circuit strength, frequency response, and the capability to restart a generation resource without aid from outside electricity sources (also known as "blackstart" capability). Specific studies will show if additional investments in the transmission system might be needed to provide these ancillary services. If a transmission system analysis is done concurrently with the IRP, the costs of these transmission investments can be included in the IRP's evaluation of different resource portfolios.

To better assure economical service, Indiana utilities are increasingly issuing all-source request for proposals (RFPs) to compare potential resources available in the market with those resources the utility would otherwise plan to build or acquire itself. One means of limiting transmission risks in the IRP process is for the RFP to specify that qualifying proposals must be located within MISO Zone 6 (i.e., generally the state of Indiana and a northern portion of Kentucky). This generally limits utility exposure to potential transmission constraints and congestion costs associated with bids for resources not directly connected to the utility that issued the RFP. Utilities also use metrics to evaluate the performance of different resource portfolios over a range of characteristics, one of which may include how far away the resource is from the utility's service territory. The basic concept is to try to evaluate how uncertainties associated with transmission service for different resource choices can create risks for higher costs than can reasonably be accepted or hedged by the utility.

Once the IRP process is complete, a more detailed evaluation of transmission performance may be conducted after the utility has decided to enter into negotiations with a limited number of developers regarding specific project proposals. Given a specific location on the transmission system for a resource, a utility can evaluate the extent to which power may be curtailed because of inadequate transmission under diverse circumstances. As with much in resource planning, the utility and regulators must use judgment when weighing different resource performance attributes and how these uncertainties can impact costs and service reliability.

While the utility develops an IRP and evaluates the potential effects of different resource portfolios on transmission system reliability, much analysis must also be conducted by the RTO. For example, a new generation project must apply with the RTO for permission to connect to the transmission system (i.e., "interconnection"). The RTO studies the impact of the new, incremental generation on the RTO system, along with the combined impact of other proposed generation projects seeking to interconnect and allocates costs to each proposed generator for required transmission system upgrades. The costs are dependent on which other generators are currently in-service, which new generators are expected to come online (the interconnection queue in MISO, PJM, or other affected systems) the order of such interconnection requests, future planned transmission projects or upgrades, and many other factors. As such, the allocated costs for "affected system network upgrades" can, and often do, vary over time. Developers of generation projects are responsible for the costs of mitigating system impacts identified through the RTO interconnection process.

The relationship between generation resource additions by a local utility and the associated impact on transmission reliability and cost increases in complexity by the effect of similar decisions being made throughout a multi-state region by other utilities. No one utility can properly and fully consider these regional interactions. The only entity with the necessary information to conduct this type of analysis is an RTO.

Everything else equal, utilities put a premium on having generator resources connected to the local transmission system or within the same RTO planning zone. The thought is that generation resources located further away from local retail customers may be subject to greater risks of reduced output due to congestion and other problems with transmission, which can translate into higher costs for the utility and its retail customers.

Commission Oversight of the IRP Process and Utility Resource Acquisition

When a utility determines it needs to supplement its resource portfolio with a specific addition, the utility brings that need to the Commission in a formal proceeding often referred to as a request for a certificate of public convenience and necessity, otherwise known as a certificate of need.[14] In a certificate of need proceeding, a utility requests Commission approval to build, purchase, or lease a generation facility. When the

[14] See Indiana Code 8-1-8.5.

Commission determines whether a utility decision to acquire new resources is reasonable, the IRP is a key piece of evidence to demonstrate how the utility evaluated the various options and the associated risks and uncertainties. The Commission does not approve IRPs, but, rather, evaluates how well the IRP supports the specific proposed resource the utility wishes to acquire. IRPs are also important when considering the development of other resource types including energy efficiency and long-term purchase power agreements.

Utility IRPs are also reviewed outside of formal hearing processes by Commission staff under the IRP administrative rule.[15] Currently, each of the eight Indiana utilities required to submit IRPs do so on a staggered three-year cycle. When an IRP is submitted, the Commission designates the Director of the Research, Policy and Planning Division responsible for preparing a report commenting on the IRP's compliance with the requirements of the IRP administrative rule. The report is not to comment on the desirability of the utility's preferred resource portfolio or a proposed resource action in the IRP. Under the rule, the Director considers public comments from diverse stakeholders on a utility IRP in preparing the draft IRP Director's report. The Director seeks public comment on a draft Director's report before issuing a final report on a specific utility IRP.

[15] See 170 IAC 4-7 Guidelines for Integrated Resource Planning by an Electric Utility; specifically subsection 2.2.

IV. SUMMARY OF THE STATE UTILITY FORECASTING GROUP'S LONG-TERM RESOURCE ANALYSIS

The Indiana Utility Regulatory Commission (IURC or Commission) tasked the State Utility Forecasting Group (SUFG) with conducting an objective analysis of the potential ramifications of different resource combinations resulting from a range of hypothetical changes in assumptions, such as different fuel costs and the timing of retirement of coal-fired generation. The SUFG's modeling considered all resources, including coal and nuclear options, under a variety of different conditions and assumptions to inform the questions the IURC was tasked to address by the Indiana General Assembly. The results of various scenarios and sensitivities for the 20–year forecast period 2018 to 2037 are meant to be informational rather than actionable. Further, the scenarios modeled are not intended to represent specific realistic futures, but instead to move the needle sufficiently to see the impact of different factors. It should also be noted that SUFG was not asked to produce a statewide IRP. SUFG does not have the information required to construct a statewide IRP.[16]

Methodology and Scenario Evaluation Results

The modeling system, including the utilization of the state-of-the-art AURORA$_{xmp}$ electric modeling and forecasting analysis software, allows the user to select from a specified set of available options. The system is then designed to develop objective projections of electricity prices and determine the least-cost mix of future resource additions. The electricity price projections and resource selections are the primary focus of this effort.

To project electricity costs and prices, generation resource plans are developed for each utility and the operation of the generation system is simulated. These resource plans reflect "need" from both a statewide and utility perspective. Retirements of existing generation resources are based on current utility IRPs. Similarly, SUFG used the energy efficiency and demand response resource levels estimated from each utility's IRP. For the reference scenario, SUFG updated the retirements from its 2019 forecast to include Indianapolis Power & Light's (IPL's) IRP submitted in December 2019. The retirement of Hoosier Energy's Merom units are not included, since the announcement occurred too late in the process for this report.

Future electricity prices by utility and customer class are determined within the modeling system. Prices are then entered into the forecasting model to determine demand for electricity and future resource needs, as well as the attendant costs and the prices paid by customers. That is, the modeling system solves iteratively until equilibrium is reached. As a result, each scenario will have its own unique set of demand and prices, even if no outside factor inputs to the forecasting are changed.

[16] SUFG cannot perform a full statewide IRP because it lacks some necessary information. A critical limitation, for example, is that SUFG does not have necessary DSM cost data. SUFG would have to acquire DSM models, have a means to develop a statewide Market Potential Study for energy efficiency and demand response, and add staff. Similar considerations apply to other distributed energy resources.

Each of the scenarios represent a change to a set of inputs from the reference scenario. The inclusion of a national price on carbon emissions was also performed on three of the scenarios as sensitivities.

It is useful to reiterate that the assumptions used by the SUFG are intended to discover the drivers that cause changes in the resource mix and should not be construed to imply that these assumptions are a reasonable expectation of the future. To this end, the results should be regarded as informative and illustrative but not actionable for Indiana utilities. The various scenarios modeled for this report were determined by IURC staff after considering stakeholder comments and SUFG feedback. The SUFG worked with IURC staff to determine modeling approaches to each scenario. To assist the reader, all of the following scenarios should be compared to the Reference Case.

Reference Case
This scenario used the 2019 SUFG forecast as a starting point, with the primary difference being the update to unit retirements from the 2019 IPL IRP. More specifically, SUFG adjusted the scenario to account for the retirement of Petersburg Unit 1 in 2021 and Petersburg Unit 2 in 2023.

The first significant resource needs occur in 2024. The AURORA$_{xmp}$ model selects a balanced mix of natural gas combustion turbine, natural gas combined cycle, and wind capacity. Solar photovoltaic capacity is added in 2036 and 2037, the last two years of the forecast.

The following figure shows the price trajectory for the reference scenario.[17]

Figure 11 – Indiana Electricity Price Projection for Reference Scenario (2017 cents/kWh)

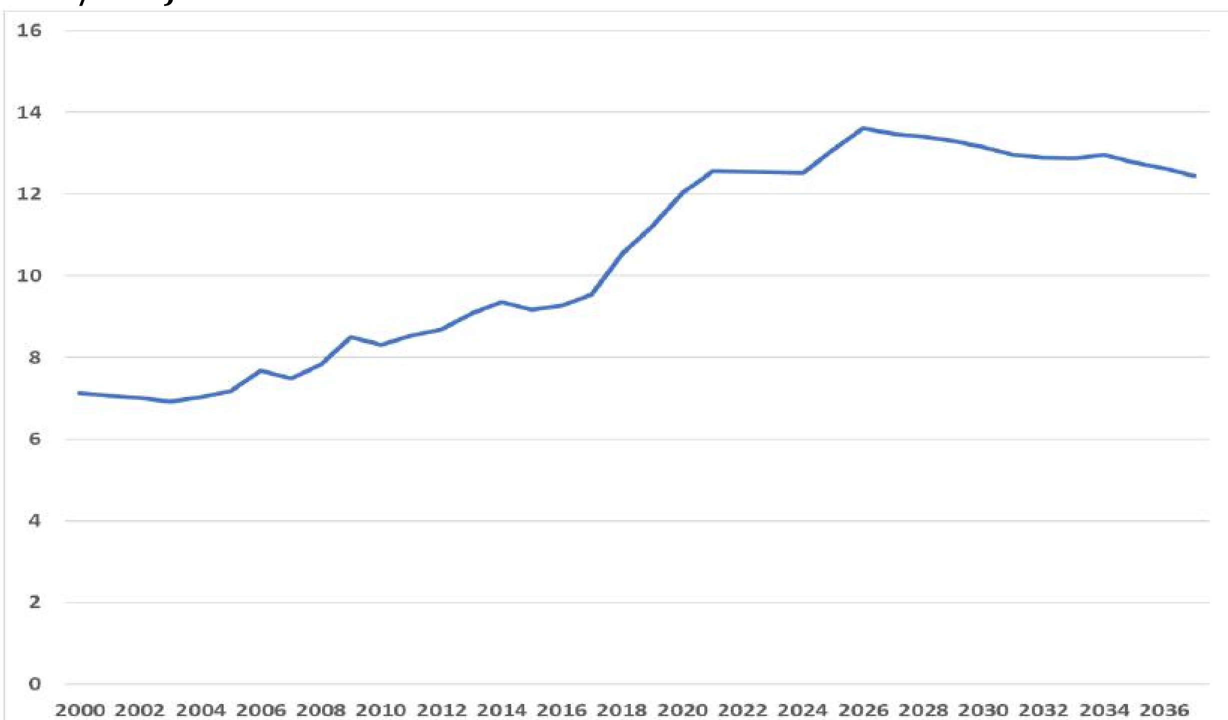


**Figure 3 from page 5 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

[17] All price trajectories provided by SUFG for the scenarios and sensitivities are an energy-weighted average across customer classes for the five investor-owned utilities. The necessary customer class information was not available for Hoosier Energy, IMPA, and WVPA.

Low Renewables Cost

The reference scenario used renewables capital cost data from the Energy Information Administration (EIA). To capture the potential impacts of lower renewable generation technology capital costs, the SUFG used cost assumptions from the National Renewable Energy Laboratory (NREL). SUFG also used a more aggressive cost reduction trajectory, also from the NREL.

Lower capital costs for renewables results in more wind and solar being selected. More than 8,200 MW of solar is selected (as compared to 579 MW in the reference scenario), with solar being added much earlier (2024 vs. 2036). Wind capacity is also higher (9.5 Gigawatts (GW)[18] vs. 5.7 GW). Between the natural gas-fired options, combined cycle additions were down significantly (3.7 GW vs. 6.0 GW), while combustion turbine additions were largely unaffected (5.1 GW vs. 5.0 GW).

Figure 12 shows the price trajectory for the low renewables cost and reference scenarios. As expected, lower capital costs for some options result in lower electricity prices.

Figure 12 – Indiana Electricity Price Projection for Reference and Low Renewables Cost Scenarios (2017 cents/kWh)

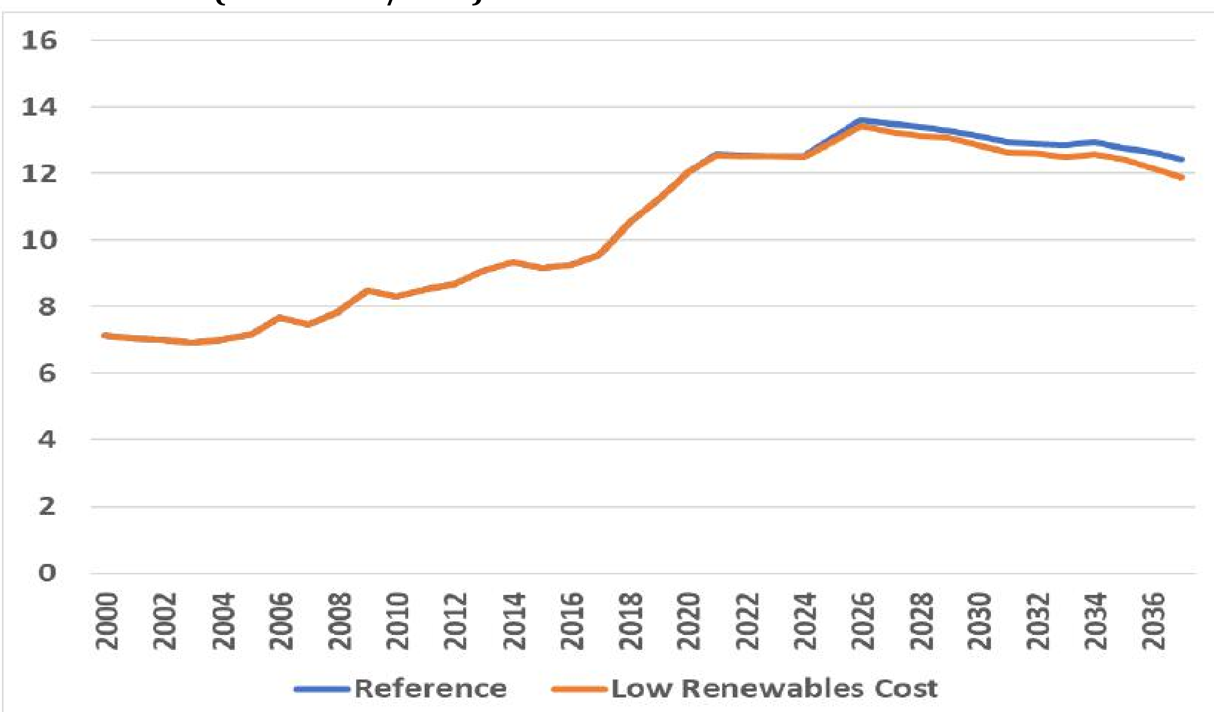


**Figure 6 from page 8 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

[18] One gigawatt equals 1,000 MW.

2025 Coal Retirement Moratorium
This entails one of two scenarios that examine the potential implications of delaying the scheduled retirement of coal-fired generators. For this scenario, coal units are not allowed to retire prior to the end of 2025 (except Duke Energy Indiana, LLC's (Duke's) Gallagher Units 2 & 4 and I&M's Rockport Unit 2). A key input to this scenario is the necessary capital investments and operating and maintenance (O&M) costs necessary to keep a unit with a planned or projected retirement prior to 2025 in commercial operation through 2025. This data was provided by all five investor-owned utilities (IOUs).

The moratorium delays the need for new resources from 2024 to 2026 but it has little long-term influence on the mix of resources selected. The model selects a balanced mix of natural gas combustion turbine, natural gas combined cycle, and wind capacity. Solar capacity is added in the last two years. These are all similar to the reference scenario.

Figure 13 shows the price trajectory for the 2025 moratorium and reference scenarios. Electricity prices are generally slightly (1- to 2%) higher in the 2025 moratorium scenario, as the costs associated with extending the life of the affected units offset the cost of the replacement capacity.

Figure 13 – Indiana Electricity Price Projections for Reference and 2025 Moratorium Scenarios (2017 cents/kWh)

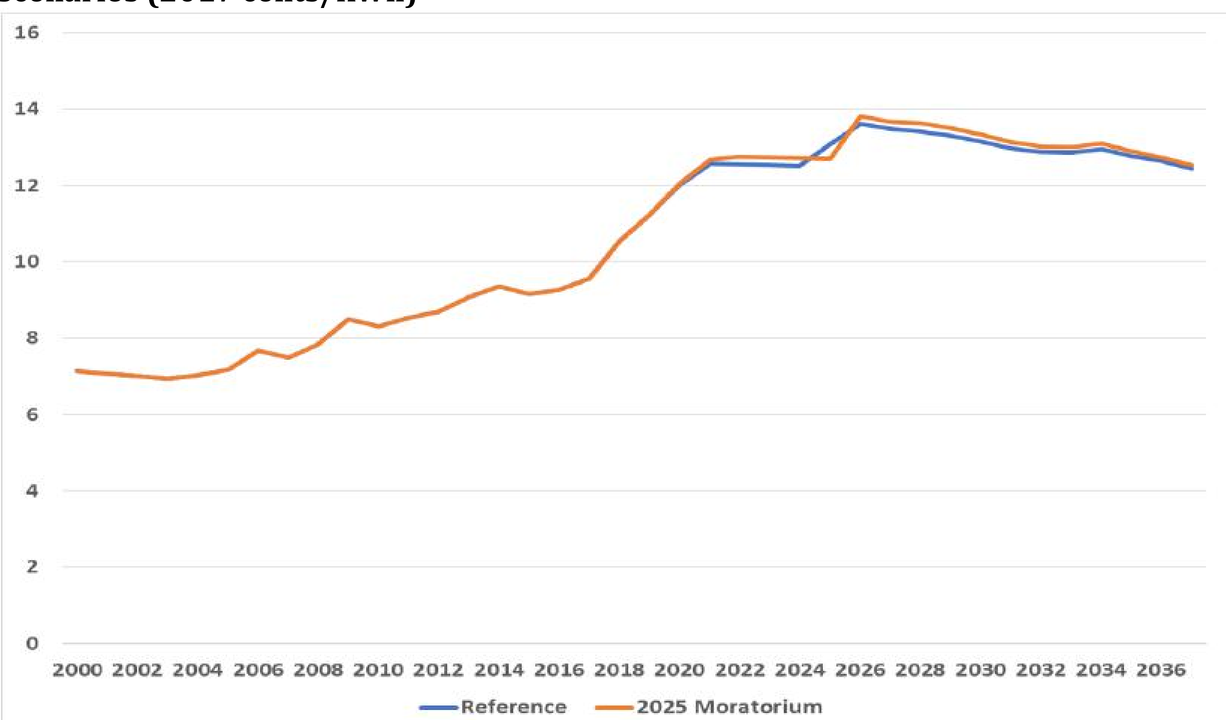


**Figure 9 from page 11 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

2030 Coal Retirement Moratorium

This scenario is similar to the 2025 moratorium scenario but extends the restrictions to coal unit retirements through the end of 2030. In addition to the three exceptions in the 2025 moratorium scenario, Rockport Unit 1 cannot operate beyond 2028 due to a Consent Decree. Utilities provided capital and O&M costs through 2030. Affected units were retired in the model at the start of 2031.

The moratorium delays resource needs to 2026, with significant new resources in 2031 when the deferred retirements occur. The mix of resources change relative to the reference scenario, with less wind (2.1 GW vs. 5.7 GW) and combustion turbines (4.3 GW vs. 5 GW) and more combined cycle generators (7.4 GW vs. 6 GW). Solar is similar to the reference case with additions occurring in the last two years.

Figure 14 shows the price trajectory for the 2030 moratorium and reference scenarios. Electricity prices are 1 to 4% higher in the short term (2021 to 2024) under the 2030 moratorium scenario and virtually unchanged in the long term.

Figure 14 – Indiana Electricity Price Project for Reference and 2030 Moratorium Scenarios (2017 cents/kWh)

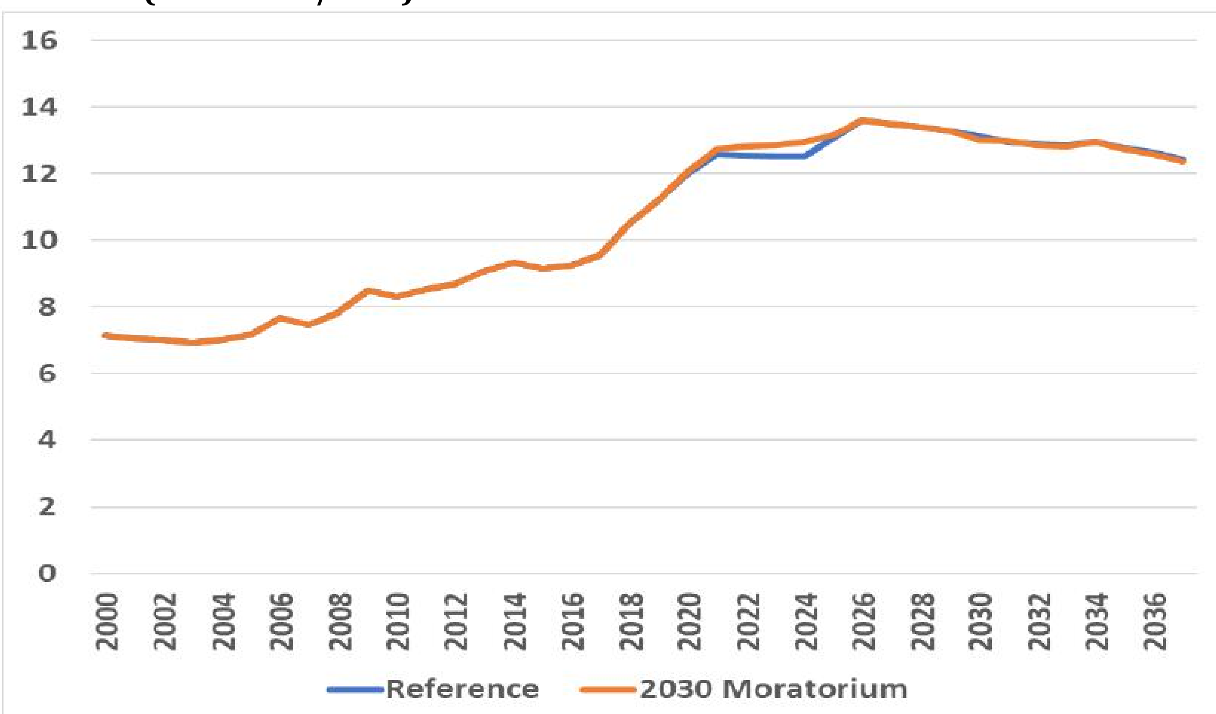


**Figure 12 from page 14 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

Additional Energy Efficiency (EE)
Modeling aggressive EE efforts by the utilities using a simplified approach was necessary since SUFG lacks information about the potential for increased EE and the resultant costs of higher levels of utility-sponsored efficiency. SUFG doubled the amount of EE identified in the IRPs at double the total cost (with the exception of Northern Indiana Public Service Company, LLC (NIPSCO) that already had very high projections of EE).

Total resources are lower than in the reference scenario due to the reduction in demand from the higher EE. This scenario had 3.3 GW compared to 5.7 GW in the reference case. Combustion turbine additions of 3.8 GW are lower than the 5 GW in the reference case. However, combined cycle units (6.3 GW vs. 6 GW) and solar (1.4 GW vs. 0.6 GW) are higher.

Figure 15 shows the price trajectory for the additional energy efficiency and reference scenarios. Electricity prices are 2 to 3% higher through 2024 as there is little avoided cost of new resources and less than 1% higher in the long term under the additional energy efficiency scenario. It should be noted that while electricity prices may be higher in this scenario, energy usage is lower for the average customer. Thus, customer bills may be lower.

Figure 15 – Indiana Electricity Price Projection for Reference and Additional EE Scenarios (2017 cents/kWh)

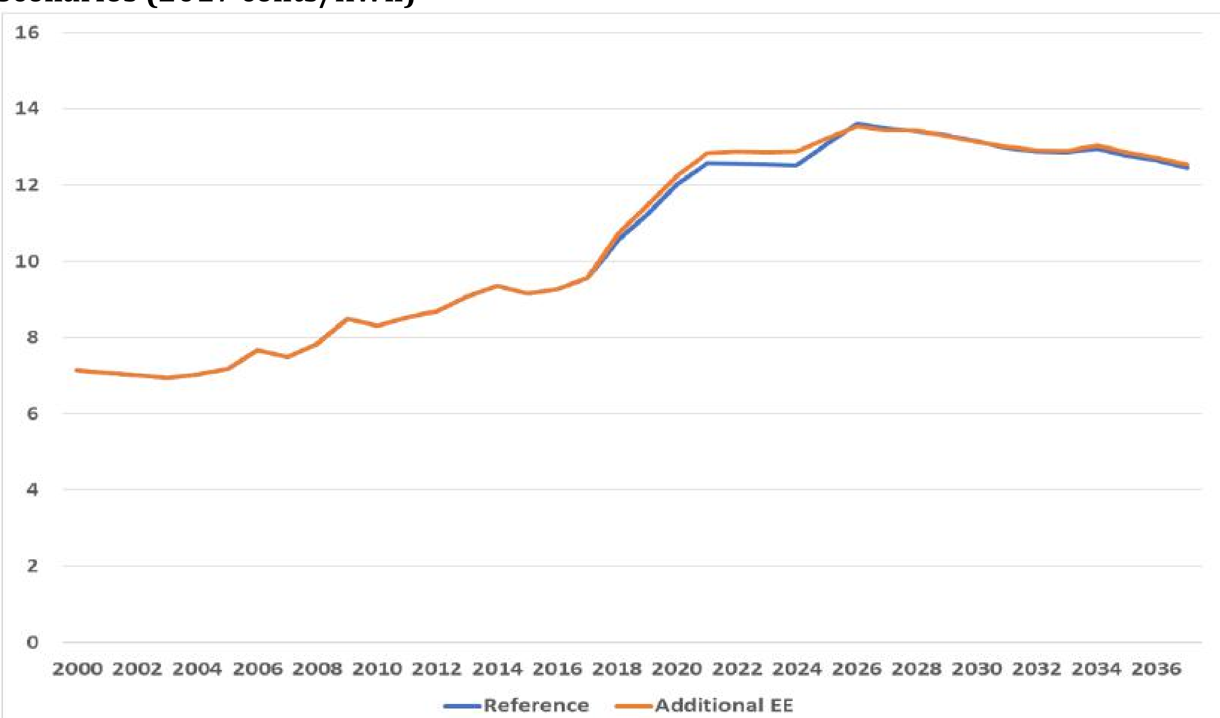


**Figure 15 from page 17 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

Industrial Self-Generation

This scenario examines potential implications of significant levels of self-generation and combined heat and power (CHP) in the industrial sector. Since future industrial self and co-generation is highly uncertain, the load forecast was reduced to completely offset future growth in industrial electricity consumption across the state's IOUs.

While overall resource needs are lower than in the reference scenario due to the reduction in demand in the industrial sector, wind capacity additions are actually higher (6.3 GW vs. 5.7 GW). Combined cycle additions are significantly lower (4.9 GW vs. 6.0 GW), while combustion turbines (4.7 GW vs. 5.0 GW) and solar (0.4 GW vs. 0.6 GW) are slightly lower.

Figure 16 shows the price trajectory for the industrial self-generation and reference scenarios. Long term prices are higher (1% in 2026 to 7% in 2037) as the reduction in sales is greater than the reduction in revenue requirements.

Figure 16 – Indiana Electricity Price Projection for Reference and Industrial Self-Generation Scenarios (2017 cents/kWh)

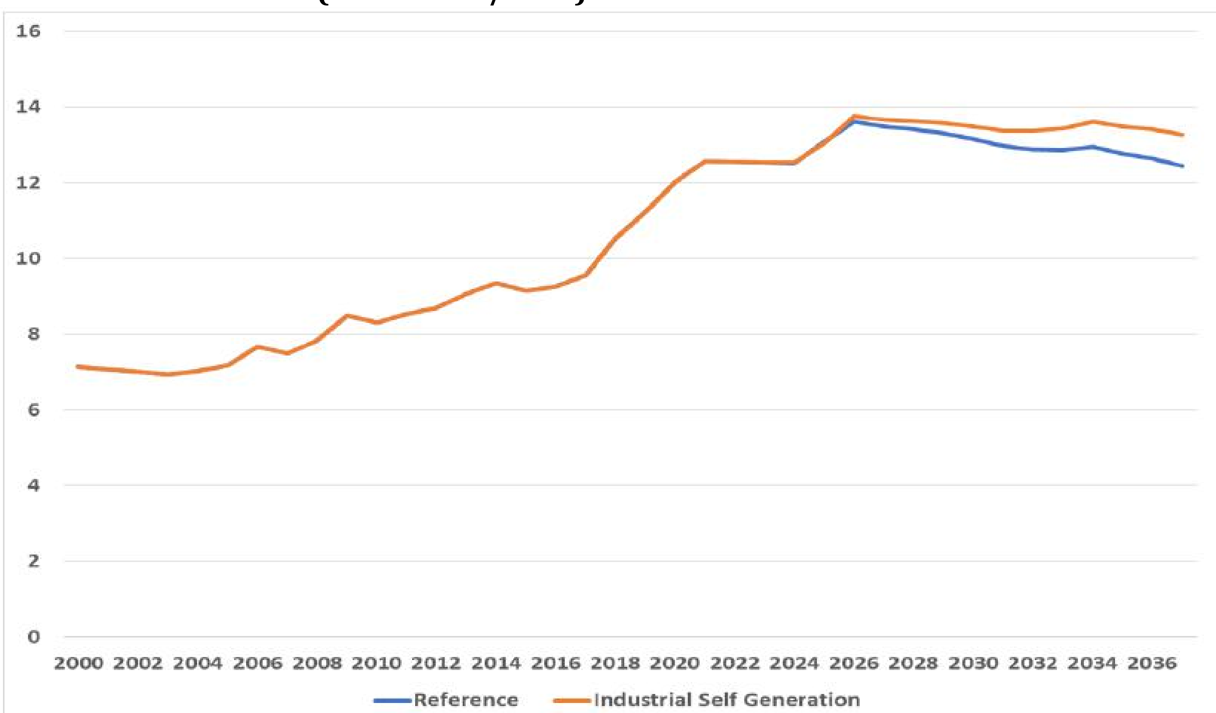


**Figure 18 from page 20 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

High Natural Gas Price
This high natural gas price future might occur if there is a long-term moratorium on hydraulic fracturing (commonly referred to as fracking). Since the price of natural gas without fracking is purely speculative, an arbitrary, very high price ($10/mmBtu) was used. Since natural gas price is an input to various models within the modeling system, such as the forecasting models, the $10 price was set for the electric utility sector. Other sectors use the same price with an adjustment for typical differences in distribution costs. For a comparison, the average gas price was $3.27 in 2018 and $2.55 in 2019. The EIA projects the average gas price to be around $2.00 in 2020 and $3.21 in 2021.[19]

The high natural gas price significantly affects the resources selected by the model. Natural gas combined cycle selections are dramatically lower than in the reference scenario (0.8 GW vs. 6.0 GW). Wind capacity is significantly higher (22.8 GW vs. 5.7 GW), with over 2 GW added as early as 2020 despite adequate resource capacity in place. Both solar (1.1 GW vs. 0.6 GW) and combustion turbine capacity (6.5 GW vs. 5.0 GW) are somewhat higher. Combustion turbines are used to supplement existing resources for times when wind output is low. It is possible that energy storage would have displaced the combustion turbines if that had been an option.

Figure 17 shows the price trajectory for the high natural gas price and reference scenarios. Prices are 1-2% higher through 2022, then increase to over 20% higher late in the analysis period.

Figure 17 – Indiana Electricity Price Projection for Reference and High Natural Gas Price Scenarios (2017 cents/kWh)

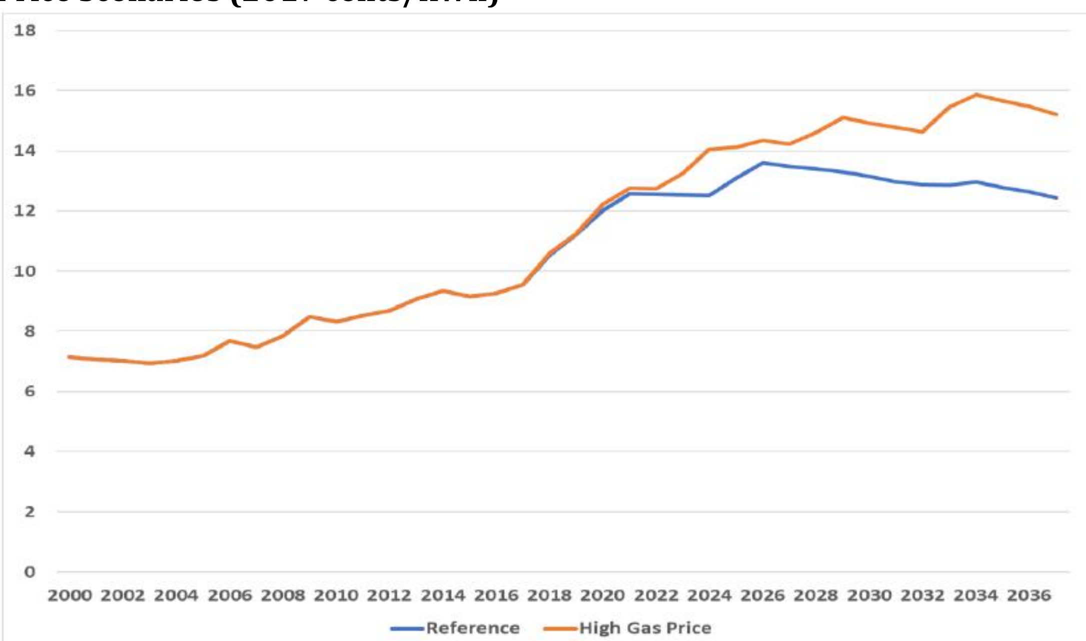


**Figure 21 from page 23 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

[19] Energy Information Administration, Short Term Energy Outlook, July 7, 2020.

<u>Carbon Price Sensitivities:</u>
In addition to the seven scenarios discussed above, three sensitivities incorporated a price on CO_2 emissions for the Reference Case, Low Renewables Cost, and 2030 Coal Retirement Moratorium scenarios. The carbon prices used in the sensitivities were developed collaboratively by the SUFG and IURC staff. The assumed carbon prices do not represent any specific proposed legislation or the result of any detailed analysis. The carbon price assumptions are intended to be in the range of prices used by Indiana utilities in the IRP process. CO_2 prices start at $2.50/ton in 2025 and increase by $2.50/ton/year every year thereafter. The same prices were used in all sensitivities.

For the Reference Scenario the imposition of a carbon price results in a significant increase in renewable capacity, with wind generation over 10 GW higher and solar additions of 3.9 GW as opposed to just 0.6 GW without a carbon price. Far less combustion turbine capacity is selected (0.6 GW vs. 5.0 GW), while total combined cycle additions are largely unchanged.

Figure 18 provides a comparison of the projected electricity prices with and without CO_2 costs for the reference scenario. The imposition of the CO_2 costs causes electricity prices to be higher. Prices in the carbon price sensitivity are 1% higher in 2025 and grow to 14% higher in 2037.

Figure 18 – Indiana Electricity Price Projection for Reference Scenario with and without Carbon Price (2017 cents/kWh)

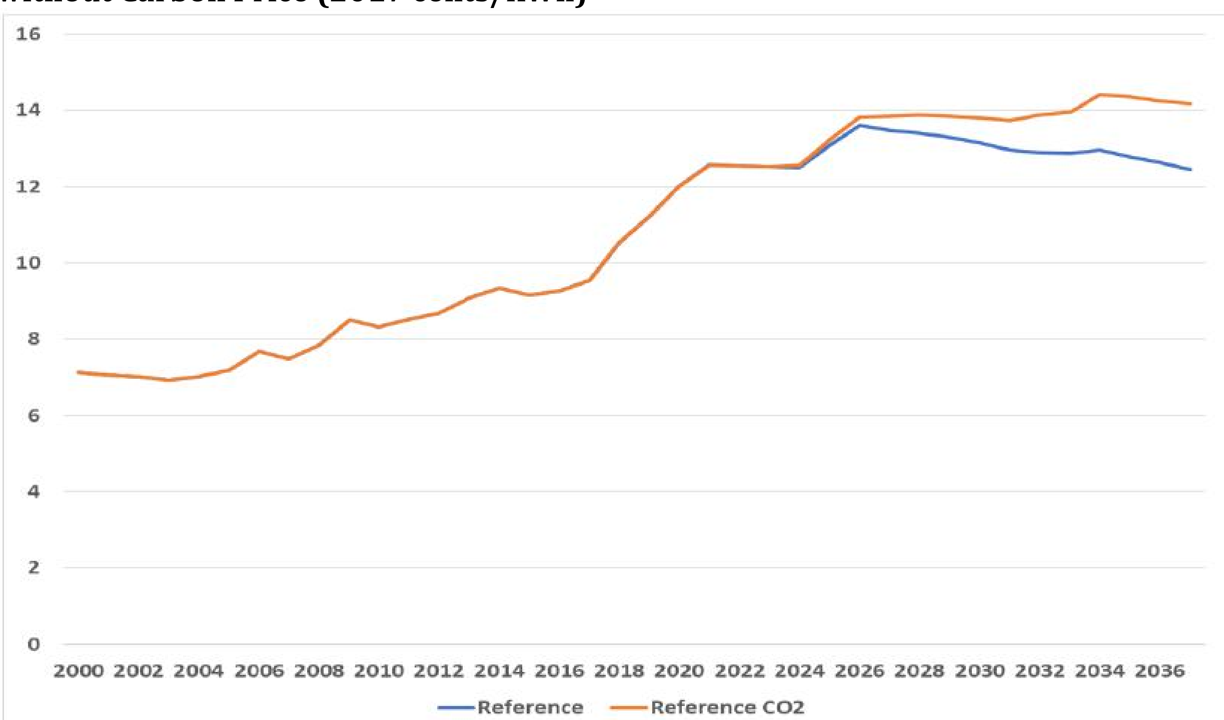


**Figure 27 from page 28 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

For the 2030 Moratorium Scenario the imposition of a carbon price has an impact similar to that seen for the reference scenario. With the carbon costs, wind capacity additions were 16.6 GW, while only 2.1 GW were added without. Solar saw 3.6 GW with carbon prices and 0.5 GW without. Only 0.3 GW of combustion turbines were chosen with the carbon prices, with 4.3 GW without. Combined cycle capacity additions were also down somewhat (6.2 GW vs. 7.4 GW).

Figure 19 provides a comparison of the projected prices with and without CO_2 costs for the 2030 moratorium scenario. The imposition of CO_2 costs resulted in higher electricity prices. Prices in the carbon price sensitivity are 2% higher in 2025, 10% higher in 2030, and 19% higher in 2037.

Figure 19 – Indiana Electricity Price Projection for 2030 Moratorium Scenario with and without Carbon Price (2017 cents/kWh)

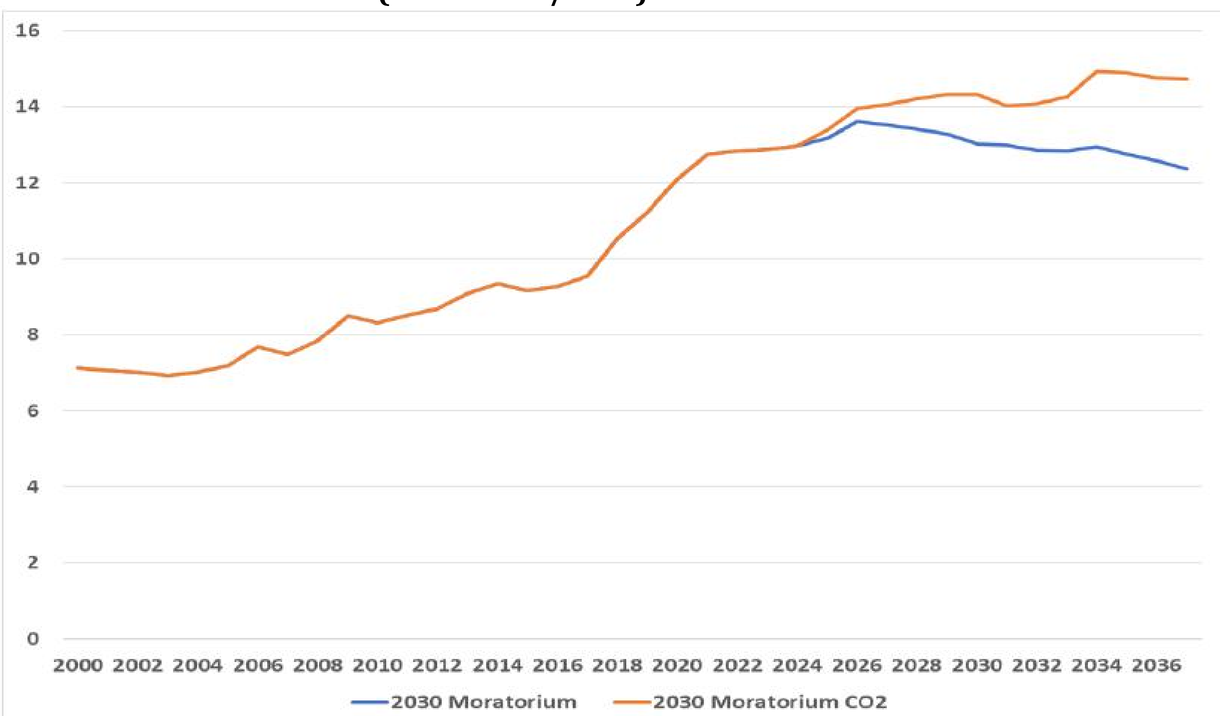


**Figure 31 from page 32 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

For the low renewables cost scenario, the inclusion of a carbon price results in an extremely large amount of wind capacity being selected (34.4 GW). A lower amount of combustion turbine capacity is selected (3.5 GW vs. 5.1 GW) and combined cycle capacity is largely unchanged. Interestingly, solar capacity is lower in the carbon price sensitivity (3.7 GW vs. 8.3 GW) as the model needs dispatchable resources to handle the intermittency of very large amounts of wind. As was the case in the high natural gas price scenario, which also saw the selection of very large amounts of wind capacity, and the availability of energy storage in the model could have resulted in a different mix.

Figure 20 provides a comparison of the projected prices with and without CO_2 costs for the low renewables cost scenario. The imposition of CO_2 costs resulted in higher electricity prices. Prices in the carbon price sensitivity are 2% higher in 2025, 10% higher in 2030, and 27% higher in 2037.

Figure 20 – Indiana Electricity Price Projection for Low Renewables Cost Scenario with and without Carbon Price (2017 cents/kWh)

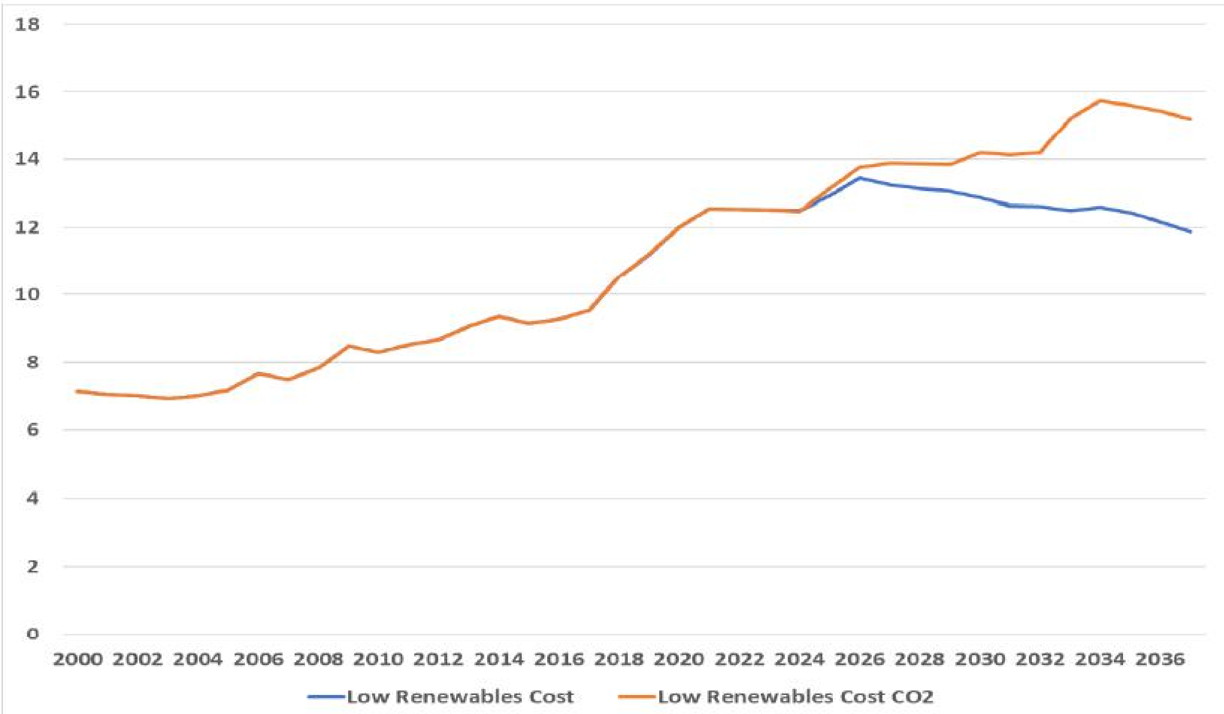


**Figure 35 from page 36 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

General Results of SUFG Analysis

Resource Selection

Future resource selections in all scenarios and sensitivities are a combination of natural gas-fired generation (combustion turbine and combined cycle), wind, and solar. Coal and nuclear were never chosen as new resources, even in the high natural gas scenario. Low renewables cost, high natural gas prices, and the imposition of carbon prices all resulted in more renewables being chosen and less natural gas generation.

Renewable Resources

Model results were highly sensitive to the price assumptions for renewable resources. While 13% of total energy in 2035 was provided by renewables in the reference scenario, that number increased to 29% in the low renewables cost scenario.

Energy from Coal

Energy derived from coal decreases over time in all scenarios due to the relatively lower cost of renewable resources and, to a lesser extent, natural gas. The imposition of retirement moratoria provides a boost to coal while they are in place, but energy from coal drops to roughly the same level in all non-carbon price scenarios (23 to 29% of total in 2035). The imposition of a carbon price results in large additional decreases in coal utilization. Energy from coal represents 6 to 9% of total in 2035 for the three carbon price sensitivities.

Natural Gas Price Impact
High natural gas prices have a very large impact on the resources selected to be developed and the extent to which these resources are dispatched to provide energy. Wind becomes the largest source of energy, producing almost half of the energy by the end of the analysis period. Energy from natural gas is about one-third of the amount in the reference case. Energy from coal is also down slightly compared to the Reference Scenario as the coal units are cycled more to adjust for the variability of wind generation.

Carbon Price Impact
An important risk consideration is the projected impact of carbon prices modeled as a sensitivity for three of the scenarios. In each of the three scenarios with carbon pricing, lower carbon prices in the earlier years tend to cause a shift from coal to natural gas-fired generation. Higher carbon prices in the later years show renewables displacing both coal and natural gas. More importantly from a risk perspective, a comparison of the projected electricity prices for each of the three sensitivities with and without carbon prices shows electricity prices to be noticeably higher under carbon prices.

The SUFG Study Limitations on Evaluating Reliability and Resilience.
Some of the scenarios and sensitivities result in a large portion of the state's energy coming from intermittent, low inertia sources like wind and solar. The SUFG's analysis does not address the operational challenges or resiliency of very high reliance on these resources.

Given these limitations, it is necessary to consider how RTOs or independent system operators help to better understand both the operational and planning impacts of changing resource portfolios across a multi-state region. Each RTO has the visibility to better understand how a changing resource portfolio across the region affects investment in incremental transmission infrastructure to enable the lowest reasonable costs for reliable electricity to be delivered to customers.

Commission Observations and Conclusions
The SUFG analysis considers both the reliability and economic aspects of changing resource portfolios in response to various scenarios which were designed with very different assumptions about the future. Because the model requires that reliability criteria be met across all scenarios throughout the planning horizon, perhaps the most informative result is seen in SUFG's comparison of the price trajectories for the seven scenarios (those not including a carbon price sensitivity). As shown in *Figure 21*, the price trajectory for each scenario over the period 2020 through 2037 is remarkably similar in shape with most differences being apparent in the 2030s. The only scenario with a price projection clearly higher than the others is the high natural gas comparison. The scenario with higher levels of industrial self-generation has projected prices somewhat higher in the 2030s than the

other scenarios with the exception of the high gas price scenario. The low renewable cost scenario had the lowest projected prices over the planning period.

These results, when viewed as a whole, indicate that Indiana's electricity price is significantly influenced by the legacy long-lived resource fleet in place today and that the future price impacts of resource policy choices made today and tomorrow will not quickly alter the price trajectory.

FIGURE 21 – Indiana Electricity Price Projection for All Scenarios (2017 cents/kWh)

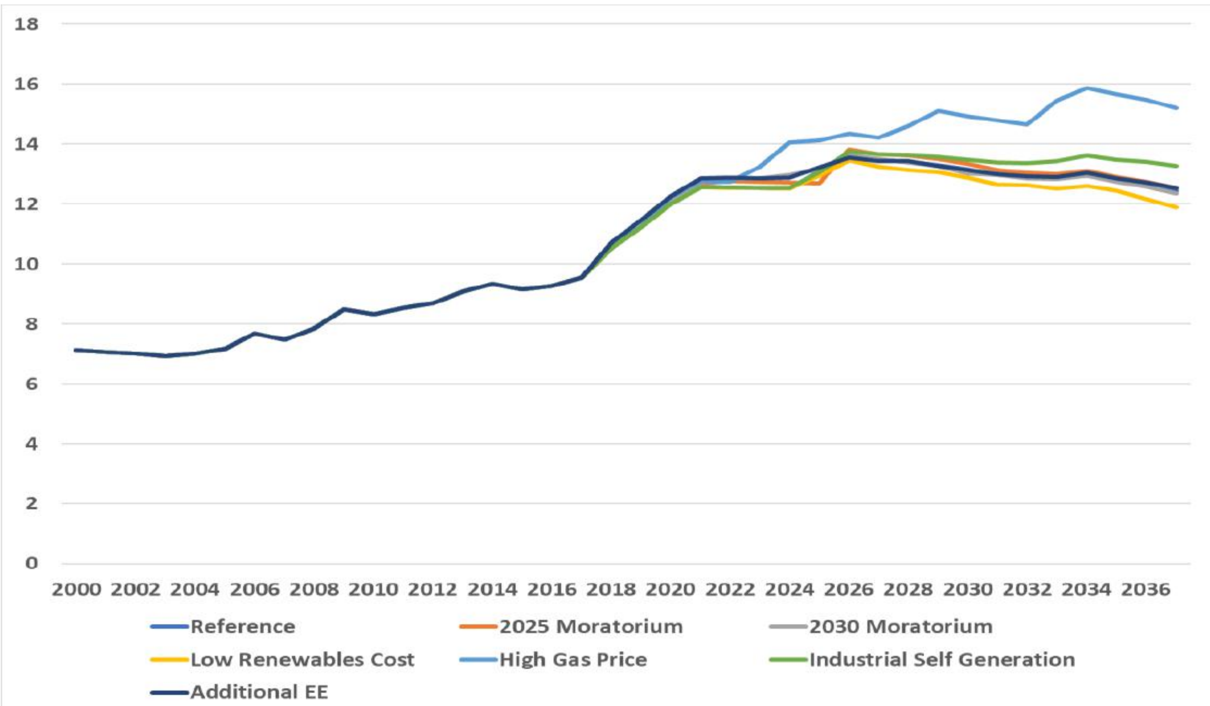


**Figure 23 from page 24 of SUFG's Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force*

A number of other general policy considerations are substantiated by the SUFG analysis:

1. The IRP process with its three-year cycle is consistent with regular evaluations of the evolution of the utility resource portfolios to changing circumstances.
2. SUFG's analysis highlights the critical impact that some variables, such as natural gas prices, renewables costs, and carbon prices, can have on the timing and type of resource commitment actions.
3. The inability to predict with any precision how these key variables will change over time underscores that maintaining optionality is critical.
4. The Industrial Self-Generation Scenario demonstrates that increased levels of customer self-generation that are mismatched with utility resource decisions can cause electricity prices for other customers to be higher than would otherwise be the case. Other customers are most likely to benefit from large industrial customers' developing self-generation facilities when the reduced customer load to be served by the utility decreases the need by the utility to add new resources in the near term.

V. RTO ROLE IN THE PROVISION OF RELIABLE AND RESILIENT ELECTRIC SERVICE AT LOWEST DELIVERED COST

A regional transmission organization (RTO) or independent system operator (ISO) is an independent entity that monitors electric reliability throughout a geographic region and is responsible for coordinating the wholesale electric transmission system in the region. When a utility company joins an RTO, it must transfer operational control, but not ownership, of its transmission system to the RTO. The dispatch of generation is the principal means by which the system operators manage the transmission grid and keep the grid within the physical limits for safe and reliable operations.

Both the Midcontinent Independent System Operator (MISO)[20] and PJM Interconnection, LLC (PJM)[21] use centralized bid-based dispatch to manage the transmission system over their regions. Centralized economic dispatch allows the generation resources throughout the regional transmission system to meet the demand for electricity at the lowest possible production cost, taking into account all transmission constraints, while maintaining reliability.

Both MISO and PJM operate highly integrated portions of the Eastern Interconnection that experience substantial flows of power between the states. The electricity flows can cause congestion on the transmission system. Congestion occurs when a transmission facility is either loaded in excess of its engineering rating for reliable operation or would be in excess of its rating in the event of a contingency. A contingency is an unplanned loss of a generation unit or plant or a significant transmission facility. The primary means of relieving congestion is to change the output of generation at different locations on the grid.

Uncoordinated and separate dispatches by different utility companies in response to congestion will not be the same as a region-wide dispatch coordinated by the RTO. The RTO is essentially acting as a single balancing authority compared to each individual utility acting as a balancing authority. The sum of stand-alone, least-cost dispatches by individual utility companies is not the same as a regional least-cost dispatch when there are transmission constraints that affect and, in turn, are affected by the dispatch of multiple utility companies throughout the region. The result of separate, uncoordinated utility dispatches is higher costs and lower overall system reliability because no individual utility has the ability (or visibility) to see the bulk power system status across the region and the

[20] Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. The fifteen states include all or portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin.
[21] PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

ability to coordinate its actions with those of the other utilities in the region. Such capability can only reside with an RTO/ISO.

Activities that Enhance System Reliability

The broad regional perspective enabled by an RTO creates the capability to improve reliability and economic efficiency of the bulk transmission system throughout the region.

State-of-the-Art Tools

RTOs have tools to observe the performance of the transmission system in their region and adjacent regions in real time. These tools monitor all transmission lines and transformers over 100 kilovolts (kV) and others that are identified as critical to maintaining reliable system operations. These tools take information from tens of thousands of points on the transmission grid, which give system operators a detailed update of the entire system every minute or so. A contingency analysis tool runs thousands of different potential scenarios every few minutes. The analysis allows transmission operators to rapidly identify changes in operating conditions and to determine whether new operating conditions require action to assure the reliability of the transmission grid.

Coordination with Adjacent Transmission Systems

While inclusion of individual utilities into RTOs reduces the number of borders or seams across which transmission systems have to be coordinated, seams remain between the RTO and other surrounding RTOs or non-RTO utilities. Both MISO and PJM have pursued arrangements to better coordinate transmission operations with bordering utility systems or RTOs. Examples include the Joint Operating Agreement (JOA) between MISO and PJM and a similar agreement between MISO and Southwest Power Pool. These agreements call for significant operational data exchange, the sharing of information regarding emergency protocols, and coordination of system planning.

The goal of coordination agreements is to reduce the reliability risks associated with these border areas. The risks are caused by poor visibility into and a lack of understanding of what is happening in the adjacent transmission system. Agreements like the JOA improve the exchange of information, clarify authority and responsibility, and specify the appropriate procedures to be implemented in specific circumstances.

Regionally Coordinated Planning of Transmission Facility Investment and Expansion

Both MISO and PJM perform regionally coordinated transmission planning that benefits the region by providing expansion decisions that are both more cost-effective and reliability-enhancing than would be the case with planning only done at the individual utility level. Given that operational and infrastructure investment actions taken by one utility impact other utilities throughout the region, a utility planning its own requirements results in transmission expansion and investment decisions that are not likely to be optimal even for that individual utility, much less the region. Individual utility company plans are unlikely to provide the optimal plan for the combined region given the highly interdependent nature of the transmission grid.

The discussion that follows treats resource adequacy and transmission planning as separate subjects but that is more for clarity of discussion. As will be seen, resource adequacy and transmission planning are interrelated, and one cannot be properly evaluated and understood without the other.

Resource Adequacy in an RTO Environment

RTOs allow for greater transfer of generation capacity resources to meet resource adequacy needs and for the exchange of energy across wide geographic distances in the real-time operation of the system. Indeed, these two benefits account for a large portion of the value proposition of the RTOs. Pooling large amounts of capacity resources across a large geographic multi-state region allows the planning reserve margin (PRM) to be lower for each utility than it would be if the utility were operating on its own.

RTOs provide a better perspective on the ability of the bulk power system to move energy into an area in real-time operations than would an individual utility performing planning on its own. RTOs accomplish this by developing local resource zones (LRZ, using MISO terminology). For example, MISO has 10 local resource zones (LRZs). LRZ 6 includes Indiana and a small segment of northern Kentucky. MISO performs an annual study, which examines the PRM for the entire RTO region necessary to maintain a specified level of reliability. The RTO also evaluates the resources within each zone and the ability to bring energy into the zone from other zones or the ability to move energy out of the zone to support other zones, if needed. The ability of the transmission system to enable these energy transfers is a key part of the study. These capacity zonal import and export limits inform stakeholders how much of their resources to serve load in their local resource zone must be located within the zone and how much can be located in other local resource zones. This allows utilities to have capacity resources located in other zones, if they determine that it is the best way to serve the zonal load. Having Indiana be in a single LRZ (with the exception of I&M, which is a member of PJM) is a critical link to utility evaluation of resource options in the IRP planning processes while taking into account policy priorities set by the state of Indiana.

The current portfolio of generation resources is a key input into the annual resources study (Loss of Load Expectations Study). The mix, location, operating performance of fossil fuel facilities, renewable resources, and demand response resources affect both the overall PRM and the capacity import and export limits between the local resource zones. MISO provides an out-year look at the import and export limits. To accomplish this, it considers how the generation mix is changing and where new generation resources are likely to be located. The generator interconnection queue of the RTO also helps to inform studies that are examining how the future may look.

RTOs are keenly aware of the resource technology transition that is occurring in the electric industry. They practice continuous improvement by studying the implications of the resource transition on their capacity constructs, reliability, and market products. RTOs, together with their wide variety of stakeholders, explore problems and the need for changes in existing constructs and markets or an entirely new requirement or market product.

MISO's Resource Availability and Need (RAN) project, for example, examines how the portfolio of capacity resources are performing on a month-to-month, day-to-day, and hour-to hour basis. The traditional industry practice that procuring enough resources to meet the summer peak day to ensure reliability throughout the year is thought to need closer examination as the composition of the generation portfolio changes with increased reliance on intermittent renewable resources. An important driver of this re-evaluation is that MISO has seen several tight supply events occur outside of the summer season, often during periods in the spring and fall when weather is unusually hot or cold combined with numerous generation units being down for planned/scheduled maintenance. Other considerations include a clearer understanding that forced outages of coal-fired and gas-fired generation facilities are more correlated with temperature and load than traditionally thought, increased seasonal operation of some resources, and increased penetrations of wind and solar. Thus, MISO and its stakeholders have developed changes designed to ensure that electricity needs are met throughout all parts of the year. The RAN currently has three areas of focus: modify the resource planning construct to better account for sub-annual risks (including reforms to the annual Planning Resource Auction), enhance resource accreditation to better align with resource availability and flexibility needs; and improve scarcity and emergency pricing to better reflect underlying system conditions.

An important complement to the evaluation of resource adequacy is a joint effort by MISO and the Organization of MISO States (OMS). Together, MISO and OMS conduct an annual resource survey of the resource owners in MISO to obtain a view into the resource situation in the upcoming years (10 years). This survey is valuable in that it allows each state to consider its own position and allows states and MISO to see the situation of the entire MISO footprint. Resource owners and utilities are continually making resource procurement decisions to ensure they meet the Planning Reserve Requirement each and every year.

The survey asks each utility to provide information as to what specific resources might be retired and when, what specific resources might be added and when, and whether these resources are included in the MISO interconnection queue and the stage. Recall the interconnection queue normally includes those resources seeking to interconnect to the MISO-operated transmission system in the next two to three years. These surveys are particularly useful because they are prepared annually while Indiana utility IRPs are normally completed once every three years. Given the rapid changes in technology and commodity market prices, it is not unusual to see significant differences between what a utility projects in generation resource additions and retirements in response to the survey and the company's projected resource portfolio in the most recent IRP. Given this circumstance, the Commission requires each Indiana utility to respond to the survey and to submit its response to the Commission.

Resource Acquisition in RTOs

Both MISO and PJM have resource adequacy constructs that employ signals, both in the form of energy prices and capacity prices, which can vary by location within the RTO region. These price signals provide important information to the industry about the relative value of capacity in different locations across the RTO footprint. The price differences help to inform the utility decision on where to locate capacity resources.

Subject to FERC approval, the RTO resource adequacy constructs have been vigorously developed by the RTOs and their stakeholders and have seen minor and major changes on a regular basis. PJM's Reliability Pricing Model (RPM) is a mandatory capacity auction. PJM allows a utility to either participate in the RPM annual auction (with periodic updates) designed to acquire resources to meet load three years into the future prior to when the resource is to provide service or to utilize the Fixed Resource Requirement (FRR) option in which the utility supplies its own capacity resource either through owning the necessary capacity or through contracts with existing resources. PJM requires all FRR participating utilities to make mandatory commitments to meet their capacity reserve requirements by providing PJM with an FRR plan three years in advance of the delivery year, similar to the three-year ahead commitment if a utility participates in the capacity auction. The RPM has seen significant changes almost annually for more than ten years and is experiencing more change in 2020. Because Indiana is not a retail choice state and the resource procurement decision is entirely up to the utility (subject to regulatory approval), Indiana utilities can choose to meet their capacity obligation with their own resources, and in general they are not subject to most of the RPM rule changes. The FRR process is used primarily by I&M as the largest Indiana utility in PJM.

The MISO resource adequacy construct is comparatively simple and has been more stable through the years, largely due to the fact that most states within MISO continue to practice traditional regulation and thus have maintained authority over the development of necessary generation resources. MISO sets a PRM requirement that each utility is expected to meet unless a state commission has set a higher reserve requirement. Each utility generally meets its resource requirement with resources it owns or has contracted for in the market. MISO runs an annual resource auction for the immediate upcoming planning year and can be considered a "residual" auction. Those utilities with resources above the reserve requirement can sell the capacity of the resource for the year to another utility that is short of the resources necessary to meet its reserve needs.

RTO Transmission Planning Processes

The focus of an RTO is to minimize the total cost of energy delivered to consumers while maintaining high levels of reliability. The total cost of electricity includes energy, generation capacity, and transmission. An important function of the RTO in the implementation of this objective is transmission planning. It is important that the RTO plan to meet the forecasted system peak demand, but it must analyze the system's ability to move bulk power from resource areas to load centers across the footprint in all hours of the day to maintain system reliability and improve resource efficiency as the resource portfolio changes. Regional planning is essential to optimize the economics and reliability of the regional bulk power system. *(MTEP 2019, page 8)*

The guiding principles of the planning process include the following:

1. Identify transmission investments that provide access to electricity at the lowest system cost.
2. Develop transmission plans that meet all applicable NERC and transmission owner planning criteria.
3. Support state and federal energy policy requirements.
4. Analyze system scenarios and make the results available to state and federal energy policy makers to provide context to inform decisions.
5. Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.
6. Allocate costs such that costs of transmission projects are roughly commensurate with the projected benefits of those projects.

Application of these principles is extraordinarily complex given the extensive uncertainty about the future with which an RTO (and the utility world more generally) must cope. Developing optimal transmission investment plans over a 20-year planning horizon is simple if one knows exactly what the future looks like. Even investment options over a three- to five-year period that seem clear are more complex when considering how these choices might be affected by developments over the remainder of the planning period.

To adequately address reliability and policy requirements, RTOs must develop plans based on a review of numerous possible futures. This is necessary because it can take 8 – 10 years from planning to operation for high voltage transmission investments, and such facilities can have operational lives well in excess of 50 years. RTOs and their stakeholders are striving to develop robust transmission plans that perform well across a range of possible futures, not just the least-cost plan under a single, specific scenario.
Planning scenarios are not intended to predict the future. Instead, the ideal is to develop a set of reasonable bookends exploring a range of plausible futures. The planning scenarios establish different ranges of economic, political, and technological changes over a 20-year planning period. Included are different assumptions about load growth, fuel prices, generator costs, retirements, and utility and state plans for future resources. *(MISO Futures White Paper, page 5)*

RTOs do not perform complete integrated resource planning, but they must still perform resource planning of a form because transmission plans depend on where load is located, where resources are located, what types of resources are located where, and how these characteristics might change over a 20-year period. For example, the retirement of generation facilities can significantly affect the reliability of the transmission system. Utilities planning to retire generation facilities are required to notify the RTO, but such notice is as short as six months. If the facility is determined by the RTO to be necessary to avoid violations of applicable NERC, regional, or transmission owner reliability and planning criteria, the RTO can require the plant owner to keep the facility operating until suitable transmission or other types of investments are completed that fix the reliability problem.

Another complication is seen in potential generator additions including the type, performance characteristics, location on the grid, and when the facility is expected to enter commercial operation. A proposed new generation facility must apply to the RTO for permission to interconnect with the transmission system. Integration of new resources often requires substantial investment in transmission upgrades, the cost of which is normally borne by the generation project developer. The RTO is only aware of those generators that are planning to enter operation in the next two to three years and, thus, seeking interconnection. However, the costs of interconnection can significantly affect which generators become operational. The possibility of higher interconnection costs can cause generators to exit the interconnection process midstream, causing additional transmission interconnection studies to be developed. Also, the interconnection queue only provides information on potential new generators and likely locations for the next few years.

Changes in Resource Portfolios Make Transmission Planning More Important
The major changes in the types of resources being deployed have caused MISO to implement a more extensive stakeholder advisory process to develop alternative futures to better inform its resource planning activities. The information gathered is to be used to model new generation expansion and forecast the optimal resource portfolio to meet the PRM requirement while meeting other constraints. The range of optimal resource choices across the diverse possible futures will inform the RTO and stakeholders as to the transmission plan that best ensures continued reliability and economic electric service. *(MISO Futures Whitepaper)*

Other Processes to Evaluate a Changing Portfolio and Transmission Planning
The MISO Renewable Integration Impact Assessment (RIIA) study is an indicative transmission study that began in 2017. Indicative means the study is for information purposes only and is not intended to result in any particular transmission projects. The RIIA seeks to find inflection points of renewable integration complexity. Inflection points are milestones where the complexity of operating the grid significantly increases. This is not to say the outcome is unmanageable or impossible, but that different and more tools would be necessary to reliably operate the MISO system. It is also important to note that the study has not yet included the emerging technology of energy storage, which could alter the conclusions of the earlier parts of the RIIA study. In the current phase of the RIIA, the results indicate that renewable integration complexity increases sharply beyond 30% renewable penetration. The complexity is assessed for four focus areas: resource adequacy, energy adequacy, operating reliability (steady state), and operating reliability (dynamics). MISO notes that grid technology needs are evolving as renewable penetration increases, which leads to an increased need for integrated planning. Types of equipment that could be needed include: a new transmission line, high-voltage direct current transmission lines, synchronous condenser, transformers, controls tuning, power system stabilizer, and a 30-minute storage battery. MISO and its stakeholders will continue to examine the implications of the RIIA study as well as monitor the changes in resource and transmission technologies to optimize choices over time.

Commission Observations and Conclusions
The bulk electric system in the Eastern Interconnection is essentially one big machine in which generation facilities have been connected to load centers through transmission facilities that evolved over decades. A generator or a major transmission facility being added to the system or suddenly going into a forced outage can impact the flow of electricity across the system for a multi-state region. In this environment, RTOs serve a critical role in the provision of reliable and economic electric service in real-time. It is the only entity with the authority and capability to monitor system conditions and take appropriate actions in response to changed system conditions.

The same benefits of superior RTO vision across the RTO region promote a more effective evaluation of economic reliability and resilience through improved understanding of both generation and transmission adequacy in the region. The implication is that the RTOs are equipped to collect the information and perform the complex analysis required to understand how increased reliance on intermittent renewable resources across multi-state regions affects the reliability and resilience of cost-effective electric service to utility retail customers.

The information collected and analysis performed by the RTOs is a critical input to Indiana utilities' resource planning processes. Similarly, the soundness of RTO planning is dependent, in part, on better understanding of individual utility resource plans and the state policies that drive these plans. Energy policy can build on the idea that better coordination of information between utilities, state policymakers, and RTOs can result in better informed decisions by all and facilitate the delivery of reliable, resilient, and cost-effective electric service.

VI. LBNL SUMMARY

Introduction
The Indiana Utility Regulatory Commission (IURC or Commission) engaged Lawrence Berkeley National Laboratory (LBNL)[22] to provide a detailed analysis of emerging technologies and their impact on generation capacity, reliability, resilience, and rates from the perspective of the electric utility distribution systems. The analysis was intended to complement the SUFG focus on the impacts to the generation and transmission components of the power delivery ecosystem.

The study explores the impacts of emergent technologies that could be deployed across Indiana investor-owned utility (IOU) distribution systems by 2025 (near-term) and 2040 (long-term). It identifies six adoption scenarios that combine deployment levels of rooftop solar (PV), electric vehicle charging (EV), and battery storage—collectively referred to as distributed energy resources (DER)—by residential and commercial customers connected to Indiana IOU distribution lines, also known as feeders. Five of the adoption scenarios implement a range of expected to optimistic deployment of these resources, while a sixth scenario is presented as a stress-test with very high adoption levels (referred to as the "Boundary" scenario). By 2040, for example, rooftop PV adoption ranges from 820 MW (Base) to nearly 6.5 GW (Boundary).

The study framework measures both the economic value and the reliability impact of DER. The analysis endeavored to answer three primary questions:

- What is the economic impact of more widespread deployment of DER within the IOU service territories?
- Do these emerging technologies lead to increased voltage violations and line losses and, if so, how can these impacts be mitigated?
- Do any of these technologies provide reliability and/or resilience benefits?

Study Methodology
There are several types of emerging technologies that are being deployed or that could be deployed in the distribution system and behind the meter. These technologies can produce electricity (e.g. solar PV panels, natural gas micro-turbines), store electricity (e.g. batteries, flywheels), consume electricity in novel ways (e.g. EVs), and improve electricity management and consumption (e.g. smart thermostats, super-efficient appliances). These technologies are grouped and identified throughout this document as DERs. Given the current landscape in Indiana and the focus of the Task Force, this study is limited to the following DERs: solar PV, battery storage, and electric vehicles, with some built-in assumptions about availability and penetration of demand response and energy efficiency.

Over the last decade, the U.S. has seen increasing uptake of customer-owned DER, particularly rooftop PV. This increase has been driven by policies, prices, consumer

[22] LBNL utilized Nexant, Inc. to support a portion of its analysis.

attitudes, and attractive financing options for customers. Penetration levels vary by state. *Figure 22* shows the percentage of small-scale PV generation as a portion of all generation by state.[23]

FIGURE 22 – Small-Scale PV Generation as a Portion of All Generation
Source: Energy Information Administration (EIA)

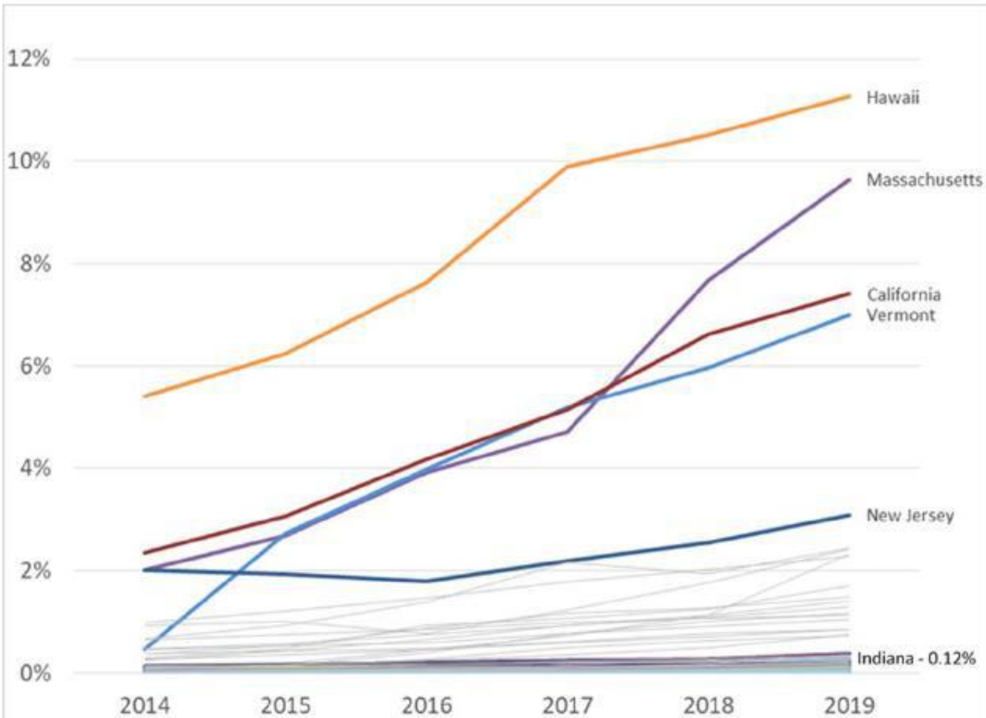


**Figure 1.1 from page 15 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

This study utilizes six scenarios based on different levels of possible future DER and EV adoption developed to explore how the distribution system would perform under different DER adoption and demand levels. DER and demand are characterized across three dimensions: PV adoption, battery storage, and system demand. Each dimension has one of three adoption levels: business as usual (BAU), high, and very high. The scenarios cover two horizons: a short-term horizon (2025) and a long-term horizon (2040).

[23] Based on the information shared by the five Indiana IOUs that are the subject of this study, the level of DER adoption varies by technology and customer class. Only 0.14% of residential customers own a PV system, while that figure is 4.7% for commercial customers. Almost no customers in Indiana own a storage system (less than 0.01%).

Table 8 summarizes the six scenarios and the proposed DER adoption category for each scenario. The colors represent adoption levels as follows:

TABLE 8 – Overview of scenarios

Scenario	Description	PV	Storage	EV (system demand)
1: Base	Reference case			
2: High Electrification	BAU DER, high demand			
3: High PV Stress Test	High PV penetration without storage breakthrough			
4: High PV and Battery Storage	High PV penetration with storage breakthrough			
5: Battery Storage Arbitrage	Storage breakthrough with BAU PV			
6: Boundary Case (Distribution system stress test)	Very High PV, storage, electrified demand			

Adoption Levels:

Business as Usual	High	Very High

**Table 2.1 from page 21 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

Table 9 reports the details of each level (BAU, High, and Very High) for each scenario dimension.

TABLE 9 – Quantitative adoption level details

Adoption Level	PV	Storage	Electric Vehicles	System Demand
BAU	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.
High	15% of customers by 2040 (Based on scenario from IPL IRP)	1% of customers by 2040	23% of vehicle stock by 2040 (Based on scenario from MISO Study)	Base Demand + EV addition
Very High	25% of customers by 2040 (Extrapolation of High Scenario)	5% of customers by 2040	68% of vehicle stock by 2040 (Based on scenario from MISO Study)	Base Demand + EV addition

**Table 2.2 from page 22 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

Figures 23 and *24* depict the expected Indiana DER installed nameplate capacity for each scenario in 2025 and 2040, respectively.

FIGURE 23 – 2025 Indiana installed DER/EV capacity by scenario

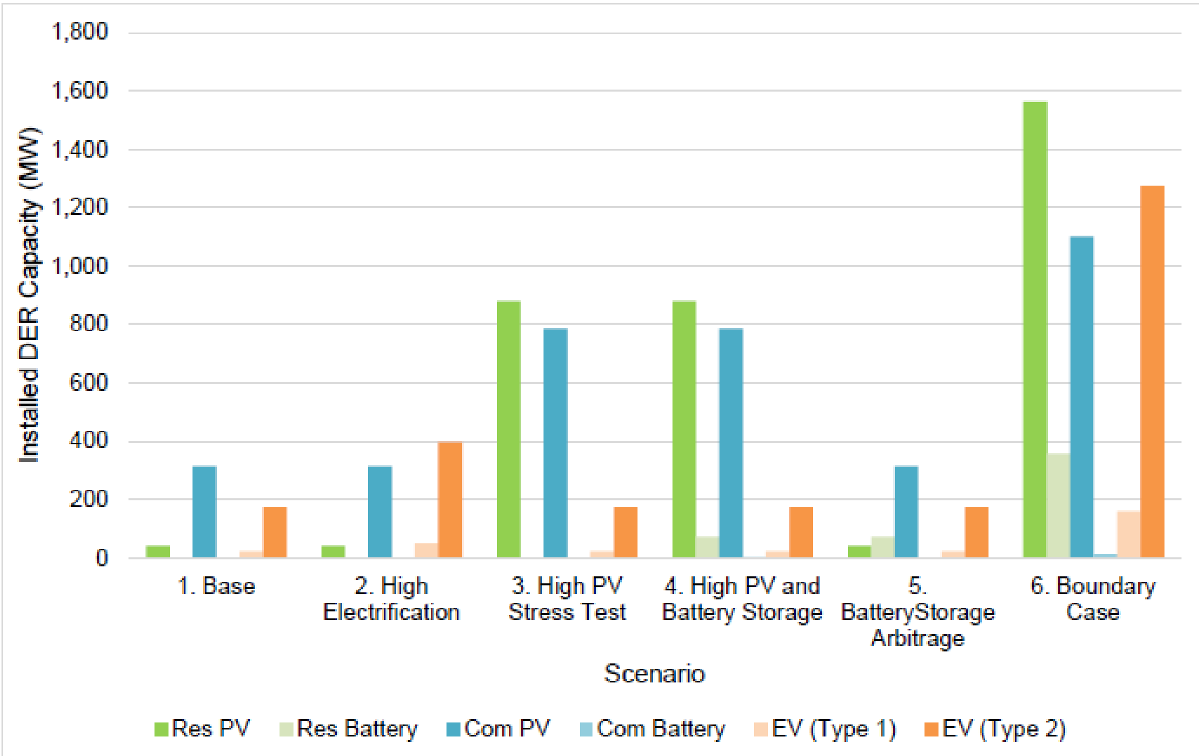


**Figure 2.6 from page 26 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

FIGURE 24 – 2040 Indiana installed DER/EV capacity by scenario

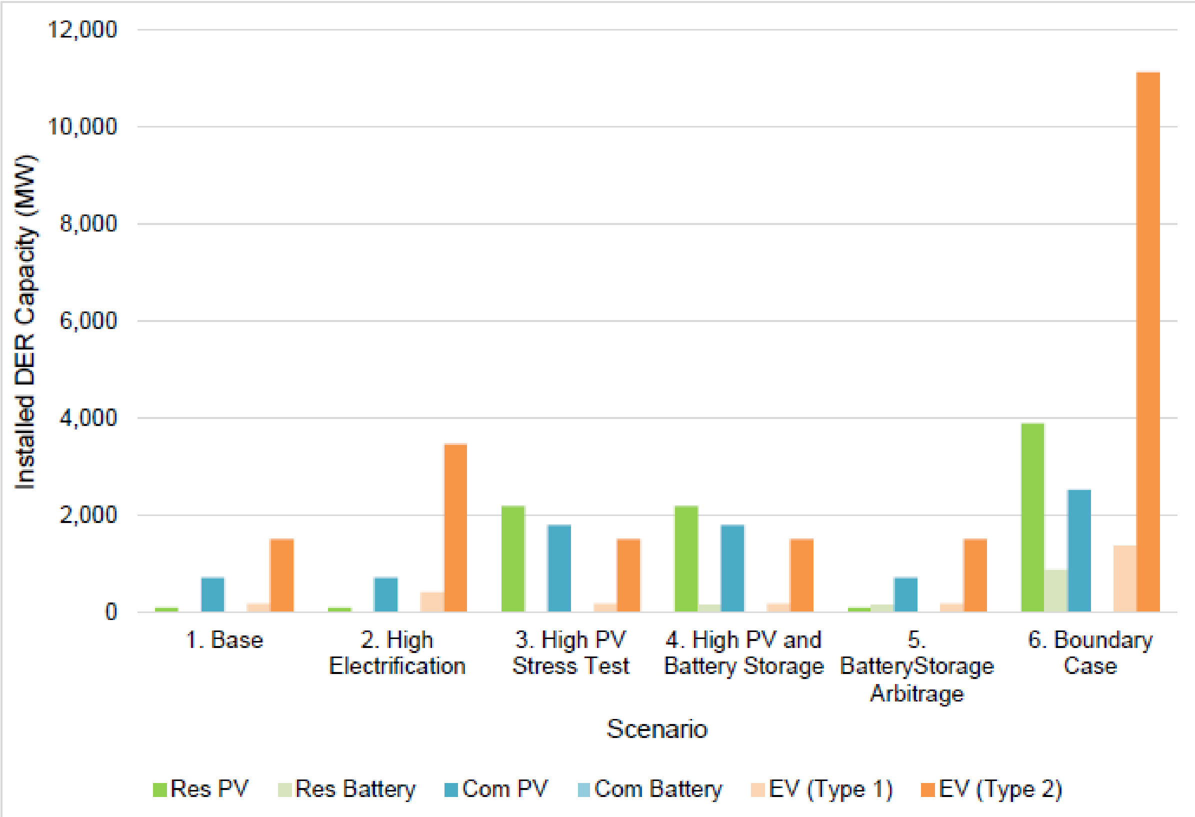


**Figure 2.7 from page 27 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

An Indiana context for the distribution system was established by classifying thousands of Indiana utility specific feeders in clusters of circuits with similar characteristics. Statistical techniques were used to classify over 2,800 feeders across Indiana into one of six groups that represent different types of feeders based on their customer mix, length, reliability, and other variables. Representative feeders from each group are selected to run power flow analyses for DER impacts on distribution systems, which can then be extrapolated to produce state-wide results. Applying the scenarios and representative Indiana specific feeders provides an empirical means to determine representative Indiana impacts.

The economic value of DER is assessed by developing capacity expansion and power flow analysis of the generation and distribution segments, respectively, under future hourly demand assumptions based on the six adoption scenarios. The assessment of generation energy and capacity impacts uses the SUFG modeling platform to simulate optimal production and expansion costs. The assessment of distribution impacts employs the industry-standard Cymdist distribution power flow model with an array of strategies to upgrade feeders to address voltage, line loading, and energy losses issues. A simplified model for transmission expansion measuring the economic impact of DER is included to allow for consideration of all three power system segments.

The reliability impact of DER adoption is measured using a pioneering method first developed for this study. LBNL used a data set of more than a half-million historical outages across the five Indiana IOUs to inform this measurement. The method simulates the impact of different levels of behind-the-meter battery storage adoption, with several operational strategies, to reduce the frequency and duration of outages from the customer's perspective. This analysis is complemented with an assessment of the impacts of DER on reducing long-duration interruptions (more than 24 hours) as an initial measure of resilience impacts on the distribution system.

Potential Economic Impact – Empirical Results

The modeling undertaken determines the potential cost and savings of the various scenarios analyzed with varying results. The estimated incremental economic impact on power system investment and operation of increased DER adoption within the IOU service territories is between -$266 million to +$106 million and -$549 million to +$1.6 billion in 2025 and 2040 relative to the Base case, respectively, with negative numbers reflecting estimated savings and positive numbers reflecting estimated costs.

TABLE 10 – Overall economic impact of DER adoption by scenario and power system segment relative to the base case (million $ 2017)[24]

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	Gen.	Trans.	Dist.	Total	Gen.	Trans.	Dist.	Total
High Electrification	$79.1	$15.8	$10.7	$105.6	$204.0	$91.3	$25.9	$321.2
High PV	-$242.4	-$32.4	$9.7	-$265.2	-$485.5	-$71.9	$8.2	-$549.2
High PV and Storage	-$242.7	-$32.4	$9.7	-$265.5	-$481.6	-$70.6	$8.2	-$544.1
Storage	$1.7	$0.0	$10.6	$12.3	$2.6	$0.0	$10.6	$13.1
Boundary	-$18.6	$27.5	$10.0	$19.0	$759.7	$734.1	$94.1	$1,587.9

**Table 5.11 from page 63 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

[24] The numbers presented in the table do not include cost incurred by the customer to acquire a DER.

In general, scenarios with high adoption of rooftop solar PV result in system-wide savings, while scenarios with high adoption and charging of EVs result in large peaks that require substantial new generation capacity and higher system costs.[25] The economic impacts of DER in the power system are concentrated in the generation segment, with about 80% of the cost impacts.

TABLE 11 – Overall incremental economic impact of DER adoption by scenario and power system segment relative to the base case (2017 cents/kWh)

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	Gen.	Trans.	Dist.	Total	Gen.	Trans.	Dist.	Total
High Electrification	0.11¢	0.02¢	0.01¢	0.14¢	0.25¢	0.11¢	0.03¢	0.39¢
High PV	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.64¢	-0.09¢	0.01¢	-0.72¢
High PV and Storage	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.63¢	-0.09¢	0.01¢	-0.72¢
Storage	0.00¢	0.00¢	0.01¢	0.02¢	0.00¢	0.00¢	0.01¢	0.02¢
Boundary	-0.03¢	0.04¢	0.01¢	0.03¢	0.96¢	0.93¢	0.12¢	2.01¢

**Table 5.12 from page 63 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

The estimated impact of DER adoption in rates was developed using the SUFG ratemaking model. Rates tend to go down in the short term for the High PV scenarios, but tend to go up for all scenarios in the long term. The increase in rates is due to a combination of lower sales that require higher rates to recover fixed costs, as well as increased peak demand that requires additional generation and transmission infrastructure investments.

TABLE 12 – Impact of DER adoption on electricity rates by scenario and customer type (2017 cents/kWh)

	2025 Rate Change Relative to Base				2040 Rate Change Relative to Base			
Scenario	Residential	Commercial	Industrial	Average	Residential	Commercial	Industrial	Average
High Electrification	0.25¢	0.24¢	0.19¢	0.22¢	-0.03¢	0.05¢	0.14¢	0.06¢
High PV	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.01¢	0.73¢	0.23¢	0.59¢
High PV and Storage	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.00¢	0.71¢	0.22¢	0.58¢
Storage	0.00¢	0.00¢	0.00¢	0.00¢	0.05¢	0.05¢	0.01¢	0.03¢
Boundary	0.52¢	0.47¢	0.18¢	0.35¢	1.88¢	1.96¢	1.46¢	1.70¢

**Table 5.13 from page 64 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

Potential Impacts on Distribution System – Empirical Results

Results for the distribution system power flow simulations show that voltage violations are relatively rare. The majority of voltage issues arise only in the Boundary case and the violations are relatively small in magnitude. Voltage violations can be mitigated at a very low cost using a combination of smart inverters in future rooftop PV systems and voltage adjustments in the feeder heads. Line loading issues are minimal and are addressed by

[25] The LBNL study did not look at rate design and how it might impact results. This is especially important for the timing of EV charging and the associated impact on utility infrastructure.

upgrading conductors at relatively low costs given the few affected segments. Line losses are approximately 4% to 10% higher than the Base case in the High Electrification and Boundary scenarios and 11% lower than the Base case in the High PV and High PV plus Storage scenarios.

TABLE 13 – Aggregate change in losses relative to base case for all IOUs (MWh)

	Annual Change in Losses Relative to Base (MWh)					
	High Electrification		High PV		Boundary	
Cluster	2025	2040	2025	2040	2025	2040
CL1	41	709	-656	-1,264	-710	10,348
CL2	306	4,478	-1,817	-3,837	-1,651	28,556
CL3	276	10,289	-2,606	-8,310	-2,861	88,606
CL4	2,005	19,655	-8,739	-13,278	-856	40,458
CL5	985	14,640	-8,310	-17,794	-6,669	39,308
CL6	0	55	-267	-401	-392	129

**Table 5.5 from page 57 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

Potential Impacts of Battery Storage – Empirical Results

Customer-sited battery storage systems can achieve multiple objectives related to improved reliability/resilience. When sized and operated appropriately, batteries can be used behind-the-meter for peak shaving or mitigating the PV 'duck curve', although their ability to mitigate power interruptions is limited. Reliability and resilience improvements are driven more by battery adoption levels than by mode of operation. The study considered battery storage adoption levels of 0.01% of customers (BAU), 1% of customers (High), 5% of customers (Very high), and 100% of residential and commercial customers (Theoretical Limit). Overall, the results show significant improvement for the customers that adopt these technologies, but modest system-level reliability improvements across the IOUs' distribution systems. The analysis assumes that the battery discharge could only be consumed behind the meter. It is possible that larger system-wide benefits could be achieved if customer-sited batteries could discharge power back to the grid under direction from utility operations staff.

FIGURE 25 – State-wide reliability changes relative to the base case for battery storage adopters under full battery mode (during normal level outage conditions and during Major Event Days (MEDs), with and without MEDs included)

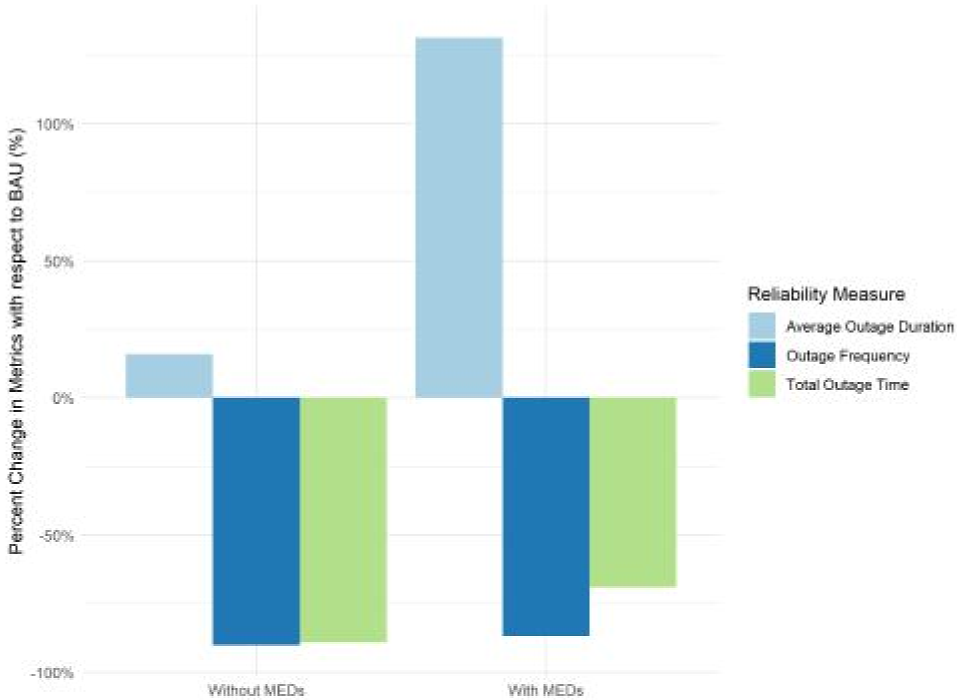


**Figure A2 from page 101 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System (in Appendix A)*

FIGURE 26 – Average state-wide SAIDI changes with respect to BAU with and without MEDs

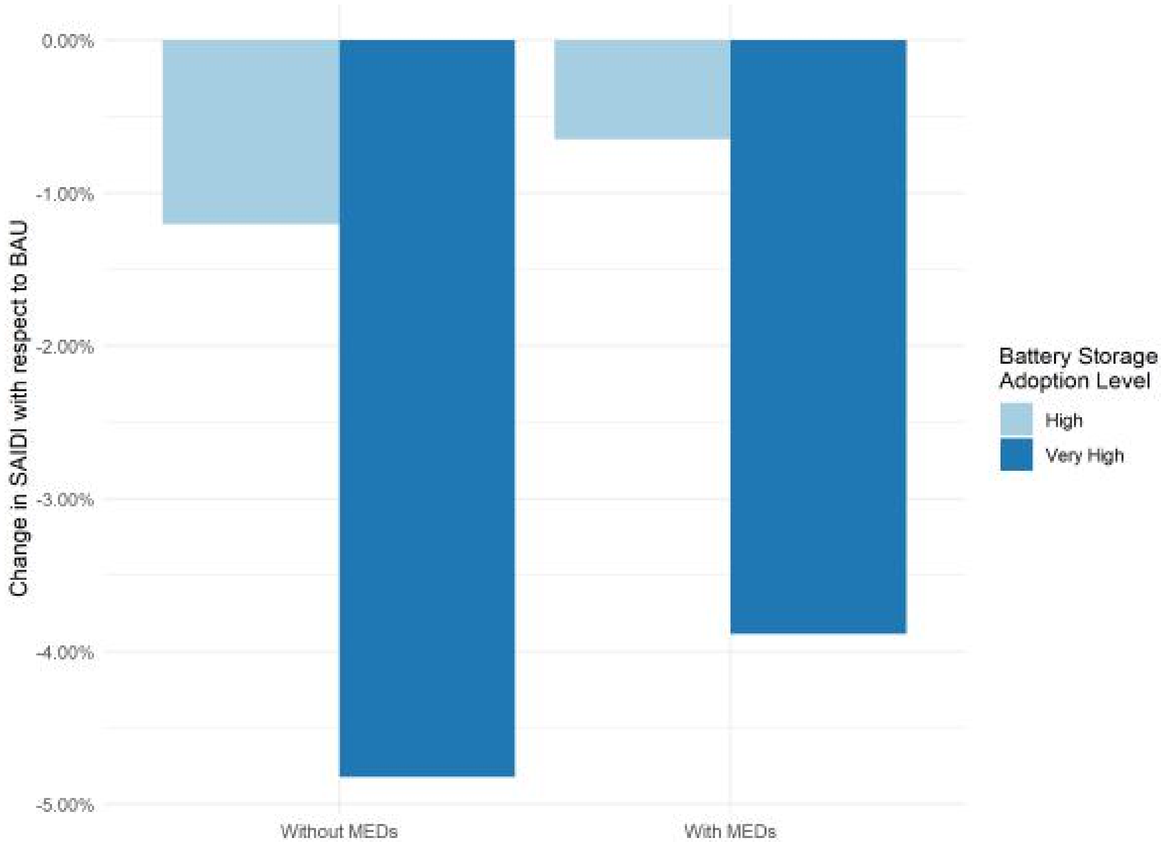


**Figure A3 from page 102 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System (in Appendix A)*

TABLE 14 – Reliability metrics under different behind-the-meter battery storage adoption levels

		Behind-the-meter Battery Storage Adoption Levels			
		BAU	High	Very High	Theoretical Limit
Without MED	SAIDI	1.66	1.64	1.58	0.18
	SAIFI	0.81	0.80	0.77	0.08
	CAIDI	2.00	2.00	2.00	2.32
With MED	SAIDI	3.09	3.07	2.97	0.96
	SAIFI	0.90	0.89	0.86	0.12
	CAIDI	2.94	2.95	2.97	6.80

**Table 5.16 from page 76 of LBNL's Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System*

Commission Observations and Conclusions

The nature of electric power system interconnectivity means that actions taken at any system component level (generation, transmission, distribution) have the ability to impact the overall system. The scale of individual actions and the specific location of those actions can reasonably be expected to impact the various components of the power system differently. The LBNL study focused on customer-scale actions at the distribution level and how the accumulation of those local actions might impact both the local distribution, often referred to in the LBNL study as the feeder level, and total system level. The study provides an important level of quantification to inform the Commission and other stakeholders as we consider the impact of emerging technologies increasingly employed at the distribution system level.

The LBNL study confirms that DER can impose technical costs to the distribution system due to their impact on voltage levels and line loading, among other impacts, and can also benefit the distribution system by reducing line and transformer losses and by potentially deferring capacity investments. Further, DER costs and benefits can also accrue at the transmission and generation levels. The LBNL study focused on a subset of possible value components including energy cost, losses, and capital deferment (capacity value).[26]

While economics are a key component in any evaluation of service solutions to meet the needs of customers, the importance of a reliable electric system is a foundational consideration that must undergird any potential solution. The LBNL study found that voltage violations, a metric of stress on the distribution system, are relatively rare and can be mitigated at a very low cost using a combination of smart inverters in future rooftop PV systems and voltage adjustments in the feeder heads. Line loading issues are minimal and can be addressed by upgrading conductors with relatively low costs given the few affected segments. A review of the LBNL study supports a conclusion that reasonable attentiveness to customer activity on the distribution system by the assigned electric utility and oversight by the Commission will ensure system reliability levels consistent with historical performance as emerging technologies are employed locally.

The LBNL study results regarding system resiliency provided important insights into how customer-sited storage benefits accrue. Viewing resilience as the capacity of a system to withstand long-duration interruptions – with a duration of over 24 hours – show that even widespread adoption of relatively large battery storage systems would still leave 60% of long-duration outages unmitigated. Further, a detailed review of the analysis identifies that the reliability/resilience benefits that do accrue do so for the benefit of customers with batteries and only provide limited system-wide benefits. The study notes this result flows from analysis limitations because it assumed that the battery discharge could only be consumed behind the meter and offered that it is possible larger system-wide benefits

[26] Due to technical and resource limitations, a number of additional value streams identified in the literature were not considered. These include DER impacts on ancillary services, fuel price hedging, and wholesale price reduction. Ancillary services such as frequency regulation can be a relevant value stream for battery storage *(Nassuato et al., 2016).* However, there is no simplified method to determine the potential contribution of DER to this value stream that could be applied within our framework.

could be achieved if customer-sited batteries could discharge power back to the grid under direction from utility operations staff. The limitation to the LBNL analysis is well founded, as the Commission's *2019 Indiana Utility Guide* acknowledges the challenge of such utility control of independent customers, noting the "reliability of the system moves from a simple command-and-control type system to one in which customers acting in self-interest play a significant role. Encouraging customer action to support system goals requires the ability to communicate timely and with accurate price signals." *(2019 Indiana Utility Guide at page 43*)

The detailed economic analysis produced through the LBNL methodology responds to the statutory directive to study the impact of emerging technologies at the distribution system level on the cost of electric utility service for customers. We begin by noting that the system-wide impacts estimated for 2025, ranging from a reduction of 0.37 cents/kWh to an increase of 0.14 cents/kWh, should be viewed in the context of an approximately 13 cents/kWh electric service cost. Accordingly, the near term system cost impacts are on the order of 1 % to 3% around such a baseline. In general, system-wide savings occur in the scenarios with high adoption of rooftop solar PV, while scenarios with high adoption and charging of EVs result in large peaks that require substantial new generation capacity and higher system costs. In the long-term analysis of the boundary case scenario we see this cost climbing over 2 cents/kWh, a result that has an impact of over 15% in the 13 cents/kWh base context. Not surprisingly, these results reveal that moderate, and perhaps slightly aggressive changes, bring what appear to be manageable and even favorable costs, while extreme changes are likely to create additional challenges to be considered.

The disaggregation of the analysis provides transparency into the cost of service impacts on a system component level. The economic impacts of distribution level DER are concentrated in the generation segment, with about 80% of the cost impacts. Accordingly, we see overall system cost benefits when customer generation increases (PV and High PV scenarios) and cost increases when system energy demand goes up (High Electrification scenario). However, customer rates are a function of both system cost and system use. So, even in the scenarios where the overall system costs decrease, the time horizon of the study and the fixed cost nature of the electric system indicate that customer rates will increase as the system use drops faster than the system cost. The reason is because a fixed cost is not an avoidable cost. In general electric rate design, some amount of fixed cost is incorporated in the variable charge component of rates. As a result, efforts that reduce usage can result in a higher variable rate in order to recover the fixed cost.

The LBNL study presents insights into the impacts of the type and pace of DER expansion that identify the ability of the distribution system to accommodate various futures and the modeled cost to do so. Customer self-generation, storage, and automotive electrification are growing, but still very nascent, trends. Proper utility planning and regulatory oversight will ensure the electric system is prepared to support and serve both participants and non-participants moving forward. The LBNL study frames the considerations stakeholders should consider to allow for an economical natural progression that balances participant choice while minimizing non-participant cost impacts.

VII. ECONOMIC, FISCAL, AND SOCIAL IMPACTS OF THE TRANSITION OF ELECTRICITY GENERATION RESOURCES IN INDIANA

As part of the Indiana Utility Regulatory Commission's (IURC or Commission) study to further evaluate the transition in Indiana's energy landscape, a team of Indiana University (IU) researchers—from the IU Public Policy Institute, the Indiana Business Research Center, and the Paul H. O'Neill School of Public and Environmental Affairs at IU—prepared an analysis of the local economic, fiscal, and social impacts of the transition in generation resources, particularly on rural communities. The report provides state and local policymakers information about the potential impact of retiring coal-fired generation and how building replacement generation will affect local communities and regions. These impacts are important to state policymakers and state and local economic development, workforce development, and other civic leaders as they craft community, regional, and statewide responses.

The research team completed three principal research elements:

- Literature reviews of current literature on the local economic and social impacts of the ongoing energy transition in the United States and Indiana.
- Assessment of potential state and local impacts of the full or partial retirement of four coal-fired power plants—Schahfer Generating Station (Schafer), Michigan City Generating Station (Michigan City), Petersburg Generating Station (Petersburg), and Rockport Generating Station (Rockport) – including interviews with local and regional stakeholders for the Schahfer and Petersburg plants. IURC, as part of this study, requested that the research team interview two to four locations, to gain some qualitative information on the impacts of closures.
- Analysis of the employment effects of planned near-term investments in wind, solar, and natural gas generation.

The results are summarized below. The research methodology, bibliography, and additional detail are provided in IU's full report.

A special note: the estimates provided in this report do not consider potential residual effects from the current economic downturn. The full extent of economic adjustment from the current downturn will not be known for several months, or longer. Therefore, the actual effects of plant closures on any county or region cannot be estimated with a high degree of confidence in the current economic environment. A more complete discussion appears in Appendix A of the full report.

Summary of Economic Impacts

The impacts of the full or partial closures of the four power plants are shown in *Table 15*. The Schahfer plant closure represents the largest loss of jobs and gross domestic product (GDP). The expected direct employment effect of this closure will be approximately 290 jobs. With a nearly equal number of ripple-effect jobs likely to be lost, the full employment impact stands at roughly 570 lost jobs and $54.1 million in lost compensation for the region. Meanwhile, the total lost GDP will reach nearly $200 million. Estimated annual state and local tax losses will be $9.7 million.

The Michigan City plant employs nearly 120 workers who earn $14.5 million in compensation. In addition to these direct effects, the supply chain purchases for this facility along with the household spending of the employees combined to support another 150 additional ripple-effect jobs for other businesses in the region. All told, the Michigan City plant's full employment footprint in the region stands at an estimated loss of 268 jobs with a total compensation loss of $21.8 million. The combined economic activity created by this generating station contributes an estimated $4.5 million to annual state and local government revenues.

The estimated economic effects from the partial closure of the Petersburg plant stand out from the other three facilities analyzed by IU because it is the only facility using Indiana coal. A partial closure of this plant will lead to an estimated loss of approximately 125 direct employees. With the loss of associated supply chain purchases and household spending, the total job loss could rise as high as 595 jobs in the region worth an estimated $44.4 million in employee compensation. Other potential economic effects from this partial closure include a total of nearly $146 million in GDP in the region and $9.6 million in annual state and local government revenues.

The estimated regional direct employment effect of the partial closure at the Rockport plant is the potential loss of nearly 120 jobs and $11.6 million in worker compensation. The ripple effects from these reductions will bring the total effects to an estimated 256 lost jobs and nearly $18 million in lost wages and benefits. Other potential impacts include a $56.1 million contribution to regional GDP and $3.8 million in state and local tax collections.

TABLE 15 – Summary of selected direct and ripple effects of full and partial plant closures

	Schahfer (full closure)	**Michigan City (full closure)**	**Petersburg (partial closure)**	**Rockport (partial closure)**
Direct effects				
Employment (2018)	293	118	125	112
Percent of county private sector employment (2018)	2.9%	0.4%	4.6%	1.9%
Counties with commuters (2018)	9	7	11	8
Total compensation (2018)	$36.1M	$14.5M	$16.0M	$11.9M
Average compensation per employee (2018)	$123K	$127K	$184K	$106K

Average county compensation per employee (2018)	$55K (Jasper) $60K (Porter)	$52K	$70K	$53K
Total goods and services (2014-2018)	$69.2M	$15.2M	$70.9M	$26.0M
Indiana goods and services (2014-2018)	$15.3M	$3.1M	$34.3M	$6.1M
Indiana counties with goods and services (2014-2018)	25	14	34	35
Annual average coal expenditures (2014-2018)	$146.1M	$40.5M	$85.5M	$144.5M
GDP	$170.4M	$65.3M	$71.7M	$46.6M
State and local tax effects	$7.5M	$3.6M	$3.4M	$2.9M
Total assessed value (assess 2019, pay 2020)	$419.2M	$135.7M	$132.7M	$396.4M
Real and personal improvements assessed value (assess 2019, pay 2020)	$386.7M	$126.3M	$127.6M	$386.2M
Plant improvements percentage of county assessed value (assess 2019, pay 2020)	15.6%	2.3%	20.4%	21.6%
Plant improvements percentage of township assessed value (assess 2019, pay 2020)	82.0%	7.0%	46.7%	63.5%
Plant improvements percentage of school assessed value (assess 2019, pay 2020)	26.9%	4.7%	10.4%	52.6%
Ripple effects				
Employees	280	150	470	140
Compensation	$18.0M	$7.3	$29.1M	$6.3M
GDP	$28.8M	$11.2	$74.1M	$9.5M
Taxes	$2.2M	$0.9M	$6.2M	$0.9M

Notes:

1. The assessed values and proportion of unit assessed values are not adjusted for the proportion of retiring capacity with partial closure.
2. The real and personal property improvements at the Michigan City plant make up 9.2% of the total Michigan City (municipal) assessed value.

**Sources: Refer to the full report.*

Employment

Among the four plants, about 650 jobs are at risk with the planned retirements. The Schahfer plant employs about 300 workers. About 120 jobs are at risk at each of the other plants. Schahfer and Michigan City employees live across the northwest region and in a few additional north central counties. Petersburg and Rockport employees live in the southwest region.

More than half of workers at each plant are between ages 45 to 64 and more than one-third of workers are between ages 25 to 44. Age is one potential indicator of whether employees will choose to remain in their communities and commute to new jobs or relocate. While younger workers might be somewhat more likely to relocate, some stakeholders in the southwest region suggested that residents are settled within their communities and, thus, more likely to remain and commute to new positions. Other stakeholders worried that employees living in Pike County will relocate, with population loss adding to the challenges faced by their rural communities. Jasper County stakeholders believed that workers who live in the county are also likely to commute.

At least three-quarters of employees at each plant were in skilled or semi-skilled positions. Ten to fifteen percent of employees were in managerial or administrative positions. Stakeholders suggested that with the tight labor markets and a number of substantial open positions in both the northwest and southwest regions, many employees will be able to find new positions. They were confident that skilled and semi-skilled plant workers could be absorbed readily within their current regions, perhaps with some additional training for semi-skilled workers. They believed that white collar workers will face more challenges finding new positions.

Employees at each of the plants earn substantially higher average wages and overall compensation than employees in each of the counties in which the plants are located. For example, average wages and the estimated average compensation per employee were $86,273 and $123,072, respectively, at the Schahfer plant. By comparison, the averages for private sector wages in Jasper and Porter counties were $42,401 and $46,392. The total estimated average employee compensations were $55,079 and $60,263 in these counties. Stakeholders suggested that replacing these premium wages and benefits may be difficult for transitioning employees. Some northwest region stakeholders suggested that some opportunities to match them may exist in the steel industry and by relocating to the Chicago area and within the northwest region.

Figure 27 – Schafer Generating Station potential employee compensation losses in Indiana from closure by zip code of employee residence (2018)

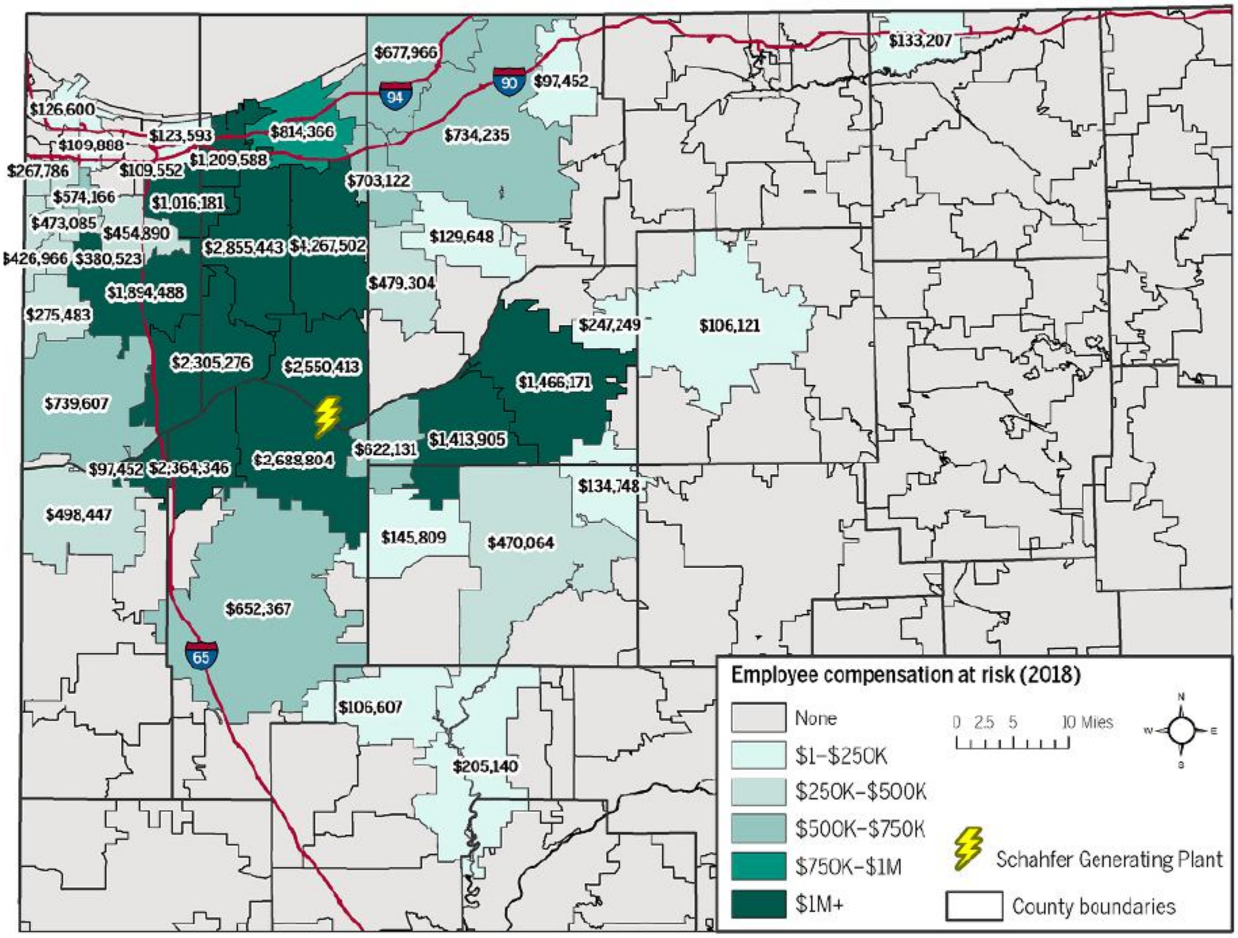


**Figure 14 from page 27 of IU's Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana.*

<u>Goods and services</u>

The average annual goods and services purchases at risk at the four plants vary. The Schahfer plant reported $69.2 million in average annual goods and services while Michigan City reported only $15.2 million. Other specialty contractors was the industry most at risk from closure.

All plants made goods and services purchases in Indiana. Among them, the most Indiana goods and services are at risk ($34.3 million) with the partial retirement of the Petersburg plant. Between $3.1 million and $15.3 million in Indiana goods and services purchases are at risk with closure of each of the other plants. These plants make purchases from firms located across Indiana. There may be some overlap in lost sales to firms with the closing of two plants in each of the two regions; however, data was unavailable to evaluate further.

Lost sales could affect firms and their employees negatively. Firms may face viability issues if sales to the plant represent a large portion of overall sales and they are not able to establish new customers. Laid off workers likely will face some of the same issues that plant employees will when transitioning.

With a large share of the supply chain spending across plants going to out-of-state vendors, modelling confirms that the industries that would suffer the biggest losses in employment in each region are maintenance, repair, and construction. These losses may be mitigated if some share of construction workers within the plant or purchases and labor associated with specialty contractors are redeployed within each company or region (see force account scenario in Appendix B of the full report).

For the Petersburg plant—the only evaluated plant utilizing Indiana coal—coal mining is among the most affected industries. The partial closure puts the purchase of 1.8 million tons of coal at an approximate value of $85.5 million at risk. In 2018, more than half of coal purchases came from mines in Gibson County, with other purchased coal coming from Indiana mines in Sullivan, Knox, Daviess, and Dubois counties. Industries that rely on household spending—such as real estate, food service, health care, and retail—account for many of the remaining industries on each list of top 10 affected industries.

Figure 28 – Petersburg Generating Station top five types of goods and services purchased, excluding coal, and potential sale losses from partial closure (2018)

**Figure 35 from page 54 of IU's Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana.*

<u>State and local taxes</u>

Modelling estimated the direct state and local tax effects of these retirements within their regions. The model predicts $7.5 million in direct annual state and local tax losses associated with the Schahfer retirement. The annual losses predicted for the Michigan City, Petersburg, and Rockport retirements are $3.6 million, $3.4 million, and $2.9 million, respectively. The model also predicts ripple effects from losses to suppliers and local businesses. The biggest indirect losses, $6.2 million, are predicted as the result of the Petersburg retirement.

The bulk of the estimated tax losses are local property taxes and local option income taxes, which are fundamental resources for local governments. The fundamental component of local government property tax revenues and fiscal well-being is assessed value. The plants located in rural contexts—in Jasper, Pike, and Spencer counties—make up a substantial portion of the total assessed value for these counties, townships, and school districts. The local governments in Jasper and Pike counties already have experienced substantial reductions in the assessed value for the Schahfer and Petersburg plants.

Table 16 – Schafer Generating Station assessed value as a share of assessed value for selected parcels and taxing units (assess 2019, pay 2020)

	TOTAL ASSESSED VALUE	SHARE OF JASPER COUNTY ASSESSED VALUE	SHARE OF KANKAKEE TOWNSHIP ASSESSED VALUE	SHARE OF KANKAKEE VALLEY SCHOOL CORPORATION ASSESSED VALUE
Parcel 006-00324-00	$38,620,400	1.6%	8.2%	2.7%
Real property improvements	$30,764,200	1.2%	6.5%	2.1%
Parcel 006-00326-00	$7,943,500	0.3%	1.7%	0.6%
Parcel 006-00327-02	$4,052,100	0.2%	0.9%	0.3%
Real property improvements	$3,205,100	0.1%	0.7%	0.2%
Personal property improvements	$352,777,190	14.3%	74.8%	24.5%
Total assessed value	$419,247,470	17.0%	88.9%	29.1%
Real and personal property improvements	$386,746,490	15.6%	82.0%	26.9%

Notes:

1. The total and personal property assessed values reported here are from the Jasper County Assessor and may include assessed value for additional parcels.
2. The certified total assessed value in Table 5 [in IU's full report] for the county, township, and school districts were used to calculate the percentages in this table.

**Table 6 from page 31 of IU's Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana.*

The property tax assessment of utilities is complex. The exact loss of property tax revenue depends on a number of factors, including levy controls, the mix of property types and property tax caps, property tax replacement strategies and other factors. These losses, however, will challenge local governments with the possible need to, increase property tax rates.

All counties in the analysis have adopted local option income taxes. These taxes are collected by county of residence. The distribution of employees across each of these regions will limit potential losses to individual counties. In addition, increasing local option income tax rates is one strategy that may be available to affected counties to replace income or property tax losses. Jasper County is the only county within these regions that has a substantial specific property tax replacement rate, limiting the adoption of an increase as a potential response.

Local responses

Stakeholders in the regions around the Schahfer and Petersburg plants generally are confident that local officials understand the severity of coming changes as the result of plant retirements and with current available information. Officials in both regions indicated that the general plans for closure have been known for some time. With the compressed timeline for the Petersburg partial closure, officials suggested that a new sense of urgency is needed. Stakeholders in both regions expressed the need for additional specific information from NIPSCO and IPL about the employees, the goods and services firms, and property taxes that will be affected by retirement. In Petersburg, they expect the recent Worker Adjustment and Retraining Notification, or WARN notice, would allow workforce officials to survey plant employees.

Stakeholders from both regions indicated that substantial local and regional efforts have been put toward preparing for the anticipated effects of closure or partial closure. For example, Jasper County convened a task force in 2019 to make recommendations for diversifying the local tax base. The committee recommended updating the county comprehensive plan and unified development ordinance (combined zoning and subdivision control), investing in quality of life projects; facilitating development around the I-65 interchanges within the county by extending utilities to those areas and adopting tax increment finance (TIF) districts; revisiting the county tax abatement policy and pursuing grant funding to support county efforts. The county and its partners are working on implementation. The Pike County Economic Development Corporation and its partners are marketing the newly-developed Southwest Indiana Megasite, a shovel ready industrial park near I-69. The Buchta Entrepreneurship and Technology Center also near I-69 is under construction and will provide support for entrepreneurs with makers, co-working, and training spaces.

Employment Impacts of Near-term Solar, Wind, and Natural Gas Generation Investments in Indiana

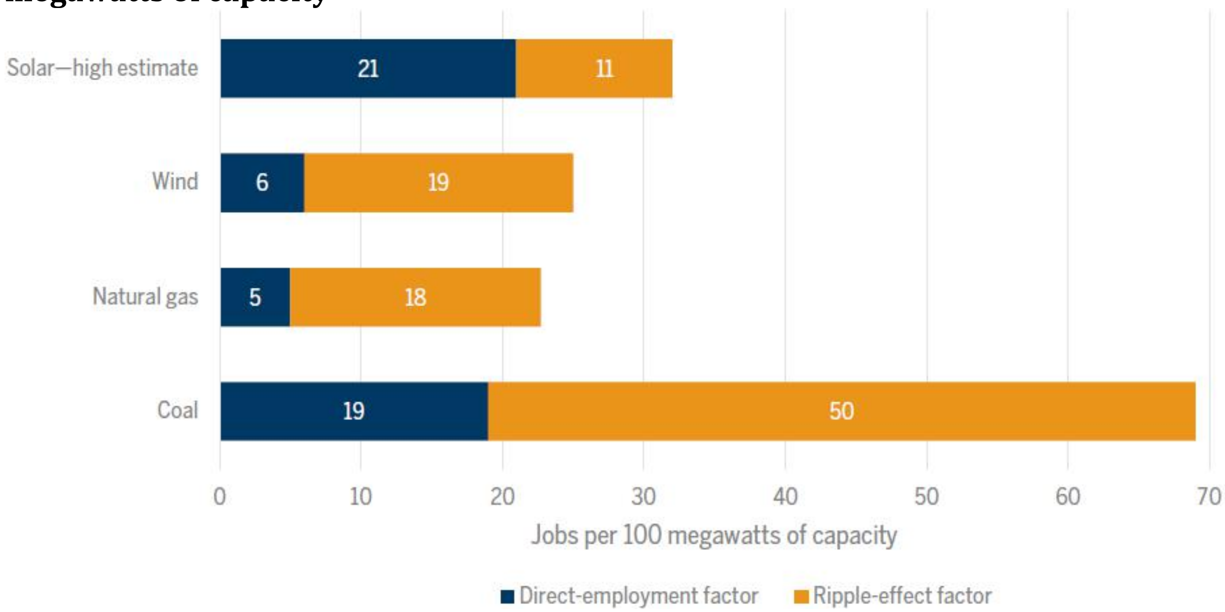
While several Indiana electric utilities are set to cut some of their coal-fired generation in the state, many have plans to expand their generation capacity for other energy sources during the next decade. This expected expansion in alternative energy sources will generate new jobs that will partially offset the job losses associated with coal-fired plant closures, although there is some uncertainty surrounding the potential size of these impacts.

The state's investor-owned electricity producers expect that Indiana's combined generation capacity of wind, solar, and natural gas energy will expand by an estimated 5,850 MW between 2023 and 2030, including 2,890 MW of solar, 950 MW of wind, and 2,010 MW of natural gas.

Table 17 summarizes the direct and indirect effects of these investments. The direct employment factor for solar energy high estimate is 21 direct jobs for every 100 MW of capacity. With an employment multiplier of 1.5, the full employment impact for solar energy generation could range as high as 32 jobs per 100 MW.[27] Meanwhile, the direct employment factors for wind and natural gas are comparatively small, but with employment multipliers greater than four for each industry, the total employment factors for these sources are 25 jobs and 24 jobs, respectively.

If Indiana experiences an expansion of alternative energy capacity in the neighborhood of 5,850 MW between 2023 and 2030, this will likely support up to 1,650 jobs in the state. If the employment impacts of these alternative energy sources reach this upper limit, it would represent 69% of the estimated statewide job losses linked to the four coal plant closures

Figure 29 – Estimated employment factors for operation and maintenance per 100 megawatts of capacity



Notes:

1. The numbers for coal production originate from IU's analysis of the four Indiana facilities covered in their report.
2. The employment factor reported by three prospective Indiana solar farms is substantially less than the high estimate reported here. IU was unable to report the specific factor due to non-disclosure issues.

**Figure 46 from page 77 of IU's Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana.*

[27] An employment multiplier is the ratio of total effects for employment to the direct effects. For example, a multiplier of 1.96, means that every direct job at a plant could lead to nearly one additional job in other industries in the region.

TABLE 17 – Potential employment effects of increased alternative energy generation

Energy type	Expected change in capacity, 2023-2030 (MW)	Total employment factor (per 100 MW capacity)	Employment change, 2023-2030
Solar	2,890	up to 32	up to 930
Wind	950	25	240
Natural gas	2,010	24	480
Total	5,850	N/A	up to 1,650

**Table 27 from page 77 of IU's Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana.*

Commission Observations and Conclusions

As a manufacturing-intensive state, Indiana has adapted to numerous economic changes that often resulted in closed plants or factories. The changes underway in the electric utility industry can produce similarly significant challenges for the communities where coal-fired generation facilities are being closed or where coal is mined. The communities where the coal generation facilities and mines are located will lose high paying jobs and tax base. Additionally, replacement generation—either renewable or natural gas—is not always sited in the same local communities that the coal-related jobs were; however, there are opportunities for renewable energy projects in these communities. Renewable energy projects generally offer large short-term, construction-based employment, as well as tax revenue and payments to landowners.

Prior to the COVID-19 pandemic, local community leaders were generally confident in the ability of their communities to adapt given the low unemployment rates and the numerous job opportunities available in other industries in the surrounding area. As the IU study notes, the actual effects of plant closures on any county or region cannot be estimated with a high degree of confidence in the current economic environment.

Economic development considerations, including local economic impacts and the changing workforce dynamics, can be included as part of Indiana's managed transition in the energy landscape as described in the preceding sections of this report.

VIII. CONCLUSION

In House Enrolled Act 1278 (2019), the Indiana General Assembly tasked the Indiana Utility Regulatory Commission (IURC or Commission) with conducting a study of the statewide impacts of transitions in fuel sources and other electric generation resources, as well as the impacts of new and emerging technologies on electric generation and distribution infrastructure, electric generation capacity, system reliability, system resilience, and the cost of electric utility service for consumers.

As part of this study, the Commission worked with the State Utility Forecasting Group (SUFG), Lawrence Berkeley National Laboratory (LBNL), and Indiana University (IU) to evaluate the statutory objectives. SUFG studied transitions in fuel sources, primarily modeling future scenarios. LBNL examined new and emerging technologies, including the potential impact of such technologies on local grids or distribution infrastructure. IU prepared an analysis of local economic, fiscal, and social impacts of the transition in generation resources, particularly on rural communities.

The electric utility industry has undergone, and continues to undergo, substantial changes in technology with particular emphasis on diverse generation technologies and institutional structures such as the formation of regional transmission organizations (RTOs). What remains a cornerstone is Indiana utilities' ongoing obligation to provide sufficient generation, distribution, and transmission capability to safely, reliably, and cost-effectively serve Indiana's retail consumers and the Commission's role in effective regulation of this obligation through these changing times.

The electric utility industry is characterized by high levels of capital-intensive and long-lived physical infrastructure. The cost-effective replacement of expensive long-lived legacy generation resources in response to changing economic forces involves complex decision-making and can only be accomplished over a significant period of time. The implications of the long-lived nature of coal-fired generation portfolios is amply demonstrated in the individual Indiana utility integrated resource plans (IRPs). The generation resource portfolios are evolving for all eight utilities in response to changing economics and technology, but the speed of change varies depending on utility-specific circumstances. Regardless, current plans indicate that the portfolios will continue to change well into the 2030s with increasingly less reliance on coal-fired generation under a wide range of potential futures.

A key statutory and regulatory tool is integrated resource planning, and a common theme in the IRPs is the need for a managed transition; meaning, the utility and Commission must evaluate how quickly the company can change its generation resource portfolio in response to economic signals while maintaining the capability to provide reliable and resilient electric service at the lowest reasonable cost to the retail customer.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum optionality or flexibility to address resource requirements. Optionality is a fundamental feature for electric service to be cost-effective in an environment characterized by rapid changes in technology, economics, commodity prices, and federal and state policies.

The results of analysis performed by the SUFG provides additional support for regular development of IRPs by Indiana utilities. The IURC tasked the SUFG with performing an analysis of the potential ramifications of different resource combinations resulting from a range of hypothetical scenarios characterized by different fuel price forecasts, changes in the cost of intermittent renewable energy resources, and the timing of retirement of coal-fired generators. The SUFG's analysis highlighted the critical impact that some variables, such as natural gas prices, renewables costs, and a price on carbon emissions, can have on the timing and type of resource commitments necessary to provide reliable and cost-effective electric service. The inability to predict with any degree of precision how these key variables will change over a 20-year planning period means that maintaining optionality is critical.

The LBNL study presents insights into the impacts of the type and pace of DER expansion that identifies the ability of the distribution system to accommodate various futures and the modeled cost to do so. Customer self-generation, storage, and automotive electrification are trends that may continue to increase, and proper utility planning and regulatory oversight will ensure the electric system is prepared to support and serve both participants and non-participants moving forward.

Indiana utility IRPs increasingly recognize that increased reliance on intermittent renewable energy resources means that the impact of any utility resource acquisition decision, on the provision of reliable and resilient service at reasonable cost, is dependent on interactions with broader changes throughout the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM) footprints. RTOs alone are equipped to collect the information and perform the complex analysis required to understand how increased reliance on intermittent renewable resources across a multi-state region affects the reliability and resilience of cost-effective electric service to utility retail customers.

Ultimately, Indiana is not an island. Electric resource decisions by Indiana utilities will affect the performance of the electric system throughout a multistate region, and the same is true for utilities in other states. Within this environment, it is incumbent that Indiana utilities and the RTOs share and effectively use the information each has to offer to the other. The Commission, with direction from policymakers at the statehouse, will continue to highlight the importance of this relationship and seek out ways to make sharing mutually beneficial information more effective.

Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force

Staff Report

State Utility Forecasting Group

May 2020

PURDUE UNIVERSITY | State Utility Forecasting Group

Executive Summary

This report is intended to provide information regarding the implications of different future outcomes of a variety of parameters, including the timing of retirement of coal-fired generators, natural gas prices, energy efficiency and customer self-generation.

Resource Selection

Future resource selections in all scenarios and sensitivities are a combination of natural gas-fired generation (combustion turbines and combined cycle units), wind, and solar. Coal and nuclear options were never chosen, even in the high natural gas price scenario. The various factors defining the scenarios altered the mix and timing of the resource additions in largely predictable fashion. For instance, low renewables costs, high natural gas prices, and the imposition of carbon prices all resulted in more renewables being chosen and less natural gas.

Renewable Resources

Model results were highly sensitive to the price assumptions for renewable resources. While 13% of total energy in 2035 was provided by renewables in the reference scenario, that number increased to 29% in the low renewables cost scenario.

Energy from Coal

Energy derived from coal decreases over time in all scenarios, which is driven by a combination of retirements of existing generators and economic competition from natural gas and renewables. The imposition of retirement moratoria provides a boost to coal while they are in place, but energy from coal drops to roughly the same level in all non-carbon price scenarios (23-29% of total in 2035). The imposition of a carbon price results in large additional decreases in coal utilization. Energy from coal represents 6-9% of total in 2035 for the three carbon price sensitivities.

Effect of Carbon Prices

In general, the lower carbon prices imposed in the earlier years, tend to cause a shift from coal to natural gas-fired generation. In 2030 for the reference scenario, energy from coal drops from 35% to 22% with the imposition of the carbon price, while energy from natural gas increases from 33% to 46%. Similarly, for the 2030 retirement moratorium scenario, coal decreases from 61% to 47% and natural gas increases from 16% to 30%. In the low renewables cost scenario, however, the shift is from coal to wind rather than coal to natural gas. Energy from coal is cut in half (from 35% to 17%) while energy from wind doubles (from 16% to 33%).

The higher carbon prices in the later years show renewables displacing both coal and natural gas. In 2035 in the reference scenario, the carbon price causes coal-fired energy to drop from 28% to 9% and for natural gas-fired energy to fall from 47% to 40%. Meanwhile, energy from renewables triples from 13% to 39%. In the 2030 retirement moratorium scenario, coal (29% to 9%) and natural gas (55% to 41%) decreases while renewables (5% to 38%) increases. For the low renewables cost scenario, the effect is more pronounced, with coal falling from 27% to 6%, natural gas dropping from 33% to 18%, and renewables increasing from 29% to 64%. Interestingly, the increase is coming from wind, with energy from solar actually decreasing from the non-carbon price scenario.

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Acronyms and Abbreviations

CO_2	Carbon dioxide
EE	Energy Efficiency
EIA	Energy Information Administration, U.S. Department of Energy
GW	Gigawatt
GWh	Gigawatthour
IOU	Investor-Owned Utility
IPL	Indianapolis Power and Light Company
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
I&M	Indiana Michigan Power Company
kWh	Kilowatthour
mmBtu	Million British thermal unit
MW	Megawatt
NREL	National Renewable Energy Laboratory, U.S. Department of Energy
NIPSCO	Northern Indiana Public Service Company
O&M	Operation and maintenance
SUFG	State Utility Forecasting Group

Foreword

This document summarizes modeling work performed by the State Utility Forecasting Group (SUFG) in support of the Indiana Utility Regulatory Commission (IURC) for their report to the 21st Century Energy Policy Task Force. While SUFG consulted with and took direction from the IURC regarding the modeling of various scenarios and sensitivities, the modeling work is solely the responsibility of the SUFG.

The work was performed using SUFG's forecasting modeling system, which was developed to produce long-term projections of electricity usage in the state of Indiana, in fulfillment of the requirements of Indiana Code 8-1-8.5. In addition to forecasts of electricity demand, the modeling system develops projections of electricity prices and determines the least-cost mix of future resource additions, given a specified set of options. The electricity price projections and resource selections are the primary focus of this effort.

Further information on the SUFG forecasting modeling system can be found in various forecast reports, which are available for free download at the SUFG website.

https://www.purdue.edu/discoverypark/sufg/

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Introduction

This report is intended to provide information regarding the implications of different future outcomes of a variety of parameters, including the timing of retirement of coal-fired generators, natural gas prices, energy efficiency and customer self-generation. It does not represent a statewide integrated resource plan (IRP), since SUFG lacks sufficient information to produce such a plan. The results of various scenarios and sensitivities are meant to be informational rather than actionable. Furthermore, the scenarios modeled are not intended to represent specific realistic futures, but instead to move the needle sufficiently to see the impacts of different factors.

First, SUFG developed a reference scenario that forms the basis of comparison to other scenarios. Each of the scenarios then represents a change to a set of inputs from the reference scenario. Furthermore, sensitivities that include a price on carbon dioxide (CO2) emissions were performed on three of the scenarios.

It should be noted that some of the scenarios and sensitivities result in a large portion of the state's energy coming from intermittent, low inertia sources like wind and solar. The analysis does not address the operational challenges of very high reliance on these sources.

Process Description

SUFG Modeling System

The SUFG modeling system explicitly links electricity costs, prices and sales on a utility-by-utility basis under each scenario. Econometric and end-use models are used to project electricity use for each major customer group — residential, commercial and industrial — using fuel prices and economic drivers to simulate growth in electric energy use. The projections for each utility are developed from a consistent set of statewide economic, demographic and fossil fuel price projections. Detailed information for the economic, demographic and fuel price inputs are provided in Chapter 4 of SUFG's 2019 forecast report.[1]

In order to project electricity costs and prices, generation resource plans are developed for each utility and the operation of the generation system is simulated. This is done using the Aurora model from Energy Exemplar. These resource plans reflect "need" from both a statewide and utility perspective. It should be noted that energy storage is not included as an option for future resources due to resource limitations. SUFG has not had sufficient time to learn Aurora's energy storage modeling capabilities.

Retirements of existing generation resources are taken from currently filed utility IRPs. For the reference scenario included here, SUFG updated the retirements from the 2019 forecast to reflect the retirements included in the Indianapolis Power & Light (IPL) IRP filed in December 2019. The retirement of Hoosier Energy's Merom units are not included, since the announcement occurred too late in the process for this report.

Future electricity prices by utility and customer class are determined within the modeling system based on the cost of supplying electricity and the amount of electricity sales. These prices are then used as an input to the forecasting model. Prices affect the electricity demand, which in turn affects future resource needs, which affects costs, which affects price. Thus, SUFG solves the modeling system

[1] https://www.purdue.edu/discoverypark/sufg/docs/publications/2019%20forecast%20final.pdf

iteratively until equilibrium is reached. This means that each scenario will have its own unique set of demand and prices, even if no exogeneous inputs to the forecasting models were changed.

Utility-sponsored energy efficiency (EE) program and demand response information were estimated from utility IRP filings and from information collected directly from the utilities by SUFG. Note that the EE and DR estimates were not changed to include the IPL IRP. See Chapter 4 of the SUFG 2019 forecast report for more information on EE and demand response modeling.

Scenario Development

The various scenarios modeled for this report were determined by IURC staff with some stakeholder and SUFG input. SUFG worked with IURC staff to come up with modeling approaches to each scenario. The following scenarios were modeled and run through the SUFG modeling system.

- Reference
- Low renewables cost
- 2025 coal retirement moratorium
- 2030 coal retirement moratorium
- Additional EE
- Industrial self-generation
- High natural gas price

In addition, sensitivities were run incorporating a price on CO2 emissions for the reference, low renewables cost, and 2030 coal retirement moratorium scenarios.

Reference Scenario

Scenario description

The reference scenario uses the base scenario from the 2019 SUFG forecast as a starting point, with a few changes to the inputs. The description here will focus on those changes with the reader directed to the forecast report for more specific information on the 2019 base scenario.

The primary change between the 2019 base scenario is the update to unit retirements from the 2019 IPL IRP. Since the IRP was released after the forecast report was published, IPL unit retirements in the 2019 base scenario were based on the most recent IPL IRP at the time, which was released in 2016. Of particular interest are the retirements of Petersburg Unit 1 in 2021 and Petersburg Unit 2 in 2023. SUFG adjusted future capital and operating expenses associated with the retiring units based on utility-provided information. Additional adjustments were made to some modeling considerations to allow comparison across scenarios (e.g., annual maximum build constraints by utility and technology were relaxed).

The reference scenario serves as the primary point of comparison for the other scenarios.

Results

The resources selected by the Aurora model are shown in Table 1. The first significant resource needs occur in 2024. The Aurora model selects a balanced mix of natural gas combustion turbine, natural gas combined cycle, and wind capacity. Solar photovoltaic capacity is added in the last two years. While new coal-fired and nuclear-powered options were available, they were not selected in any of the scenarios.

Table 1. Indiana Resource Plan for Reference Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,313	25,175	-96	0	0	0	0	0	0
2020	19,325	25,429	254	0	0	0	0	0	0
2021	19,180	25,288	-141	0	0	0	0	0	0
2022	19,135	25,433	145	0	0	0	0	0	0
2023	19,100	23,688	-1,744	0	0	23	0	0	23
2024	19,210	21,347	-2,341	1,534	389	1,726	0	0	2,114
2025	19,305	21,348	1	1,646	411	1,818	2,884	0	5,113
2026	19,242	20,522	-826	2,397	787	2,089	5,449	0	8,324
2027	19,297	20,523	0	2,462	884	2,126	5,696	0	8,705
2028	19,342	19,398	-1,124	3,640	1,505	2,136	5,696	0	9,337
2029	19,415	17,775	-1,623	5,349	1,810	2,970	5,696	0	10,476
2030	19,659	17,370	-405	6,046	2,363	3,113	5,696	0	11,173
2031	19,831	17,258	-112	6,362	2,594	3,199	5,696	0	11,489
2032	20,015	16,846	-412	6,994	3,191	3,233	5,696	0	12,120
2033	20,209	15,136	-1,710	8,935	4,209	4,157	5,696	0	14,062
2034	20,399	13,496	-1,640	10,801	4,971	5,261	5,696	0	15,928
2035	20,688	13,286	-210	11,355	4,971	5,815	5,696	0	16,482
2036	20,904	13,236	-50	11,662	4,971	5,880	5,696	347	16,893
2037	21,149	13,211	-25	11,979	4,971	6,034	5,696	579	17,280

Figure 1 shows the energy mix by fuel source through the 20-year forecast horizon while Figure 2 shows the same information on a percentage basis for 2020, 2025, 2030, and 2035. Generation from coal declines by roughly 50% over time, with natural gas generation tripling. It should be noted that these figures exclude energy acquired through purchased power agreements, which is presently the manner in which Indiana utilities acquire wind energy. Thus, no wind energy is shown until the first Aurora-selected wind addition in 2025.

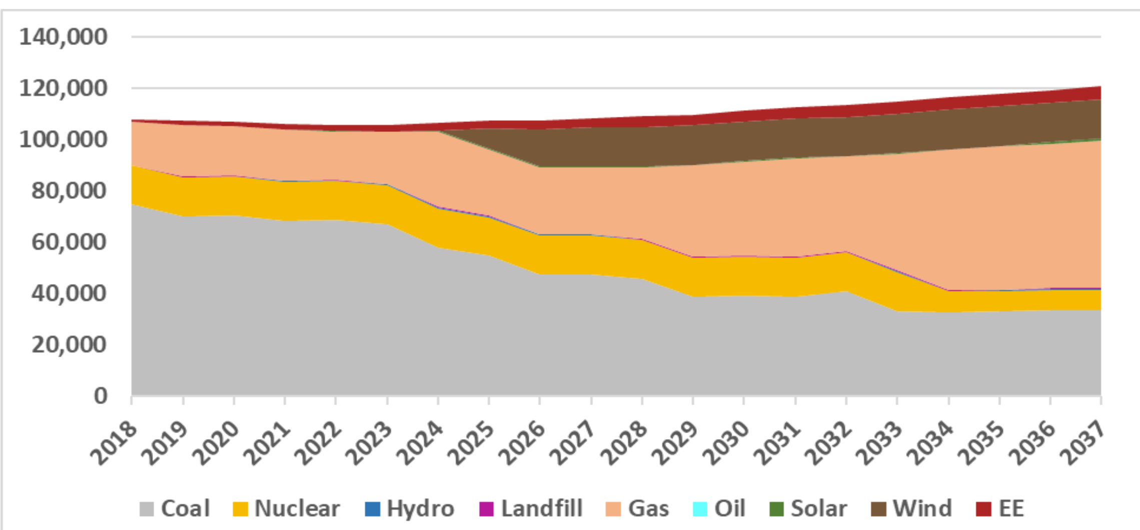

Figure 1. Electricity Supply by Resource for Reference Scenario (GWh)

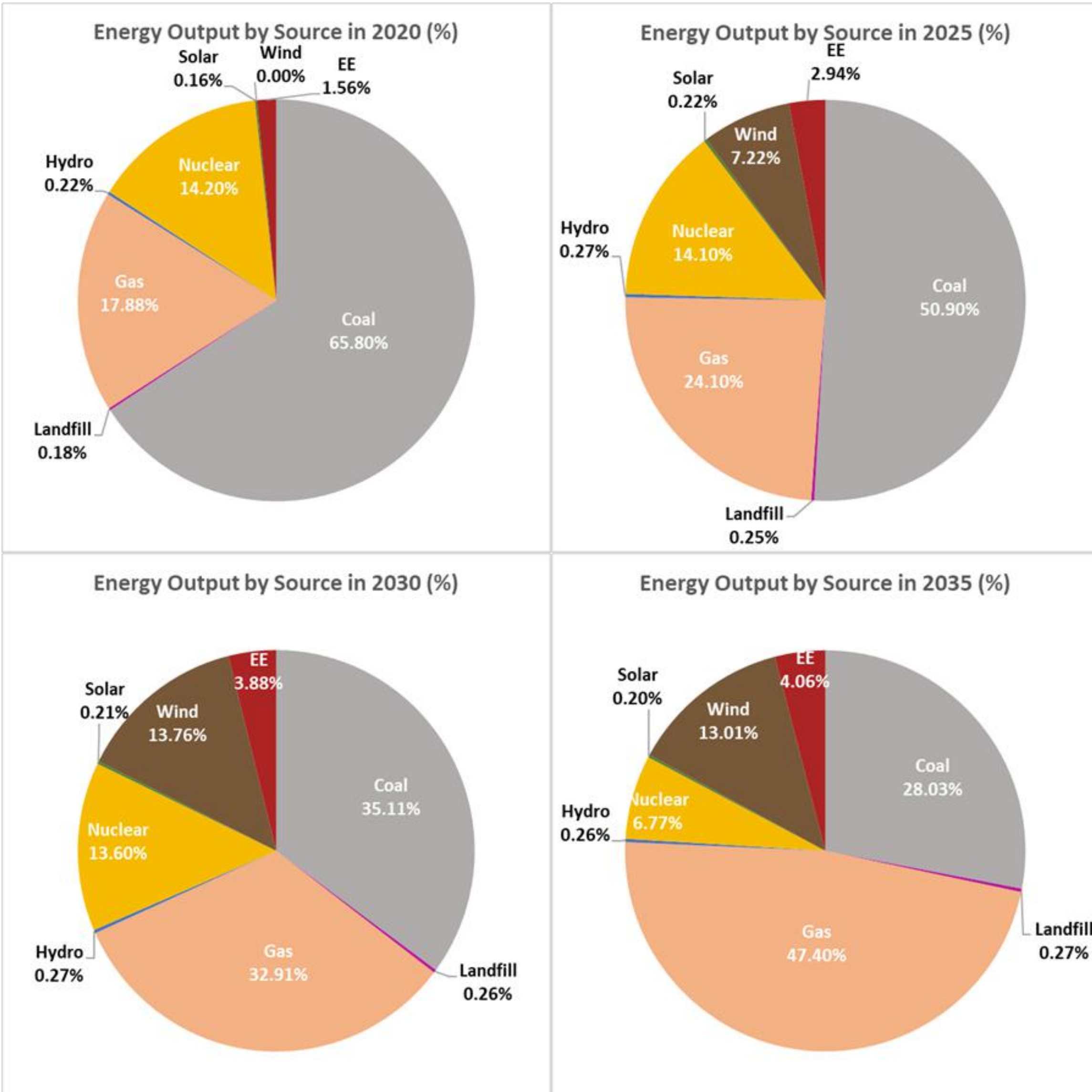

Figure 2. Energy Output by Source by Year for Reference Scenario (%)

Figure 3 shows the price trajectory for the reference scenario. Prices provided are an energy-weighted average across customer classes for the five investor-owned utilities.

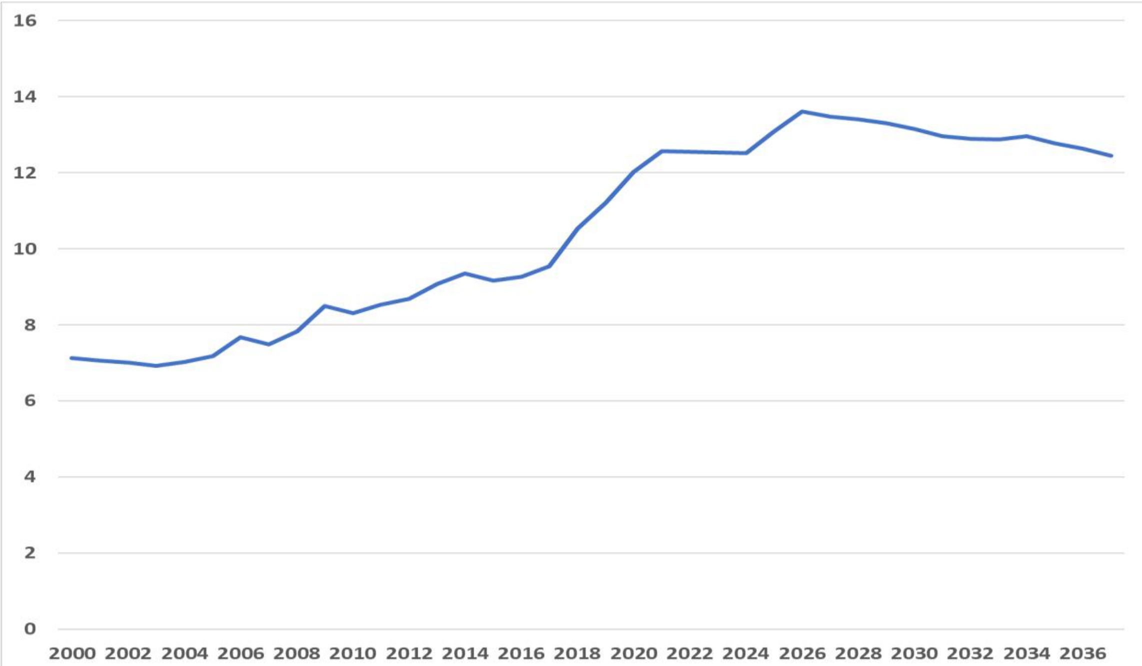

Figure 3. Indiana Electricity Price Projection for Reference Scenario (2017 cents/kWh)

Low Renewables Cost Scenario

Scenario description

As was the case with the 2019 base scenario, the reference scenario uses capital cost data from the Energy Information Association (EIA). There was some concern expressed by stakeholders that EIA's capital costs for wind and solar were higher than the levels indicated in other studies and in responses to utility requests for proposals. In order to see the impact of lower capital cost assumptions for renewable generation, this scenario was developed using cost assumptions from the National Renewable Energy Laboratory (NREL). In addition to using the lower starting costs values from NREL, the more aggressive cost reduction trajectory from NREL was used (the reference scenario used NREL's medium cost reduction rate).[2]

Results

As expected, lower capital costs for renewables resulted in more wind and solar being selected. Table 2 shows that more than 8,200 MW of solar is selected (as compared to 579 MW in the reference scenario), with solar being added much earlier (2024 vs. 2036). Wind capacity is also higher (9.5 GW vs. 5.7 GW). Between the natural gas-fired options, combined cycle additions were down significantly (3.7 GW vs. 6.0 GW), while combustion turbine additions were largely unaffected (5.1 GW vs. 5.0 GW).

[2] https://atb.nrel.gov/

Table 2. Indiana Resource Plan for Low Renewables Cost Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,316	25,175	-96	0	0	0	0	0	0
2020	19,329	25,429	254	0	0	0	0	0	0
2021	19,193	25,288	-141	0	0	0	0	0	0
2022	19,151	25,433	145	0	0	0	0	0	0
2023	19,119	23,688	-1,744	0	0	23	0	0	23
2024	19,258	21,347	-2,341	1,591	836	1,222	0	131	2,189
2025	19,359	21,348	1	1,710	915	1,267	2,975	170	5,327
2026	19,332	20,522	-826	2,504	1,618	1,292	6,255	432	9,597
2027	19,428	20,523	0	2,618	1,698	1,470	6,255	504	9,926
2028	19,509	19,398	-1,124	3,839	2,046	1,478	6,255	849	10,627
2029	19,609	17,775	-1,623	5,580	2,900	1,878	6,582	933	12,292
2030	19,869	17,370	-405	6,296	2,900	1,878	6,608	4,330	15,716
2031	20,076	17,258	-112	6,655	2,900	1,878	6,608	4,872	16,258
2032	20,283	16,846	-412	7,313	3,353	1,878	7,350	5,005	17,585
2033	20,517	15,136	-1,710	9,302	3,950	2,462	7,350	6,093	19,853
2034	20,732	13,496	-1,640	11,198	4,636	3,351	7,434	7,451	22,872
2035	21,050	13,286	-210	11,787	4,636	3,377	8,511	7,719	24,244
2036	21,327	13,236	-50	12,167	4,952	3,663	8,979	7,872	25,467
2037	21,641	13,211	-25	12,566	5,075	3,663	9,530	8,257	26,525

Figures 4 and 5 show the energy mix by fuel source for the low renewables cost scenario. In comparison to the reference scenario, the low renewables cost scenario gets much more of its energy from wind and solar (about 30% vs. 13% by the end of the analysis period). Renewables primarily displace natural gas as an energy source, with coal largely unchanged. This scenario achieves the most balanced blend of energy sources, with 27% coal, 33 % natural gas, and 29% wind and solar in 2035.

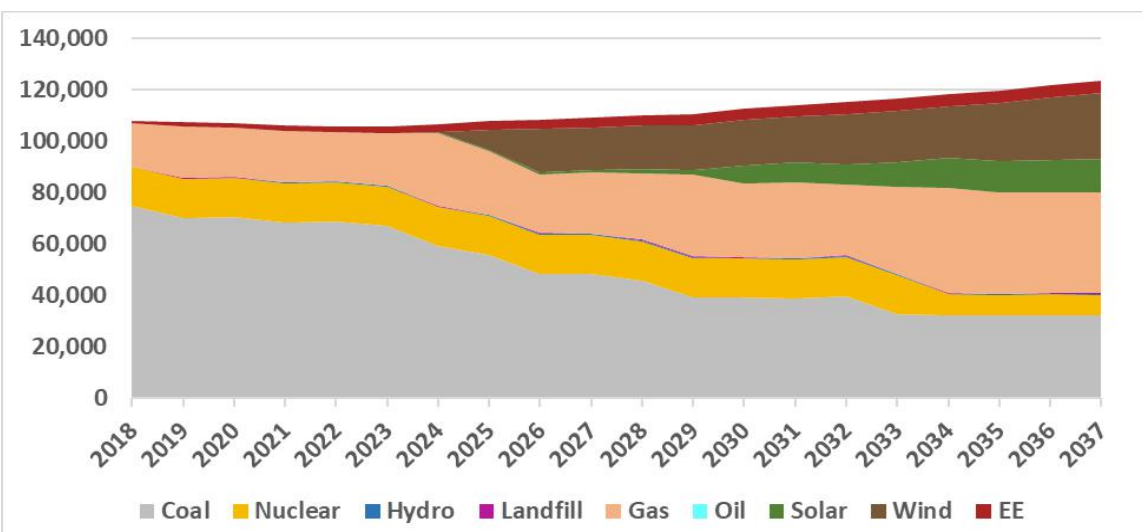

Figure 4. Electricity Supply by Resource for Low Renewables Cost Scenario (GWh)

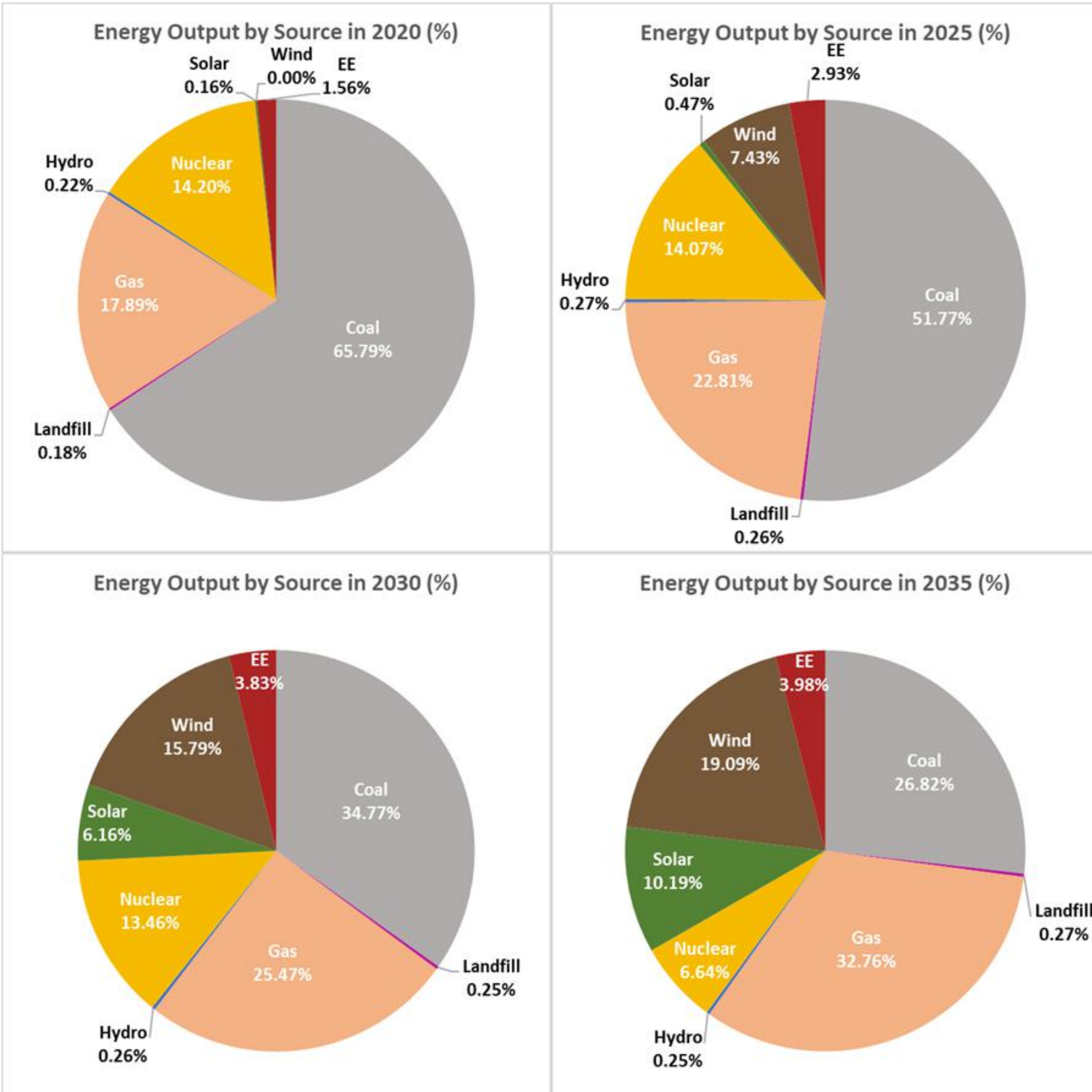

Figure 5. Energy Output by Source by Year for Low Renewables Cost Scenario (%)

Figure 6 shows the price trajectory for the low renewables cost and reference scenarios. As expected, lower capital costs for some options result in lower electricity prices.

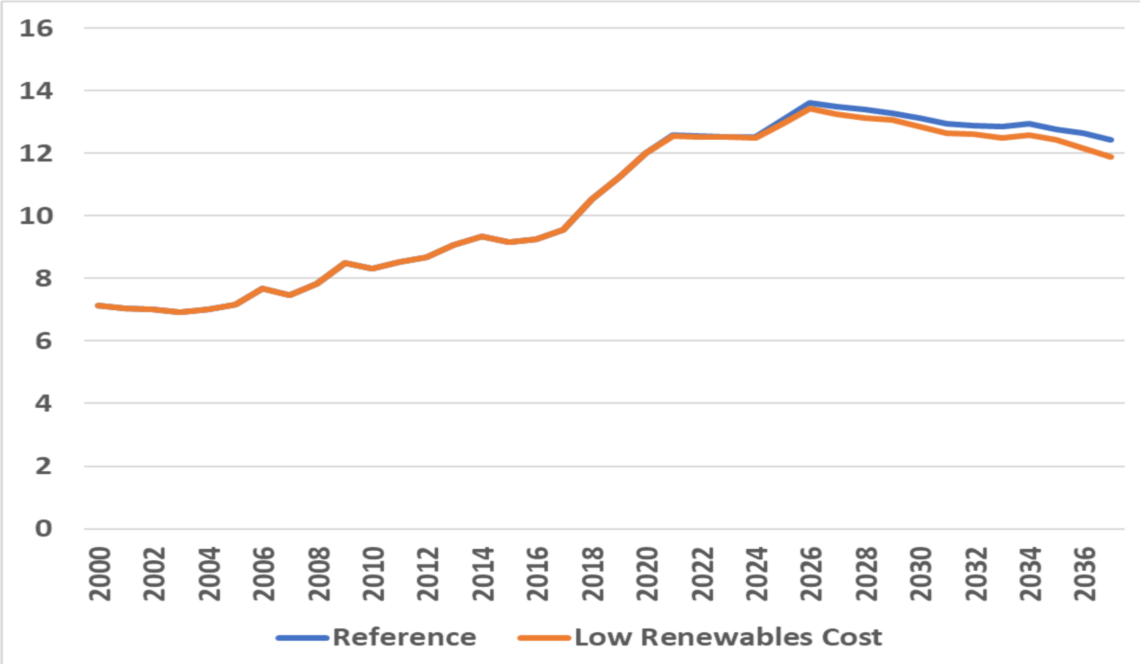

Figure 6. Indiana Electricity Price Projection for Reference and Low Renewables Cost Scenarios (2017 cents/kWh)

2025 Moratorium Scenario

Scenario description

The 2025 moratorium scenario is one of two scenarios that examine the impacts of delaying the scheduled retirement of coal-fired generators. For this scenario, coal retirements are not allowed to retire prior to the end of 2025. Exceptions to this are Duke Energy's Gallagher units 2 & 4 which cannot continue operation past the date of the Consent Decree and I&M's Rockport Unit 2 due the expiration of the lease agreement. The units affected by the moratorium are retired in the model as of the start of 2026.

A key input to this scenario is the necessary capital investments and operating and maintenance (O&M) costs necessary to keep a unit with a planned or projected retirement prior to 2025 in commercial operation through 2025. This data was provided by all five investor-owned utilities.

Results

While the moratorium pushes back the need for new resources from 2024 to 2026, it has little long-term influence on the mix of resources selected. As can be seen in Table 3, the Aurora model selects a balanced mix of natural gas combustion turbine, natural gas combined cycle, and wind capacity. Solar capacity is added in the last two years. These are all similar to the reference scenario.

Table 3. Indiana Resource Plan for 2025 Moratorium Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,316	25,175	-96	0	0	0	0	0	0
2020	19,324	25,429	254	0	0	0	0	0	0
2021	19,169	25,500	71	0	0	0	0	0	0
2022	19,106	25,645	145	0	0	0	0	0	0
2023	19,057	24,315	-1,329	0	0	23	0	0	23
2024	19,111	24,126	-189	0	0	23	0	0	23
2025	19,250	24,127	1	0	0	46	0	0	46
2026	19,260	20,522	-3,605	2,419	1,003	1,840	5,917	0	8,760
2027	19,316	20,523	0	2,485	1,089	1,903	6,082	0	9,074
2028	19,370	19,398	-1,124	3,674	1,712	1,917	6,082	0	9,711
2029	19,448	17,775	-1,623	5,389	2,035	2,746	6,082	0	10,863
2030	19,686	17,370	-405	6,078	2,661	2,808	6,082	0	11,551
2031	19,860	17,258	-112	6,397	2,943	2,846	6,082	0	11,871
2032	20,053	16,846	-412	7,039	3,578	2,853	6,082	0	12,512
2033	20,259	15,136	-1,710	8,995	4,516	3,870	6,082	0	14,468
2034	20,465	13,496	-1,640	10,880	5,096	5,176	6,082	0	16,354
2035	20,769	13,286	-210	11,452	5,096	5,747	6,082	0	16,925
2036	20,999	13,236	-50	11,776	5,096	5,831	6,082	343	17,352
2037	21,259	13,211	-25	12,111	5,096	5,831	6,082	823	17,832

Figures 7 and 8 show the energy mix by fuel source for the 2025 moratorium scenario. The energy picture follows a similar path as the resource additions. Energy from various sources is stable through 2025. As coal units begin retiring in 2026, coal-fired generation drops and energy from wind and natural gas increases. The long-term mix is quite similar to the reference scenario.

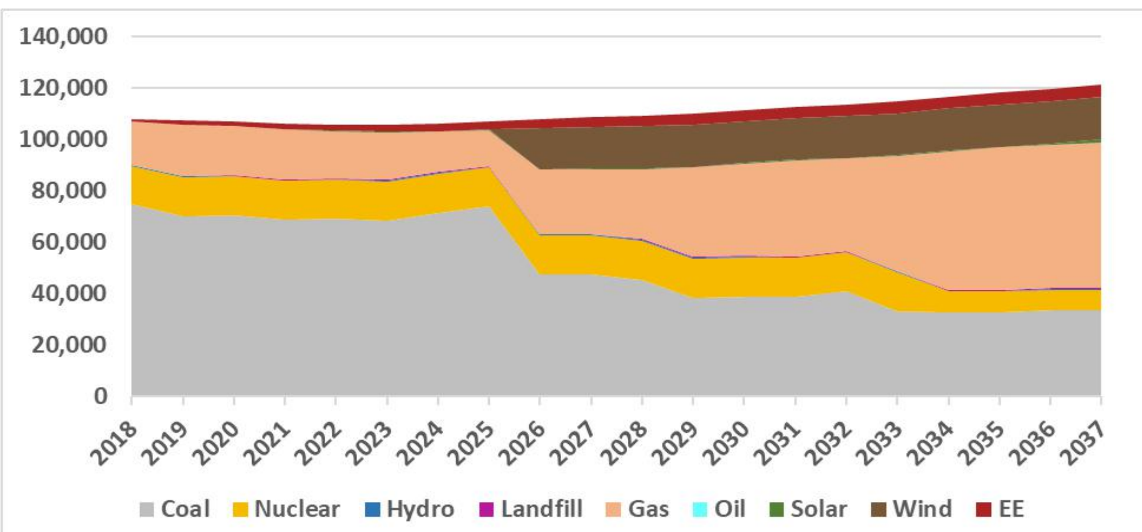

Figure 7. Electricity Supply by Resource for 2025 Moratorium Scenario (GWh)

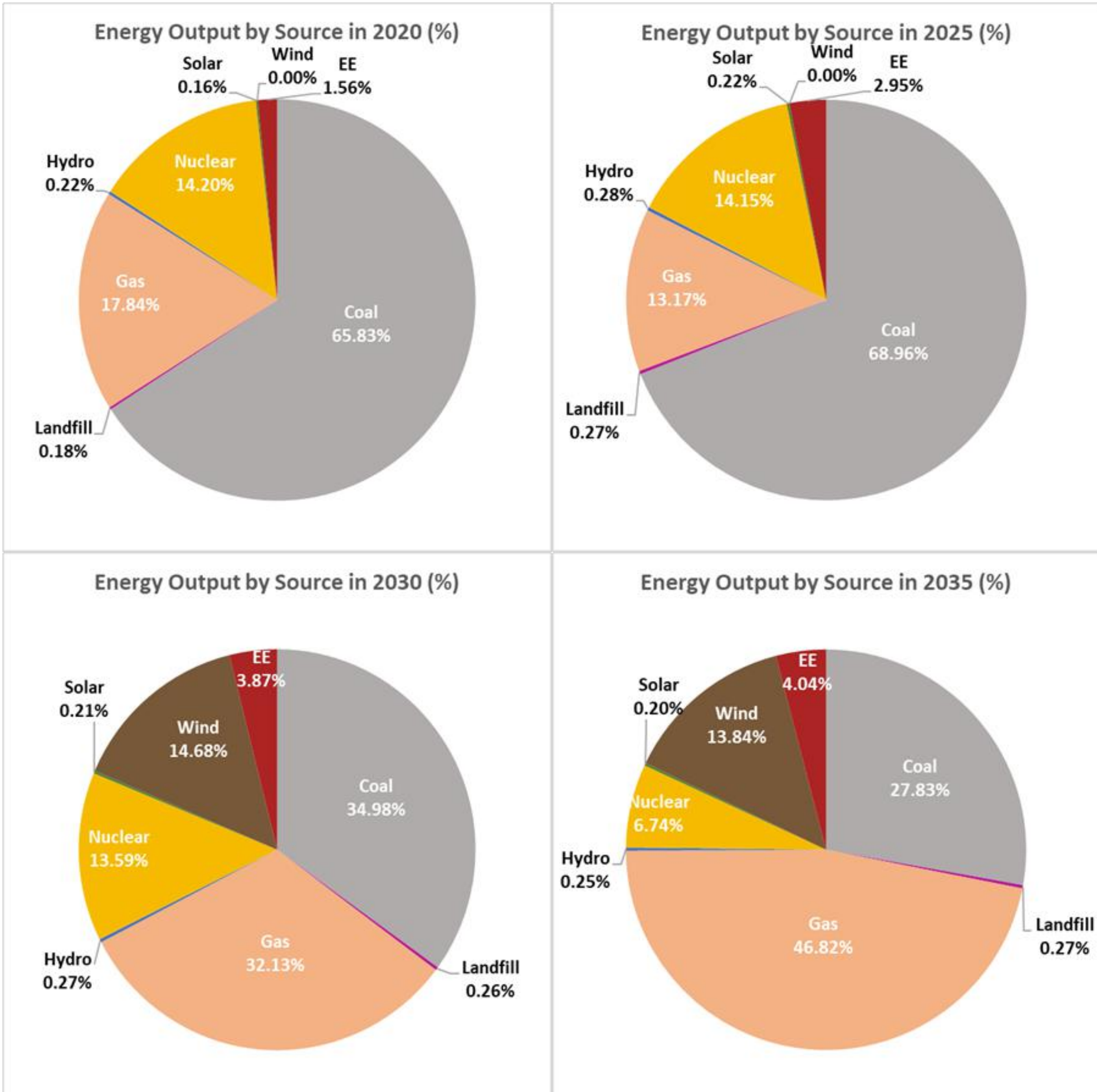

Figure 8. Energy Output by Source by Year for 2025 Moratorium Scenario (%)

Figure 9 shows the price trajectory for the 2025 moratorium and reference scenarios. Electricity prices are generally slightly (1-2%) higher in the 2025 moratorium scenario, as the costs associated with extending the life of the affected units offset the cost of replacement capacity.

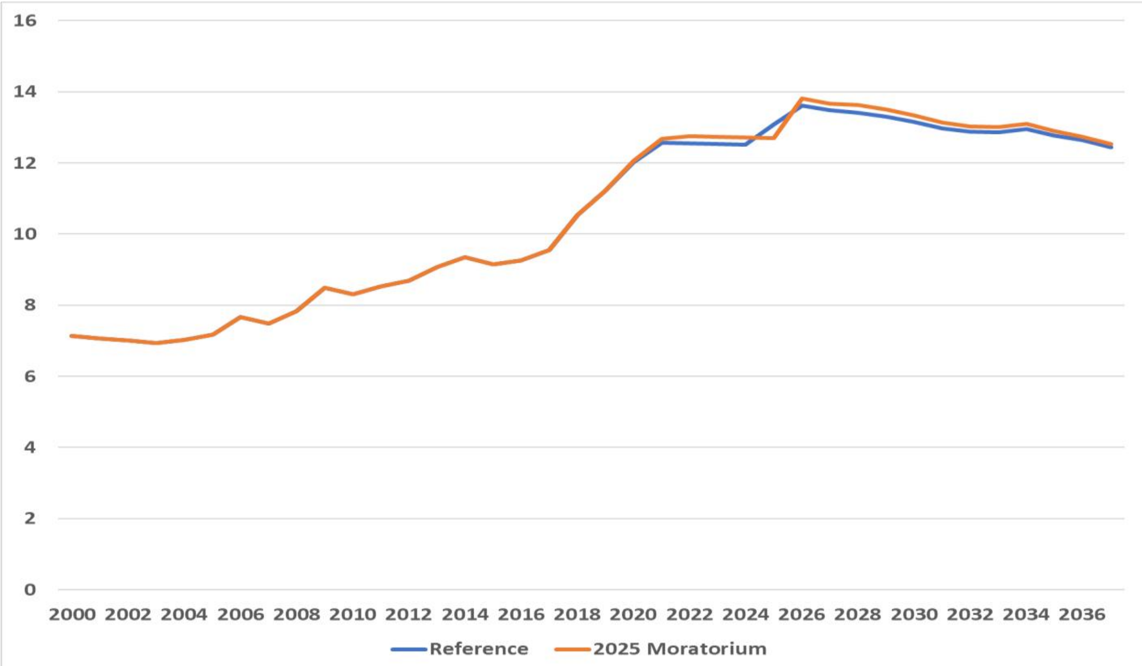

Figure 9. Indiana Electricity Price Projection for Reference and 2025 Moratorium Scenarios (2017 cents/kWh)

2030 Moratorium Scenario

Scenario description

This scenario is similar to the 2025 moratorium scenario but extends the restrictions to coal unit retirements through the end of 2030. In addition to the three exceptions in 2025 moratorium scenario, Rockport Unit 1 cannot operate beyond 2028 given it is subject to a Consent Decree. For this scenario, utilities provided capital and O&M costs associated with keeping the affected plants operational through 2030. Affected units were retired in the model at the start of 2031.

Results

The moratorium delays resource needs to 2026, with significant new resources in 2031 when the deferred retirements occur. The mix of resources change relative to the reference scenario, with less wind (2.1 GW vs. 5.7 GW) and combustion turbines (4.3 GW vs. 5.0 GW) and more combined cycle generators (7.4 GW vs. 6.0 GW). Solar is similar to the reference case with additions occurring in the last two years. Table 4 provides the resource mix selected by the model.

Table 4. Indiana Resource Plan for 2030 Moratorium Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,316	25,175	-96	0	0	0	0	0	0
2020	19,321	25,429	254	0	0	0	0	0	0
2021	19,161	25,500	71	0	0	0	0	0	0
2022	19,084	25,645	145	0	0	0	0	0	0
2023	19,021	24,315	-1,329	0	0	23	0	0	23
2024	19,041	24,126	-189	0	0	23	0	0	23
2025	19,134	24,127	1	0	0	46	0	0	46
2026	19,196	23,923	-204	0	21	140	2,115	0	2,276
2027	19,302	23,924	0	0	330	162	2,115	0	2,607
2028	19,394	23,774	-149	0	330	176	2,115	0	2,621
2029	19,511	22,600	-1,174	639	735	577	2,115	0	3,426
2030	19,777	22,195	-405	1,361	806	669	2,115	0	3,590
2031	19,973	17,258	-4,937	6,531	3,279	3,041	2,115	0	8,435
2032	20,184	16,846	-412	7,195	3,731	3,253	2,115	0	9,098
2033	20,404	15,136	-1,710	9,167	3,731	5,225	2,115	0	11,071
2034	20,614	13,496	-1,640	11,057	4,329	6,517	2,115	0	12,960
2035	20,919	13,286	-210	11,631	4,329	7,091	2,115	0	13,534
2036	21,155	13,236	-50	11,962	4,329	7,244	2,115	253	13,941
2037	21,428	13,211	-25	12,312	4,329	7,403	2,115	528	14,374

Figures 10 and 11 show the energy mix by fuel source for the 2030 moratorium scenario. As expected, energy from coal does not begin to decrease significantly until after the moratorium ends, with over 60% of energy coming from coal in 2030 (as compared to 35% in the reference case). At the end of the analysis period, over half of the energy is coming from natural gas.

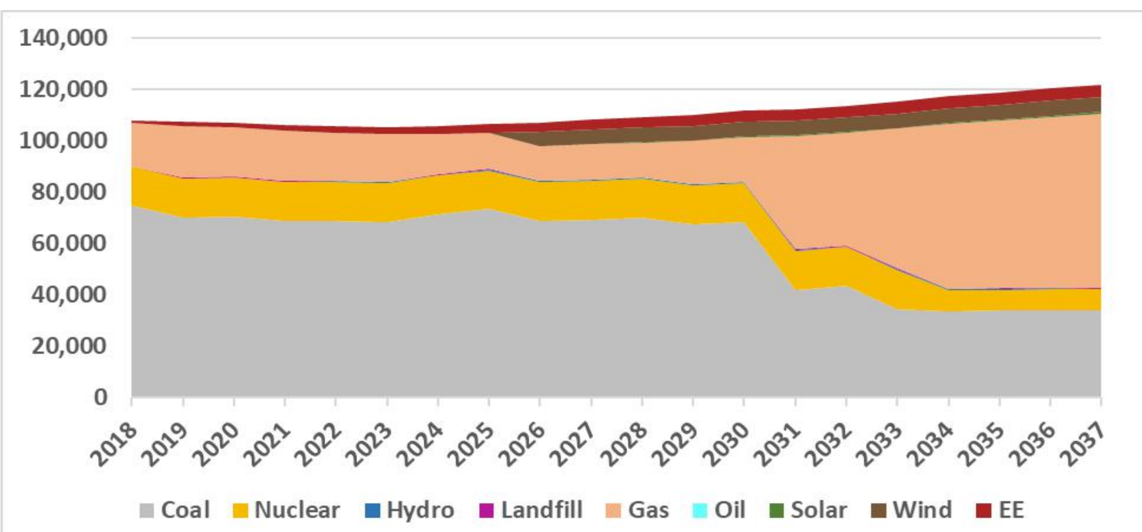

Figure 10. Electricity Supply by Resource for 2030 Moratorium Scenario (GWh)

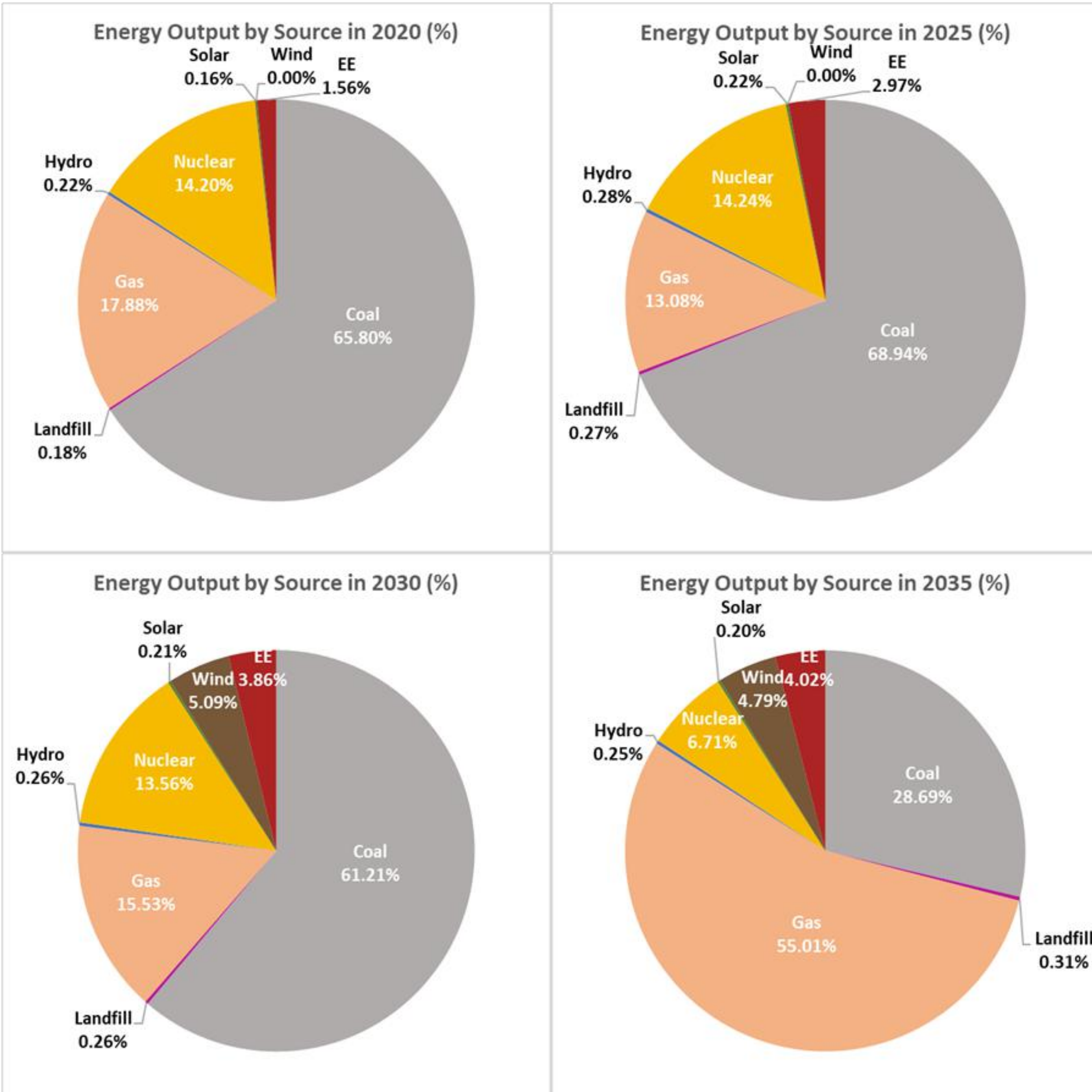

Figure 11. Energy Output by Source by Year for 2030 Moratorium Scenario (%)

Figure 12 shows the price trajectory for the 2030 moratorium and reference scenarios. Electricity prices are 1-4% higher in the short term (2021-2024) under the 2030 moratorium scenario and virtually unchanged in the long term.

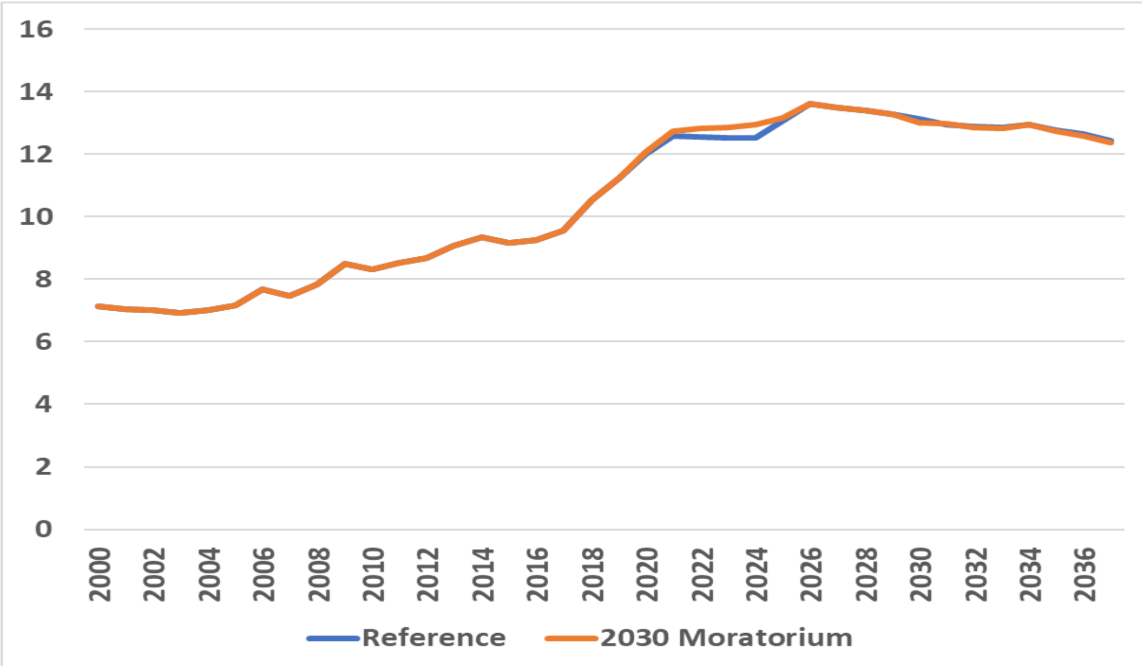

Figure 12. Indiana Electricity Price Projection for Reference and 2030 Moratorium Scenarios (2017 cents/kWh)

Additional EE Scenario

Scenario description

This scenario examines the impacts of more aggressive EE efforts by the utilities. Since SUFG lacks information on the potential for and costs of higher levels of utility-sponsored efficiency, a simplified approach was used. SUFG doubled the amount of EE identified in the IRPs at double the total cost, with the exception of NIPSCO.[3] It should be noted that this likely results in an understatement of EE program costs, since it is probable that the incremental EE (which was not selected in the IRP process) would be more expensive than the EE programs that were selected. Rather than arbitrarily choose a higher cost that could be either too high or too low, SUFG opted to use a cost where the direction of the likely error was known, even if the magnitude was not.

Results

Table 5 shows the resources selected by the model. Total resources are lower than in the reference scenario due to the reduction in demand from the higher EE. While wind (3.3 GW vs. 5.7 GW) and combustion turbine (3.8 GW vs. 5.0 GW) additions are lower, combined cycle (6.3 GW vs. 6.0 GW) and solar (1.4 GW vs. 0.6 GW) are higher.

[3] SUFG originally modeled double EE in NIPSCO, but found that this caused net sales to approach zero (EE savings roughly equal to pre-EE sales) in the residential and commercial sectors. This caused prices to rise to an unreasonably high level. Thus, NIPSCO's EE levels and costs were kept the same as in the reference scenario.

Table 5. Indiana Resource Plan for Additional EE Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,302	25,271		0	0	0	0	0	0
2019	19,077	25,175	-96	0	0	0	0	0	0
2020	19,047	25,429	254	0	0	0	0	0	0
2021	18,855	25,288	-141	0	0	0	0	0	0
2022	18,754	25,433	145	0	0	0	0	0	0
2023	18,672	23,688	-1,744	0	0	23	0	0	23
2024	18,705	21,347	-2,341	933	228	1,371	0	0	1,600
2025	18,802	21,348	1	1,047	256	1,789	1,484	0	3,529
2026	18,774	20,522	-826	1,840	600	2,019	2,999	0	5,618
2027	18,837	20,523	0	1,914	741	2,071	3,330	0	6,141
2028	18,889	19,398	-1,124	3,101	741	2,563	3,330	407	7,040
2029	18,962	17,775	-1,623	4,810	1,036	3,157	3,330	407	7,929
2030	19,220	17,370	-405	5,523	1,457	3,339	3,330	562	8,688
2031	19,392	17,258	-112	5,839	1,834	3,339	3,347	734	9,254
2032	19,563	16,846	-412	6,456	2,052	3,555	3,347	734	9,688
2033	19,755	15,136	-1,710	8,394	2,888	4,657	3,347	734	11,627
2034	19,947	13,496	-1,640	10,263	3,842	5,573	3,347	734	13,496
2035	20,246	13,286	-210	10,829	3,842	6,139	3,347	734	14,062
2036	20,464	13,236	-50	11,138	3,842	6,209	3,347	1,077	14,474
2037	20,716	13,211	-25	11,464	3,842	6,334	3,347	1,363	14,885

Figures 13 and 14 show the energy mix by fuel source for the additional EE scenario. The major differences between this scenario and the reference scenario are increased energy from EE programs and solar, with energy from wind roughly halved.

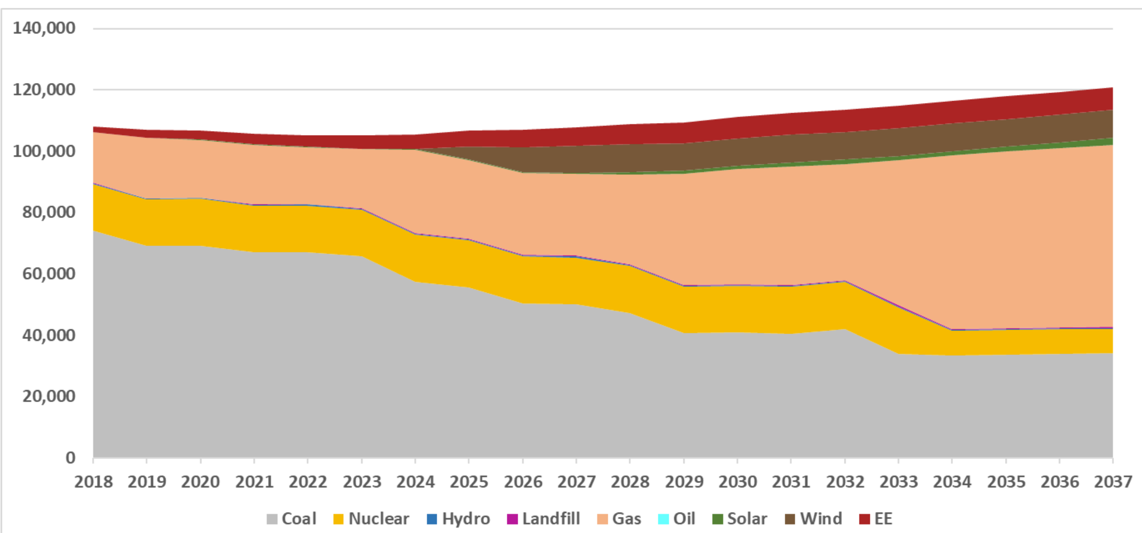

Figure 13. Electricity Supply by Resource for Additional EE Scenario (GWh)

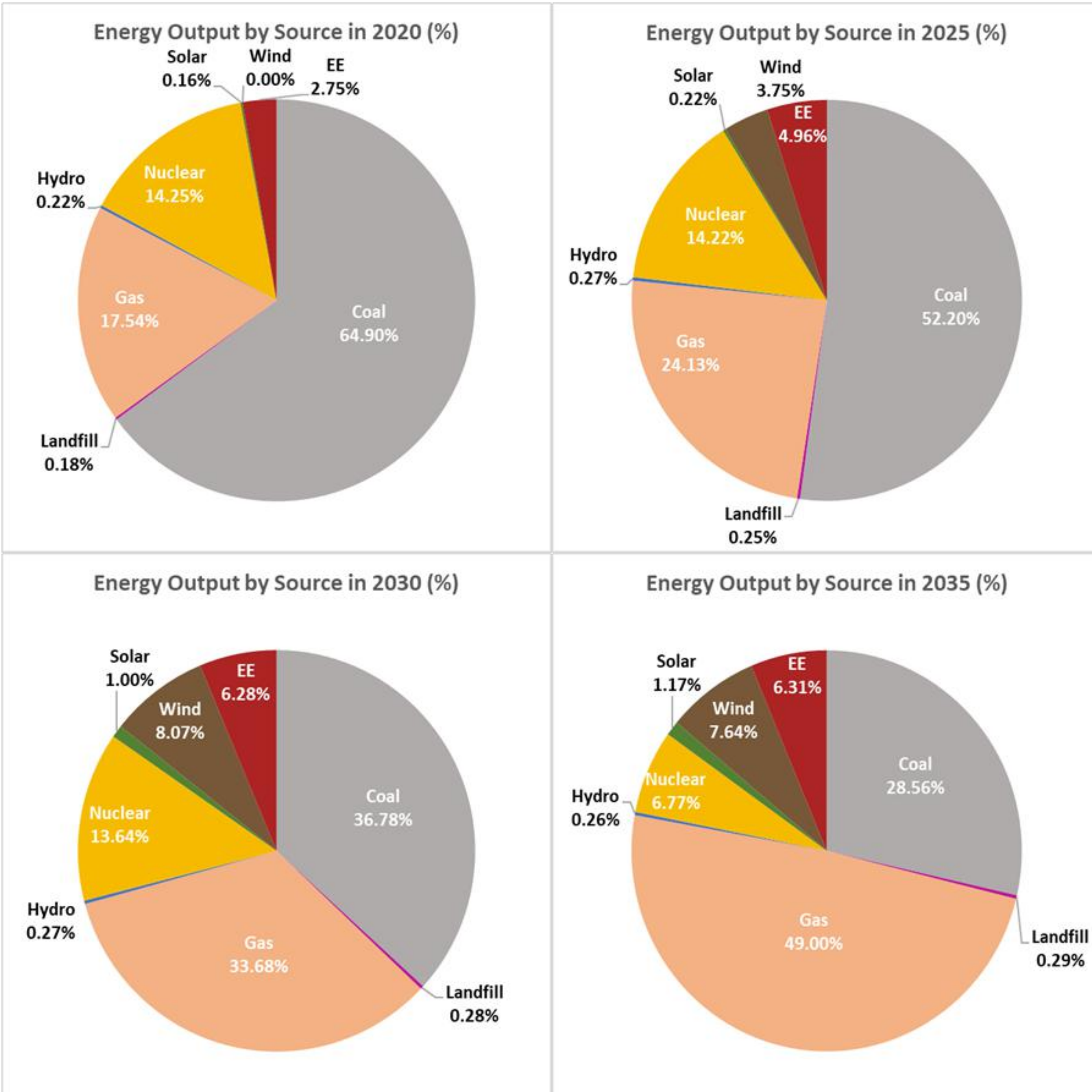

Figure 14. Energy Output by Source by Year for Additional EE Scenario (%)

Figure 15 shows the price trajectory for the additional EE and reference scenarios. Electricity prices are 2-3% higher through 2024 as there is little avoided cost of new resources and less than 1% higher in the long term under the additional EE scenario. It should be noted that while electricity prices may be higher in this scenario, energy usage is lower for the average customer. Thus, customer bills may be lower.

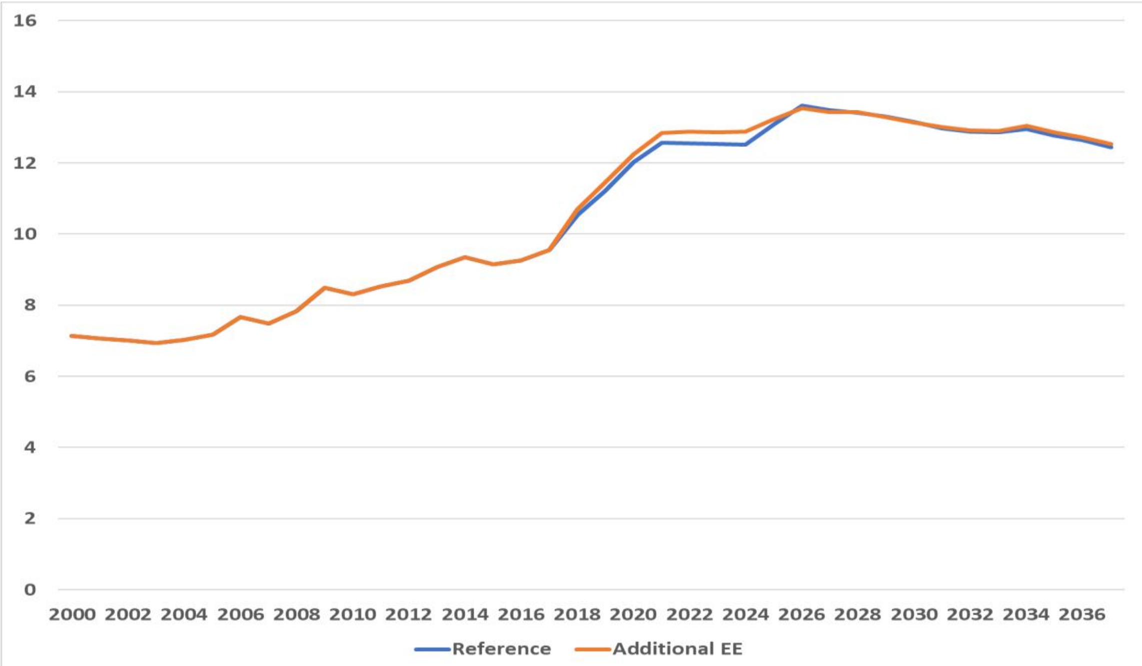

Figure 15. Indiana Electricity Price Projection for Reference and Additional EE Scenarios (2017 cents/kWh)

Industrial Self-Generation Scenario

Scenario description

This scenario examines the impact of the development of significant levels of self-generation, co-generation, and combined heat and power in the industrial sector. Since future industrial self and co-generation is highly uncertain and SUFG lacks the capability to credibly forecast these developments, a proxy was used such that self-generation completely offsets future growth in industrial electricity consumption. This was modeled by keeping the industrial load forecast flat across the state's IOUs. Note that SUFG's not-for-profit models are not at the sectoral level, so determining a flat industrial forecast for them is problematic. Also, since industrial sales in the reference scenario are declining through 2021, industrial sales are held constant at that level rather than from the beginning of the forecast period.

Results

Table 6 shows the resources selected by the model. While overall resource needs are lower than in the reference scenario due to the reduction in demand in the industrial sector, wind capacity additions are actually higher (6.3 GW vs. 5.7 GW). Combined cycle additions are significantly lower (4.9 GW vs. 6.0 GW), while combustion turbines (4.7 GW vs. 5.0 GW) and solar (0.4 GW vs. 0.6 GW) are slightly lower.

Table 6. Indiana Resource Plan for Industrial Self-Generation Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,317	25,175	-96	0	0	0	0	0	0
2020	19,331	25,429	254	0	0	0	0	0	0
2021	19,192	25,288	-141	0	0	0	0	0	0
2022	19,145	25,433	145	0	0	0	0	0	0
2023	19,111	23,688	-1,744	0	0	23	0	0	23
2024	19,192	21,347	-2,341	1,513	677	1,288	0	0	1,965
2025	19,246	21,348	1	1,576	699	1,367	2,570	0	4,636
2026	19,202	20,522	-826	2,349	1,075	1,638	5,982	0	8,695
2027	19,220	20,523	0	2,370	1,247	1,681	6,293	0	9,221
2028	19,209	19,398	-1,124	3,482	1,815	1,690	6,293	0	9,798
2029	19,214	17,775	-1,623	5,110	2,184	2,297	6,293	0	10,774
2030	19,354	17,370	-405	5,683	2,654	2,400	6,293	0	11,347
2031	19,404	17,258	-112	5,854	2,825	2,400	6,293	0	11,518
2032	19,453	16,846	-412	6,324	3,295	2,400	6,293	0	11,987
2033	19,516	15,136	-1,710	8,110	4,276	3,204	6,293	0	13,773
2034	19,603	13,496	-1,640	9,853	4,747	4,477	6,293	0	15,517
2035	19,768	13,286	-210	10,260	4,747	4,884	6,293	0	15,923
2036	19,845	13,236	-50	10,401	4,747	4,893	6,293	189	16,122
2037	19,950	13,211	-25	10,551	4,747	4,893	6,293	404	16,336

Figures 16 and 17 show the energy mix by fuel source for the industrial self-generation scenario. Energy from natural gas is lower relative to the reference scenario (about 8,600 GWh lower in 2037), while wind is higher (1,500 GWh higher in 2037). Other sources are almost unchanged. Note that the percentages may increase from those in the reference case because total energy is lower.

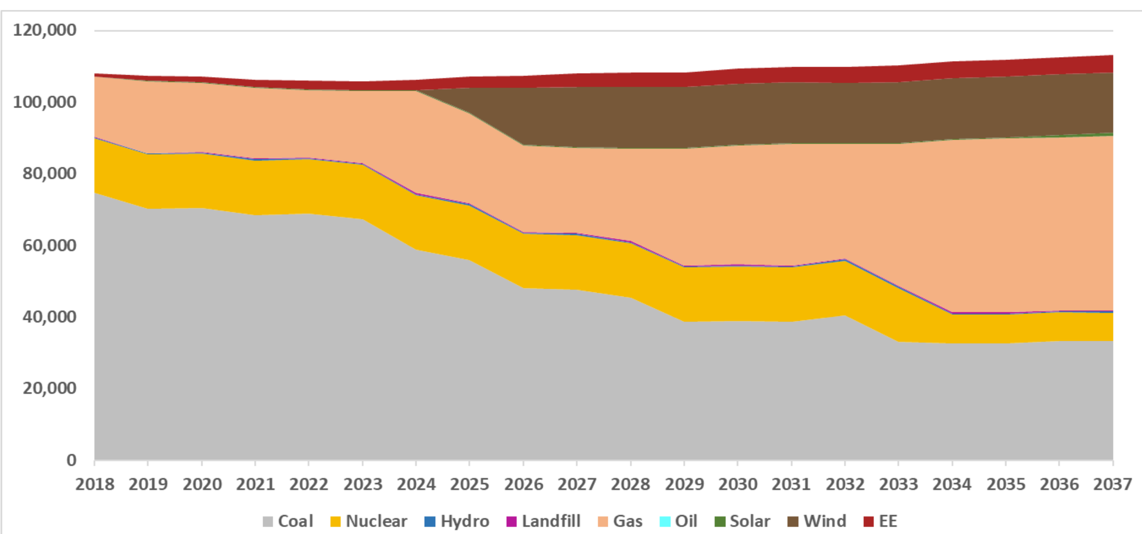

Figure 16. Electricity Supply by Resource for Industrial Self-Generation Scenario (GWh)

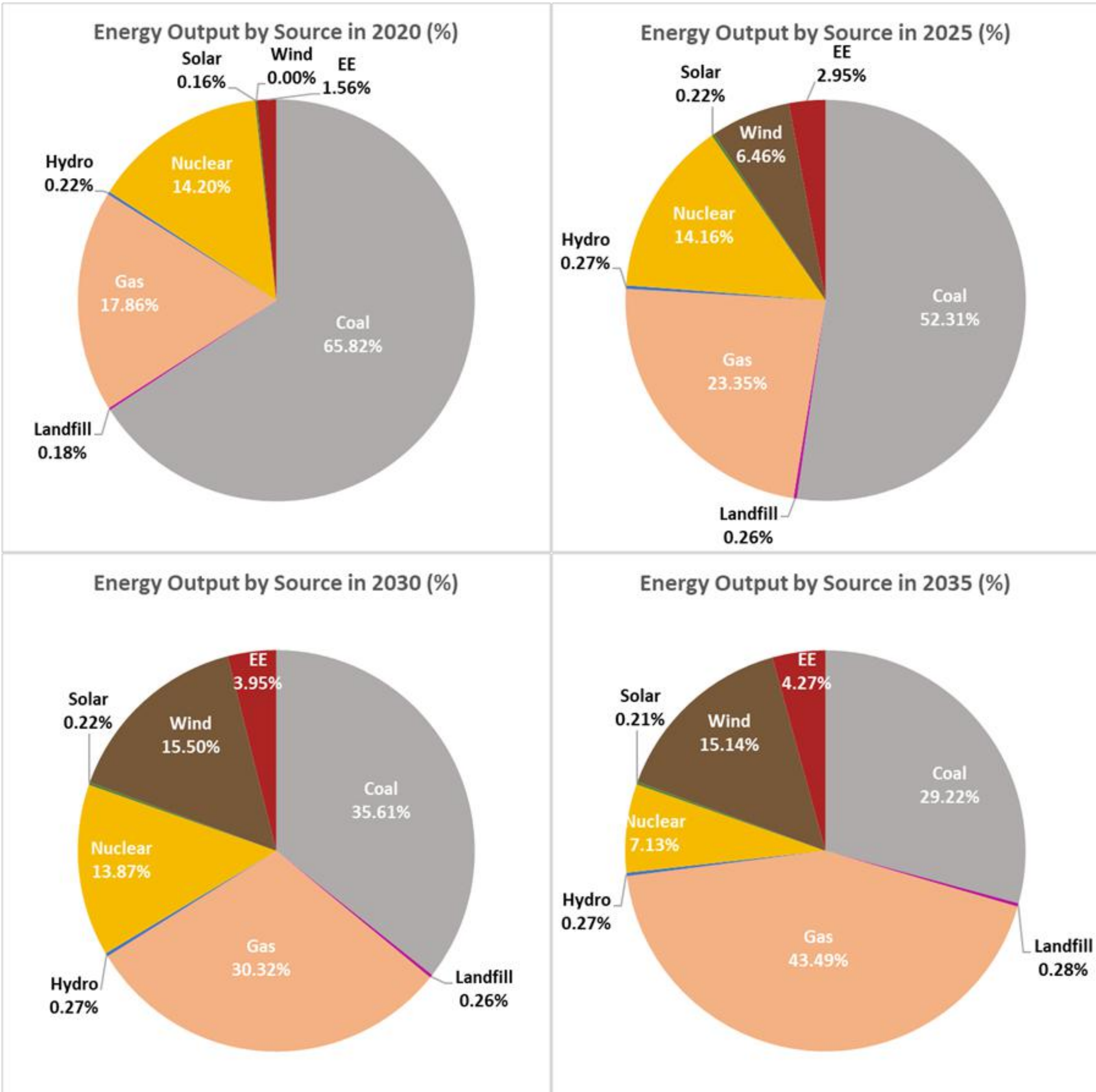

Figure 17. Energy Output by Source by Year for Industrial Self-Generation Scenario (%)

Figure 18 shows the price trajectory for the industrial self-generation and reference scenarios. Long-term prices are higher (1% in 2026 to 7% in 2037) as the reduction in sales is greater than the reduction in revenue requirements.

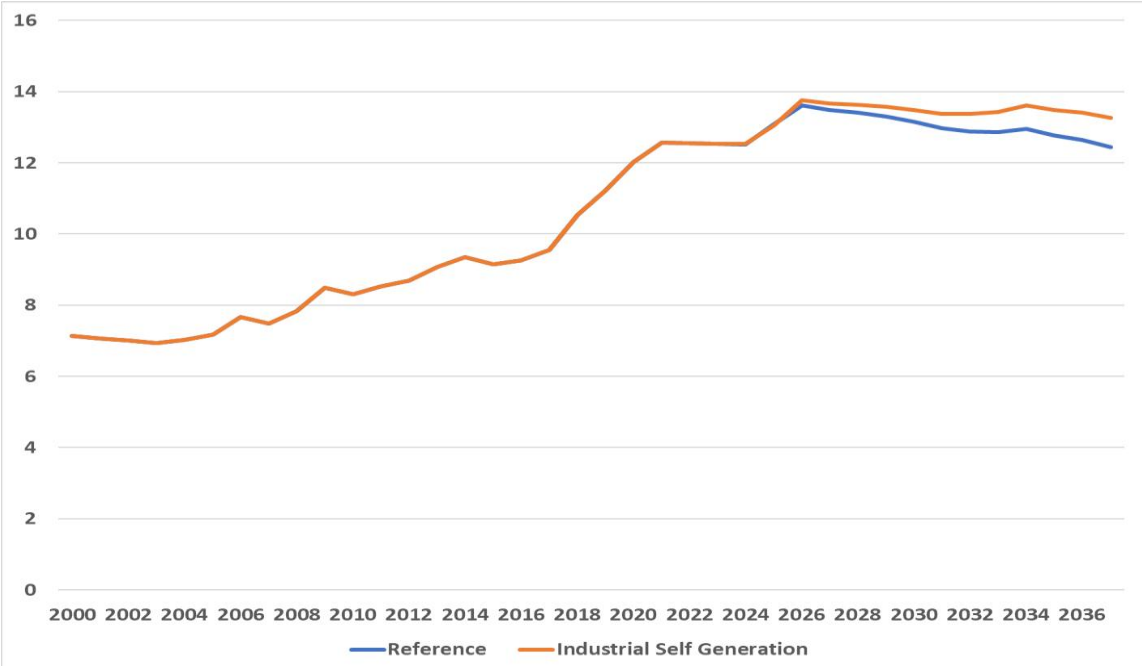

Figure 18. Indiana Electricity Price Projection for Reference and Industrial Self-Generation Scenarios (2017 cents/kWh)

High Natural Gas Price Scenario

Scenario description

This scenario models a high natural gas price future similar to that which might occur with a long-term moratorium on hydraulic fracturing (commonly referred to as fracking). Since the price of natural gas without fracking is purely speculative, an arbitrary, very high price ($10/mmBtu) was used. Since natural gas price is an input to various models within the modeling system, such as the forecasting models, the $10 price was set for the electric utility sector. Other sectors use the same price with an adjustment for typical differences in distribution costs.

Results

As shown in Table 7, the high natural gas price has a very large impact on the resources selected by the model. Natural gas combined cycle selections are dramatically lower than in the reference scenario (0.8 GW vs. 6.0 GW). Wind capacity is significantly higher (22.8 GW vs. 5.7 GW), with over 2 GW added as early as 2020 despite adequate resource capacity in place. Both solar (1.1 GW vs. 0.6 GW) and combustion turbine capacity (6.5 GW vs. 5.0 GW) are somewhat higher. Combustion turbines are used to supplement existing resources for times when wind output is low. It is possible that energy storage would have displaced the combustion turbines if that had been an option.

Table 7. Indiana Resource Plan for High Natural Gas Price Scenario (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,451	25,271		0	0	0	0	0	0
2019	19,507	25,175	-96	0	0	0	0	0	0
2020	19,597	25,429	254	0	0	0	2,304	0	2,304
2021	19,492	25,288	-141	0	0	0	2,475	0	2,475
2022	19,445	25,433	145	0	0	0	2,803	0	2,803
2023	19,311	23,688	-1,744	0	0	0	6,048	0	6,048
2024	19,153	21,347	-2,341	1,466	1,364	0	9,325	0	10,689
2025	19,144	21,348	1	1,454	1,367	0	9,698	0	11,065
2026	19,124	20,522	-826	2,256	2,018	0	11,228	0	13,245
2027	19,147	20,523	0	2,284	2,163	0	11,616	26	13,804
2028	19,113	19,398	-1,124	3,367	3,210	0	13,896	26	17,132
2029	19,069	17,775	-1,623	4,938	3,374	263	15,971	97	19,704
2030	19,217	17,370	-405	5,519	3,839	354	16,270	97	20,560
2031	19,281	17,258	-112	5,707	4,187	388	17,132	120	21,828
2032	19,371	16,846	-412	6,226	4,246	594	17,435	146	22,420
2033	19,382	15,136	-1,710	7,950	4,895	848	21,532	602	27,877
2034	19,395	13,496	-1,640	9,605	6,429	848	22,392	618	30,287
2035	19,541	13,286	-210	9,989	6,469	848	22,392	618	30,328
2036	19,644	13,236	-50	10,162	6,469	848	22,586	837	30,741
2037	19,809	13,211	-25	10,384	6,469	848	22,764	1,129	31,210

Figures 19 and 20 show the energy mix by fuel source for the high natural gas price scenario. In this scenario, wind becomes the largest source of energy, producing almost half of the energy at the end of the analysis period. Energy from natural gas is about 1/3 of the amount in the reference case. Energy from coal is also down somewhat as the units are utilized more in a cycling mode to adjust for the variability of the wind output.

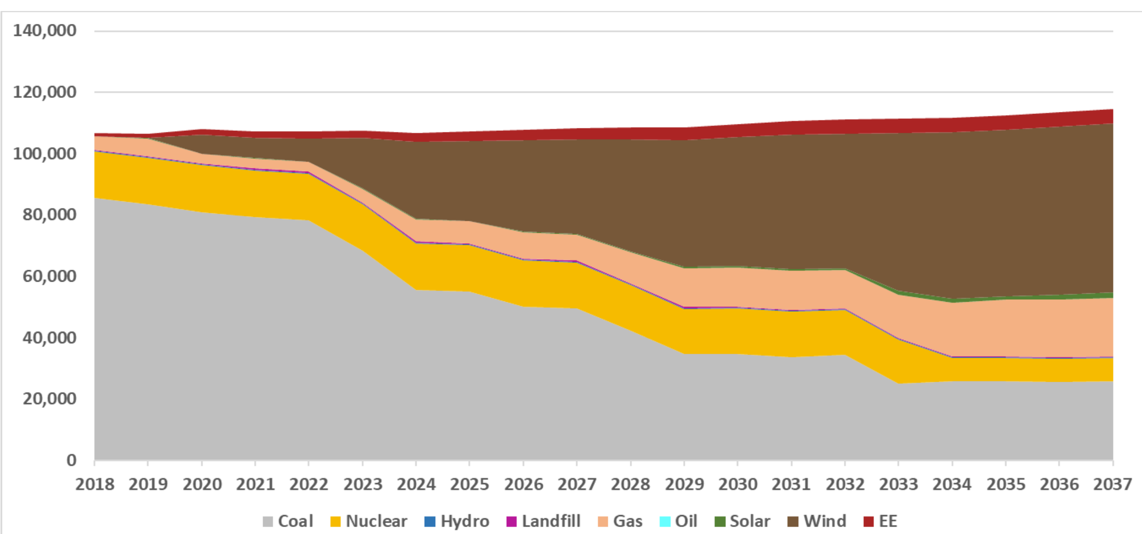

Figure 19. Electricity Supply by Resource for High Natural Gas Price Scenario (GWh)

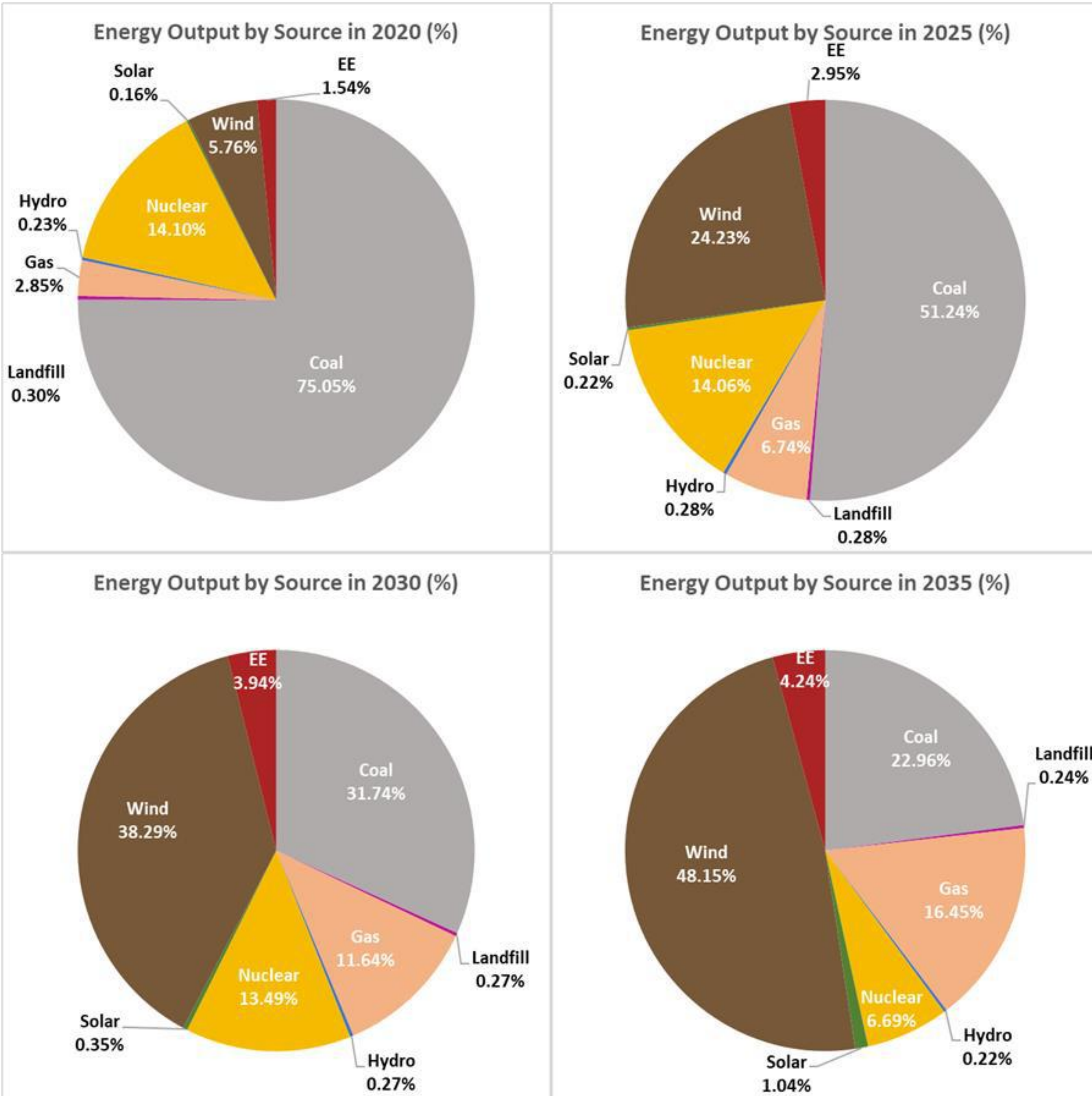

Figure 20. Energy Output by Source by Year for High Natural Gas Price Scenario (%)

Figure 21 shows the price trajectory for the high natural gas price and reference scenarios. Prices are 1-2% higher through 2022, then increase to over 20% higher late in the analysis period.

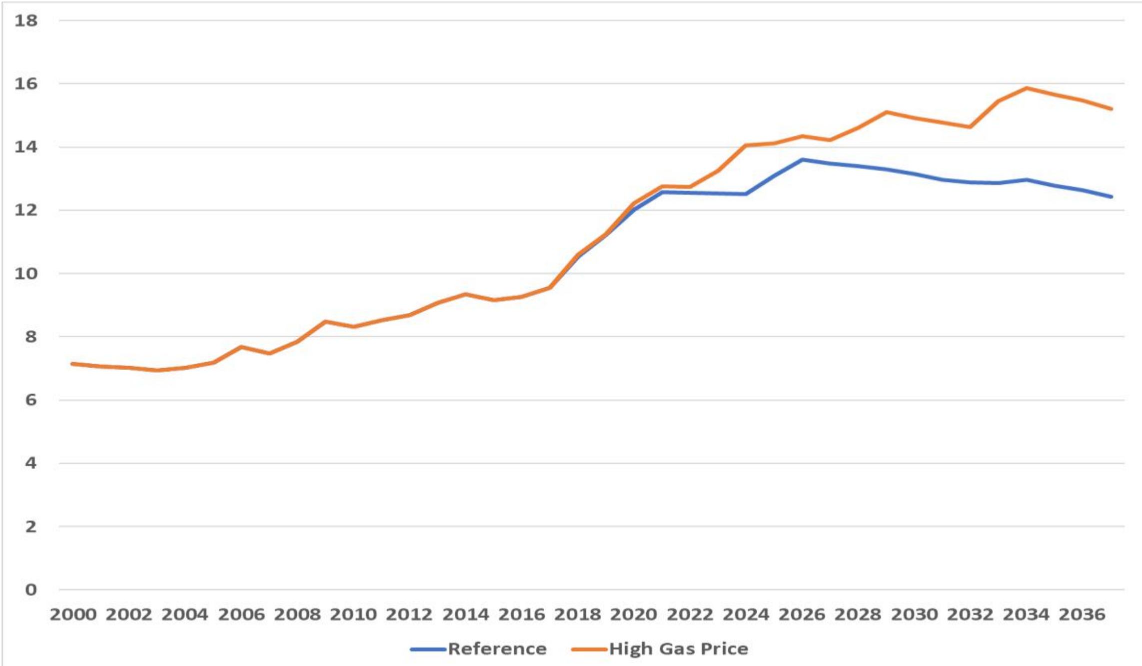

Figure 21. Indiana Electricity Price Projection for Reference and High Natural Gas Price Scenarios (2017 cents/kWh)

Comparison Across Scenarios

Figure 22 provides the total resource additions and Figure 23 provides the electricity prices across all scenarios.

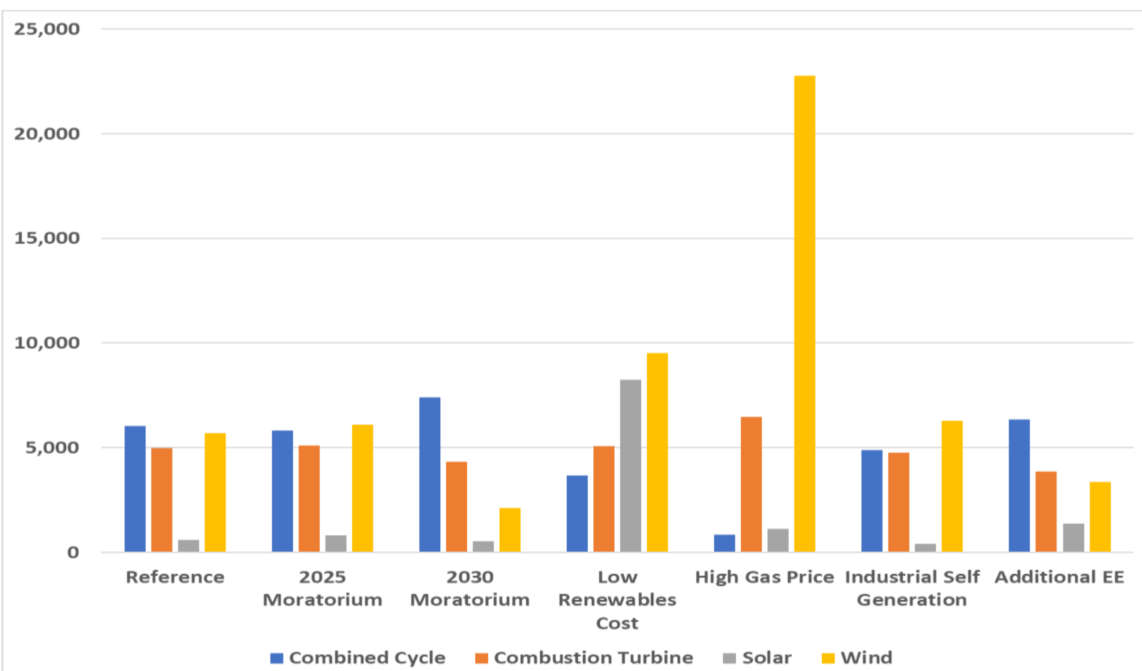

Figure 22. Resource Additions by Type through 2037 for All Scenarios (MW)

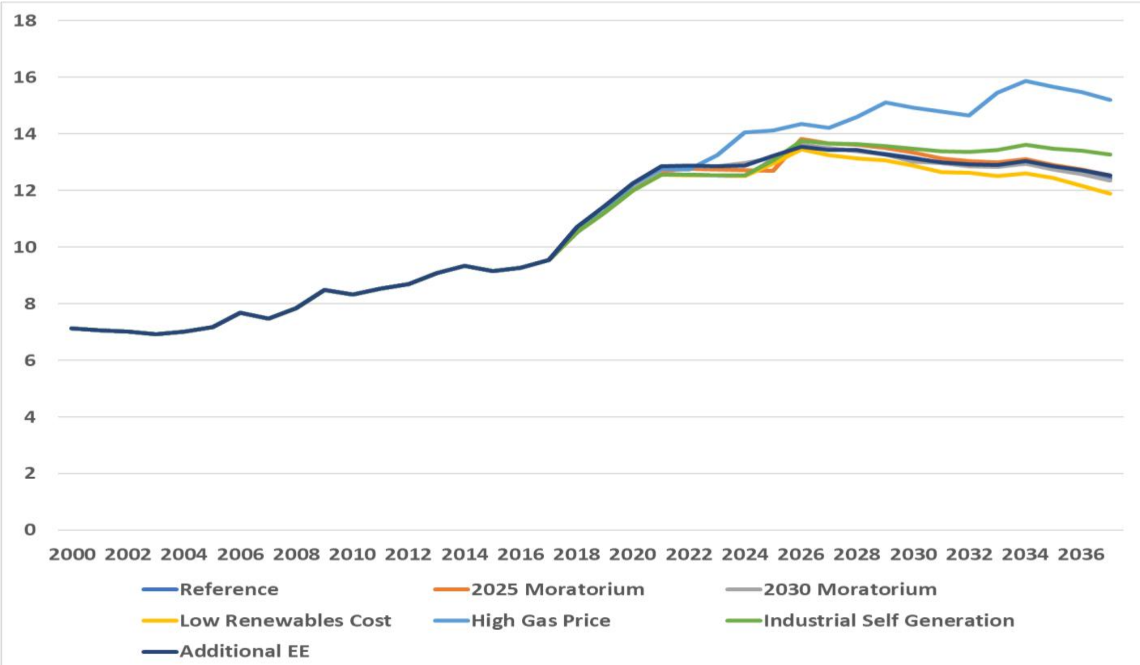

Figure 23. Indiana Electricity Price Projection for All Scenarios (2017 cents/kWh)

Carbon Price Sensitivities

Three scenarios were selected for sensitivity analysis examining the impact of a price on CO2 emissions; reference, 2030 moratorium, and low renewables cost. As with the scenarios, the purpose of the sensitivities is not to model a specific future but instead to see the broader impacts. CO2 emissions modeled are from combustion only and do not consider life cycle emissions.

The carbon prices used in the sensitivities were developed collaboratively by the SUFG and IURC. They do not represent any specific proposed legislation or the result of any detailed analysis. They are intended to be in the range of prices used by Indiana utilities in the IRP process. CO2 prices start at $2.50/ton in 2025 and increase by $2.50/ton/year every year thereafter. The same prices were used in all sensitivities.

Carbon Price Sensitivity for Reference Scenario

Table 8 shows the selected resources for the carbon price sensitivity to the reference scenario and Figure 24 compares the total resources added with and without the carbon price. The imposition of a carbon price results in a significant increase in renewable capacity, with wind generation over 10 GW higher and solar additions of 3.9 GW as opposed to just 0.6 GW without a carbon price. Far less combustion turbine capacity is selected (0.6 GW vs. 5.0 GW), while total combined cycle additions are largely unchanged.

Table 8. Indiana Resource Plan for Reference Scenario with Carbon Price (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,315	25,175	-96	0	0	0	0	0	0
2020	19,329	25,429	254	0	0	0	0	0	0
2021	19,190	25,288	-141	0	0	0	0	0	0
2022	19,145	25,433	145	0	0	0	0	0	0
2023	19,115	23,688	-1,744	0	0	23	0	0	23
2024	19,243	21,347	-2,341	1,573	0	1,842	0	0	1,842
2025	19,331	21,348	1	1,678	0	2,174	2,853	0	5,026
2026	19,233	20,522	-826	2,386	0	2,595	5,267	0	7,862
2027	19,256	20,523	0	2,413	0	2,818	5,456	0	8,274
2028	19,254	19,398	-1,124	3,535	0	3,534	5,456	0	8,990
2029	19,281	17,775	-1,623	5,190	234	4,410	5,456	0	10,100
2030	19,474	17,370	-405	5,826	317	4,948	5,456	21	10,743
2031	19,592	17,258	-112	6,078	354	5,163	5,456	21	10,995
2032	19,706	16,846	-412	6,625	354	5,535	6,830	76	12,795
2033	19,825	15,136	-1,710	8,478	354	6,065	7,543	1,862	15,825
2034	19,906	13,496	-1,640	10,214	354	6,065	13,084	3,552	23,056
2035	20,074	13,286	-210	10,625	411	6,065	14,146	3,905	24,527
2036	20,165	13,236	-50	10,782	567	6,065	15,072	3,905	25,610
2037	20,326	13,211	-25	11,000	609	6,065	15,916	3,905	26,496

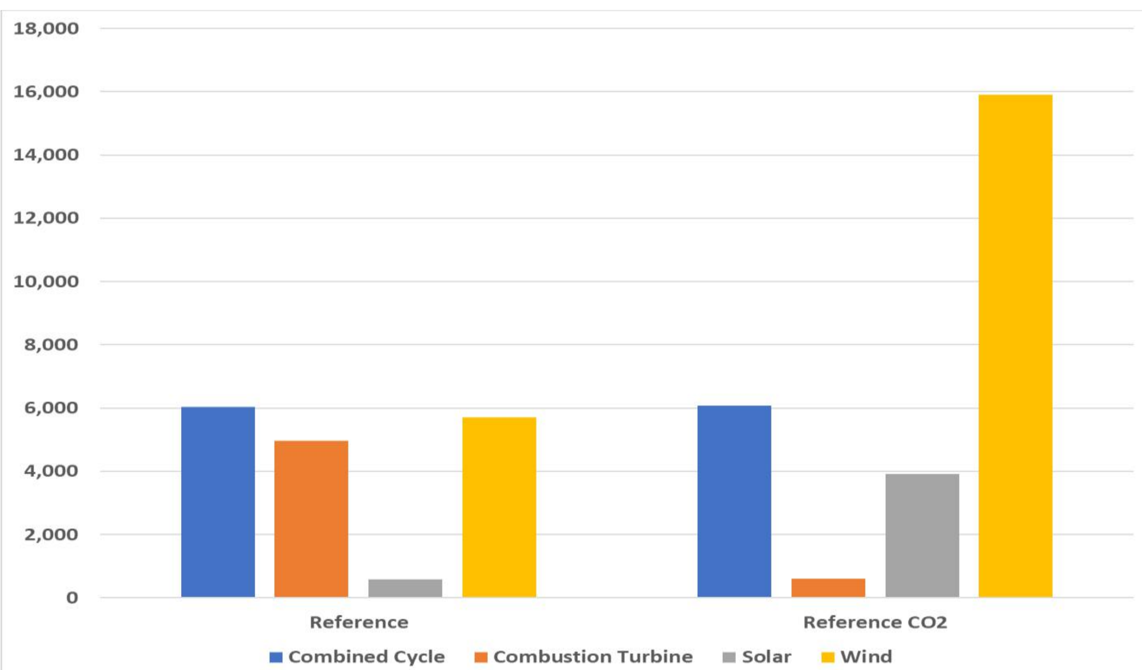

Figure 24. Resource Additions by Type through 2037 for Reference Scenario with and without Carbon Price (MW)

Figures 25 and 26 show the energy mix by fuel source for the carbon price sensitivity to the reference scenario. Energy from coal drops consistently as the carbon price grows starting in 2025. In the earlier years of the carbon price, natural gas makes up for most of the decline in coal utilization. However, as the carbon price gets higher in the later years, energy from natural gas also starts to decline, with energy from wind and solar increasing. Comparing the percentage charts with (Figure 2) and without (Figure 26) the carbon price, it can be seen that there are small differences in 2025, the first year of the CO2 costs. By 2030, energy from coal is down from 35% to less than 22%, while energy from natural gas has increased from 33% to over 45%. By 2035, coal-fired energy is down to 9% (compared to 28% without a carbon price), natural-gas fired energy has dropped (40% vs. 47%) and 1/3 of electrical energy is supplied by wind.

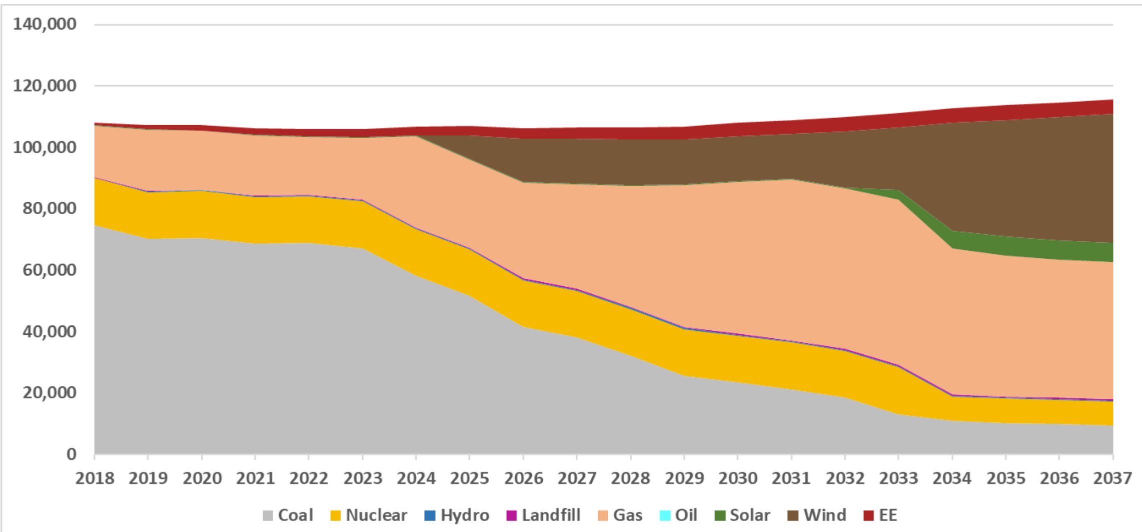

Figure 25. Electricity Supply by Resource for Reference Scenario with Carbon Price (GWh)

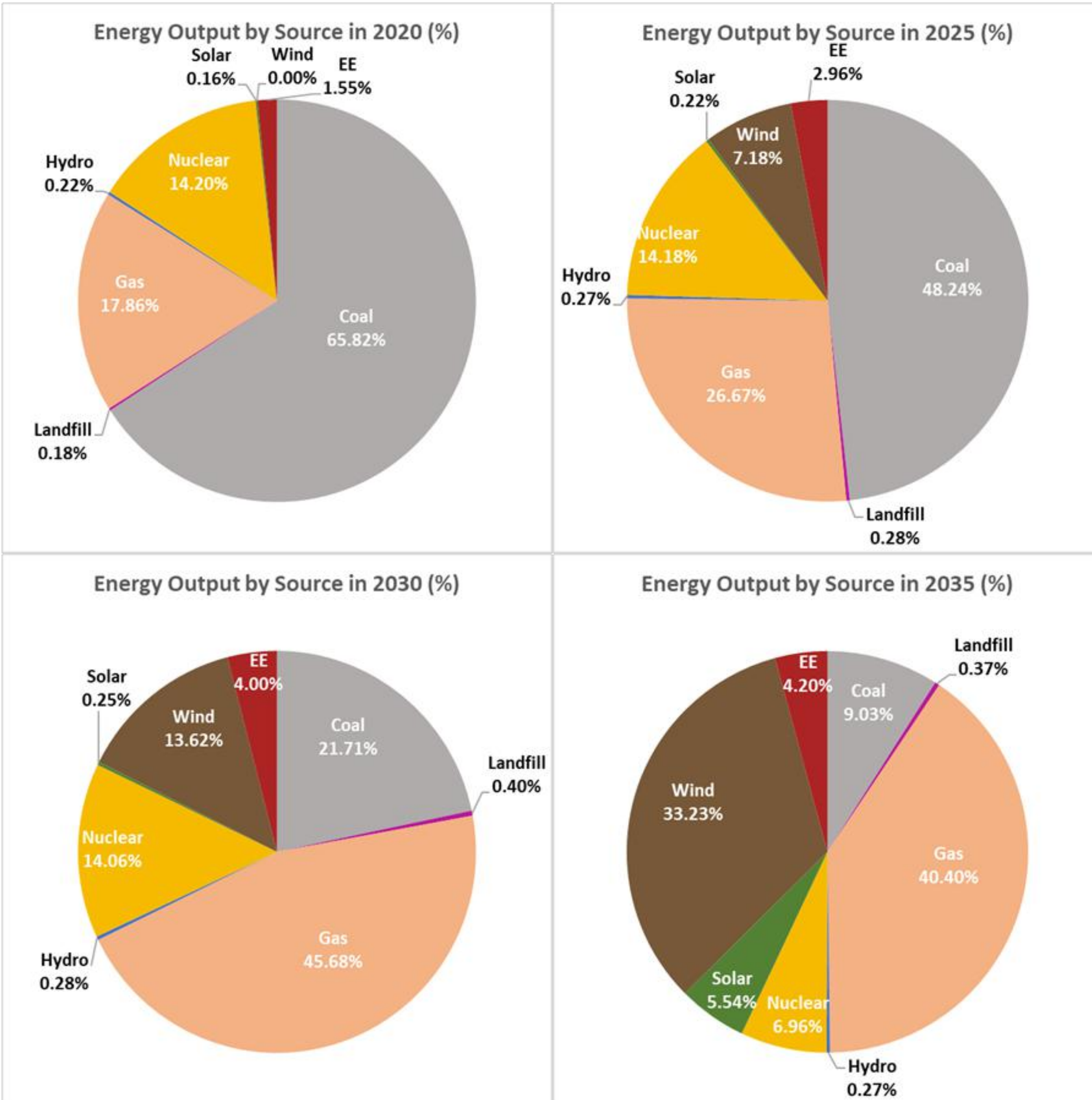

Figure 26. Energy Output by Source by Year for Reference Scenario with Carbon Price (%)

A comparison of the projected electricity prices with and without CO2 costs is provided in Figure 27. As expected, the imposition of CO2 costs causes electricity prices to be higher. Prices in the carbon price sensitivity are 1% higher in 2025 and grow to 14% higher in 2037.

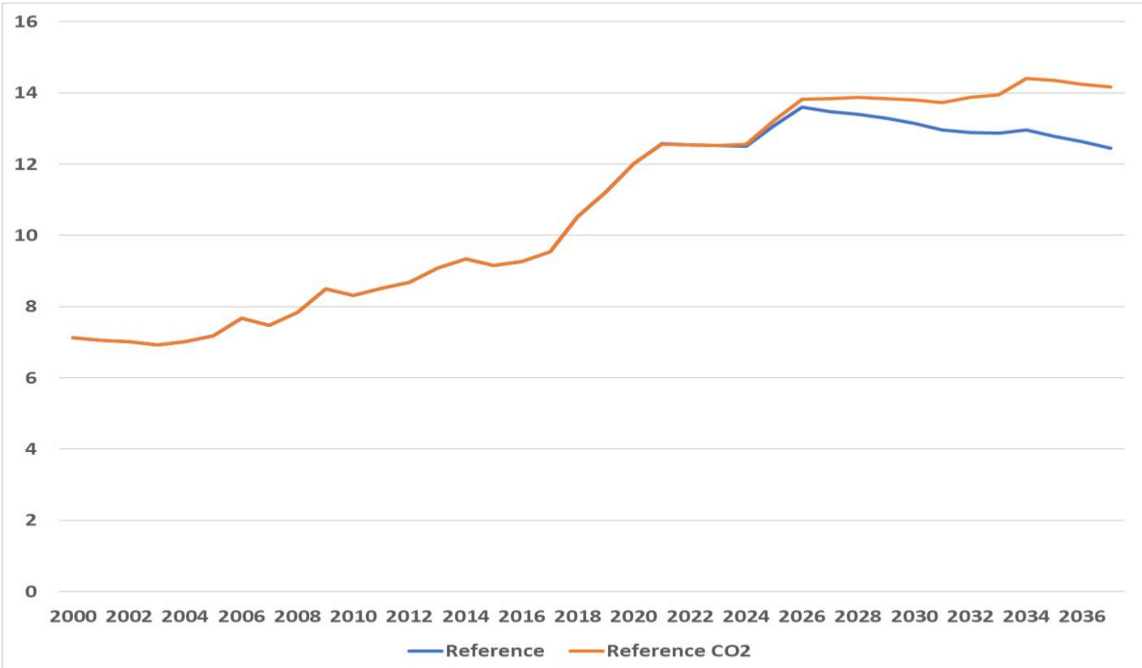

Figure 27. Indiana Electricity Price Projection for Reference Scenario with and without Carbon Price (2017 cents/kWh)

Carbon Price Sensitivity for 2030 Moratorium Scenario

Table 9 shows the selected resources for the carbon price sensitivity to the 2030 moratorium scenario and Figure 28 compares the total resources added with and without the carbon price. The overall impact of the carbon price is similar to that seen in the reference scenario; significant increases in wind and solar capacity and a severe decrease in combustion turbines. With the carbon costs, wind capacity additions were 16.6 GW, while only 2.1 GW were added without. Solar saw 3.6 GW with and 0.5 GW without. Only 0.3 GW of combustion turbines were chosen with the carbon prices, with 4.3 GW without. Combined cycle capacity additions were also down somewhat (6.2 GW vs. 7.4 GW).

Table 9. Indiana Resource Plan for 2030 Moratorium Scenario with Carbon Price (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,316	25,175	-96	0	0	0	0	0	0
2020	19,321	25,429	254	0	0	0	0	0	0
2021	19,160	25,500	71	0	0	0	0	0	0
2022	19,083	25,645	145	0	0	0	0	0	0
2023	19,021	24,315	-1,329	0	0	23	0	0	23
2024	19,041	24,126	-189	0	0	23	0	0	23
2025	19,100	24,127	1	0	0	46	0	0	46
2026	19,116	23,923	-204	0	0	157	1,556	0	1,713
2027	19,150	23,924	0	0	0	356	1,556	0	1,912
2028	19,153	23,774	-149	0	0	370	1,556	0	1,926
2029	19,158	22,600	-1,174	219	0	1,495	1,556	0	3,051
2030	19,308	22,195	-405	803	0	2,044	1,556	0	3,599
2031	19,422	17,258	-4,937	5,876	34	6,024	1,556	65	7,679
2032	19,545	16,846	-412	6,434	93	6,024	2,666	71	8,855
2033	19,661	15,136	-1,710	8,282	93	6,150	3,819	2,367	12,429
2034	19,714	13,496	-1,640	9,985	93	6,150	12,308	3,588	22,139
2035	19,858	13,286	-210	10,367	288	6,150	13,993	3,614	24,045
2036	19,930	13,236	-50	10,502	330	6,150	14,927	3,614	25,021
2037	20,051	13,211	-25	10,672	330	6,150	16,619	3,614	26,713

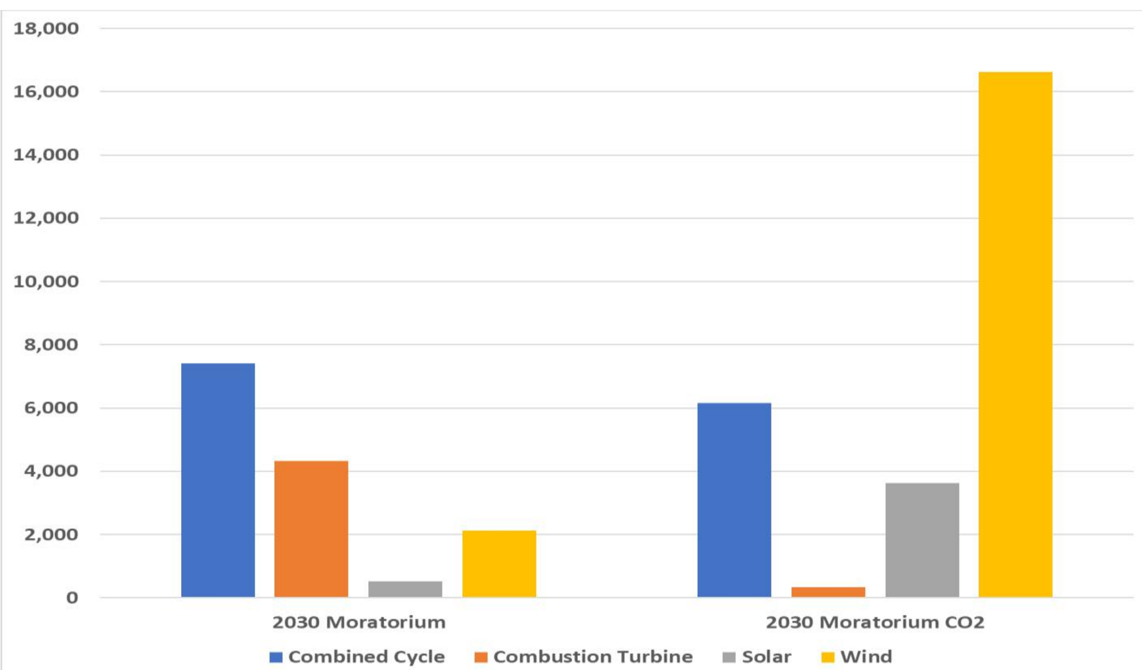

Figure 28. Resource Additions by Type through 2037 for 2030 Moratorium Scenario with and without Carbon Price (MW)

Figures 29 and 30 show the energy mix by fuel source for the carbon price sensitivity to 2030 moratorium scenario. Energy from coal declines gradually through the end of the moratorium, then decreases precipitously. A comparison of the scenario results in 2030 with (Figure 11) and without (Figure 30) a carbon price shows that natural gas has displaced some coal; energy from natural gas represents 30% of total with and 16% without and coal is 47% with and 61% without. By 2035, natural gas and wind are the major energy sources. Wind provides 33% of total energy with a carbon price vs. 5% without. Natural gas provides 41% with and 55% without. Coal, which provided 29% of energy without a carbon price, was down to 9% in the sensitivity.

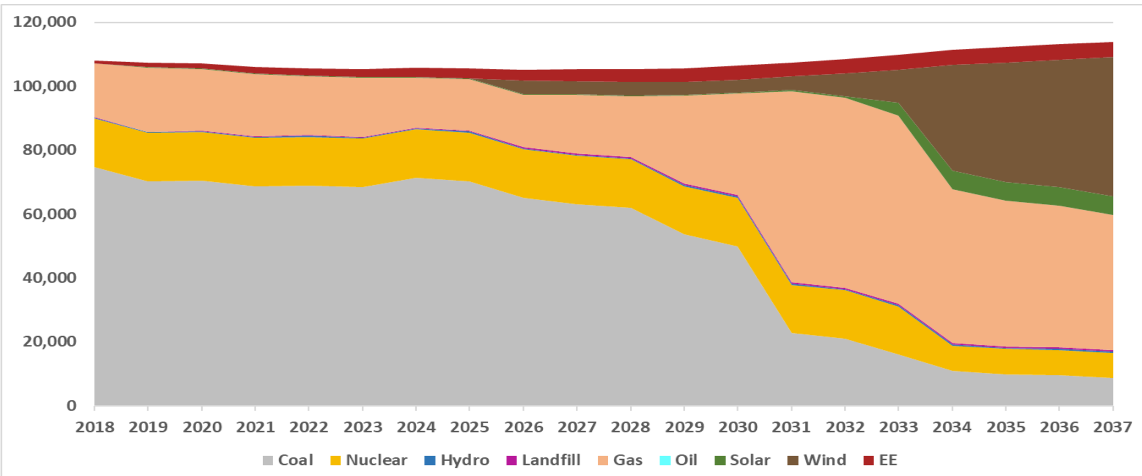

Figure 29. Electricity Supply by Resource for 2030 Moratorium Scenario with Carbon Price (GWh)

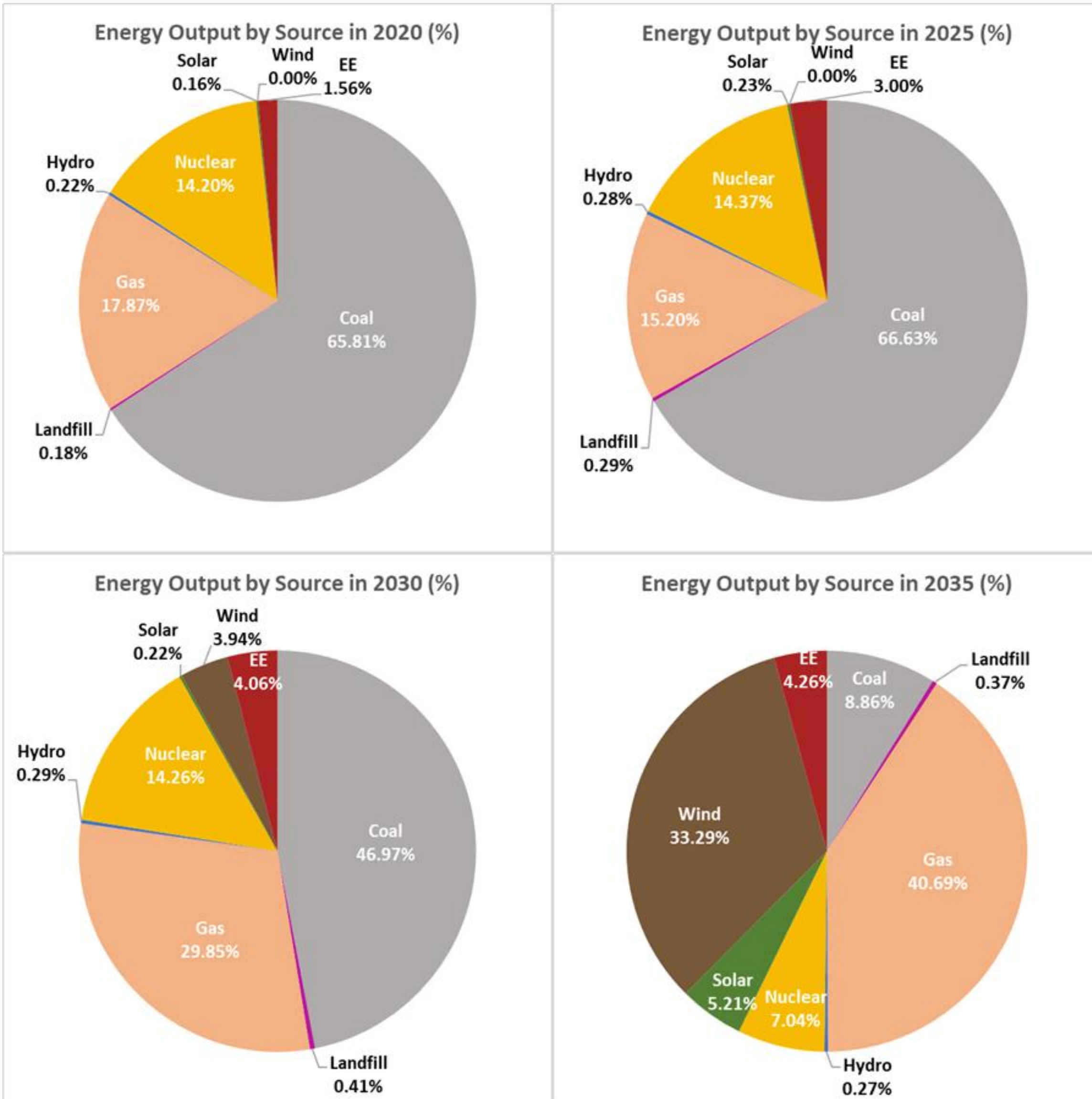

Figure 30. Energy Output by Source by Year for 2030 Moratorium Scenario with Carbon Price (%)

A comparison of the projected electricity prices with and without CO2 costs for the 2030 moratorium scenario is provided in Figure 31. As was seen in the reference scenario, the imposition of CO2 costs resulted in higher electricity prices. Prices in the carbon price sensitivity are 2% higher in 2025, 10% higher in 2030 and 19% higher in 2037.

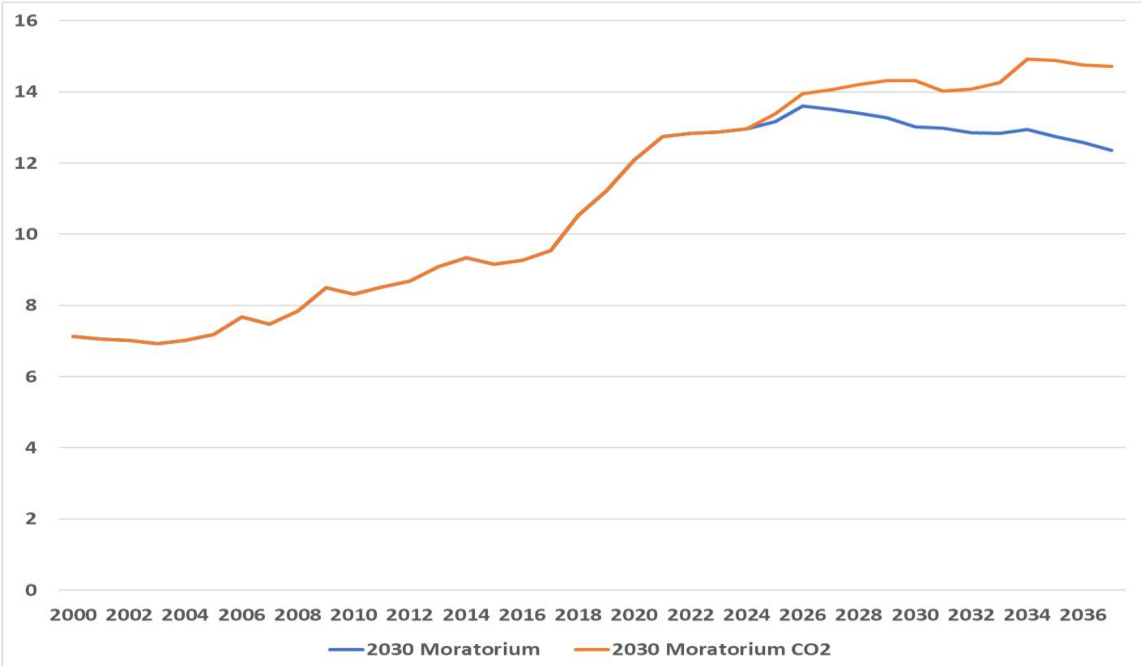

Figure 31. Indiana Electricity Price Projection for 2030 Moratorium Scenario with and without Carbon Price (2017 cents/kWh)

Carbon Price Sensitivity for Low Renewables Cost Scenario

Table 10 shows the selected resources for the carbon price sensitivity to the 2030 moratorium scenario and Figure 32 compares the total resources added with and without the carbon price. The inclusion of a carbon price results in an extremely large amount of wind capacity being selected (34.4 GW). A lower amount of combustion turbine capacity is selected (3.5 GW vs. 5.1 GW) and combined cycle capacity is largely unchanged. Interestingly, solar capacity is lower in the carbon price sensitivity (3.7 GW vs. 8.3 GW) as the model needs dispatchable resources to handle the intermittency of very large amounts of wind. As was the case in the high natural gas price scenario, which also saw the selection of very large amounts of wind capacity, the availability of energy storage in the model could have resulted in a different mix.

Table 10. Indiana Resource Plan for Low Renewables Cost Scenario with Carbon Price (MW)

Year	Peak Demand	Existing/ Approved Resources	Incremental Change in Resources	Required Additional Resources	Additional Selected Resources				
					CT	CC	Wind	Solar	Total
2018	19,444	25,271		0	0	0	0	0	0
2019	19,316	25,175	-96	0	0	0	0	0	0
2020	19,329	25,429	254	0	0	0	0	0	0
2021	19,193	25,288	-141	0	0	0	0	0	0
2022	19,151	25,433	145	0	0	0	0	0	0
2023	19,119	23,688	-1,744	0	0	23	0	0	23
2024	19,261	21,347	-2,341	1,594	79	1,840	23	348	2,290
2025	19,318	21,348	1	1,662	269	1,904	2,947	526	5,646
2026	19,251	20,522	-826	2,408	269	2,090	6,539	1,091	9,988
2027	19,256	20,523	0	2,413	269	2,234	7,887	1,631	12,021
2028	19,244	19,398	-1,124	3,524	269	2,314	7,999	1,717	12,299
2029	19,260	17,775	-1,623	5,166	613	3,141	7,999	3,479	15,232
2030	19,390	17,370	-405	5,726	613	3,141	13,373	3,511	20,638
2031	19,471	17,258	-112	5,934	613	3,141	14,314	3,511	21,579
2032	19,547	16,846	-412	6,437	613	3,141	16,939	3,511	24,204
2033	19,536	15,136	-1,710	8,133	1,205	3,434	25,854	3,511	34,004
2034	19,518	13,496	-1,640	9,752	2,893	3,502	29,196	3,511	39,102
2035	19,629	13,286	-210	10,095	3,517	3,502	30,872	3,683	41,573
2036	19,682	13,236	-50	10,207	3,539	3,502	32,371	3,683	43,095
2037	19,812	13,211	-25	10,387	3,539	3,502	34,421	3,690	45,153

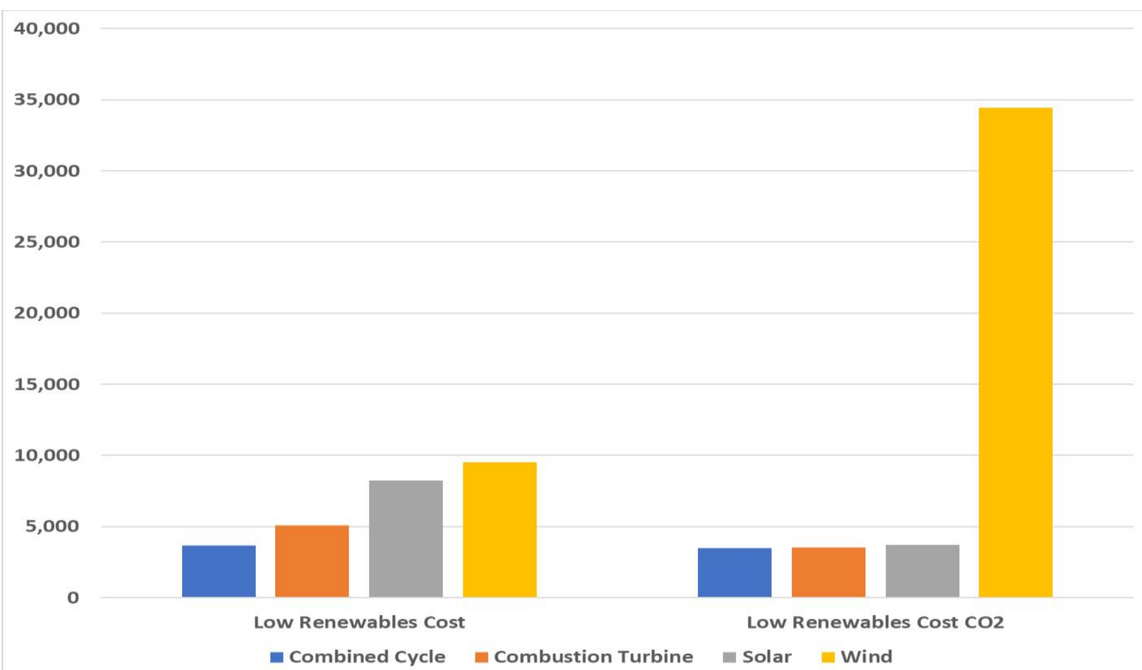

Figure 32. Resource Additions by Type through 2037 for Low Renewables Cost Scenario with and without Carbon Price (MW)

Figures 33 and 34 show the energy mix by fuel source for the carbon price sensitivity to the low renewables cost scenario. This sensitivity acquires the least amount of energy from coal (6% in 2035) and the most from wind (59% in 2035) of any of the scenarios and sensitivities. Only the high natural gas price scenario uses less natural gas-fired generation. Comparing the results with (Figure 34) and without (Figure 5) shows that the carbon price causes energy from coal to drop (17% vs. 35% in 2030 and 6% vs. 27% in 2035), natural gas to drop late in the analysis period (18% vs. 33% in 2035) and wind to increase (33% vs. 16% in 2030 and 59% vs. 19% in 2035).

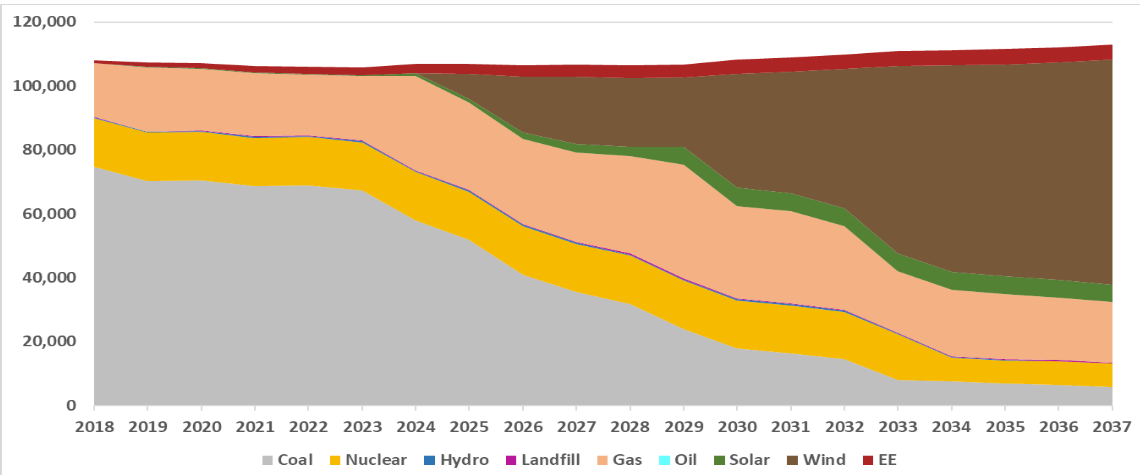

Figure 33. Electricity Supply by Resource for Low Renewables Cost Scenario with Carbon Price (GWh)

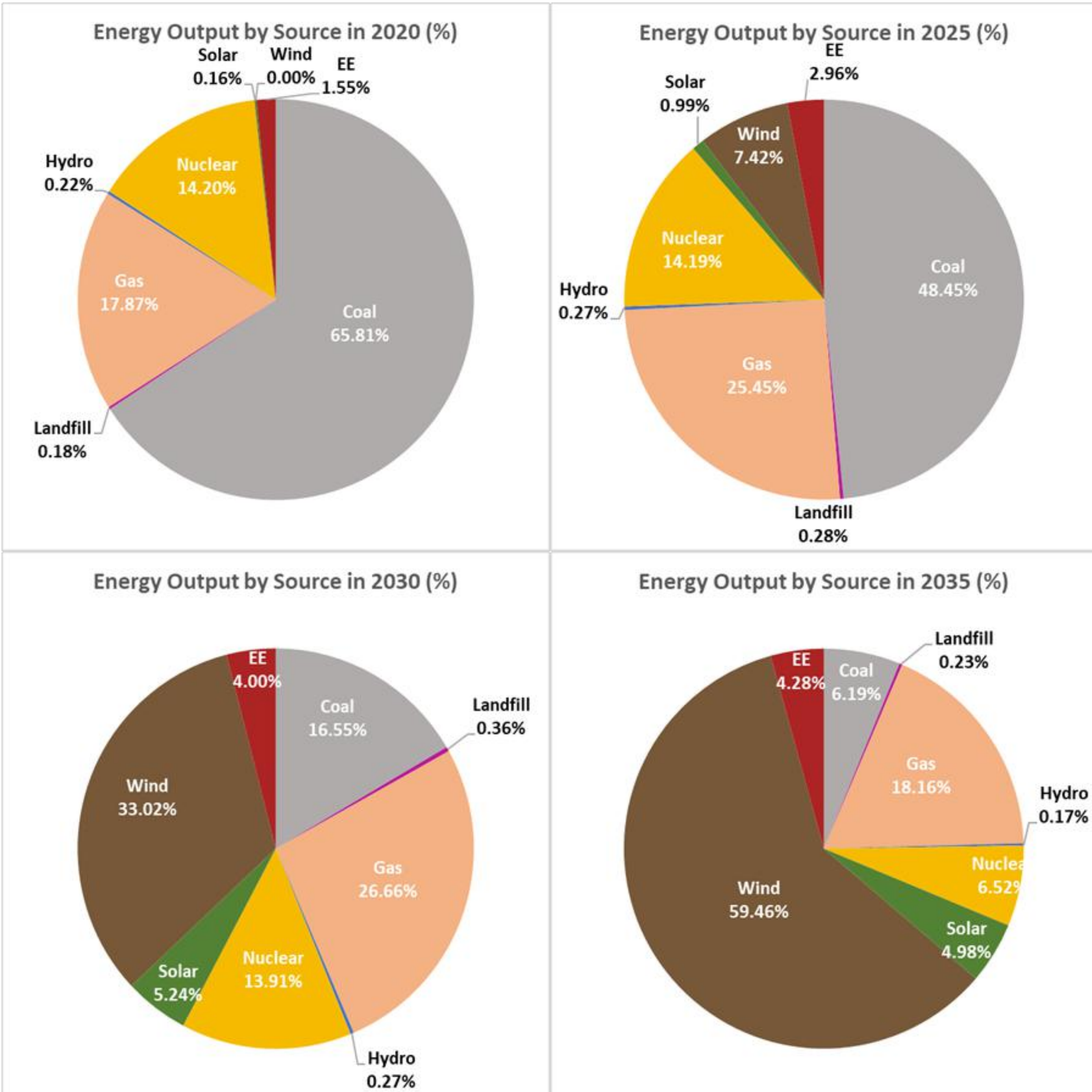

Figure 34. Energy Output by Source by Year for Low Renewables Cost Scenario with Carbon Price (%)

A comparison of the projected electricity prices with and without CO2 costs for the low renewables cost scenario is provided in Figure 35. As was seen in the previous sensitivities, the imposition of CO2 costs resulted in higher electricity prices. Prices in the carbon price sensitivity are 2% higher in 2025, 10% higher in 2030 and 27% higher in 2037.

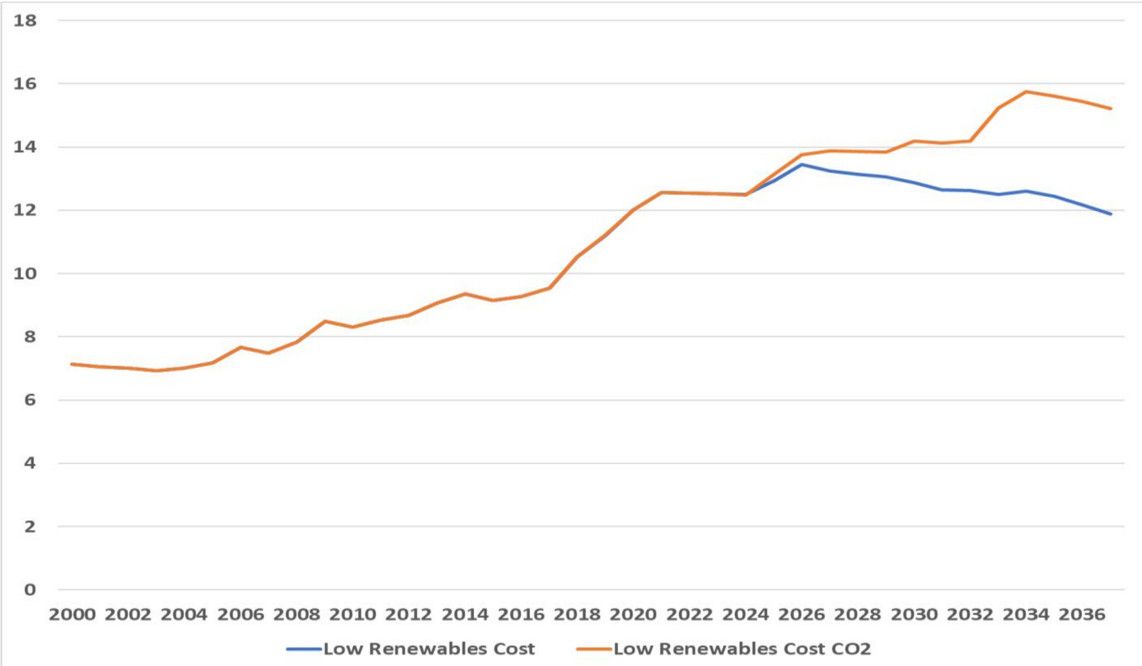

Figure 35. Indiana Electricity Price Projection for Low Renewables Cost Scenario with and without Carbon Price (2017 cents/kWh)

Observations

Resource Selection

Future resource selections in all scenarios and sensitivities are a combination of natural gas-fired generation (combustion turbines and combined cycle units), wind, and solar. Coal and nuclear options were never chosen, even in the high natural gas price scenario. The various factors defining the scenarios altered the mix and timing of the resource additions in largely predictable fashion. For instance, low renewables costs, high natural gas prices, and the imposition of carbon prices all resulted in more renewables being chosen and less natural gas.

Renewable Resources

Model results were highly sensitive to the price assumptions for renewable resources. While 13% of total energy in 2035 was provided by renewables in the reference scenario, that number increased to 29% in the low renewables cost scenario.

Energy from Coal

Energy derived from coal decreases over time in all scenarios, which is driven by a combination of retirements of existing generators and economic competition from natural gas and renewables. The imposition of retirement moratoria provides a boost to coal while they are in place, but energy from coal drops to roughly the same level in all non-carbon price scenarios (23-29% of total in 2035). The imposition of a carbon price results in large additional decreases in coal utilization. Energy from coal represents 6-9% of total in 2035 for the three carbon price sensitivities.

Effect of Carbon Prices

In general, the lower carbon prices imposed in the earlier years, tend to cause a shift from coal to natural gas-fired generation. In 2030 for the reference scenario, energy from coal drops from 35% to 22% with the imposition of the carbon price, while energy from natural gas increases from 33% to 46%. Similarly, for the 2030 retirement moratorium scenario, coal decreases from 61% to 47% and natural gas increases from 16% to 30%. In the low renewables cost scenario, however, the shift is from coal to wind rather than coal to natural gas. Energy from coal is cut in half (from 35% to 17%) while energy from wind doubles (from 16% to 33%).

The higher carbon prices in the later years show renewables displacing both coal and natural gas. In 2035 in the reference scenario, the carbon price causes coal-fired energy to drop from 28% to 9% and for natural gas-fired energy to fall from 47% to 40%. Meanwhile, energy from renewables triples from 13% to 39%. In the 2030 retirement moratorium scenario, coal (29% to 9%) and natural gas (55% to 41%) decreases while renewables (5% to 38%) increases. For the low renewables cost scenario, the effect is more pronounced, with coal falling from 27% to 6%, natural gas dropping from 33% to 18%, and renewables increasing from 29% to 64%. Interestingly, the increase is coming from wind, with energy from solar actually decreasing from the non-carbon price scenario.

Electricity Markets and Policy
Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System

Impact on Rates, Reliability, and Resilience

Juan Pablo Carvallo, Myles T. Collins[1], Stephanie Bieler[1], Joscha Mueller, Christoph Gehbauer, and Peter H. Larsen

[1] Nexant, Inc.

June 2020

ELECTRICITY
MARKETS &
POLICY

This work was commissioned by the Indiana Utility Regulatory Commission to Lawrence Berkeley National Laboratory under Strategic Partnership Projects Agreement No. FP00009789.

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Acronyms and Abbreviations

ANSI	American National Standards Institute
BAU	Business As Usual
BPS	Bulk Power System
CAIDI	Customer Average Interruption Duration Index
CCCT	Combined Cycle Combustion Turbine
CMI	Customer Minutes Interrupted
DER	Distributed Energy Resources
DG	Distributed Generation
DSM	Distribution Side Management
EE	Energy Efficiency
EV	Electric Vehicle
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor Owned Utility
IRP	Integrated Resource Plan/Planning
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission
LBNL	Lawrence Berkeley National Laboratory
LTC	Load Tap Changer
MED	Major Event Day
MISO	Midcontinent Independent System Operator
NREL	National Renewable Energy Laboratory
PAM	Partitioning Around Medoids
PCA	Principal Component Analysis
PV	Photovoltaic (solar panel)
SEIA	Solar Energy Industry Association
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCCT	Simple Cycle Combustion Turbine
SUFG	State Utility Forecasting Group

Glossary

Capacity expansion model: an optimization model of the power system that determines least-cost investment decisions in generation assets to meet resource adequacy requirements over time for a given region.

Feeder: the electrical network operating in primary distribution voltage (typically between 4 kV and 33 kV) that electrically connects the secondary busbar in the transmission substation to distribution step-down transformers.

Line loading: the ratio between the average current flow over a period of time and the ampacity (maximum current, in amperes, that a conductor can carry continuously under the conditions of use without exceeding its temperature rating) of a conductor. A line overloading occurs when the current flow is above the rated ampacity.

Power flow simulation: numerical analysis or simulation of the flow of electricity in an interconnected grid.

Reliability: "The probability that the system will perform its intended function for a given period of time under stated environmental conditions" (Singh and Billinton, 1977)

Resilience: "[T]he ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." (PPD, 2013)

Voltage violation: a condition of the distribution system where voltage in any node is below or above an established limit, usually the America National Standard Institute's optimal and normal levels.

Executive Summary

In 2019, the Indiana General Assembly enacted House Enrolled Act No. 1278 to explore the impact that fuel transitions and emerging technologies may have on the state's power system. The Act created the 21st Century Energy Policy Development Task Force, whose work will be informed by a comprehensive study to be conducted by the Indiana Utility Regulatory Commission. As indicated in the Act:

> *"[…] the commission shall conduct a comprehensive study of the statewide impacts, both in the near term and on a long term basis, of:*
>
> *(1) transitions in the fuel sources and other resources used to generate electricity by electric utilities; and*
>
> *(2) new and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure;*
>
> *on electric generation capacity, system reliability, system resilience, and the cost of electric utility service for consumers. In conducting the study required by this subsection, the commission shall consider the likely timelines for the transitions in fuel sources and other resources described in subdivision (1) and for the implementation of new and emerging technologies described in subdivision (2)."*

The study presented here explores the impacts of emergent technologies that could be deployed across Indiana investor owned utility distribution systems by 2025 and 2040. The statutory task mandated in the Act is broken down in three components: the physical impact on distribution, transmission, and generation capacity; the economic and rate impact on customers; and the reliability and resilience impacts on the distribution system.

This study identifies six adoption scenarios that combine deployment levels of rooftop solar (PV), electric vehicle charging (EV), and battery storage—collectively referred to as DER—in residential and commercial customers connected to Indiana IOU feeders. Five of the adoption scenarios implement a range of expected to optimistic deployment of these resources, while a sixth scenario is presented as a stress-test with very high adoption levels. Figure ES-1 shows 2040 DER penetration by share of customers for each scenario. By 2040, for example, rooftop PV penetration ranges from 0.5% of customers (Base) to nearly 20% (Boundary). In addition, the Boundary scenario assumes over 70% of residential customers will charge EVs in their homes by 2040, compared to 10% in the Base scenario.

This study develops and employs an empirical framework that measures the impact of emerging distributed technologies on the power system for the six scenarios. The framework measures the technical, economic value, and reliability impact of DER:

- The economic value of DER is assessed by developing technical assessments employing capacity expansion and power flow analysis of the generation and distribution segments, respectively, under future hourly demand assumptions based on the six adoption scenarios. The assessment of generation energy and capacity impacts uses State Utility Forecasting Group (SUFG) modeling platform to simulate optimal production and expansion costs. The assessment of distribution impacts employs the industry-standard Cymdist distribution power flow model with an array of strategies to upgrade feeders to address voltage, line loading, and energy losses issues. A simplified model for transmission expansion complements the two technical tools to estimate the economic impact of DER on the three power system segments.

- The reliability impact of DER adoption is measured using a pioneering method first developed for this study. We use a data set of over half a million of historical outages across the five Indiana IOUs to inform this measurement. The method simulates the impact of different levels of behind-the-meter battery storage adoption, with several operational strategies, to reduce the frequency and duration of outages less than 24-hours long from the customer's perspective. This analysis is complemented with an assessment of the impacts of DER on reducing long-duration (more than 24 hours) interruptions as an initial measure of resilience impacts on the distribution system.

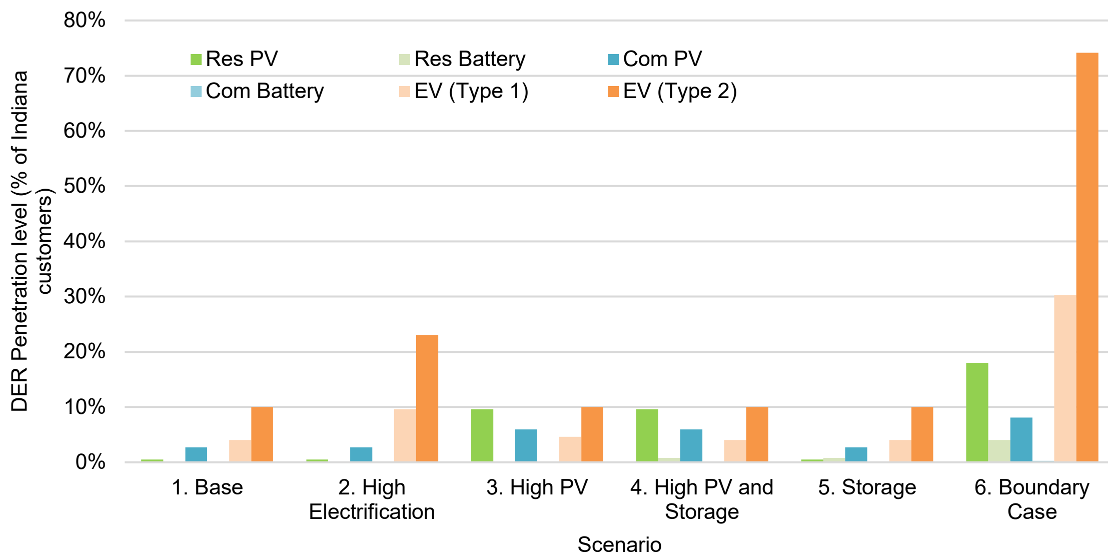

Figure ES-1 DER penetration levels in 2040 for the six adoption scenarios

This study uses statistical techniques to classify over 2,800 feeders across Indiana into one of six groups that represent different types of feeders based on their customer mix, length, reliability, and other variables. Representative feeders from each group are selected to run power flow analyses for DER impacts on distribution systems, which can then be extrapolated to produce state-wide results.

Do these emerging technologies lead to increased voltage violations, line loading, and line losses and, if so, how can these impacts be mitigated?

Results for the distribution system power flow simulations show that voltage violations are relatively rare. Only 159 out of 3,456 simulated hours exhibit voltage violations of the ANSI optimal range levels, generally spanning a relatively small fraction of load nodes in a feeder. The majority of voltage issues arise only in the Boundary Case and the violations are relatively small in magnitude. Voltage violations can be mitigated at a very low cost using a combination of smart inverters in future rooftop PV systems and voltage adjustments in the feeder heads. Line loading issues are minimal, with only eight simulation hours showing loading levels above 100% of capacity in about 3% of segments for feeders in clusters 3, 4, and 5. Line loading issues are addressed by upgrading conductors with relatively low costs given the few affected segments. Line losses are ~4%-10% higher than the Base case in the High Electrification and Boundary scenarios and 11% lower than the Base case in the High PV and High PV and Storage scenarios. Energy losses are not mitigated in this analysis, but monetized using the wholesale generation power costs that are output by the SUFG model.

What is the economic and rate impact of more widespread deployment of DER within the IOU service territories?

We estimate that the incremental economic impact on power system investment and operation costs of increased DER adoption within the IOU service territories will be between -$265 million to +$105 million and -$550 million to +$1.6 billion in 2025 and 2040 relative to the Base Case, respectively (see Tables ES-1 and ES-2). In general, scenarios with high adoption of rooftop solar result in system-wide savings, while scenarios with high adoption and charging of electric vehicles result in large peaks that require substantial new generation capacity and higher system costs. The economic impacts of DER in the power system are concentrated in the generation segment, with about 80% of the cost impacts. It is important to note that the results only account for the infrastructure requirements to maintain resource adequacy and operational standards—they do not account for avoided costs of power interruptions to customers.

Table ES-1 Economic impact of DER adoption by scenario and power system segment relative to the base case (millions of $2017)

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	**Gen.**	**Trans.**	**Dist.**	**Total**	**Gen.**	**Trans.**	**Dist.**	**Total**
High Electrification	$79.1	$15.8	$10.7	$105.6	$204.0	$91.3	$25.9	$321.2
High PV	-$242.4	-$32.4	$9.7	-$265.2	-$485.5	-$71.9	$8.2	-$549.2
High PV and Storage	-$242.7	-$32.4	$9.7	-$265.5	-$481.6	-$70.6	$8.2	-$544.1
Storage	$1.7	$0.0	$10.6	$12.3	$2.6	$0.0	$10.6	$13.1
Boundary	-$18.6	$27.5	$10.0	$19.0	$759.7	$734.1	$94.1	$1,587.9

Table ES-2 Economic impact of DER adoption by scenario and power system segment relative to the base case (2017 cents/kWh)

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	**Gen.**	**Trans.**	**Dist.**	**Total**	**Gen.**	**Trans.**	**Dist.**	**Total**
High Electrification	0.11¢	0.02¢	0.01¢	0.14¢	0.25¢	0.11¢	0.03¢	0.39¢
High PV	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.64¢	-0.09¢	0.01¢	-0.72¢
High PV and Storage	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.63¢	-0.09¢	0.01¢	-0.72¢
Storage	0.00¢	0.00¢	0.01¢	0.02¢	0.00¢	0.00¢	0.01¢	0.02¢
Boundary	-0.03¢	0.04¢	0.01¢	0.03¢	0.96¢	0.93¢	0.12¢	2.01¢

We estimate the impact of DER adoption in average retail rates using the SUFG ratemaking model (see Table ES-3). Rates tend to go down in the short term for the High PV scenarios, but tend to go up for all scenarios in the long term. The increase in rates is due to a combination of lower sales that require higher rates to recover fixed costs, as well as increased peak demand due to uncoordinated EV charging that requires additional generation and transmission infrastructure investments. On average, rates increase from 0.03 ¢/kWh to 1.7 ¢/kWh in the Boundary scenario.

Table ES-3 Impact of DER adoption on electricity rates by scenario and customer type (2017 cents/kWh).

	2025 Rate Change Relative to Base				2040 Rate Change Relative to Base			
Scenario	**Residential**	**Commercial**	**Industrial**	**Average**	**Residential**	**Commercial**	**Industrial**	**Average**
High Electrification	0.25¢	0.24¢	0.19¢	0.22¢	-0.03¢	0.05¢	0.14¢	0.06¢
High PV	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.01¢	0.73¢	0.23¢	0.59¢
High PV and Storage	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.00¢	0.71¢	0.22¢	0.58¢
Storage	0.00¢	0.00¢	0.00¢	0.00¢	0.05¢	0.05¢	0.01¢	0.03¢
Boundary	0.52¢	0.47¢	0.18¢	0.35¢	1.88¢	1.96¢	1.46¢	1.70¢

What are the reliability and resilience costs and/or benefits of emergent technologies in the distribution system?

Customer-sited battery storage systems can achieve multiple objectives related to improved reliability/resilience. When sized and operated appropriately, batteries can be used behind-the-meter for peak shaving or mitigating the PV 'duck curve' although their ability to mitigate power interruptions is limited. We find that reliability and resilience improvements are driven more by battery adoption levels than by mode of operation. We study battery storage adoption levels of 0.01% of customers (BAU), 1% of customers (High), 5% of customers (Very high), and 100% of residential and commercial customers (Theoretical Limit). The impact of these adoption levels on system-level average interruption duration (SAIDI) and frequency (SAIFI) and customer-average duration (CAIDI) are reported in Table ES-4. This analysis assumes that the battery discharge could only be consumed behind the meter. It is possible that larger system-wide benefits could be achieved if customer-sited batteries could discharge power back to the grid under direction from utility operations staff.

Table ES-4 Reliability metrics under different behind-the-meter battery storage adoption levels

		Behind-the-meter Battery Storage Adoption Levels			
		BAU	**High**	**Very High**	**Theoretical Limit**
Without MED	**SAIDI**	1.66	1.64	1.58	0.18
	SAIFI	0.81	0.80	0.77	0.08
	CAIDI	2.00	2.00	2.00	2.32
With MED	**SAIDI**	3.09	3.07	2.97	0.96
	SAIFI	0.90	0.89	0.86	0.12
	CAIDI	2.94	2.95	2.97	6.80

There are several definitions of resilience of the power system used in the literature. We define resilience as the capacity of a system to withstand long-duration interruptions – with a duration of over 24 hours. Figure ES-2 shows the number of long-duration customer-outages under the different battery storage adoption levels. These results show that even widespread adoption of relatively large battery storage systems would still leave 60% of long-duration outages unmitigated. Additional technologies and strategies would be needed to further improve resilience of the distribution system.

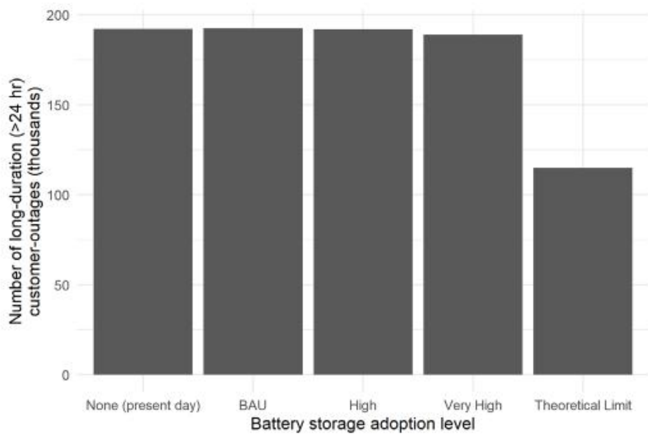

Figure ES-2 Number of long-duration customer-outages by battery adoption level

This report is one of the first manuscripts to estimate the economic impact of increased adoption of distributed technologies across the different segments of the power system—generation, transmission, and distribution—using a forward-looking simulation framework. This study is also novel in that it develops an empirically-based estimation of the impact of behind-the-meter battery storage adoption on reliability indices from the customer and grid operators' perspective. This report identifies a number of future research opportunities including:

- The investigation of impacts to secondary distribution networks.
- More targeted upgrade assessments for representative feeders that consider a wider range of expansion options to integrated DER.
- Estimating the economic value of avoiding power interruptions due to DER adoption.
- A more thorough examination of the impacts of DER adoption on transmission expansion using an optimization model with explicit transmission representation.
- Development and implementation of additional methods to measure and mitigate impacts on distribution system resilience, including integration of battery storage with demand management processes.

The framework developed for this report can serve as a blueprint for utilities, policymakers, and other stakeholders who may be interested in conducting more targeted and expansive technology adoption impact studies.

1. Introduction

In 2019, the Indiana General Assembly enacted House Enrolled Act No. 1278 to explore the impact that fuel transitions and emerging technologies may have on the state's power system. The Act created the 21st Century Energy Policy Development Task Force (see Indiana Code § 8-1-8.5-3.1 (b)), which is tasked with identifying energy policy recommendations for the House focused on affordability and reliability of future electric utility service. A comprehensive study of the impacts of fuel transitions and emerging technologies across Indiana is one of the key inputs for the Task Force.

The Indiana Utility Regulatory Commission (IURC) was tasked with producing a comprehensive study of the statewide impacts of fuel transitions and emerging technologies on generation capacity, reliability, resilience, and rates. As indicated in the Act:

> *"[…] the commission shall conduct a comprehensive study of the statewide impacts, both in the near term and on a long term basis, of:*
>
> *(1) transitions in the fuel sources and other resources used to generate electricity by electric utilities; and*
>
> *(2) new and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure;*
>
> *on electric generation capacity, system reliability, system resilience, and the cost of electric utility service for consumers. In conducting the study required by this subsection, the commission shall consider the likely timelines for the transitions in fuel sources and other resources described in subdivision (1) and for the implementation of new and emerging technologies described in subdivision (2)."*

The IURC divided the technical aspects of the study into two components: (1) technology and fuel changes in generation-transmission and (2) and emerging technologies in distribution systems. Purdue University's State Utility Forecasting Group (SUFG) is leading the assessment of impacts on generation, while Lawrence Berkeley National Laboratory (LBNL) and Nexant, Inc. are leading the assessment of impacts of distributed technologies across the power system. The study presented here explores the impacts of emergent technologies that could be deployed across Indiana investor owned utility distribution systems by 2025 and 2040. The statutory task mandated in the Act is broken down in three components: the physical impact on distribution, transmission, and generation capacity; the economic and rate impact on customers; and the reliability and resilience impacts on the distribution system.

There are several types of emerging technologies that are being deployed or could be deployed in the distribution system and behind the meter. Technologies can produce electricity (e.g. solar photovoltaic (PV) panels, natural gas micro-turbines), store electricity (e.g. batteries, flywheels), consume electricity in novel ways (e.g. electric vehicles) and improve electricity management and consumption (e.g. smart thermostats, super-efficient appliances). These technologies are grouped and identified throughout this document as Distributed Energy Resources (DER). Given the current landscape in Indiana and the focus of the Task Force, this study is limited to the following DER: solar PV, battery storage, and electric vehicles, with some built in assumptions about availability and penetration of demand response and energy efficiency.

1.1 Distributed resource landscape

Over the last decade, the U.S. has seen increasing uptake of customer-owned DER, particularly rooftop PV. This increase has been driven by policies, prices, consumer attitudes, and attractive financing options for customers. Penetration levels vary by state. Figure 1.1 shows the percentage of small-scale PV generation as a portion of all generation by state. In 2019, four states showed percentages higher than six percent, with Hawaii greater than ten percent. Most states, including Indiana, were below one percent.

Battery storage is still an emerging technology and has not achieved widespread adoption. In 2019, less than 5 percent of solar PV systems were paired with storage. The Solar Energy Industry Association (SEIA) estimates that by 2025, 25 percent of new solar PV installations will be paired with a battery storage system (SEIA, 2020). The number of expected EVs by 2020 reported in the IOUs IRP was approximately 14,000 total in Indiana (Duke Energy, 2019; I&M, 2019; IPL, 2019; NIPSCO, 2018; Vectren, 2016).

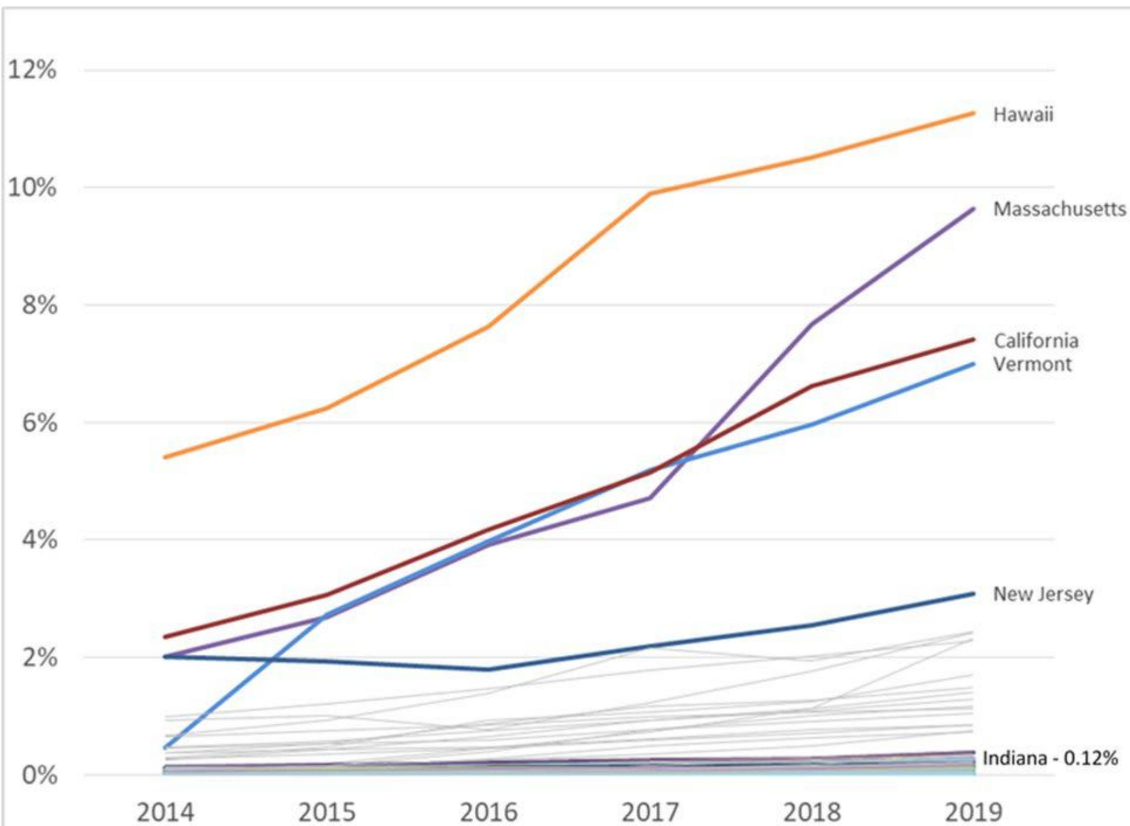

Figure 1.1 Small-Scale PV Generation as a Portion of All Generation
Source: Energy Information Administration (EIA)

Based on the information shared by the five Indiana IOUs that are the subject of this study, the level of DER adoption varies by technology and customer class. Only 0.14 percent of residential customers own a PV system, while that figure is 4.7 percent for commercial customers. Almost no customers in Indiana own a storage system (less than 0.01%).

Integrated Resource Plans (IRPs) are a useful source of data for understanding the expected trajectory of different generation resources in the state. While utility-scale solar and storage were often included in IRPs, this study examined customer-owned generation resources—and the treatment of DER forecasts varied by utility. Table 1.1 summarizes the treatment of DERs in IRPs for each utility. NIPSCO did not explicitly model or vary DER adoption by scenario. Duke Energy modeled customer-owned DER adoption, but did not explicitly vary it by scenario. Vectren modeled customer-owned DER and varied it by scenario. I&M and IPL both included a DER-focused scenario in their IRPs. All of the IOUs except for NIPSCO included a forecast of light duty EV adoption in their IRPs. No utilities forecasted customer-owned batteries or heavy duty EV adoption.

Table 1.1 Treatment of DER and EVs in utility IRPs

Utility (IRP Year)	Energy Efficiency	Demand Response	PV	Battery Storage	Electric Vehicles	Notes on DER Scenarios
Duke Energy (2018)	✓	✓	✓		✓	Customer-owned DER adoption was not explicitly varied by scenario
I&M (2018-2019)	✓	✓	✓		✓	Included a DER-focused scenario
IP&L (2016)	✓	✓	✓		✓	Included a DER-focused scenario
NIPSCO (2018)	✓	✓				DER adoption was not explicitly modeled or varied by scenario
Vectren (2016)	✓	✓	✓		✓	Customer-owned DER adoption varied by scenario

The two main DER forecasts from the utility IRPs that were leveraged for the analysis were customer-owned PV and EV. Section 2 describes how these forecasts were incorporated into the analysis.

1.2 Review of pertinent literature

Several fields of study contribute to the growing body of literature examining the implications of increasing DER penetration. These studies explore current and future DER adoption trajectories and assess the impact across a number of dimensions, including the distribution system, bulk power system, distribution planning processes, ratepayer and societal costs and benefits, and utility business models. These subjects are summarized below.

1.2.1 Impacts of DERs on the distribution system

A number of studies have modeled high PV penetration on feeders and assessed the impacts. Brown and Freeman (2001) found that distributed generation (DG) can have positive impacts (voltage support, deferred capital investments) and negative impacts (protection coordination, voltage regulation, voltage flicker, short circuit levels). They also developed methods to analyze DG impacts using predictive reliability assessment tools. CIRED (2019) presents a flexible DER modelling framework along with recent developments in DER dynamic modelling. It also reviews DER system impact studies in California. PNNL summarizes the major types of analysis conducted on electric distribution systems along with their applications and relative maturity levels (PNNL, 2017a). Special emphasis is placed on distribution system analyses required for increasing levels of DERs. NREL (Seguin et al., 2016) catalogs distribution-level impacts of high PV penetration, including overload-related, voltage-related, reverse power flow, and system protection impacts. It also provides a model-based study guide for assessing PV impacts and lists techniques for mitigating impacts.

EPRI (2015) provides an overview of the hosting capacity method, which was developed to determine the ability of feeders to accommodate PV. The impact of PV penetration on distribution performance and the amount of PV (and other DERs) a feeder can accommodate depend on a number of factors, such as the characteristics of both the feeder and the DER, the location of the DER on the feeder, the feeder operating criteria, and the control mechanisms. EPRI (2010) discusses practical planning limits for adding DG to distribution circuits. The report classifies the limits into four categories: voltage regulation (e.g. voltage rise), rapid voltage change (fluctuations, sudden loss of generation), thermal limits (capacity, losses), and protection limits (overcurrent, islanding). The study used a set of IEEE test feeders to investigate the limits of each category. Over ten years ago, the IEEE developed this set of test feeders for researchers to use when modeling the distribution system (Schneider et al., 2008; K. Schneider et al., 2009; Schneider et al., 2018). Schneider et al. (2018) provides an overview of the existing distribution feeder models and clarifies the specific analytic challenges that they were originally designed to examine. The set of feeders reflect the diversity in design and have been used for a wide range of research (Cale et al., 2014). We explore the literature on representative feeder methodology in section 4.1.

1.2.2 Bulk power system impacts

Several studies have addressed the impacts of DER on the Bulk Power System (BPS). ERCOT identified areas of concern related to reliability impacts of DER to the BPS: increased error in load forecasting, less accurate inputs to ISO functions, and uncoordinated system restoration after a load shed event (ERCOT, 2017). NERC examined the potential reliability risks and mitigation approaches for increased levels of DER on the BPS. The objective was to help regulators, policy makers, and other stakeholders better understand the differences between DER and conventional generation with regards to the effect on the BPS (NERC, 2017). NERC also created a DER Task Force which developed DER modeling recommendations for BPS planning studies (NATF, 2018).

1.2.3 Value of DER

A growing body of literature analyzes the benefits and costs of DER. NREL (2014) reviews methods for analyzing the benefits and costs of distributed PV generation to the U.S. electric utility system. This

NREL review is one of the main sources for the DER valuation framework used in this study. Utilities will occasionally commission "value of solar" studies in their service territories to understand the benefits and costs specific to their geographic location, generation portfolio and customer base. RMI (2013) reviews sixteen distributed PV benefit/cost studies by utilities, national labs, and other organizations. Completed between 2005 and 2013, these studies reflect a significant range of estimated distributed PV value. Some studies examine costs and benefits at a broader level. Cohen et al. (2015) estimated the economic impact of distributed PV in California, and, closer to Indiana, PNNL (Orrell et al., 2018) estimated the value of DG in Illinois.

1.2.4 Utility of the future

Some states have conducted "Utility of the Future" studies. These studies generally examine the role and business model of today's utilities and explore ways they could change in the face of an evolving business environment measured by customer expectations, DER adoption, and technological advances. In the Midwest, several states have conducted such studies: Ohio, Michigan, Illinois, and Kentucky. Ohio's PowerForward Roadmap examined potential future regulatory paradigms, distribution grid architecture, and grid modernization (Ohio PUC, 2018). Michigan's study specifically focused on the near-term challenge of ensuring an adequate electricity supply (Public Sector Consultants, 2014). Illinois' NextGrid study assessed options for further grid modernization and candidate updates of state regulatory policies (NextGrid Illinois, 2018). Kentucky developed a Smart Grid Roadmap in 2012, where it examined the modernization of the electric power grid (KSGRI, 2012).

1.2.5 DER forecasting and planning integration

A critical input to the body of work on DER impacts is the adoption forecast for DERs. The methods for developing these forecasts can be divided into two categories: top-down and bottom-up (Horowitz et al., 2019). Top-down methods tend to be simpler and require less data and computing power. They include time series models, econometric models, and Bass diffusion models. Time series models are the most straightforward to implement, as they take historical data and extrapolate to future outcomes. Econometric models use statistical methods to explain historical observations by finding relationships between penetration levels and other variables. Researchers can then use these relationships to predict future adoption levels. Bass diffusion models represent adoption patterns of new products or technologies and are the most frequent top-down model used (Horowitz et al., 2019). Bottom-up methods require more data and are more methodologically sophisticated, as they evaluate DER adoption based on characteristics of individual customers. For example, agent-based models simulate the actions of individuals to model the impacts to the larger system. These types of models allow for more complex decision-making processes and can simulate a more heterogeneous customer base (Mills, 2018).

A number of researchers have examined how to incorporate DERs into the distribution planning process. For example, LBNL conducted a comparative analysis and evaluation of roughly 30 recent planning studies, identifying innovative practices, lessons learned, and state-of-the-art tools (Mills et al., 2016). PNNL describes activities in states that have adopted some advanced elements of integrated distribution system planning and analysis and also covers a broader array of state approaches (PNNL, 2017b). State regulators in several states including MN, CA, HI, and NY have developed integrated distribution planning guidelines for their utilities to actively incorporate DER into the distribution planning process (Schwartz, 2020).

This literature review informs the structure and content of the analysis that follows. Figure 1.1 provides an overview of the analytical process developed in this study. The analysis benefited from references on DER adoption forecast methodologies, trends on emerging technologies, methodologies to assess the impacts of DER in power systems, and techniques to identify representative feeders for these analyses, among others. In the rest of the report, section 2 explains the scenario creation and section 3 the assessment framework developed for this study. Section 4 delves into the method and results for selecting representative feeders, and section 5 presents the results for power flow and reliability impact assessments. Section 6 concludes with a summary of methods and results. All monetary values in this report are expressed in real 2017 dollars unless otherwise indicated.

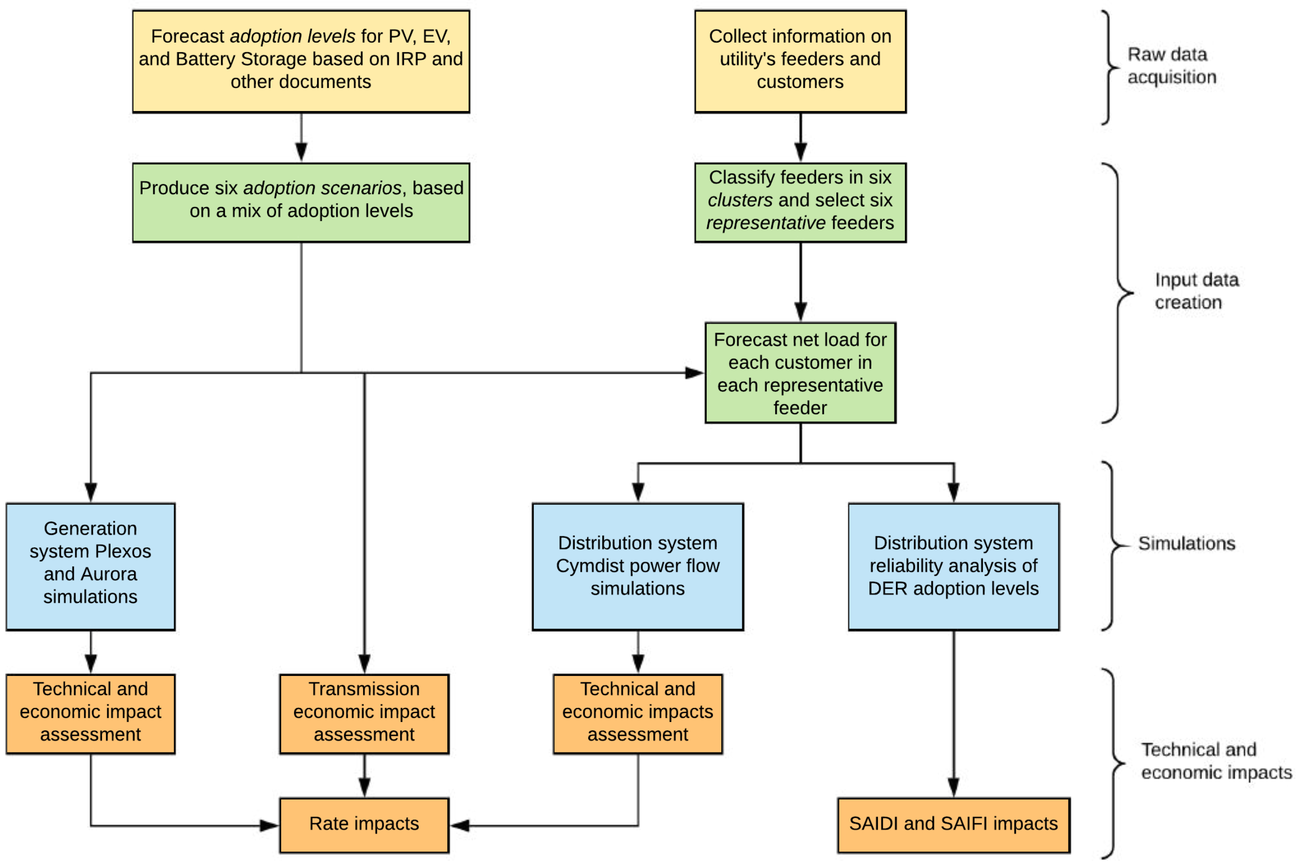

Figure 1.2 Flow diagram describing the analytical process developed in this study

2. Scenarios

This study utilizes six scenarios based on different levels of DER and EV adoption to examine the performance of the distribution system and to examine certain impacts to reliability and resilience. This section describes the scenario development process and the dimensions that define each scenario.

2.1 Scenario logic

The scenarios were developed to explore how the distribution system would perform under different DER adoption and demand levels. DER and demand are characterized across three dimensions: PV adoption, battery storage, and system demand. Each dimension has one of three adoption levels: business as usual (BAU), high, and very high. The scenarios cover two horizons: a short-term horizon (2025) and a long-term horizon (2040).

The scenarios do not represent a prediction of the future trajectory of DER adoption or system demand. Their purpose is to represent a set of possible futures for the purpose of exploring the behavior of the distribution system under different circumstances. This type of scenario exploration can help to identify situations in which the system may perform poorly and thus inform decision-makers. The scenarios are policy-agnostic. We do not assume any type of policy is in place in each scenario. Put differently, there is no assumption whether the DER adoption or system demand levels are attained through a particular policy mechanism. Logically, the adoption levels in these scenarios would be more or less feasible for Indiana depending on the set of policy decisions made over the next twenty years.

The PV and storage dimensions for each scenario reflect the adoption of behind-the-meter DER by customers—and not utility-scale solar or storage. PV systems would thus be customer-installed rooftop PV for residential and commercial customers. Battery storage systems are less common than PV in each scenario and are assumed to be installed at the same site as PV. The batteries were sized to reflect the capacity of a system on the customer side of the meter and did not include any utility-scale batteries. The levels of system demand are driven by the adoption of electric vehicles. While a number of factors could arise to impact system demand, EVs are the most likely option for large-scale changes and provide a means to simplify scenario development.

The six scenarios are as follows:

1. ***Base***: Represents the base case scenario. Each scenario dimension (PV, battery storage, and system demand) are taken from the base case scenarios of the utility IRPs. Note the distinction between "Base" to refer to this scenario and business-as-usual (BAU) to refer to the specific DER projection level as in BAU, high, and very high (see Table 2.2).
2. ***High Electrification***: Represents a scenario where system demand increases beyond base case projections, but DER adoption does not. This allows the analysis to explore the behavior of the distribution system in the case of high EV adoption—but with a configuration that reflects BAU levels of remaining DER penetration.
3. ***High PV***: Tests the scenario where PV adoption increases beyond BAU projections, but without large-scale additional system demand and without a large increase in battery storage adoption.

Battery storage can mitigate some of the integration challenges for the utility of high rooftop PV penetration and this scenario tests the ability of the grid to handle more PV without the customer-side storage.

4. ***High PV and Battery Storage***: Examines a scenario where a high level of rooftop PV penetration is coupled with a relatively high penetration of battery storage systems. The scenario assumes some breakthrough in battery technology, financing, and/or policy that would boost adoption, as current levels are close to zero. Even at a 'high' level, only one percent of customers adopt batteries. In this scenario, all battery storage systems are co-located with rooftop PV—though many rooftop PV systems are installed without batteries due to high PV penetration.
5. ***Battery Storage Arbitrage***: Reflects a scenario where a storage breakthrough occurs, achieving a 'high,' one percent penetration level, with BAU levels of rooftop PV adoption. This scenario allows exploration of the impact of higher-than-expected battery storage adoption, while holding other factors at the baseline level.
6. ***Boundary Case***: Extrapolates adoption of rooftop PV, battery storage, and EVs to 'very high' penetration trajectory levels. The purpose of this scenario is to act as a boundary case and test the behavior of the distribution system with stressors that are beyond even the 'high' project levels. The 'very high' adoption levels are not present in any other scenarios.

Table 2.1 summarizes the six scenarios, and the proposed DER adoption category for each scenario. The colors represent adoption levels as follows:

Table 2.1 Overview of scenarios

Scenario	Description	PV	Storage	EV (system demand)
1: Base	Reference case			
2: High Electrification	BAU DER, high demand			
3: High PV Stress Test	High PV penetration without storage breakthrough			
4: High PV and Battery Storage	High PV penetration with storage breakthrough			
5: Battery Storage Arbitrage	Storage breakthrough with BAU PV			
6: Boundary Case (Distribution system stress test)	Very High PV, storage, electrified demand			

Adoption Levels:

Business as Usual	High	Very High

Table 2.2 reports the details of each level (BAU, High, and Very High) for each scenario dimension and year 2040; values for 2025 are interpolated between current levels and 2040 levels. The base case adoption level was based the forecasted DER adoption for each Indiana IOU. Figure 2.1 depicts forecasted annual EV adoption for Indiana. An aggregate analysis of the IOUs IRP shows that Indiana may have almost 14,000 EVs in 2020 and more than 550,000 EVs by 2040. The 'High' and 'Very High' scenarios for EVs is based on a scenario from MISO (Greenblatt et al., 2019). Figure 2.2 depicts the forecasted installed PV capacity (in MW) for the state of Indiana based on the forecast in the base scenario for the five IOU IRPs. It is estimated that Indiana will have 230 MW of installed PV capacity in 2020 and 830 MW of installed PV capacity in 2040. The 'High' PV scenario is based on a scenario from the IPL IRP. Projecting adoption of battery storage proved challenging, due to very low adoption rates outside of California, a lack of public-available forecasts, and significant uncertainty related to the future of the battery storage market. The adoption levels for the 'High' and 'Very High' scenarios were extrapolated from states with higher penetration levels.

Table 2.2 Quantitative adoption level details

Adoption Level	PV	Storage	Electric Vehicles	System Demand
BAU	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.
High	15% of customers by 2040 (Based on scenario from IPL IRP)	1% of customers by 2040	23% of vehicle stock by 2040 (Based on scenario from MISO Study)	Base Demand + EV addition
Very High	25% of customers by 2040 (Extrapolation of High Scenario)	5% of customers by 2040	68% of vehicle stock by 2040 (Based on scenario from MISO Study)	Base Demand + EV addition

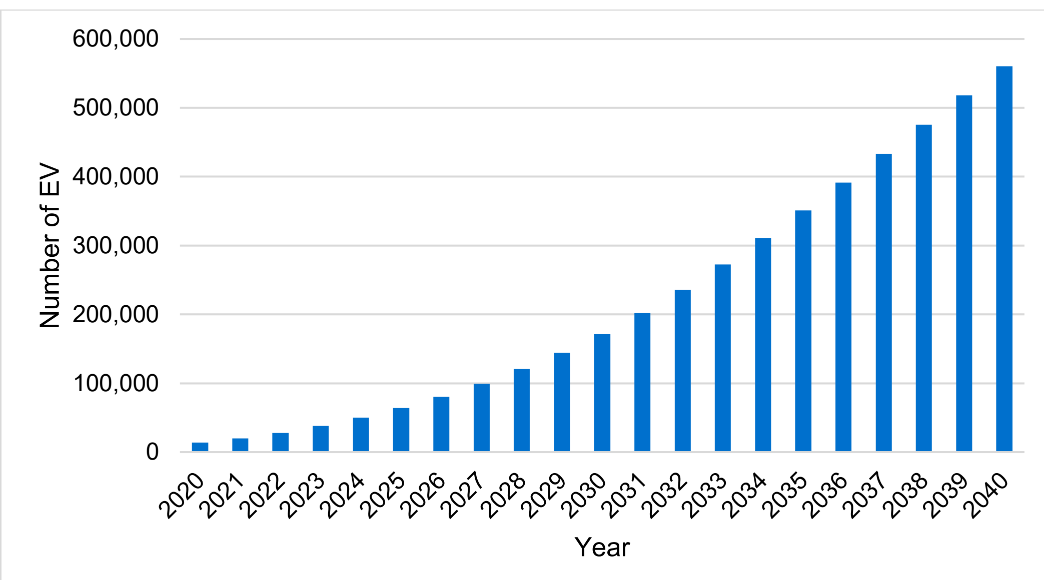

Figure 2.1 EV adoption forecast based on IOU IRPs (BAU)

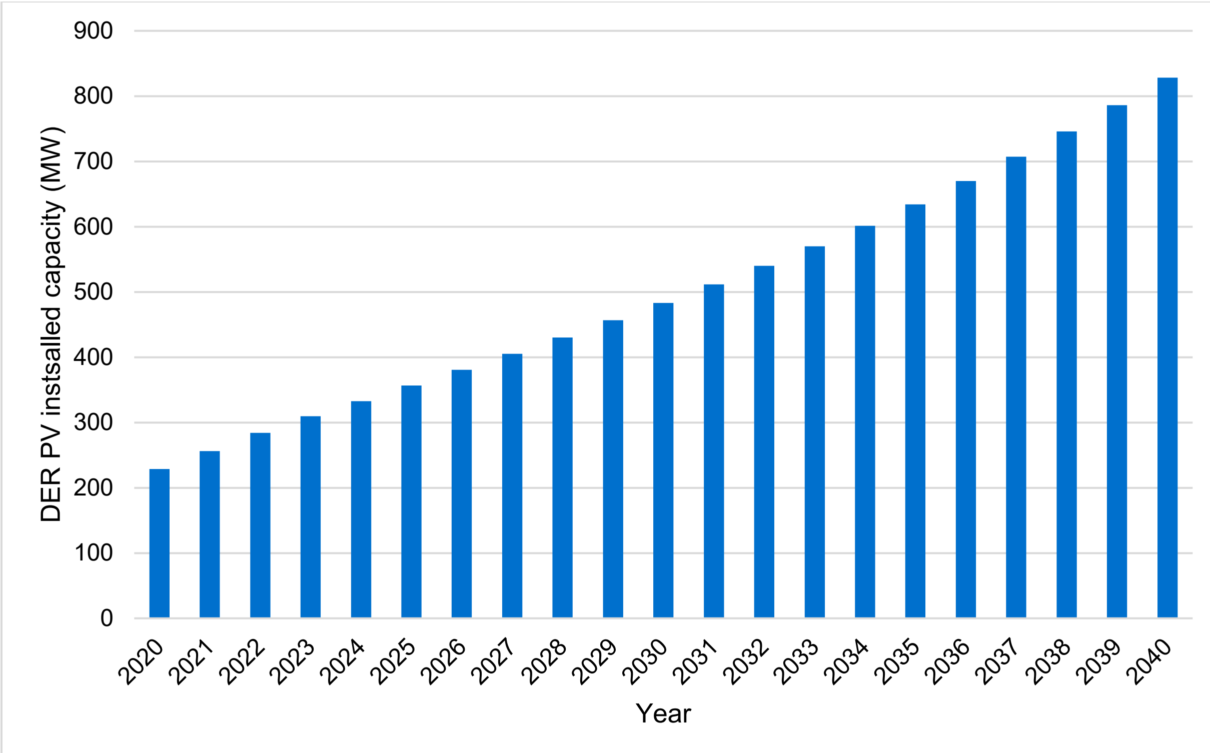

Figure 2.2 DER PV forecast based on IOU IRPs (BAU)

2.2 Scenario outputs

2.2.1 Load forecast by scenario

Figure 2.3 and Figure 2.4 summarize the estimated annual consumption for Indiana in GWh by customer class for each scenario in 2025 and 2040, respectively. Variations in annual consumption for each customer class are due to additional load from EV adoption (residential) and subtracted load due to annual PV generation (residential and commercial). Customer-owned storage is assumed to have small annual net consumption because of the 90% roundtrip efficiency in the charge/discharge patterns. The annual consumption for industrial customers does not vary by scenario, and so is not included in the figures. Industrial customers, however, make up a large portion of Indiana's overall consumption, accounting for 46% of total annual consumption in 2025 and 45% of total annual consumption in 2040.

Overall, there is a relatively small amount of variation in total annual consumption for each scenario in 2025, as DER adoption does not differ greatly between scenarios over the next five years. By 2040, there are comparatively larger changes in annual consumption, with overall consumption levels increasing or decreasing depending on the scenario. The High Electrification and Boundary scenarios have relatively high levels of EV adoption and annual consumption for residential customers increase by 8% and 21%, respectively, compared to the base case. The scenarios with BAU EV adoption and high PV adoption show a 10% decrease in residential annual consumption and an 8% decrease in commercial annual consumption compared to the base case.

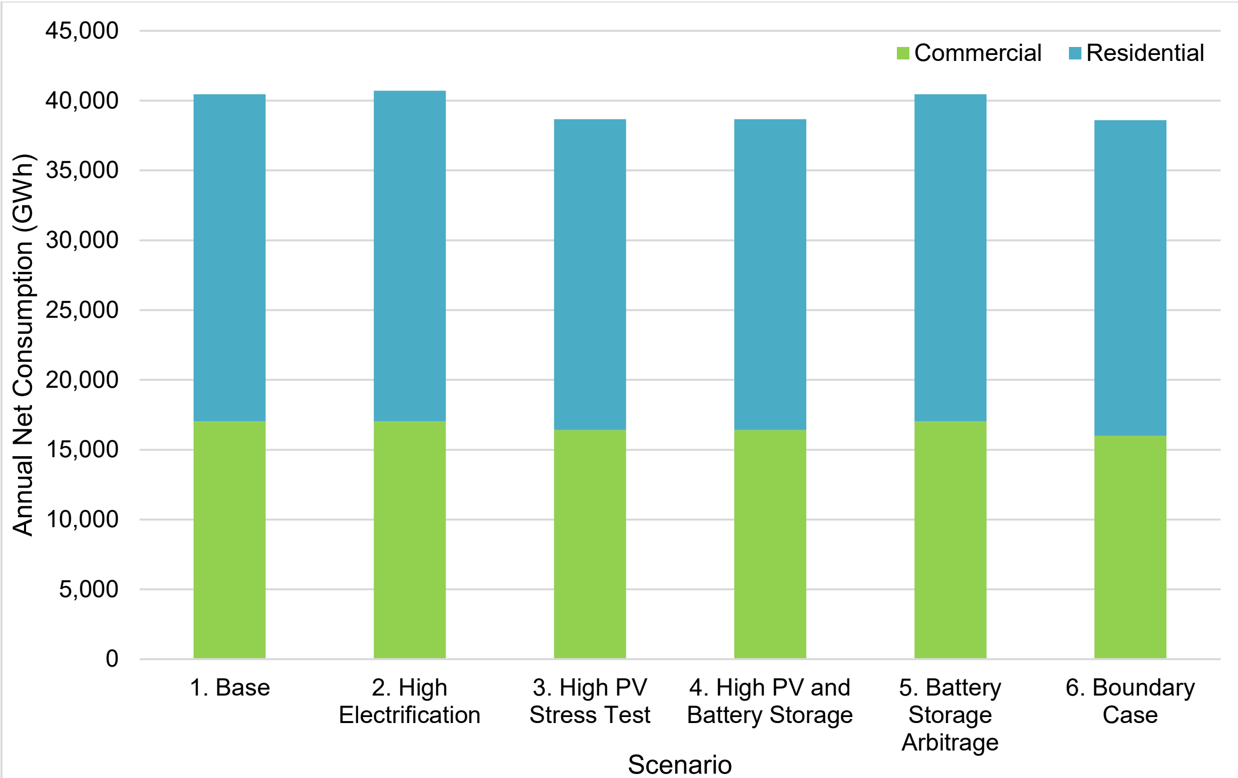

Figure 2.3 2025 annual net consumption by scenario and customer segment

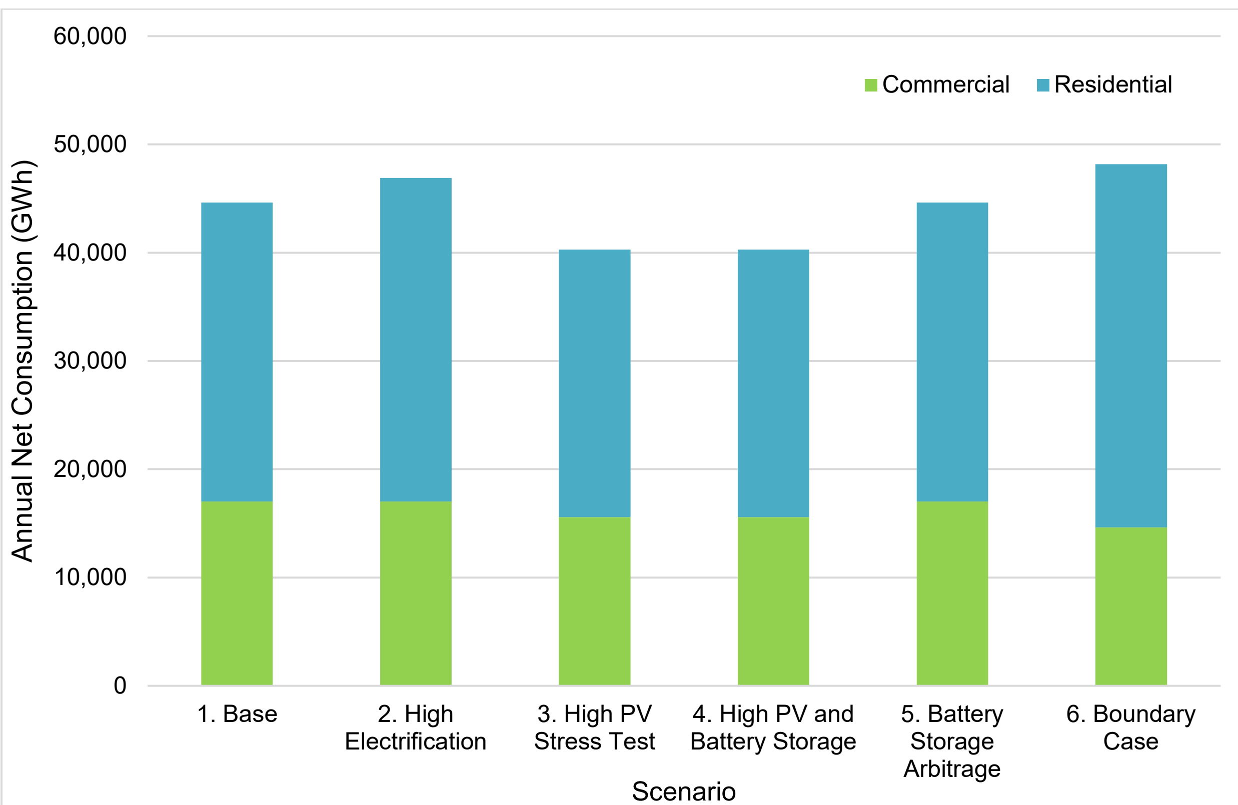

Figure 2.4 2040 annual net consumption by scenario and customer segment

The above figures do not portray the impact of each DER on an hourly basis. Impacts during specific hours of the day exist even though on an annual basis net demand may not change substantially as a result of additional DERs. Solar PV and EV charging, for example, offset each other on an annual basis, but solar discharge and EV charging generally happen at different times during the day. Therefore, there are potentially large changes on an hourly level on each scenario. One of these changes is a shift in the hours that have the highest load concentration on peak days. Figure 2.5 illustrates the timing of state-level aggregate peak day usage for each scenario. The plot shows the average hourly loads over the top ten peak load days in 2040 for each scenario. We can compare scenarios by displaying the percentage of usage in each hour (the area under each curve adds up to 100%). Peak days occur during summer months in all scenarios, but the peak hour changes depending on which DER is dominant. For scenarios with high levels of solar penetration, the peak hour tends to occur later in the evening, between 6-7 pm (hour 19 on the plot). For the Base, High Electrification, and High Storage scenarios the peak occurs earlier in the day, between 3-4 pm (hour 16 on the plot). The Boundary scenario, with large PV and solar penetration, shows a high concentration of load in the evening hours, with load from 6-9 pm, accounting for more than 30% of the daily load on peak days.

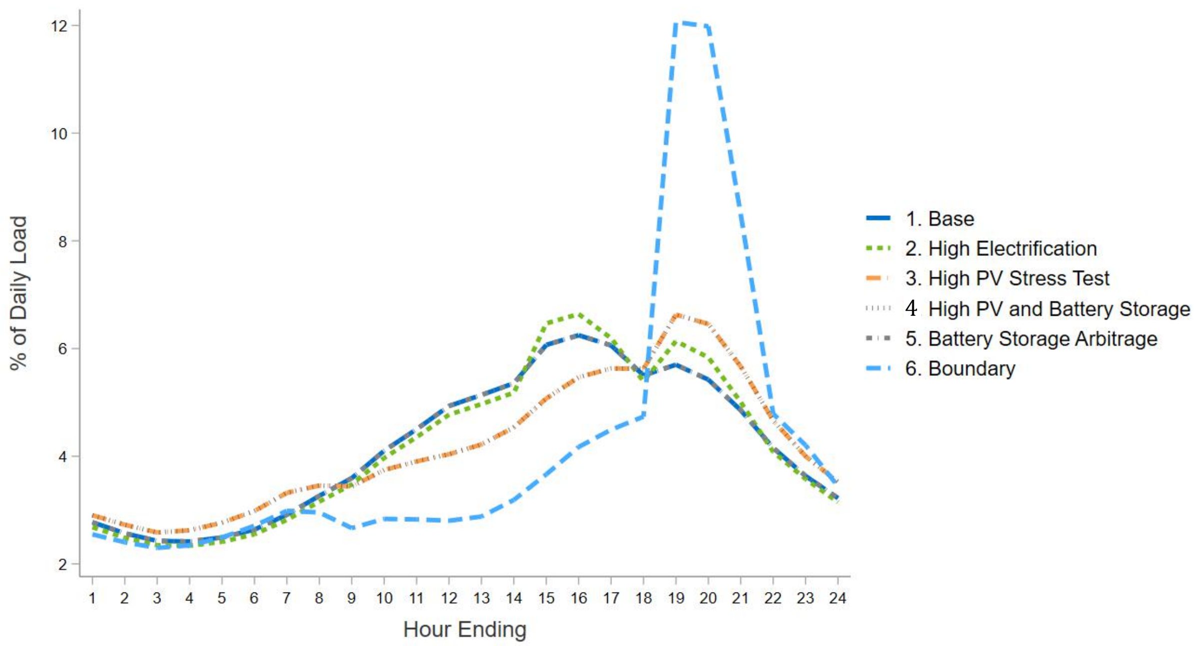

Figure 2.5 Peak day load concentration by scenario

In addition to changes in peak load concentration, the magnitude of the annual peak as compared to the Base Case also changes. The High Electrification and Boundary scenarios have relatively high levels of EV adoption and peak consumption increases by 17% and 83%, respectively. The scenarios with BAU EV adoption and high PV adoption show a 6% decrease in peak consumption.

2.2.2 DER adoption forecasts for Indiana

Figure 2.6 and Figure 2.7 depict the expected Indiana DER installed capacity for each scenario in 2025 and 2040, respectively. These charts present nameplate installed capacity of each DER rather than coincident peak capacity. There is some variation in DER adoption for each scenario in 2025, with much larger variation in 2040. By 2040, in the Base scenario, there is 356 MW of installed PV capacity and 1 MW of installed storage capacity. High PV adoption scenarios deploy 1,667 MW of PV capacity; high storage adoption scenarios install 74 MW of battery storage capacity. Similarly, 2040 BAU installed capacity of EV charging is 1,706 MW, equal to 560,562 vehicles, and a high installed capacity of 3,907 MW of charging equal to 1,282,022 vehicles. EV capacity is broken out by the type of charger used for the vehicle. Type 1 EV charges use less load at any given time, but take longer to charge, while Type 2 EVs charge quickly and use more load during a given hour. As a result, Type 1 EV makes up 21% of EV customers but only 11% of EV capacity. The Boundary scenario has significantly higher DER penetration than the other scenarios with 6,438 MW of PV, 921 MW of storage, and 12,523 MW of EV from 4,115,648 vehicles (see Figures 2.6 and 2.7). The Boundary scenario then acts as a stress-test case to analyze the behavior of the distribution system with adoption levels beyond the most optimistic existing adoption scenarios.

The DER with the highest capacity varies with the scenario. For the Base, High Electrification, and Boundary scenarios, EV charging provides the highest installed capacity. For the other scenarios solar PV has the highest installed capacity. However, it is important to highlight that, in reality, EV charging may occur at different times of day while PV injections across the Indiana territory will be highly correlated. This means that the coincident hourly impact of PV may be higher than that of EV, even in scenarios where the latter has larger installed capacity.

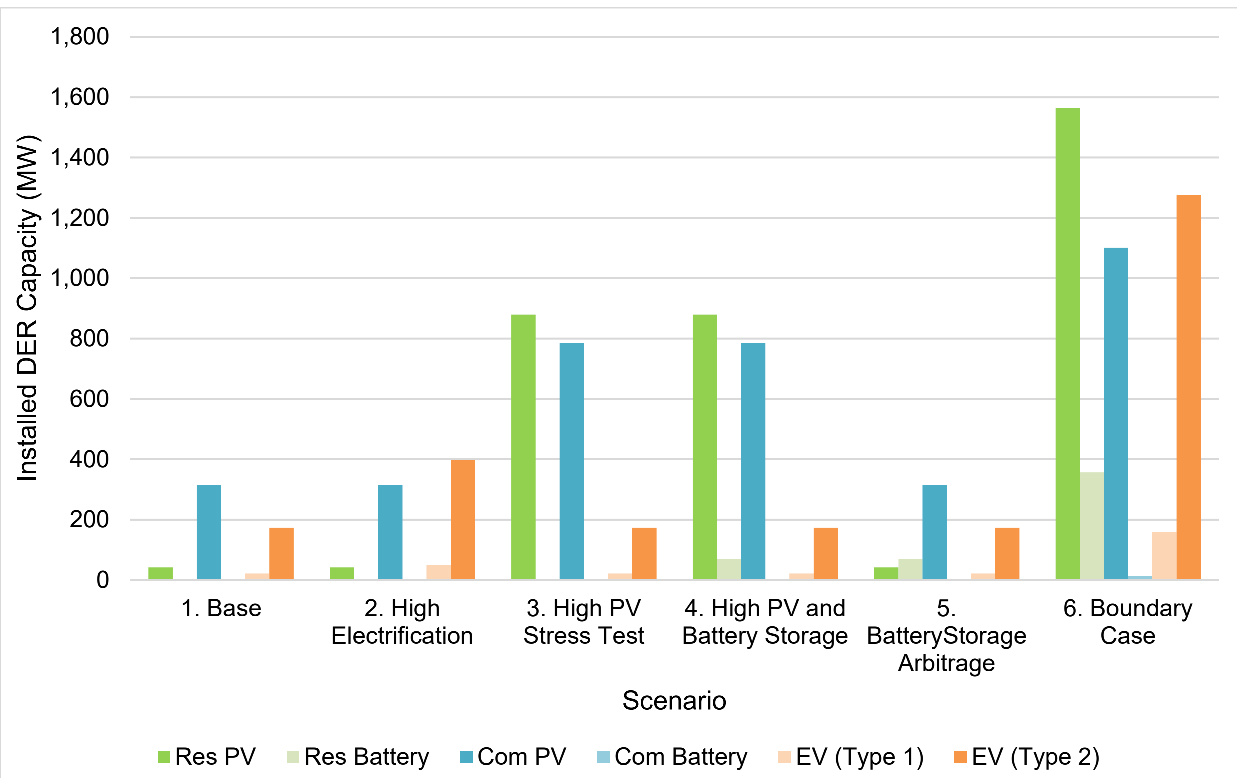

Figure 2.6 2025 Indiana installed DER/EV capacity by scenario

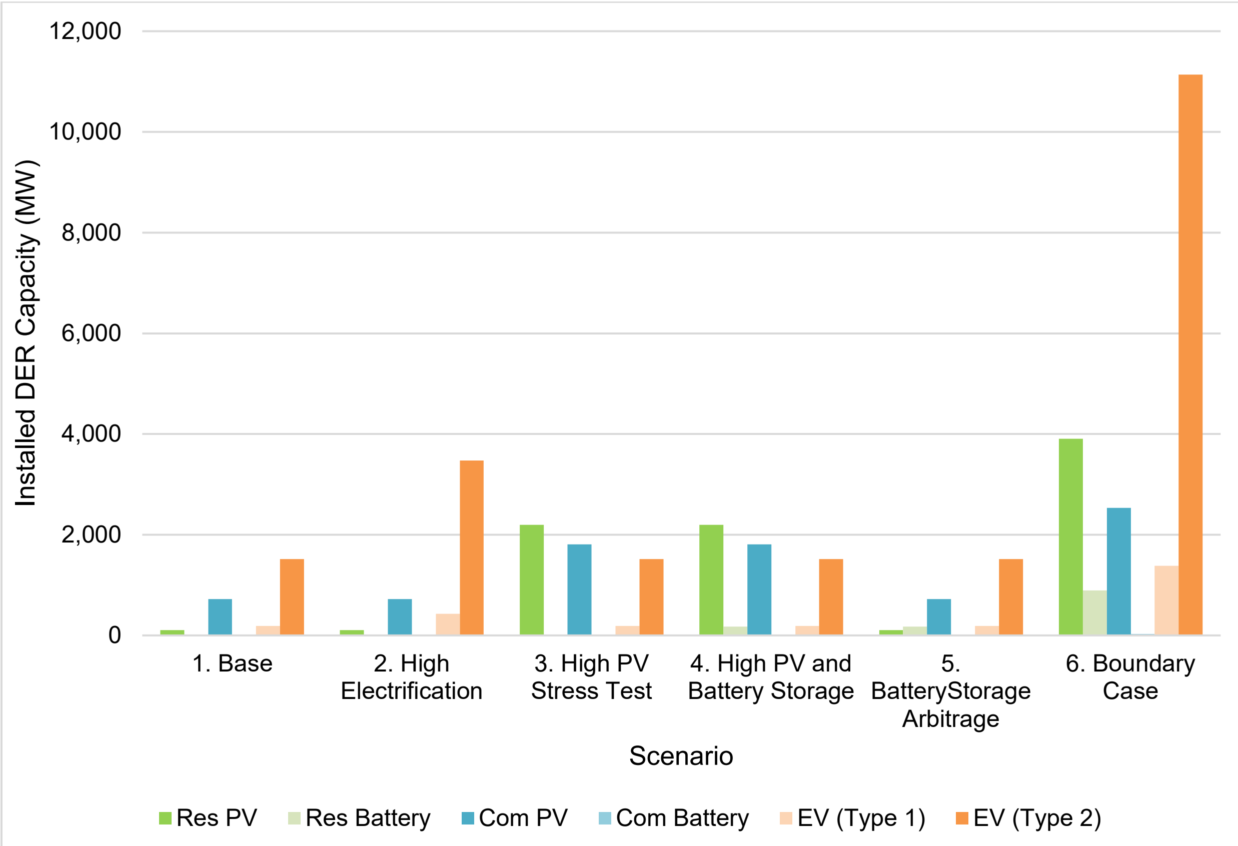

Figure 2.7 2040 Indiana installed DER/EV capacity by scenario

2.2.3 Comments on DR and EE availability/potential

DR and EE availability were based on IRP forecasts provided by the IOUs. Unlike the other DERs, customer participation in EE and DR programs are largely driven by utility efforts. Therefore, EE and DR adoption were not varied in the above scenarios. For both 2025 and 2040, Indiana is expected to have a total DR capacity of almost 750 MW and total annual EE savings of almost 1,900 GWh.

2.3 Equivalence between scenarios in this study and in the SUFG study

The SUFG is developing the assessment of impacts of emergent generation technologies, fuels, and trends in the generation segment of the power system. The scenarios used for that assessment are not influenced by the scenarios employed in this study or vice versa, because each analysis is focused on testing the impacts of technological change on each specific segment.

However, this study does develop a methodology to assess the impacts of DER adoption on the generation segment of the power system. For this, the scenarios developed in this section were ported into the appropriate format to be input as net demand to the production cost and capacity expansion models. More information on this method is available in Sections 3.1.1, 3.1.2 and 4.3.

3. Metrics to assess the impact of emerging DER technologies

This paper seeks to trace emergent technologies in distribution systems and measure their impact across the different segments of the power system. In this section, we present the methodological framework used to measure and monetize the techno-economic impact, and to measure the reliability impacts of different scenarios for DER adoption in Indiana.

In general terms, this paper develops an empirical strategy to make the results directly applicable to the Indiana context. We develop an economic impacts analysis based on the scenarios in Section 2 and representative feeders identified by classifying thousands of Indiana feeders in clusters of circuits with similar characteristics (see Section 4 for more information). We then produce net demand inputs to run power flow simulations in selected feeders using the industry-standard Cymdist model (CYME, 2018). The same inputs are aggregated, scaled, and adapted to be input into the Plexos and Aurora modeling platforms for generation expansion and estimation of production costs. A simplified method is used to assess the impacts of DER on transmission costs. Grouping these three analyzes together allows to estimate rate impacts of DER penetration for different adoption scenarios and years.

Finally, we conduct a reliability impacts analysis using five years of outage data for the five Indiana IOUs. We introduce a methodology to estimate the frequency and duration of interruptions—from the customers' perspective—under alternative DER deployment pathways. We perform these calculations for a consistent set of feeder clusters, and then scale the results to the state-wide level.

3.1 Economic impacts of DER on the power system

DER can impose technical costs to the distribution system due to their impact on voltage levels and line loading, among other impacts. DER can also benefit the distribution system by reducing line and transformer losses and by deferring capacity investments. Due to the integrated nature of power systems, DER costs and benefits can also accrue in the transmission and generation levels. We call these economic outcomes of DER integration "value streams". DER have a wide array of value streams (EPRI, 2014; Frick et al., 2018; Shenot et al., 2019), but this study focuses on a subset of possible value components including energy cost, losses, and capital deferment (capacity value).

Due to technical and resource limitations, a number of additional value streams identified in the literature were not considered. These include DER impacts on ancillary services and fuel price hedging. Ancillary services such as frequency regulation can be a relevant value stream for battery storage (Nassuato et al., 2016). However, there is no simplified method to determine the potential contribution of DER to this value stream that could be applied within our framework.

The framework used in this analysis is largely based on an NREL study titled "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System" (Denholm et al., 2014). This study is focused on DER PV, but its methodology can be extended to other types of DER. The DER valuation framework components and measurement methodology specific to our study are described below.

3.1.1 Energy costs

Operation of DER changes the shape and level of the net demand that is supplied by the BPS. The change in shape can produce costs or benefits depending on how the BPS dispatch curve changes and whether more flexible resources for ramping are needed (e.g. to address the "duck curve" phenomenon) that would incur additional fuel charges.

Change in levels can also be bidirectional: net demand can decrease with high levels of PV generation, often resulting in savings from less energy produced at the utility-scale. However, BPS energy consumption can also increase with EV charging. The timing of these changes, captured by the shape component, impacts resource adequacy requirement at the BPS-level. However, these capacity requirements are captured through a different value stream described later.

Changes in energy consumption and their monetization will employ the SUFG's production cost modeling platform with the Plexos and Aurora models. The process follows these steps:

1. Produce hourly net demand differentials between the base case scenario and each one of the five adoption scenarios presented in Section 2.
2. Add the scenario net demand differentials to SUFG's base case to produce five net demand sets that are consistent with their assumptions, but at the same time reflect the adoption levels determined in this study's scenarios.
3. Interpolate the years between 2025 and 2040 to provide the data needed for the capacity expansion model.
4. Input these assumptions in the model and run it for each hour of the year.
5. Calculate the dispatch costs (fuel and non-fuel variable costs, ramping costs, and spinning and non-spinning reserves costs) for each hour, and produce annual totals.
6. Compare state-wide present value of dispatch costs for each adoption scenario against the base case.

3.1.2 Losses

Transmission and distribution losses may be reduced or increased due to the presence of DER. Distribution losses can go in either direction depending on their capacity relative to the hosting capacity and their location within the feeder. Traditionally, distribution feeders follow a "conic" construction method, with higher gauge wire close to the head and lower gauge wire close to the ends. Then, higher power flow levels close to the end of the feeder have a disproportionate impact on losses compared to the same flow levels close to the feeder head. Transmission losses would generally decrease due to reduced loading in the lines. For the purposes of this study, we do not assume that DER deployment results in power flowing back into the transmission system with a corresponding increase in losses.

Distribution line losses for the primary voltage system will be assessed directly from the Cymdist modeling results for each representative feeder. We will prepare and run a specific set of simulations for energy losses using 24 hours on a typical day per season (fall, winter, spring, and summer). The days are selected as the median load day on each season. The objective of this approach is to capture typical losses levels that are representative of the adoption scenario, rather than losses at maximum/minimum load conditions. Feeder-level energy losses levels for each scenario will be compared against the base case. Losses differences can then be monetized using either retail rate or an average wholesale purchase price.

Transmission losses cannot be directly calculated because there is no explicit modeling of the transmission system in the Comprehensive Study. We will estimate transmission losses changes based on the difference between aggregate net demand in the base case scenario and the adoption scenarios. For example, if energy consumption is 10% higher in one adoption scenario compared to base case, then we will assume that transmission system losses will be 10% higher as well. While imperfect, this will allow to monetize transmission losses changes into rates.

3.1.3 Capital deferment (capacity value)

DER operation can defer or increase future investments in generation, transmission, and distribution. As with losses reductions, DER may produce capital deferments in generation and transmission. However, DER deployment can require flow capacity and safety upgrades in the distribution system and can trigger the need for flexible resources at the generation and transmission level to meet additional ramping requirements.

Generation

Capacity value of DER for the generation system can be directly calculated using the results from the Aurora capacity expansion model ran by the SUFG. Typically, most studies estimate the capacity credit of the different DER technologies, accounting for T&D losses (i.e. referring the capacity credit to the transmission network). However, since the SUFG model is able to simulate capacity expansion for different net demand scenarios, we can directly compare the adoption scenarios against the Base scenario to determine the difference in resource type, capacity mix, and cost.

We estimate potential reductions in planning reserve margin that come from peak demand reductions as part of the generation capacity value. We will implement a simple method that values the changes to the reserve margin based on the reserve requirement output from the Aurora and Plexos models.

Transmission

Transmission expansion costs are complex to estimate because of the bulky nature of transmission investments and the spatial distribution of transmission system lines and substations. The NREL study proposes three methods to assess capital deferments in transmission systems. Two of these methods require explicit modeling of the transmission network, which is out of the scope of the Comprehensive Study. The third method proposes obtaining transmission locational marginal prices (LMP) and determining the marginal contribution of DER to reduce those LMPs. This reduction serves as a proxy for transmission capacity values. However, this method assumes that DER penetration levels do not substantially change the underlying LMP data used for the estimates. This assumption can produce large distortions when applied on analysis performed over long time frames such as this study’s.

We developed a simplified method that involves linearizing transmission expansion by estimating a cost of transmission per peak MW transported. These costs are estimated by the SUFG using the rate base information separated by functional category.

Distribution

The methods to assess impacts of DER on distribution system vary significantly in complexity and outcomes. Given that this is a focus of the study, we implement a more sophisticated method based on power flow simulation of actual primary voltage feeder and load data as indicated earlier in this Section. This method has three parts. First, we run power flow simulations for each representative feeder for several combinations of adoption scenarios, hours of the year, and horizon (2025 and 2040). Second, we analyze the technical outcome of each power flow simulation by tracking voltage levels per node, line losses, and line loading. These three parameters are drivers of the feeder upgrades. Finally, we scale feeder upgrades for each cluster to the whole cluster level, and then estimate state-wide DER distribution system integration costs and benefits.

Simulations are performed on the Cymdist power engineering software from CYME/Eaton. Cymdist has a Python API that is used to automate simulations[1]. All active and reactive loads from each Cymdist feeder model are overwritten by reading a csv file with pre-determined hourly values based on the Cymdist input data explained in section 4.3. The automated framework allows executing thousands of simulations within a short period of time.

We assume that feeders will be upgraded, if needed, to maintain voltage drop, line and transformer loading and losses, within prescribed and accepted levels. In some cases, the DER scenarios may be such that they will prevent an upgrade that would otherwise be required in the base case, accruing savings to the system. This means that we will estimate upgrades required for the base case and determine a total cost for a representative feeder. We then compare these reference costs against the costs to maintain the representative feeders for other adoption scenarios. The cost differential is the DER integration value, which could be positive (a cost) or negative (a savings).

There are no trustworthy automatic upgrade algorithms for distribution systems that can be applied to our setting (Denholm et al., 2014). Given the volume of simulations performed (close to 1800 individual power flows), we select certain scenarios, years, and hours of the year that reflect maximum and minimum loading levels to manually inspect each representative feeder and decide to implement the following strategies to correct technical issues with feeders:

- Repowering conductors (line loading and losses)
- Add a new voltage regulator or modify the setting of an existing voltage regulator (voltage regulation)
- Modify a substation’s tap changers (voltage regulation)
- Adopt and calibrate smart inverters for DER PV (voltage regulation)

Finally, distribution-level capital investments or deferments will be monetized based on current infrastructure costs that were provided by the three Indiana utilities whose feeders were used as the

[1] The Cymdist power flow simulations were performed using models and Functional Mockup Units developed during the DOE-funded project “CyDER: A Cyber Physical Co-Simulation Platform for Distributed Energy Resources in Smart Grids”, which delivered a co-simulation platform based on the Functional Mockup Interface standard.

basis of this analysis (see Section 4).

3.1.4 Rate impacts

The methods developed in subsections 3.1.1, 3.1.2, and 3.1.3 produce cost estimates for energy, losses, and capacity in generation, transmission, and distribution systems due to DER adoption. We calculate aggregate energy consumption by utility and year and pass this information along with the DER value changes to the SUFG's ratemaking model. As stated in Phillips et al. (2019, pp. 2–2), "the [ratemaking] models determine annual revenue requirements based on each utility's costs associated with existing and future capital investments, operational expenses, debt, and taxes. Those costs are then allocated to the customer sectors and rates are determined using the annual energy forecasts." We maintain modeling consistency by using the same ratemaking model employed by the SUFG in developing its long-term demand forecasts for Indiana.

3.2 Reliability impacts of DER for the distribution system

DERs have the potential to reduce the frequency and duration of power interruptions[2] for utility customers. This study focuses specifically on battery storage and PV systems—two key dimensions in defining the alternative DER scenarios. PV adoption continues to increase throughout the U.S. and customers are also beginning to have more options for installing battery storage systems behind the meter. These systems could be operated to supply electricity during power interruptions, store electricity generated by a PV system during the day to use at night, and shave system peak load. This analysis examined the ability of behind-the-meter battery storage systems—both with and without coupled PV systems—to mitigate outage impacts to customers under different adoption assumptions and modes of operation. It applied these adoption and operational assumptions to historical outage data to estimate the reliability and resilience improvements. This section describes the framework and approach for assessing these impacts.

3.2.1 Reliability

The IEEE Standard 1366 defines twelve indices that utilities use to measure and benchmark reliability. These include the three most common metrics—SAIFI, SAIDI and CAIDI, explained below. These metrics are reported from the perspective of the utility, meaning that even if a customer had a battery storage system with which to power their site during an outage, the absence of power at the meter would still be considered an outage when calculating the metric. For this analysis, we adjust the metrics to calculate them from the perspective of the customer. Then, an outage from the utility perspective would not be considered as such from the customer perspective if the customer has a battery storage system that can be used for backup.

Indiana IOUs report annual reliability metrics under both normal conditions and inclusive of major event days (MEDs). IEEE Standard 1366 defines how to separate reliability into normal conditions and MEDs. A major event "designates a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating

[2] This report uses the words "interruption" and "outage" interchangeably.

area experience a sustained interruption during a 24 hour period."[3,4] Utilities exclude MEDs when reporting reliability metrics to indicate how reliable the grid is during "blue sky" days. For this analysis, we assess reliability under two situations: including MEDs and excluding MEDs.

The definitions for SAIFI, SAIDI, and CAIDI are as follows:

SAIFI (System Average Interruption Frequency Index) is the average number of interruptions per year for a typical customer (see Equation 3.1). Battery storage systems installed onsite can reduce the frequency with which customers experience interruptions when the battery has enough charge and capacity to power the site for entire duration of the interruption to the grid.

Equation 3.1: SAIFI

$$SAIFI = \frac{\sum \lambda_i N_i}{N_T}$$

Where:

- N_i is the number of customers
- N_T is the total number of customers served
- λ_i is the failure rate for location *i*

SAIDI (System Average Interruption Duration Index) is the total annual duration of interruptions for a typical customer (see Equation 3.2). Batteries will reduce the total interruption time per year experienced by customers who install them and thus reduce the average yearly interruption time across all customers.

Equation 3.2: SAIDI

$$SAIDI = \frac{\sum U_i N_i}{N_T}$$

Where:

- U_i is the annual outage time for location *i*
- N_i is the number of customers affected by outages
- N_T is the total number of customers served

CAIDI (Customer Average Interruption Duration Index) is the average length of time that a typical customer outage lasts; or the average restoration time (see Equation 3.3). Note that CAIDI is equivalent to SAIDI divided by SAIFI, or the average duration per interruption. Batteries could increase or decrease CAIDI based on the characteristics of the battery and the distribution of outage durations. It is possible that batteries would help customers avoid shorter duration interruptions, but still experience longer duration outages. In this case, batteries would lead to an increase in system-wide average duration.

Equation 3.3: CAIDI

[3] IEEE Std. 1333 Section 3.13

[4] It should be noted, however, that not all utilities (or regulatory jurisdictions) follow IEEE standard 1366 when defining what constitutes a major event (LaCommare and Eto, 2008).

$$CAIDI = \frac{\sum U_i N_i}{\sum \lambda_i N_i} = \frac{SAIDI}{SAIFI}$$

Where:

- U_i is the annual outage time for location *i*
- N_i is the number of customers affected by outages
- N_T is the total number of customers served
- λ_i is the failure rate for location *i*

Table 3.1 gives a preliminary overview of the framework for assessing impacts.

Table 3.1 Reliability and resilience assessment metrics

Metric*	Battery Storage Impacts
SAIFI	Some interruptions eliminated when battery has enough charge and capacity to power site for entire duration
SAIDI	Reduction in average yearly interruption time per customer reduced
CAIDI	Average interruption duration may increase when shorter-duration interruptions are eliminated

*Includes assessments both with and without MEDs

This analysis uses two metrics to summarize outages and characterize outages by location and cause. First, the number of customer-outages is the sum of the number of customers interrupted across all outages for the time period. It also corresponds to the numerator for the SAIFI metric. For example, if two outages each interrupted 1,000 customers, then this would be equivalent to 2,000 customer-outages—regardless of whether any customers experienced both outages. A second useful summary metric is customer minutes interrupted (CMI). This is the sum of interruption minutes for all customers, and corresponds to the numerator of the SAIDI metric. To extend the previous example, if each of the two outages lasted 100 minutes, then the total CMI would be 2,000 customer outages x 100 minutes = 200,000 CMI. Customer-outages and CMI are not reliability metrics, but ways to measure outages in electric utility operation.

3.2.2 Resilience

The utility industry does not have a consistently applied definition of resilience (LaCommare et al., 2017; Schwartz, 2019). Presidential Policy Directive 21 (EOP, 2013) on Critical Infrastructure Security and Resilience defines resilience as the "ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." Some researchers have arbitrarily defined a long-duration, severe interruption as any interruption lasting longer than 24 hours in duration (Larsen et al., 2019; Sullivan et al., Under review; Zamuda et al., 2019). The ability to recover quickly from severe power outages is one way of measuring a power system's resilience, but there are other examples of metrics that capture system resilience in theory or in practice (e.g., see Eto, 2018). For the purposes of this study, we narrowly define resilience as the reduction in the frequency of severe power interruptions lasting 24 hours or longer. Future research should be devoted to developing other resilience metrics and the associated benefits to customers.

To assess resilience, this study examines the impacts of battery storage systems on the number of customer outages lasting longer than 24 hours.

3.2.3 Approach

This analysis applied simulated battery storage capacity to historical outage data to determine how the batteries could have mitigated the interruptions. We use outage data from the five IOUs from 2014-2018, where each row of the dataset represented a different outage characterized by utility, circuit, cause, number of customers interrupted, start time, end time, and duration of the interruption. The process of assessing the reliability and resilience impacts followed the five steps outlined in Figure 3.1. The steps are summarized below.

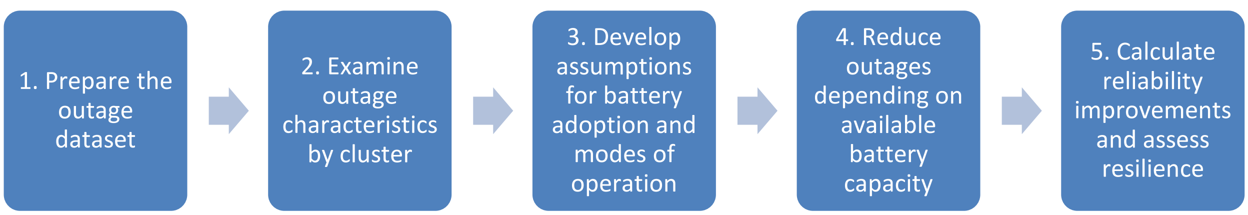

Figure 3.1 Overview of approach for assessing reliability and resilience improvements

1. **Prepare the outage dataset:** We clean the outage data from the five IOUs to remove outliers and inconsistent data, standardize outage cause descriptions, and exclude similar time frames and outage types.
2. **Examine outage characteristics by cluster:** Circuits were grouped into six clusters of similar circuits using the method outlined in Section 4.2. We summarize historical outage characteristics and compared them between clusters to gain an understanding of the 'baseline' level of outages.
3. **Develop assumptions for battery adoption and modes of operation:** We develop assumptions for customer battery adoption (described in Section 4.3) and apply them to each cluster to obtain cluster-level residential and commercial penetration levels. We develop five modes of operation, which characterized the hourly and seasonal charging and discharging patterns for battery storage systems. These modes represented different ways that customers could operate their batteries—including one peak shaving mode that could represent operating the battery from the perspective of the utility.
4. **Reduce outages depending on available battery capacity:** Using the load profile of average residential and commercial customers and the battery capacity profile for each mode of operation, we reduce the impact of each outage in the dataset. The extent of impacts

depended on the season, outage onset hour, battery penetration level, and mode of battery operation.

5. **Calculate reliability improvements and assessed resilience:** We calculate new values for SAIDI, SAIFI, and CAIDI (from the customer perspective) to assess the impacts from battery storage by cluster, adoption level, and mode of operation. We also examine the impact of battery storage on the overall number of customer interruptions longer than 24 hours.

4. Representative feeder selection

4.1 Background

Distribution systems are widespread due to their role in providing electric service to each individual customer across a service area. Despite their expanse, distribution systems are relatively homogenous in terms of the topology of feeders and circuits. This is due, in part, to standardization in their construction, but also because most utilities have similar climates within their service territory. Any differences in distribution system topology are driven by the types and number of connected customers, their density, consumption levels, and specific geographical features. These drivers suggest that there are a common set of distribution system topologies within a utility, or across utilities that share relatively similar climates and design standards.

It follows that commonalities across distribution systems can be leveraged to perform complex analyses on representative systems that would otherwise be very time-consuming to perform over the entire service territory. For example, earlier work by Willis, Tram, and Powell (1985) sought to reduce a set of 1,350 feeders in a utility's distribution system to 12 representative feeders to improve analytical processing times. Feeders are a natural unit of analysis for distribution systems: their topologies are well identified; feeders (i.e. medium voltage) are more "stable" over time than secondary (i.e. low voltage) distribution systems; they encompass all customers connected to both low and medium voltage levels; and utilities track many important metrics at the feeder level including peak demand and reliability indices. The IEEE formed the Test Feeder Working Group in 1991 and detailed a set of five feeders that represented specific distribution system conditions, including load imbalance or non-transposed distribution systems (Kersting, 2001, 1991). These feeders were not intended to represent typical circuits, but their release increased the use of test feeders as a step towards generalization of methods and techniques when performing distribution system analysis (Schneider et al., 2018).

Increasing penetration of DERs has renewed the interest in feeder clustering techniques allowing utilities to simulate a small number of representative feeders to understand the impacts of these resources across their entire service territory. Other researchers produced a set of 24 representative feeders in three voltage levels to represent distribution systems across the U.S. (Schneider et al., 2009). The aforementioned authors obtained 575 distribution feeders from 17 utilities across the nation and classified feeders according to their climate region, producing between four to eight feeders per region. More targeted analyses were developed for the Western U.S. (Broderick and Williams, 2013) and western Australia (Li and Wolfs, 2014) for over thousands of feeders. Broderick and Williams found that four representative feeders in the 12 kV class were enough to capture the range of parameters used to categorize feeders. Li and Wolfs recommended nine clusters to represent the 22 kV feeders that are typical in Australia. Building from these studies, Cale et al. (2014) developed a clustering analysis for 1,295 distribution feeders in the Arizona Public Service territory, resulting in nine representative clusters.

This study employs these techniques, especially the method developed by Cale et al. (2014), to produce a set of six representative feeders for the five IOUs in the state of Indiana. The number of representative feeders balances breadth with the ability to accommodate the number of power flow simulations necessary given the number of customer loads, time horizons, and DER adoption scenarios. On average, each feeder is simulated approximately 570 times. It should be noted that the addition of even a few more feeders would render the simulation process and analysis of results intractable. The number of feeders is also well within the range of typical feeder numbers developed in previous reports, which ranged between four and nine.

4.2 Sampling method

The method to identify the optimal number of representative feeders and ultimately select the final clusters largely follows the most recent work on this topic by Cale et al. (2014). The method employed is based on the following steps:

1. Identify available feeder metrics for clustering
2. Transform the data using Principal Component Analysis (PCA) and identify outliers
3. Determine the optimal number of clusters
4. Select representative feeders for each cluster

The following subsections describe each of these steps in more detail.

4.2.1 Identifying available metrics

A representative feeder analysis depends on the choice of parameters used to classify feeders as well as the quality and availability of data from each utility. The studies cited earlier characterize feeders with varying degrees of complexity, ranging from the six parameters in Broderick and Williams (2013) to the 35 parameters in Schneider et al. (2009). In this study, we initially asked the five Indiana IOUs to provide 23 parameters for all of their distribution feeders between the voltages of four to 33 kV. In a subsequent request, the utilities were asked to provide reliability metrics for each feeder for the years 2014 to 2018. This information was used to calculate five-year average SAIFI, SAIDI, and CAIDI for each feeder, which added three more parameters to the feeder characterization dataset. The completeness of the 26-parameter datasets varied substantially across utilities (see Table 4.1). In addition to the data completeness issue, I&M submitted a set of representative feeders rather than their entire feeder population.

Approximately 92% of the 2,790 feeders submitted by utilities corresponded to the 12 kV family (nominal voltage between 11 and 13.8 kV). Three percent of feeders belonged to the 33 kV family and five percent to the four kV family. This study focused on the 12 kV feeder family only (2,573 feeders) given the predominance of 12 kV family feeders and that most four kV feeders are single-customer feeders.

This report performs a number of data quality detection and cleaning steps for all feeders in the 12 kV feeder family. The report focuses on DER adoption impacts on distribution feeders, hence all non-distribution feeders were excluded from the analysis as they were not considered relevant for the focus of the study. The definition for non-distribution feeders were those shorter than 0.1 mile or with fewer than 10 customers. Subsequently, 2,552 feeders were available for the analysis.

Table 4.1 Share of feeders by utility reporting characterization parameters

		Share of feeders reporting parameter				
Parameter name	**Description**	**Duke**	**I&M**	**IP&L**	**NIPSCO**	**Vectren**
agg_tr_cap	Aggregate MV/LV transformer capacity (MVA)	99%	100%	100%	98%	100%
avg_caidi	Average feeder CAIDI (2014-2018)	98%	100%	100%	97%	98%
avg_saidi	Average feeder SAIDI (2014-2018)	98%	100%	100%	97%	98%
avg_saifi	Average feeder SAIFI (2014-2018)	98%	100%	100%	97%	98%
enclo	Number of underground enclosures	100%	100%	100%	100%	0%
len_oh	Total overhead circuit length (miles)	100%	100%	100%	100%	100%
len_ug	Total underground circuit length (miles)	100%	100%	100%	100%	100%
num_cust_ag	Number of agricultural customers	0%	22%	100%	0%	0%
num_cust_com	Number of commercial customers	98%	97%	100%	98%	0%
num_cust_ind	Number of industrial customers	68%	49%	100%	98%	0%
num_cust_other	Number of other customers	94%	20%	100%	98%	0%
num_cust_res	Number of residential customers	95%	97%	100%	98%	0%
num_cust_tot	Total number of customers in feeder	100%	100%	100%	100%	100%
peak_dm	2018 feeder peak demand (MVA)	0%	100%	90%	100%	100%
poles	Number of poles	100%	100%	100%	100%	100%
sh_cap_ag	Share of connected capacity, agricultural customers	0%	22%	100%	0%	100%
sh_cap_com	Share of connected capacity, commercial customers	98%	97%	100%	98%	100%
sh_cap_ind	Share of connected capacity, industrial customers	98%	48%	100%	98%	100%
sh_cap_other	Share of connected capacity, other customers	98%	20%	100%	98%	100%
sh_cap_res	Share of connected capacity, residential customers	98%	97%	100%	98%	100%
sh_ene_ag	Share of energy sales to agricultural customers	0%	19%	100%	0%	100%
sh_ene_com	Share of energy sales to commercial customers	0%	94%	100%	98%	100%
sh_ene_ind	Share of energy sales to industrial customers	0%	46%	100%	98%	100%
sh_ene_other	Share of energy sales to other customers	0%	18%	100%	98%	100%
sh_ene_res	Share of energy sales to residential customers	0%	94%	100%	98%	100%
tot_len	Total feeder circuit length (miles)	100%	100%	100%	100%	100%

The final step after the 12 kV feeder family filtering and the removal of feeders that were not relevant for the analysis was parameter selection. The varying levels of data completeness, even after requesting utilities to fill in the missing information, created a trade-off between the number of parameters and the size of the definitive dataset. The sample size was dramatically reduced when only feeders that reported all the required data characteristics were included. However, choosing parameters without checking which utility reported it risked leaving an entire utility outside of the sample, which was undesirable.

We selected a subset of parameters that encompassed the largest amount of feeders, included all utilities, and still captured the critical variables identified in previous studies. For example, two utilities did not sufficiently report the number of feeder customers by segment, but all of them reported the total number of customers. Several utilities did not sufficiently report the share of energy sales by customer segment, but they did report the share of installed capacity by customer segment. Table 4.2 shows the selected parameters with summary statistics. The final number of feeders by utility employed in the analysis is shown in Table 4.3. As indicated, the reduced I&M feeder sample resulted in a relatively reduced representation compared to the other IOUs.

Table 4.2 Selected feeder parameters, with summary statistics

Parameter name	Description	Count	Mean	Standard deviation
poles	Number of poles	2,252	549	474
len_oh	Total overhead circuit length (miles)	2,252	13	14
len_ug	Total underground circuit length (miles)	2,252	6	8
agg_tr_cap	Aggregate MV/LV transformer capacity (MVA)	2,252	13,485	8,385
sh_cap_res	Share of connected capacity, residential customers	2,252	57%	30%
sh_cap_com	Share of connected capacity, commercial customers	2,252	29%	23%
sh_cap_ind	Share of connected capacity, industrial customers	2,252	9%	17%
sh_cap_other	Share of connected capacity, other customers	2,252	5%	10%
avg_caidi	Average feeder CAIDI (2014-2018)	2,252	137	55
num_cust_tot	Total number of customers in feeder	2,252	902	659
tot_len	Total feeder circuit length (Derived)	2,252	19	17
sh_len_und	Share of underground length from total length (Derived)	2,252	32%	26%

Table 4.3 Definitive number of feeders by utility with complete data

IOU	Number of feeders
Duke Energy	938
I&M	20
IP&L	364
NIPSCO	756
Vectren	174
Total	2,252

The definitive subset of parameters did not include SAIDI or SAIFI because utilities used a different customer base to calculate these indicators. Two utilities used feeder-level customer counts, while the other three used system-level customer counts. This differences made the SAIFI and SAIDI data not reconcilable. CAIDI was then employed because the metric is indifferent to the number of customers, and also because it summarizes SAIDI and SAIFI and generally reflects feeder-level reliability.

The next steps in finding representative feeders involves transforming the feeder data and then applying a clustering algorithm. These steps are needed to make sure data is comparable across the different feeder variables, and that the feeders are grouped based on a rigorous statistical method.

Details for these steps are reported in Appendix B.1.

The first stage in the clustering process recommended four clusters to represent the IOUs' feeders. In the second stage, we ran the clustering algorithm with five, six, seven, and eight clusters, and manually compared basic metrics between the clusters. This approach follows the lead of Schneider et al. (2009), who sought to define feeder topologies that would describe actual feeders based on their density, location, and customer segments served. We found that six clusters classified feeders in reasonably mutually exclusive categories that were characterized by specific service, topology, and reliability configurations (see Table 4.4)

Table 4.4 Six representative clusters and a sample set of parameter statistics

Cluster	General description of feeders in cluster	Average customer number	Average total length (miles)	Average CAIDI (min)	Share of installed capacity (residential)	Share of installed capacity (commercial)	Share of installed capacity (industrial)	Share of circuit length that is underground
1	Short and high commercial, about 1/3 underground	445	9.5	145.1	25%	58%	6%	30%
2	Short, urban residential	567	11.5	142.4	77%	17%	2%	19%
3	Suburban mostly overhead, residential, relatively dense	1,472	21.7	135.4	70%	21%	7%	20%
4	Very long residential mostly rural	1,133	59.3	148.5	78%	15%	3%	19%
5	Suburban underground residential relatively dense	1,535	26.2	121.4	77%	17%	5%	67%
6	Short, heavy industrial, substantial underground	463	10.0	120.8	15%	31%	51%	39%

As shown in Table 4.4, the basic statistics for each cluster lead to the following cluster interpretation:

1. The first cluster represents circuits with a higher concentration of commercial customer capacity, and with extensive underground sections. This cluster may correlate with urban and suburban commercial areas.
2. The second cluster corresponds to short, urban and suburban feeders.
3. The third cluster corresponds to relatively dense and long, residential feeders served mostly by overhead power lines (i.e., typical of older suburban areas).
4. The fourth cluster groups very long and sparse residential feeders. These types of feeders are common in semi-rural and rural areas.
5. The fifth cluster classifies feeders with substantial underground share of the total circuit length, largely residential with better reliability indices (i.e., may be typical of newer suburban subdivisions).
6. The sixth cluster groups short feeders that serve primarily industrial customers with high levels of reliability. This is the result of undergrounding long portions of the feeder, but also of connecting fewer customers to the feeders to minimize failure points.

4.2.2 Selecting representative feeders

Once the clusters were determined, each feeder was assigned into a cluster based on its principal component decomposition. The resulting assignment by IOU is reported in Table 4.5. The clustering allocation by utility suggests that the largest utility, Duke Energy, has a relatively even distribution of feeders across the six clusters. However, smaller utilities tend to concentrate their feeders in specific clusters. For example, the majority of IP&L feeders were classified in clusters 3, 5 and 6, while most of NIPSCO feeders correspond to clusters 1 and 2. While these concentrations are interesting and possibly logical, it is important to remember that the purpose of the clustering is to analyze feeders based on their characterizing features regardless of the utility it belongs to.

Table 4.5 Count of feeders assigned to representative clusters by IOU

	Cluster					
IOU	**1**	**2**	**3**	**4**	**5**	**6**
Duke	103	237	231	127	201	39
I&M	8	1	5	2	0	2
IP&L	15	5	93	14	110	127
NIPSCO	395	197	49	30	38	47
Vectren	35	55	23	30	28	3

A single representative feeder is selected for each cluster using statistical methods that identify an “average” feeder across multiple dimensions or variables (see Appendix B.1.3 for more details of this process). In processing the existing feeder metrics, Duke Energy feeders had to be excluded because their feeder models are not available in the Cymdist format that will be used for the power flow simulations. No I&M feeders were selected as representative by this method because of the limited number of I&M feeders in the analysis. Definitive representative feeders were then assigned by the D^2 distance analysis to NIPSCO, IP&L, and Vectren (see Table 4.6).

Table 4.6 Definitive representative feeders

Cluster	IOU	Representative feeder
1	NIPSCO	SPRING
2	NIPSCO	WARNER ROAD
3	IP&L	LAWRENCE_08
4	Vectren	HORNVILLE
5	IP&L	TREMONT_04
6	IP&L	EAST_07

These feeder selections were communicated to the respective IOUs to request detailed customer level data that was used to prepare input data for the simulation (see section 4.3). In this process, NIPSCO reported that one of the feeders we had originally selected had suffered a major reconfiguration after a large customer was disconnected from this feeder and connected at the transmission level. That feeder was discarded and the next closest feeder in terms of D^2 distance was selected (shown in Table 4.6). The sampled IOUs also provided individual feeder models that would speed up the simulation process by avoiding the need to simulate larger portions of the distribution system. The next section explains the methodology used to set up and calibrate the simulations of the representative feeders.

4.3 Creating input data for simulations

The next step in the analysis involves selecting a number of representative feeders to run power flow simulations in different DER adoption scenarios, hours of the day, and time horizons. In this section, we explain how the scenarios from Section 2 are used to calibrate net demand for each load in the six representative feeders selected for this analysis.

The basic procedure to create the input data for the Cymdist power flow simulations is detailed as follows:

1. Obtain information for each customer connected to each one of the six feeders
2. Define basic DER configuration parameters by customer segment, such as battery storage size, battery storage operational strategy, and PV system size
3. Develop a method to forecast DER adoption by customer for the two analysis years, 2025 and 2040.
4. Produce hourly demand and production curves for native load and the three DER considered in this study (PV, electric vehicle charging, and storage operation) using synthetic hourly load data derived in part from information provided by the IOUs
5. Create an annual vector of hourly active and reactive net demand for each customer across the six representative feeders

This five-step procedure results in hourly net demand vectors that reflect seasonal, weekly, weekend-weekday, and hourly variation in the demand and production of electricity by each customer. The simulation process will select all the hours in the peak demand day and the lowest demand day to simulate a power flow over the entire feeder. We explain the content of each step in the procedure as follows.

In the first step, we requested information to characterize each customer connected to the representative feeders. This information included the customer's segment, their rate class, facility square footage, annual income, demand response participation (kW reduced), energy efficiency reductions (kWh), consumption (kWh), and whether the customer has DER, among others. Information on income by customer was available only for one utility. Even in this case, it was an estimate based on zip code-level data that did not capture individual customer income levels so it was not considered. Customer-level information was aggregated at the transformer level to locate it within the primary voltage feeders to be simulated.

In the second step, DER systems were designed based on typical existing and forecasted sizes as indicated in Table 4.7. We assumed that industrial customers would not adopt distributed resources. While this is not necessarily true, their adoption patterns do not follow the same generalizable logic as those of residential and commercial customers, and hence would have to be modeled on a case by case basis.

Table 4.7 Assumed size for DER systems by customer segment

DER System	Residential	Commercial	Industrial
Rooftop PV	• 8 kW	• 16 kW	N/A
Battery storage	• 7 kW max discharge capacity • 12 kWh storage capacity • 90% roundtrip efficiency • 25% maximum discharge level	• 14 kW max discharge capacity • 0.1% of annual kWh consumption of storage capacity • 90% roundtrip efficiency • 25% maximum discharge level	N/A
Electric vehicle charging	• T1 charger: 1.75 kW peak capacity • T2 charger: 5.25 kW peak capacity	N/A	N/A

We assume residential customers would adopt 8 kW PV systems on average and commercial customers would adopt a 16 kW system. For battery storage, we used the parameters of a Tesla Powerwall 2 for residential customers (12 kWh useful storage capacity), and a custom-sized system for commercial customers based on their annual consumption. The 0.1% of annual consumption parameter was based on an analysis of existing installed systems for commercial customers. Finally, we assumed that electric vehicles were adopted by residential customers. For simplicity, we assume that charging also takes place at home using Type 1 and Type 2 charging technologies. Type 1 chargers have a peak demand of 1.75 kW, while Type 2 chargers have a peak demand of 5.25 kW. We assumed no vehicle-to-grid interaction or smart charging management since data to calibrate these charging modes is unavailable.

Aggregate scenarios for DER adoption were reported in Section 2. The third step in the input development process involves identifying a method to determine DER adoption at the customer-level to match the state-wide estimates. These customer adoption levels are scaled to the cluster and state level and verified against the aggregate levels by year and scenario defined in Section 2. The DER allocation method has two components: (1) scaling factors for each feeder and; (2) energy consumption thresholds for each DER, customer segment, and adoption level.

First, scaling factors reflect feeder-level DER adoption aggregates at the cluster-level. These factors were calculated for each representative feeder as the ratio between the number of customers at each feeder and the total number of customers for the cluster that the feeder represents. We obtain state-level adoption values by adding the cluster-level scaled adoption values.

Next, energy consumption thresholds were defined for each DER and each customer segment, and for the base, high, and very high adoption levels in the scenarios. Customers that had an annual native load consumption (without considering EV and PV) above those threshold levels would be marked as DER adopters. This method assumes that higher consumption will correlate with higher adoption, which is supported by the fact that, in the absence of policy incentives, the main reason customers adopt solar energy is to save money (Moezzi et al., 2017). The energy consumption thresholds are described in Table 4.8.

Table 4.8 Annual energy consumption thresholds for DER adoption

		Residential		Commercial	
DER	Adoption level	2025 threshold level (kWh)	2040 threshold level (kWh)	2025 threshold level (kWh)	2040 threshold level (kWh)
PV	Base	50,000	41,000	75,000	34,000
PV	High	24,500	18,500	32,000	7,600
PV	Very High	21,000	14,250	18,000	3,000
EV-T1	Base	44,000	24,500	N/A	N/A
EV-T1	High	36,000	18,500	N/A	N/A
EV-T1	Very High	27,000	11,000	N/A	N/A
EV-T2	Base	34,500	18,100	N/A	N/A
EV-T2	High	28,200	12,800	N/A	N/A
EV-T2	Very High	19,350	4,700	N/A	N/A
Storage	Base	N/A	140,000	N/A	N/A
Storage	High	46,500	37,000	700,000	600,000
Storage	Very High	32,000	24,500	400,000	220,000

In general, threshold levels for residential and commercial customers decrease over time due to higher 2040 adoption rates compared to 2025. Similarly, thresholds decrease for higher adoption levels (e.g. the residential 2025 PV adoption levels is lower in the "high" case compared to the "BAU" case). The resulting DER adoption rates by customer segment, year, and adoption levels are reported in Table 4.9. These adoption rates are calculated as the number of customers that adopt a given DER divided by the total number of customers for the same segment on each feeder. Adoption rates across clusters vary substantially as it follows the customer mix and consumption levels, which are heterogeneous. For example, PV adoption in the base adoption level for 2040 is eight times higher in cluster six compared to cluster three.

Table 4.9 Resulting DER adoption rates by customer segment and year

		Residential		Commercial	
DER	Adoption level	2025 adoption rate (% of customers)	2040 adoption rate (% of customers)	2025 adoption rate (% of customers)	2040 adoption rate (% of customers)
PV	Base	0.2%	0.6%	12.2%	23.5%
PV	High	4.6%	10.9%	24.6%	51.9%
PV	Very High	7.7%	20.5%	35.5%	70.4%
EV-T1	Base	0.5%	4.6%	N/A	N/A
EV-T1	High	1.0%	10.9%	N/A	N/A
EV-T1	Very High	3.4%	34.4%	N/A	N/A
EV-T2	Base	1.3%	11.4%	N/A	N/A
EV-T2	High	3.0%	26.2%	N/A	N/A
EV-T2	Very High	9.6%	84.3%	N/A	N/A
Storage	Base	0.0%	0.0%	0.0%	0.0%

		Residential		Commercial	
DER	Adoption level	2025 adoption rate (% of customers)	2040 adoption rate (% of customers)	2025 adoption rate (% of customers)	2040 adoption rate (% of customers)
Storage	High	0.4%	0.9%	0.6%	0.6%
Storage	Very High	1.8%	4.6%	1.3%	2.5%

The fourth step in the creation of input data is to use hourly profiles to generate an 8760-hour annual vector for each customer's native load and DER operation. Profiles were generated for native load, EV charging, PV generation, and battery operation. Native load profiles were generated for each customer class (residential, commercial, and industrial), and were based on historic rate class load profiles provided by the utilities. EV profiles were generated for Type 1 and Type 2 chargers. The charging profiles assumed that charging would begin at 6 pm on weekdays and 2 pm on weekends, and would charge each EV enough for the owner to drive the next day. Annual charging assumed each EV would need to be driven 12,000 miles annually, which is the current average distance driven in the U.S. Production profiles for PV were created using NREL's PVWatts model. Storage operational profiles are obtained by assuming that storage owners seek to maximize the netting of their DER PV, subject to a maximum discharge of 25% of their storage capacity. There are no assumptions about time of use rates or other incentives that would inform storage operation within the power flow analysis. Figure 4.3 depicts an example of what a representative residential customer's DER loads with no EV charging might look like on an average summer weekday.

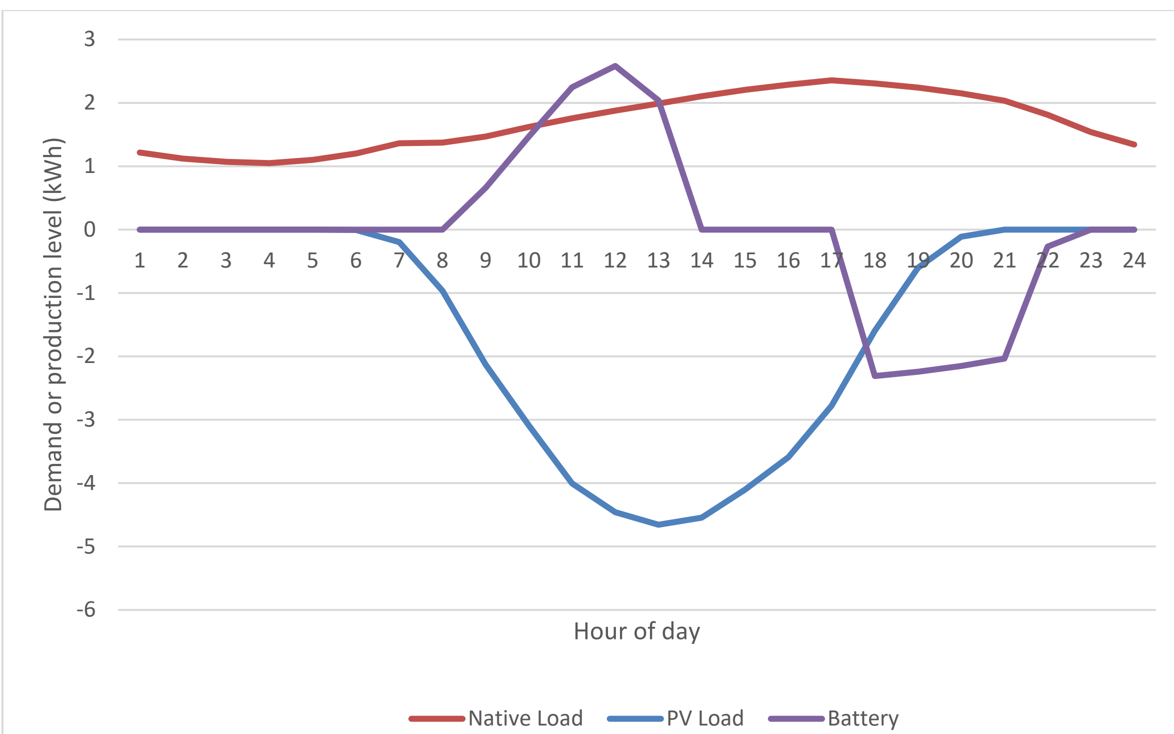

Figure 4.1 Sample residential DER hourly operational profile for average summer weekday (kWh)

The final step involves making assumptions about power factor and phase balancing, as the Cymdist input data is provided for each connected phase and for active and reactive power. The models sent by IP&L and NIPSCO included power factor for each load node; these power factors are used to represent reactive power demand on these feeders. The feeder for cluster four, a Vectren feeder, did not include these values. In their place, we use the median value for the other five feeders. We finally assume that loads are balanced and allocate hourly net demand in equal way to reported connected phases for each load node.

4.4 Output metrics

Three specific variables from the power flow simulation are tracked to inform potential DER integration benefits or costs. These variables include: voltage violation by node, line loading (thermal constraints), and line losses.

Voltage violations by node

Voltage violation will be tracked by each load node in the feeder. Two metrics are tracked: (1) voltages above/below the ANSI C84.1 standard and (2) voltage differences across the adoption scenarios. First, we track whether any load node has a per unit (p.u.) voltage below or above the ANSI C84.1 standard (ANSI, 2016). In the case of 12 kV feeders, the optimal range is 97.5%-105% of nominal voltage (0.975 – 1.05 p.u.) and the acceptable range is 95%-105.8% (0.95 – 1.058 p.u.). Next, we track the differences in voltage by node between the base case and each of the five adoption scenarios. In this case, voltage levels may still be within ANSI standard, but we want to track whether higher levels of DER integration cause relevant voltage deviations compared to the base case.

Line loading (thermal constraints)

Line loading reflects the current flowing over a line segment in proportion to its nominal current carrying capacity given by the wire gauge, type, and configuration. While it is not uncommon to overload lines in normal distribution operation, we use a conservative approach and identify the number of hours in which a line segment is loaded more than 100% of its capacity.

Line losses

Line loss management is largely an economic decision, rather than a technical threat to power quality. A utility may upgrade[5] a conductor that is not permanently overloaded, but whose losses are such that is cost effective to reduce them. Generally, overload and losses issues are correlated. We will measure the variation in losses for the scenarios compared to the base case and monetize them, but we do not suggest intervention strategies to correct losses.

There are several variables that are not captured in the power flow simulations and can also accrue integration costs. These include sub-hourly dynamics such as voltage sag or flicker, reverse power flow issues, and protection coordination issues (Horowitz et al., 2019). The limitations of the available data and limited computational resources do not allow assessment of secondary voltage networks and distribution transformers. For this reason, they are excluded from this analysis.

[5] Upgrading lines with higher gauge conductors than existing is usually called repowering or re-conductoring.

4.5 Method for upgrading feeders

The method for upgrading feeders is largely based on work by NREL in assessing PV integration costs (Horowitz et al., 2018). There are several interventions to respond to substandard conditions in the three tracked variables:

Voltage violations

There are three strategies implemented for voltage violation interventions: installation of advanced inverters in PV systems, adjustment of the substation's load tap changer (LTC), and connecting a voltage regulator.

Modern PV inverters are able to consume or generate reactive power up to 30% of their rated apparent power. They are usually programmed to generate reactive power when voltage drops from a certain level, and consume it when it goes above, with a dead band in between. The installation of advanced inverters in PV systems can be used to regulate voltage drops and increases at the point of injection of the distributed resource.

Adjustment of the LTC at the substation is a traditional mechanism to correct for ongoing voltage excursions. It affects the entire feeder by shifting the head voltage up or down, and it is commonly used to fix voltage drops at the end of the feeder. They are generally not used in real-time, but to permanently adjust voltage in the feeder head. It is worth noting that not all substations are necessarily equipped with LTC.

Connecting a voltage regulator performs a similar function as advanced inverters, with a wider range of operation and significantly higher capacity to manage reactive power. They can be used to correct for voltage drops and increases in real-time.

Line loading

In the case of line loading, installing higher gauge conductors (i.e., re-conductoring), which have higher ampacity, reduces the line loading for similar current levels. As indicated before, we are not able to implement and test feeder reconfigurations as a line loading strategy within the framework for this study although this is a commonly used strategy by distribution utilities.

Line losses

As is the case with line loading, re-conductoring is a common way to reduce line losses. Utilities will occasionally reconfigure a feeder by routing circuits to a different feeder. This has the effect of balancing the load and reducing the overall losses due to their non-linearity. We will not explore feeder reconfiguration in this study, but it is a recommendation under consideration.

5. Results

5.1 Distribution system power flow technical results

Simulations are executed on each of the six representative primary voltage feeders, and characterized by (1) the year of analysis (2025 or 2040), which drives load growth and adoption levels; (2) six adoption scenarios, which establish different combinations for adoption levels of distributed PV, storage, and electric vehicles; and (3) twenty-four hours (a full day) on the minimum and maximum load days, for a total of 48 hours per feeder-scenario-year-cluster combination. These variables result in 576 power flow simulations per representative feeder, for a total of 3,456 simulations.

5.1.1 Voltage regulation

Results for voltage regulation are reported in Figure 5.1 (next page). In this figure, the column panel report the six adoption scenarios while the row panel depict the six representative feeders identified by their cluster CL1 to CL6. The charts show the distribution of voltage in p.u. (per unit or the fraction of nominal voltage) for each simulated node-hour[6], where the red shade represents 2025 and the blue shade 2040. The vertical lines represent the two ANSI voltage violation criteria: orange for the optimal range and red for the acceptable range.

At first glance, voltage violations are rare and minimal. About 0.5% of the node-hours simulated are under the 0.975 p.u. lower voltage range for the optimal scenario and 0.3% node-hours are above the 1.05 p.u. upper range. Only 0.04% of the node-hours are under the 0.95 p.u. lower acceptable range, and none are above the 1.058 upper acceptable range. The absolute minimum and maximum voltages are reasonably close to the ANSI limits for all of the node-hours simulated (Table 5.1).

High voltage violations are very small, exceeding the optimal range by 0.009 p.u. in the worst case. Low voltage violations are also very limited, with a worst case excursion 0.053 p.u. below the optimal limit. Low load day simulation hours fall almost entirely within optimal and acceptable ranges; the majority of the voltage violations occur during high load days.

Table 5.1 Ranges in voltage regulation for low and high load day simulated hours, by year

		Voltage Levels (p.u.)				
Year	Type of Load Day	Minimum	25th Percentile	Median	75th Percentile	Maximum
2025	High	0.957	1.009	1.02	1.033	1.054
2025	Low	0.988	1.016	1.025	1.038	1.046
2040	High	0.908	1.008	1.019	1.031	1.058
2040	Low	0.945	1.016	1.026	1.038	1.057

[6] A node-hour is a unique observation for a node on one of the 48 simulated hours. We treat node-hours as a single variable to be able to show results for the same node across different hours in the same chart, and avoid one additional dimension in the visualization.

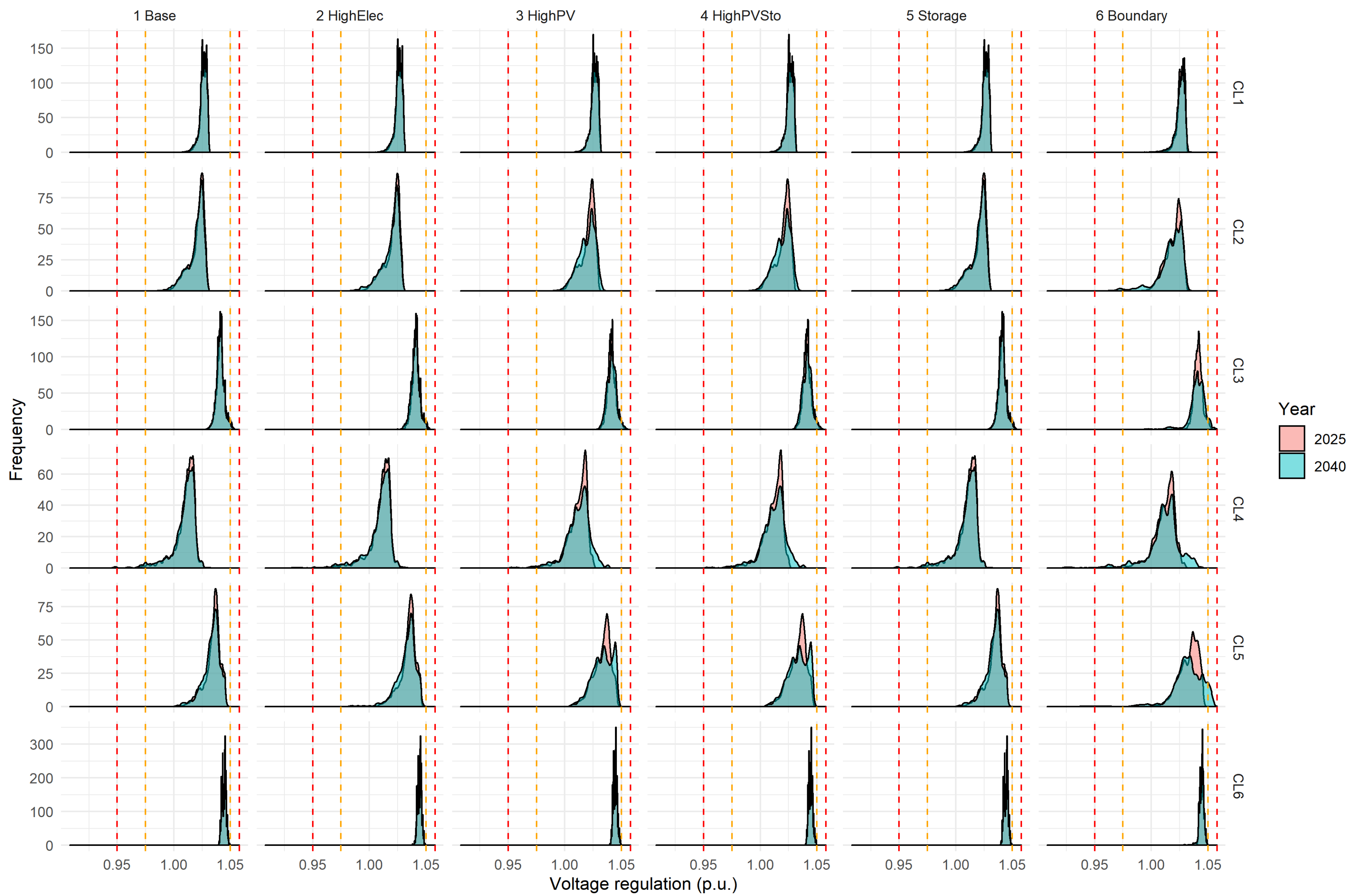

Figure 5.1 Distribution of voltage regulation by node-hour

However, it is important to study power systems in the extreme, because critical issues can be lost in a simple analysis of averages. We find optimal range voltage violations in at least one feeder node on 159 of the 3,456 simulated hours and acceptable range violations in 17 simulated hours (see Table 5.2 for optimal range violations). Representative feeders in clusters 1, 5, and 6 exhibit voltage violations, but only in the Boundary scenario. Cluster 2 feeder has two to three simulation hours with violations in the Base, High PV, High PV and Storage, and Storage scenarios; and five hours in the Boundary and High Electrification scenarios. Feeders for clusters 3 and 4 – among the longest in the sample – have the highest number of hours of voltage violations. In cluster 3, almost 20% of the simulated hours in the Boundary Case show voltage issues.

Table 5.2 Number of simulation hours with ANSI optimal range voltage violations by cluster and scenario for 2025 and 2040

	Scenario					
Cluster	**Base**	**High Electrification**	**High PV**	**High PV and Battery Storage**	**Storage**	**Boundary Case**
CL1	0	0	0	0	0	9
CL2	3	5	2	2	3	5
CL3	9	8	11	11	9	19
CL4	11	11	6	6	11	9
CL5	0	0	0	0	0	8
CL6	0	0	0	0	0	1

This overview of voltage violation results suggests that some representative feeders are much more impacted by DER adoption than others and that the impact produces both low and high voltage issues. A detailed feeder by feeder analysis is included in Appendix B.2.

5.1.2 Line loading

Cymdist calculates the percent loading of each line segment for each simulated hour, based on the line segments' capacity and power flow solution for a specific hour. Results for line loadings are reported in Figure 5.2. In general, lines loading issues are non-existent in the short-term (2025) and minimal in the long-term (2040). Loading issues in 2040 arise in the Boundary scenario for clusters 3, 4, and 5 and in the High Electrification scenario for cluster 4.

Only eight simulation hours out of 3,456 simulated hours have overloaded line segments. In these eight hours, between 0.4% and 8% of line segments are overloaded, depending on the cluster (see Table 5.3). Line overloading takes place in very specific times of day, coinciding with peak residential demand (2-3 pm) or with DER PV production decline coupled with EV charging (6-7 pm). Overloading is also incremental, which means that mitigating the overload for the worst case scenario in each cluster (6 pm at each cluster) will also mitigate issues for the other simulated hours in the same cluster.

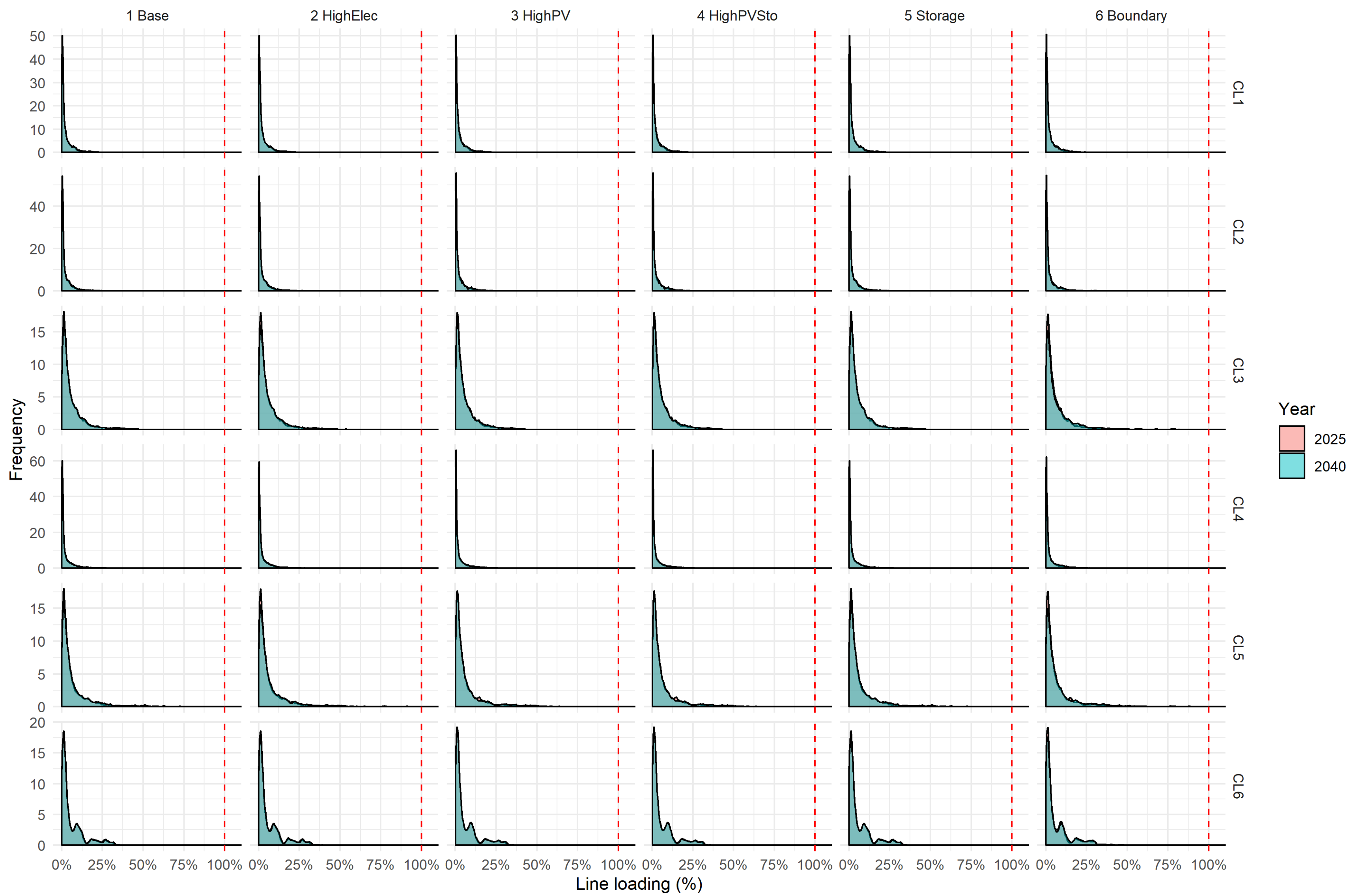

Figure 5.2 Distribution of line loading by node-hour

Table 5.3 Simulation hours with overloading issues

Scenario	Cluster	Hour of Day	Number of Overloaded Segments	Number of Total Segments	Share of Overloaded Segments (% total)
Boundary	CL3	6 pm	31	592	5.2%
Boundary	CL3	7 pm	28	592	4.7%
Boundary	CL4	6 pm	15	1,621	0.9%
Boundary	CL4	7 pm	12	1,621	0.7%
High Electrification	CL4	2 pm	10	1,621	0.6%
High Electrification	CL4	3 pm	10	1,621	0.6%
Boundary	CL5	6 pm	43	535	8.0%
Boundary	CL5	7 pm	42	535	7.9%

Adoption of distributed PV has a beneficial effect in line loading. In the scenarios with higher PV adoption (High PV and High PV with Storage) the worst case line loading is typically 10%-15% less than the High Electrification scenario (with high EV adoption) and 5% less than the BAU scenario (with very little PV adoption). In contrast, it is likely that electric vehicle charging is leading to overloading issues across clusters because the timing of some of the overloading issues coincide with residential type I charging operations.

It is important to highlight limitations of the loading analysis performed in this study. Annual energy consumption by customer was allocated using aggregate load profiles for the three customer types provided by some IOUs due to the lack of actual hourly load shapes or peak power consumption for each customer. The simulation results show that even in the Base case some line segments experience very high loading, while the average line segment loadings are around 5 percent for most clusters and scenarios. These high line loadings may have originated in the method of load allocation, which does not reflect actual customer peak loads. On one hand, the method employed may result in a higher peak load for customers with a relatively flat load demand. On the other hand, the method may produce lower peak load (and lower line loading) for customers with a volatile load profile.

In summary, these results suggest that the existing capacity of line segments in representative feeders would be enough to accommodate the DER deployed under even the most stringent adoption scenario. Required re-conductoring expenditures should be relatively small considering the DER adoption levels. These costs are discussed in Section 5.2. It is important to note that this analysis does not cover distribution transformer loading or secondary network loading. It is possible that these two components do not have the flexibility that the primary distribution system has and would therefore require additional DER integration costs.

5.1.3 Line energy losses

Unlike voltage violations and overloading issues, line energy losses do not translate to power quality issues for customers. However, utilities monitor line losses to maintain a level that is cost-effective for the utility as well as their customers. This means that there is no set standard or benchmark for assessing an acceptable limit for line losses as this cost-effectiveness test will vary across utilities and over time. Consequently, we focus on measuring change in losses between the Base scenario and the other scenarios as a measure of the differential impact of DER adoption.

Feeder losses for the highest hour of the year may be several times higher than average losses calculated using annual aggregates, but it is the latter that informs the overall economic impact of increases or reductions in energy losses. For this reason, we develop a special set of simulations depicting typical conditions in four seasons of the year that are more conducive to aggregate estimates. We select one day per season to capture seasonal patterns in demand and solar PV production. We report hourly losses to show the variation of losses throughout the day and how they correlate with specific DER usage patterns.

Feeder losses for 2025 and 2040 are reported in Figure 5.3 and Figure 5.4, respectively. We report the average percentage change in feeder losses for three selected adoption scenarios: High Electrification, High PV, and Boundary relative to the Base case. We use these three scenarios because results for the High PV and Storage and Storage scenarios are almost identical to the results for the other scenarios and the Base case, respectively.

Results show that line losses follow the new patterns of net demand that arise with PV and EV adoption. Losses are higher than the Base case during the times of day when EV is charging (High Electrification scenario, between 2 pm and 7 pm). Losses are lower than the Base case in the scenarios with higher PV penetration and during the hours of PV production between 10 am and 4 pm. The Boundary scenario in years 2025 and 2040 shows the highest variation in losses compared to the Base case, because it includes very high PV and EV adoption levels. Losses can be 10 to 13 times higher than the Base case during peak demand hours with substantial amounts of residential EV charging.

We estimate annual average losses by calculating the average for each cluster and scenario across all simulated hours for all seasons (see Table 5.4).

Table 5.4 Average hourly change in losses relative to base case (kWh)

	Average Hourly Change in Losses Relative to Base (kWh)					
	High Electrification		High PV		Boundary	
Cluster	2025	2040	2025	2040	2025	2040
CL1	0.01	0.16	-0.15	-0.29	-0.16	2.35
CL2	0.06	0.91	-0.37	-0.78	-0.34	5.80
CL3	0.04	1.57	-0.40	-1.27	-0.44	13.49
CL4	0.42	4.13	-1.84	-2.79	-0.18	8.50
CL5	0.36	5.30	-3.01	-6.45	-2.42	14.24
CL6	0.00	0.10	-0.50	-0.75	-0.73	0.24

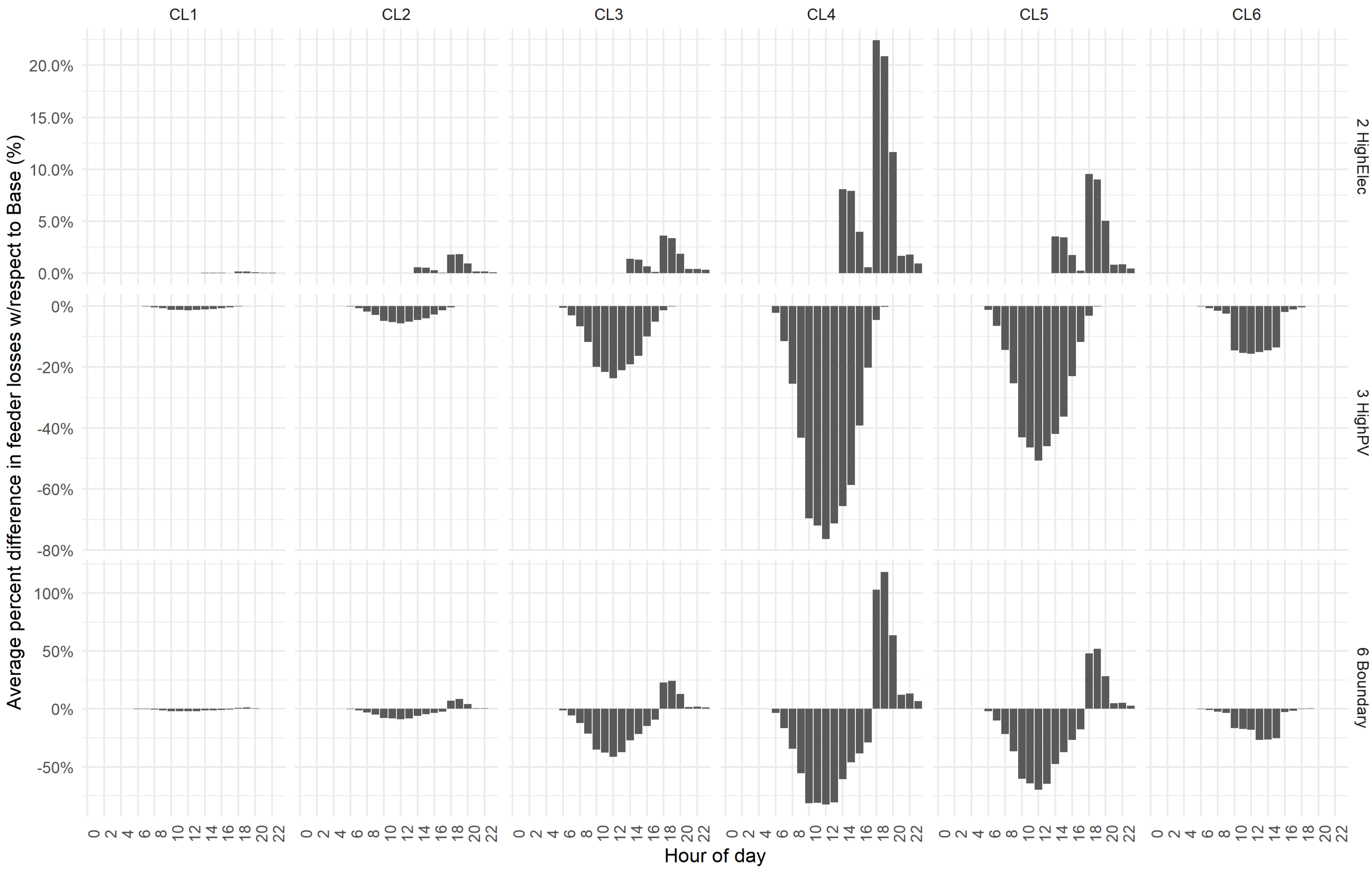

Figure 5.3 Average hourly feeder losses by cluster and scenario (2025)

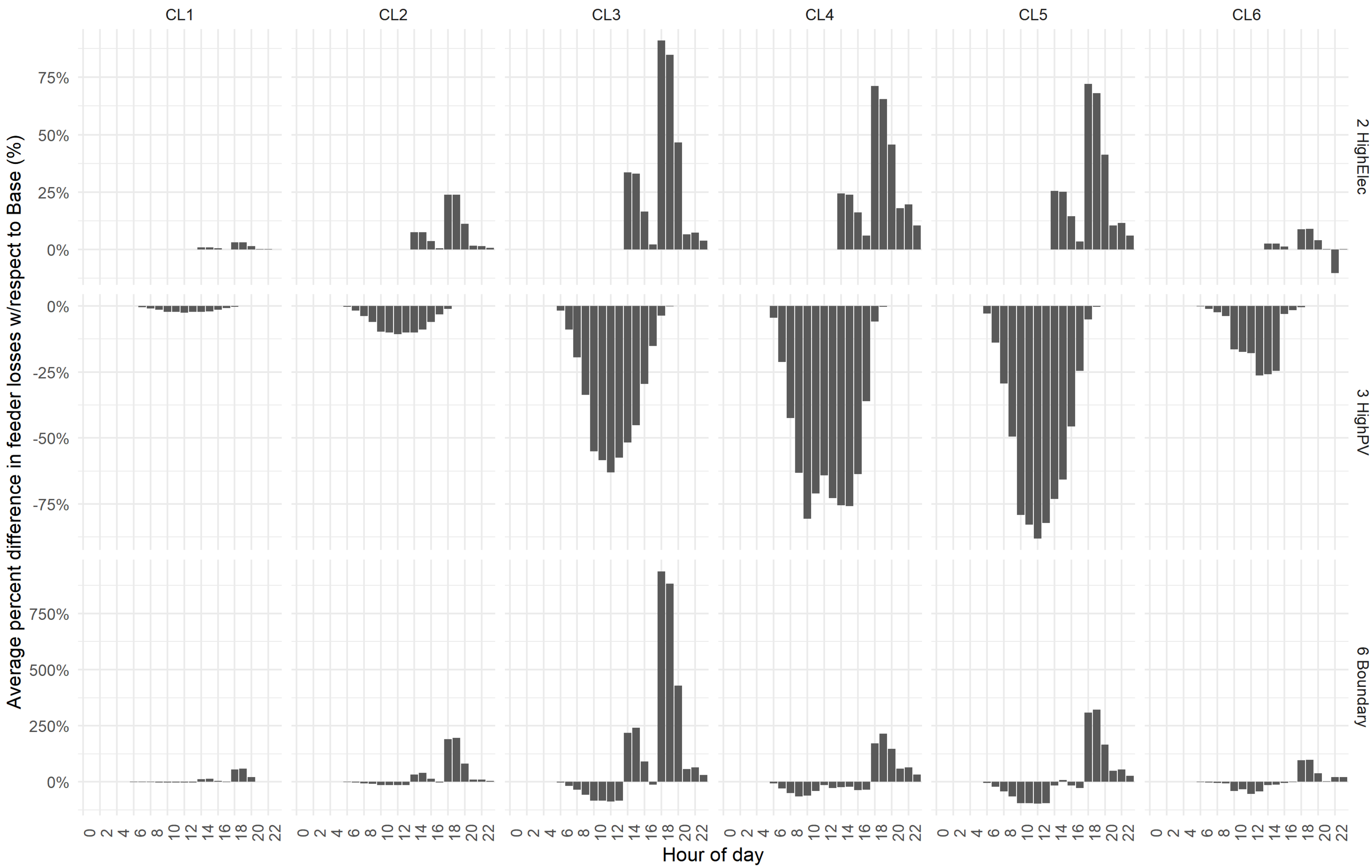

Figure 5.4 Average hourly feeder losses by cluster and scenario (2040)

Average results show moderate increases or decreases in losses across clusters and scenarios for 2025, following the hourly patterns. For 2040, all clusters have higher losses than the base case in the High Electrification scenario, and all clusters have lower losses in the High PV scenario. In the Boundary scenario, losses increase across clusters due to the dominance of EV charging load over PV production.

We extrapolate feeder-level results in Table 5.4 for all IOU service territories by applying the same escalation factors described in Section 4.3 and by multiplying the average hourly losses by 8,760 to extend these estimates to a whole year (Table 5.5). These results will then be used in the following section to provide a first-order estimate of the economic impacts.

Table 5.5 Aggregate change in losses relative to base case for all IOUs (MWh)

	Annual Change in Losses Relative to Base (MWh)					
	High Electrification		High PV		Boundary	
Cluster	2025	2040	2025	2040	2025	2040
CL1	41	709	-656	-1,264	-710	10,348
CL2	306	4,478	-1,817	-3,837	-1,651	28,556
CL3	276	10,289	-2,606	-8,310	-2,861	88,606
CL4	2,005	19,655	-8,739	-13,278	-856	40,458
CL5	985	14,640	-8,310	-17,794	-6,669	39,308
CL6	0	55	-267	-401	-392	129

5.2 Cost and benefits of DER

The costs and benefits of DER are determined separately for the three major components of the power system: (1) generation, (2) transmission, and (3) distribution. Generation and transmission cost impacts are based on simulations performed by the SUFG using input data consistent with the six adoption scenarios developed in this study. Distribution cost impacts are based on the methodology described in section 4.5.

5.2.1 Generation

Hourly net demand for each scenario was shared with the capacity expansion and production cost models. The simulation then reflects the incremental generation investment needs and annual costs to meet those demand levels for years 2025 and 2037[7]. We report four components of generation costs produced by the simulations: (1) annualized capital costs, (2) fixed costs, (3) fuel costs, and (4) non-fuel variable costs (usually O&M).

In the short-term, all scenarios, including the Boundary case, exhibit similar costs relative to the Base case (Figure 5.5). However, over the long-term, the cost differences associated with increased adoption levels become more evident. Scenarios with relatively higher adoption of PV (High PV and High PV and Storage) have 8% lower costs relative to the Base case, largely driven by reduced capital and fixed costs. Costs are roughly 3% higher relative to the Base case in the High Electrification scenario, likely driven by EV charging taking place in the middle of the day. This is supported by the much higher adoption of

[7] This is the latest year available in the SUFG models, hence it is being used as equivalent to 2040 for our purposes.

utility-scale solar PV—whose production peaks midday—in this scenario compared to any other scenario (e.g. twice as much as the Base case).

The Battery Storage scenario is basically identical to the Base case. This is, in part, due to the relatively small levels of adoption of DER storage. However, it also suggests that when customers manage their DER storage without following wholesale market signals, their decisions do not necessarily benefit the system through lower peak demand needs. Finally, the Boundary scenario has ~12% higher costs than the Base case, driven by the strong demand growth of EV charging. It is important to note that the Boundary scenario is serving a 50% higher peak demand than the Base case.

These results suggest that DER adoption, especially PV, could create significant costs savings in both energy and capacity for the Indiana power system. The High PV scenario has 3% higher fuel costs, but 30% lower annual capacity costs compared to the Base case by 2040. In contrast, the higher demand levels of EV charging in the High Electrification scenario result in ~17% additional capital costs relative to the Base case.

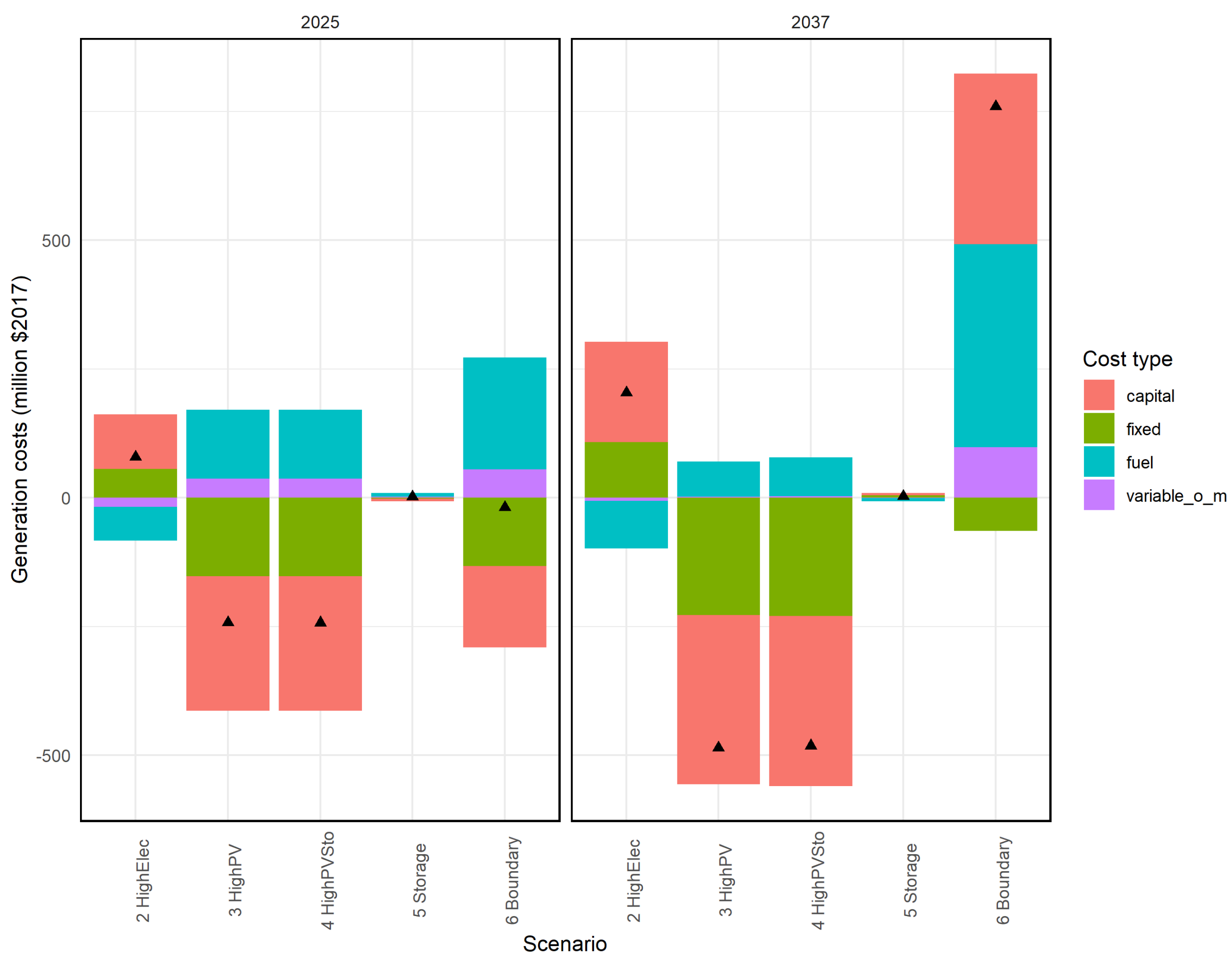

Figure 5.5 Generation costs by type (bars) and net outcome (point) relative to the Base case

We also report differences in capacity additions under each scenario over the long-term (see Table 5.6). Natural gas simple-cycle combustion turbines (SCCT) are deployed in larger amounts in scenarios with higher penetration of electric vehicles, and lower amounts in scenarios with higher PV penetration. The Boundary scenario—dominated by EV adoption—requires more than three times the incremental capacity of SCCTs compared to the Base case despite having only 50% higher peak demand. In contrast, capacity additions of natural gas combined-cycle combustion turbines (CCCT) remain relatively constant across scenarios. The significant adoption of SCCT in the Boundary scenario reflects the flexibility and resource adequacy demands that large swaths of coincident EV charging may impose on the power system.

Table 5.6 Utility-scale resource mix by scenario in year 2037

	Incremental Installed Capacity (MW)			
Scenario	**Natural Gas: Simple Cycle Combustion Turbine**	**Natural Gas: Combined Cycle Combustion Turbine**	**Wind**	**Solar**
Base	4,971	6,034	5,696	579
High Electrification	6,214	5,748	7,000	1,278
High PV	3,879	6,330	2,385	414
High PV and Storage	3,960	6,338	2,384	316
Storage	4,987	6,010	5,766	579
Boundary	16,959	7,360	4,030	55

Wind and solar adoption is substantially higher in the High Electrification scenario compared to any other scenario. This is may be due to coincidence between solar and wind production and EV charging patterns. Higher DER PV adoption in scenarios 3 and 4 correlates with lower wind and solar adoption than the Base case. This is explained by DER PV reducing the capacity value of solar PV given the high production correlation of both resources.

5.2.2 Transmission

Transmission expansion is not modeled directly in the comprehensive study. We estimate the impact of DER on transmission costs by calculating an incremental transmission expansion cost per MW transmitted during peak hours in 2025 and 2037 and multiplying this value by the peak demand in each adoption scenario.

The SUFG estimated the incremental transmission expansion costs by comparing the revenue requirements for the reference scenario in their ratemaking model both with and without incremental transmission expenditures. These expenditures include the return on investment and depreciation of all future capital expenditures, but not from the current rate base, and future transmission system O&M costs. These costs were translated to a dollar per peak MW basis for the revenue requirements in 2025 and 2037 for the reference scenario. This process produces an incremental transmission cost of $55,821 per peak MW in 2025 and $68,896 per peak MW in 2037 that are reasonable approximations for expansion costs in the transmission system.

We apply these values to the statewide peak demand by scenario to estimate transmission costs and calculate the difference from the Base case (see Table 5.7 for cents per kWh costs and Table A.7

Appendix for total costs). DER impact is relatively modest in all but the Boundary scenario, with savings of 3 cents per MWh in the High PV and High PV and Storage scenarios in 2025 to an increase of 57 cents per MWh in the High Electrification scenario in 2037. These figures translate to differences in the -0.3% to 4.7% range.

Table 5.7 Changes to incremental transmission costs relative to the base case

	Cost Change with Respect to Base Case (¢/kWh)		Annual Cost Change with Respect to Base Case (million $)	
	2025	2037	2025	2037
High Electrification	0.01¢	0.06¢	$15.8	$91.3
High PV	0.00¢	0.01¢	-$32.4	-$71.9
High PV and Storage	0.00¢	0.01¢	-$32.4	-$70.6
Storage	0.00¢	0.00¢	$0	$0.01
Boundary	0.07¢	0.64¢	$27.5	$734

The Boundary scenario has the highest cost difference for both planning horizons. Transmission costs are almost 7% higher in 2025 and up to 53% higher in 2037. This is explained due to the peak demand levels of this scenario, which at 31.8 GW in 2037 are roughly 50% higher than the 21.1 GW in the Base scenario.

5.2.3 Distribution

There are three cost components tracked for the integration of DER into the distribution system: (1) voltage regulation, (2) line loading, and (3) line energy losses.

Voltage regulation

Results discussed earlier show that voltage issues are a relatively minor issue across scenarios and that, in some cases, they are driven by the high voltage set point at the substation load tap changer. In this study, we assume that smart inverters are a standard feature in PV systems deployed within every scenario presented. Accordingly, we find that voltage issues for all scenarios can be mitigated by a combination of load tap changer (LTC) adjustments and smart inverter use with PV systems. Consequently, simulations using a combination of volt-var control at PV systems and adjustment of substation LTC result in no voltage issues in the short and long term. This approach and result is consistent with similar studies on management of voltage issues due to rooftop solar adoption (e.g., Horowitz et al. 2018).

The no-cost result for voltage regulation is based on the assumption that LTC is available and adjusted in the IOU-operated electricity substations across Indiana. Unfortunately, we do not have information confirming the reasonableness of this assumptions. For this reason, we include a cost to retrofit half of the existing substations with LTC—assuming the remainder already have LTC installed.

Horowitz et al. (2018) reports that it costs $310,000 per substation to implement LTC based on a Northeastern U.S. utility. We adjust this cost down by 25% to $232,500 based on information from two Indiana utilities. We estimate there are ~1,000 substations serving distribution customers across the Indiana territory. It will cost ~$235 million, or an annual equivalent of $20 million, to retrofit all of these substations. In the end, we assume that half of the substations need the LTC retrofit resulting in an annual cost of ~$10 million.

Line loading

Line loading was addressed by manually replacing conductors in underground and overhead line segments as needed. We re-ran simulations for the affected cluster-scenario combinations to verify that the re-conductoring effectively solved line overloading. Appendix A (Tables A.8 to A.10) include the segment-by-segment details for this re-conductoring process. The lengths of upgraded circuits are reported in Table 5.8

Table 5.8 Length of re-conductored segments by material and cluster

	Underground Cable Length (feet)		Overhead Line Length (feet)	
Cluster	**Copper**	**Aluminum**	**Copper**	**Aluminum**
3	0	0	0	3,634
4	57	0	2,386	0
5	172	0	0	6,461

We monetize re-conductoring using costs per foot of conductor as reported in two sources. First, two of the three IOUs with representative feeders reported costs of $95/ft and $80/ft for overhead and underground line re-conductoring, respectively. The overhead costs include replacing supporting structures to bear additional conductor weight. Second, an NREL cost study reported low, medium, and high costs of $130/ft, $173/ft, and $258/ft, respectively.

We use the preceding cost information to estimate costs based on four re-conductoring "steps" that depend on the ampacity difference between the original and replaced conductor. Each step reflects a 15% increase in conductor ampacity. We assume that the lower cost applies to the first step, and the highest cost to the fourth step. Underground cables are upgraded in a single step, so we use the $80/ft reported by the utility. Finally, we use a 50% cost adder for copper conductors assuming that all costs are for aluminum conductors. Feeder level results are escalated to the aggregate IOU level using the scaling factors described earlier in this manuscript (Table 5.9).

Table 5.9 Feeder-level and aggregate costs for line loading by scenario and cluster

	Feeder Costs (million $2017)		Aggregate Costs for All IOUs (million $2017)	
Cluster	**High Electrification**	**Boundary**	**High Electrification**	**Boundary**
1				
2				
3		$0.396		$297.0
4	$0.271	$0.412	$147.4	$223.8
5		$0.973		$306.5
6				

Re-conductoring was only required for clusters 3, 4 and 5 and for the High Electrification and the

Boundary scenarios. We estimate about $150 million in upgrade costs for feeders in cluster 4 in the High Electrification scenario, and roughly $820 million in investments for the Boundary scenario. These investment values correspond to approximate annualized costs of $12.5 million for the High Electrification scenario and $70 million for the Boundary scenario.

It is important to acknowledge that this linear segment-by-segment upgrade method is just one of the ways in which utilities address real line loading issues in their systems. Our assessment uses individual segment upgrades, usually called an “incremental line upgrade”, largely due to data availability and resource constraints. Another example of an incremental upgrade not employed in this study is adding phases to a single-phase circuit to increase its capacity. Furthermore, in some situations, poles will need to be replaced along supporting structures and conductors in a “major line upgrade”. In some cases these methods will be insufficient and utilities may be required to build additional feeder sections and reconfigure feeders to offload affected circuits. Regulators, utilities, and/or other stakeholders should consider sponsoring a more detailed line-loading study under different DER adoption pathways.

Energy losses

Distribution system energy losses is energy that a utility procured, but could not deliver to end-use customers. Estimating the cost of these losses entails using an average wholesale market delivery cost to value the energy losses first reported in Table 5.5. We use the generation and transmission costs—reported in dollars per MWh— from the SUFG to monetize energy losses under each scenario relative to the base case (see Table 5.10). The cost of energy-related losses in the High PV and High PV and Storage scenarios are identical and there is no difference between the Base case and Storage scenario.

Table 5.10 Changes in the cost of energy losses relative to the base case

	2025		2040	
Scenario	**Wholesale Electricity Cost Assumption (¢/kWh)**	**Cost of Energy Losses (million $2017)**	**Wholesale Electricity Cost Assumption (¢/kWh)**	**Cost of Energy Losses (million $2017)**
High Electrification	4.23¢	$0.15	5.40¢	$2.69
High PV	4.05¢	-$0.91	5.21¢	-$2.34
High PV and Storage	4.05¢	-$0.91	5.21¢	-$2.34
Storage	4.16¢	$0	5.32¢	$0
Boundary	4.31¢	-$0.57	6.05¢	$12.55

By 2025, the economic impact of energy losses under increased DER adoption in energy losses is modest, ranging from an additional cost of $150,000/year in the High Electrification scenario to savings of almost $1 million per year in the two High PV scenarios. The economic impact becomes more over the long-term. The High PV scenarios save over $2 million in distribution-related energy losses compared to the Base case, while the Boundary scenario has an additional $12.5 million in energy loss-related costs compared to the Base case.

5.2.4 Economic impact of DER adoption

Tables 5.11 and 5.12 shows the incremental combined economic impact of increased DER adoption relative to the Base case. Costs are reported by scenario and for the three segments of the power system: generation, transmission, and distribution. Table 5.11 reports the absolute cost changes. Table 5.12 shows cost changes in cents per kWh; In this case, we divide the absolute costs reported in Table 5.11 by forecasted retail sales.

Table 5.11 Overall economic impact of DER adoption by scenario and power system segment relative to the base case (million $2017)

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	**Gen.**	**Trans.**	**Dist.**	**Total**	**Gen.**	**Trans.**	**Dist.**	**Total**
High Electrification	$79.1	$15.8	$10.7	$105.6	$204.0	$91.3	$25.9	$321.2
High PV	-$242.4	-$32.4	$9.7	-$265.2	-$485.5	-$71.9	$8.2	-$549.2
High PV and Storage	-$242.7	-$32.4	$9.7	-$265.5	-$481.6	-$70.6	$8.2	-$544.1
Storage	$1.7	$0.0	$10.6	$12.3	$2.6	$0.0	$10.6	$13.1
Boundary	-$18.6	$27.5	$10.0	$19.0	$759.7	$734.1	$94.1	$1,587.9

Table 5.12 Overall incremental economic impact of DER adoption by scenario and power system segment relative to the base case (2017 cents/kWh)

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	**Gen.**	**Trans.**	**Dist.**	**Total**	**Gen.**	**Trans.**	**Dist.**	**Total**
High Electrification	0.11¢	0.02¢	0.01¢	0.14¢	0.25¢	0.11¢	0.03¢	0.39¢
High PV	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.64¢	-0.09¢	0.01¢	-0.72¢
High PV and Storage	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.63¢	-0.09¢	0.01¢	-0.72¢
Storage	0.00¢	0.00¢	0.01¢	0.02¢	0.00¢	0.00¢	0.01¢	0.02¢
Boundary	-0.03¢	0.04¢	0.01¢	0.03¢	0.96¢	0.93¢	0.12¢	2.01¢

There are relatively modest economic impacts of DER adoption for all scenarios in the short term. Over the long term, impacts range from ~$550 million in savings for the High PV scenarios to $1.6 billion in additional costs for the Boundary scenario, all relative to the Base case. The largest cost impacts are observed in the generation sector, with nearly 90% of the cost savings occurring in this segment for the High PV scenarios. Distribution-related cost impacts from DER adoption are generally the smallest among the power system segments studied, ranging 1% to 10% of the overall cost change under any given scenario.

Finally, the rate impacts of these incremental costs are reported in Table 5.13. This assessment employs the SUFG ratemaking model using the existing rate base and the incremental cost changes reported in Table 5.11. In contrast to the incremental costs reported earlier, average rates increase for all scenarios in the long term. In the High PV scenarios this is due to the reduction in sales that needs to be compensated with higher rates for utilities to recover their fixed costs. In the other scenarios this is compounded with the need for incremental generation and transmission infrastructure to meet increased peak demand. Overall, the average changes in rates are relatively modest in the non-Boundary scenarios.

Table 5.13 Impact of DER adoption on electricity rates by scenario and customer type (2017 cents/kWh)

	2025 Rate Change Relative to Base				2040 Rate Change Relative to Base			
Scenario	**Residential**	**Commercial**	**Industrial**	**Average**	**Residential**	**Commercial**	**Industrial**	**Average**
High Electrification	0.25¢	0.24¢	0.19¢	0.22¢	-0.03¢	0.05¢	0.14¢	0.06¢
High PV	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.01¢	0.73¢	0.23¢	0.59¢
High PV and Storage	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.00¢	0.71¢	0.22¢	0.58¢
Storage	0.00¢	0.00¢	0.00¢	0.00¢	0.05¢	0.05¢	0.01¢	0.03¢
Boundary	0.52¢	0.47¢	0.18¢	0.35¢	1.88¢	1.96¢	1.46¢	1.70¢

5.3 Reliability impacts of increased DER adoption

This section details an assessment of the impact of customer-sited battery storage on reliability and resilience from both the system's and the customer's perspectives. Reliability from the customer's perspective may differ from the utility's or system's perspective given that, with DER adoption, utility outages may not lead to end-use interruption from the customer perspective. In this report we focus on system level impacts, but in this section we also highlight the changes in reliability experienced by customers who own DER.

We focus solely on battery storage, because we found no evidence in the literature and practice that the other DER technologies (e.g., PV systems without batteries, EV charging) had any meaningful impact on reliability metrics from the customers' perspective. The metrics for measuring reliability are described in Section 3.2 and include SAIFI, SAIDI, and CAIDI from the perspective of average customers as well as customers who adopted batteries. We examine the number of customers impacted by longer duration, severe interruptions (i.e., 24 hours or longer) as one metric for system resilience. We start by providing an overview of historical power outages for IOU customers by cluster. Next, we explain assumptions about the batteries, including adoption levels and modes of operation. We conclude by detailing the impacts of different battery adoption and operations assumptions on a trio of reliability metrics and one resilience metric—the ability to avoid longer duration power interruptions.

5.3.1 Outage characteristics

Examining historical 2014-2018 outage data from the five IOUs provided a baseline with which to estimate the impacts of battery storage deployed at customer sites. The IOUs each provided a dataset containing details of historical outages from 2014-2018. Each row of data includes details of an outage that impacted a certain number of customers on a particular circuit as well as the start and end times—thus allowing us to calculate the duration of each interruption. Other key details of the outages were whether the outage occurred during a major event day (MED), whether the outage was planned, and the cause of the outage. Planned outages are initiated by the utility in order to perform equipment replacement that can only be completed on a de-energized circuit.

The first step in examining outage information was to clean the data, which involved removing outliers and applying consistent rules for which outages to include and how to characterize them. This analysis includes only sustained outages, defined as any interruption lasting five minutes or longer. We excluded five outages with reported durations of over 10 days. We also removed a small percentage of outages containing data inconsistencies (e.g. negative durations).

Figure 5.6 shows a histogram of the number of interruptions of each duration for the five IOUs from 2014-2018, excluding MEDs and truncated at 1,000 minutes (16.7 hours). Each outage represented by the histogram impact a different number of customers. The shape of the histogram is typical of outage duration distributions, with a long tail to the right. The tail extends to nearly 9 days, but the outages less than 1,000 minutes represent greater than 99 percent of all non-MED outages. Quartiles are indicated by the red lines. The median duration was 84 minutes and three quarters of all outages had a duration of 154 minutes or less. When MEDs were included in the distribution (Figure A.1, Appendix), the median increased to 92 minutes and the 75th percentile to 187 minutes. Interestingly, more than 10 percent of outages lasted longer than one day if MEDs were included.

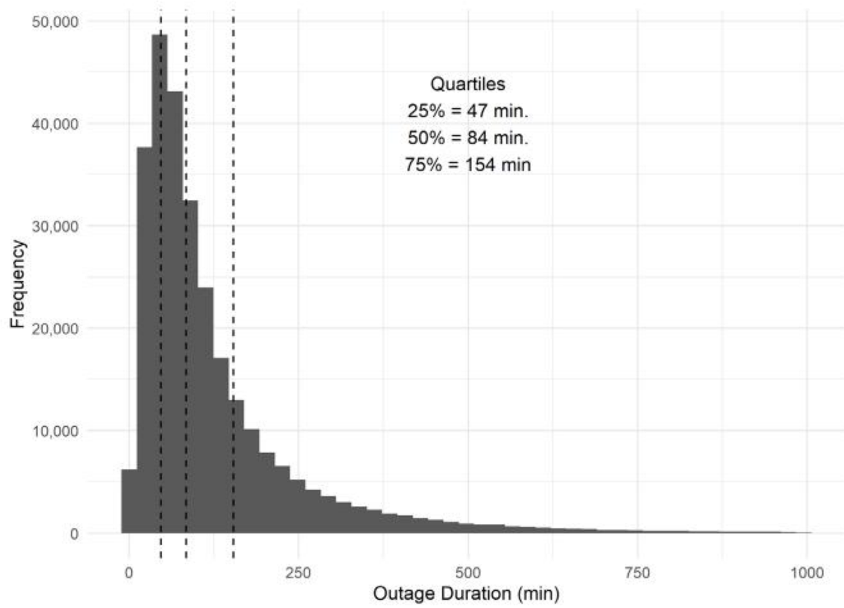

Figure 5.6 Frequency of outages by duration (truncated at 1,000 minutes) (2014-2018)

Outage cause descriptions in the datasets varied by utility. Utilities categorize their outages with cause codes of varying detail: the number of different codes ranges from 10 to 115. We categorized all outages into seven higher-level cause categories to ensure that outages were categorized consistently and at a level that would allow for meaningful assessment and comparison. The seven categories include:

- *Equipment Failure*: outage cause description indicated failure of a specific component or equipment in general
- *Loss of Supply*: unexpected loss of generation or power supply
- *Planned*: outage initiated to allow for planned system maintenance or infrastructure replacement

- *Public*: outage caused by actions of the general public (e.g., vehicle accidents, vandalism, contractors accidentally damaging cables)
- *Vegetation*: trees or other vegetation came into contact with conductors, poles, or other utility equipment to cause an outage
- *Other*: outages with cause descriptions that did not number enough to merit a separate category. Some of the larger subcategories included outages caused overloads, foreign objects, and load management
- *Unknown*: no cause given or cause unknown

Each outage in the dataset had a field that indicated the circuit impacted. We were also provided with a set of characteristics for each circuit, including the number and mix of customers served. This dataset was used to create the six clusters described in Section 4.2. Using these two sources of data, it was possible to map outage causes to detailed information about the characteristics of these circuits. Approximately 86% of outages occurred on circuits included in the characteristics file.

Figure 5.8 shows average annual customer minutes interrupted (CMI) by outage cause category and cluster. We are interested in understanding how outages in major event days compare to outages in days with no major events. Then, in Figure 5.7 outages without major event days are presented in the left panel and outages that only include MEDs are presented in the right panel.

Most outages are caused by either vegetation or equipment failure. Cluster 3, characterized as relatively dense suburban residential with mostly overhead lines, has the highest average annual CMI. Cluster 6, composed of circuits that were relatively shorter, more heavily industrialized, and with a significant amount of underground components, has the lowest CMI. Cluster 5 has the largest proportion of underground circuit length (67%) and, not surprisingly, shows the lowest portion of CMI due to vegetation aside from Cluster 6, which has the second highest proportion of underground circuit length (39%). In major event days the majority of the outages are caused by equipment failure and vegetation, with increased intensity due to inclement weather.

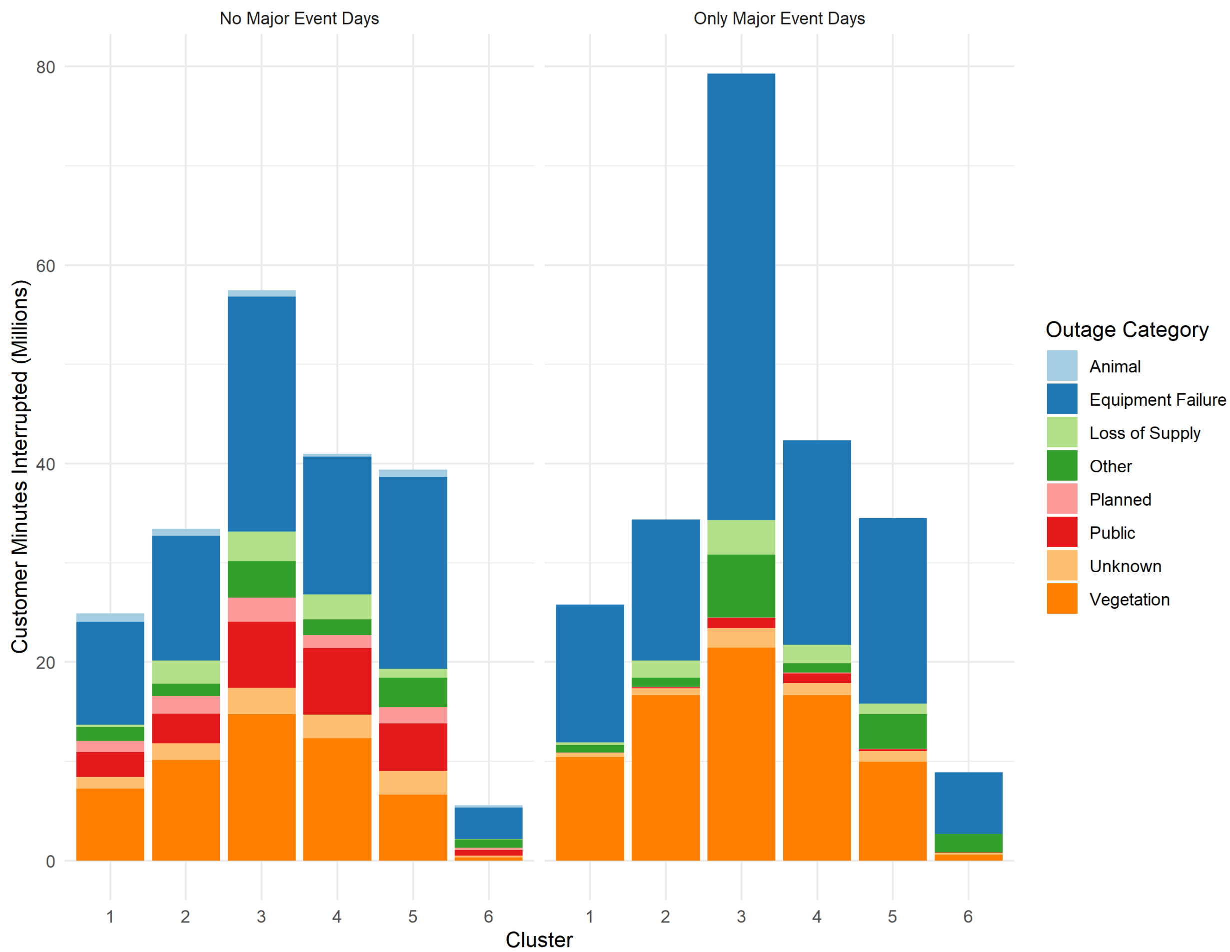

Figure 5.7 Average annual CMI by MED and outage category (2014-2018)

Figure 5.8 shows the number of customer outages by outage cause category[8]. The number of non-MED annual customer outages was higher than the number of MED-only customer outages for all clusters. Overall, the number of non-MED customer outages was approximately four times higher than the number of MED-only outages. When analyzed in combination with the CMI reported in Figure 5.7, it appears that outages on major event days tend to last longer than those that occurred during 'blue sky' conditions and result in more CMI per outage.

[8] Note that a "customer outage" is different from an "outage" in that an outage can impact multiple customers, whereas a customer outage refers to one customer experiencing one interruption. Thus, an outage that impacts 10 customers equates to ten customer outages.

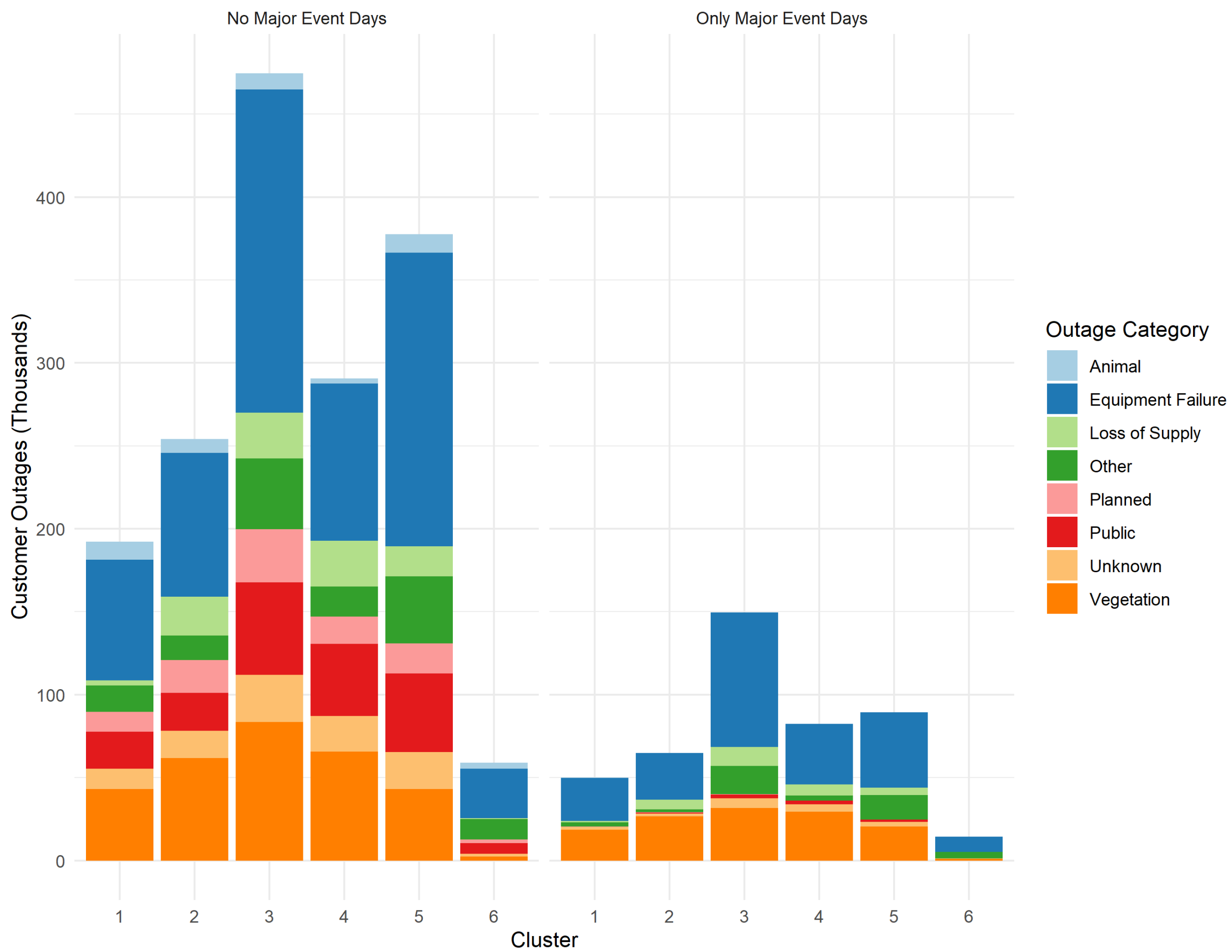

Figure 5.8 Average annual customer outages by MED and outage category (2014-2018)

One reason for the difference in outage totals between clusters is due to the number of customers in each cluster. Figure 5.9 shows the number of customers by type and cluster. The total number of customers ranges from close to 600,000 for Clusters 3 and 5 to only 100,000 for Cluster 6. Residential customers make up a large percentage of the customer totals for each cluster. However, these portions do not account for differences in aggregate battery installed capacity; residential installed capacity was only 25 percent and 15 percent for Clusters 1 and 6, respectively (see Section 4.2.3)

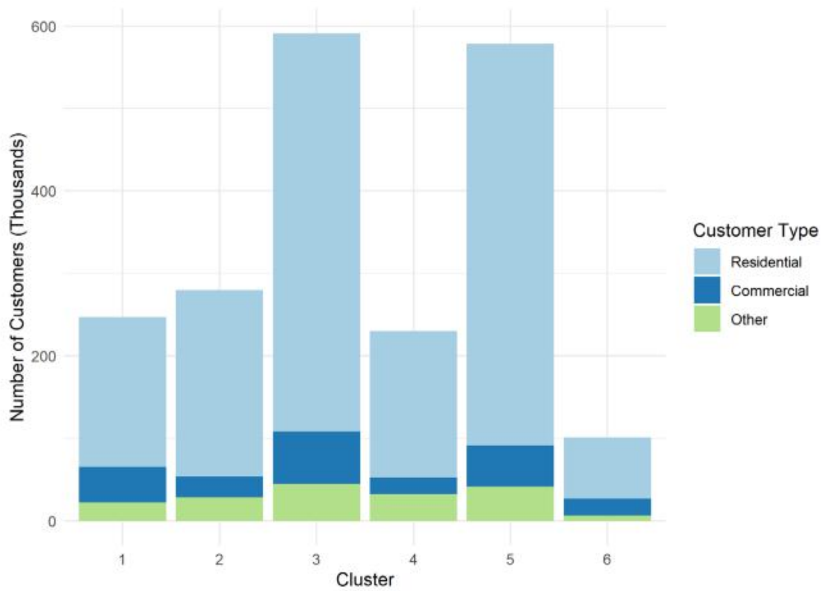

Figure 5.9 Number of customers by type and cluster

5.3.2 Battery storage characteristics

A set of assumptions regarding battery characteristics, penetration levels, and modes of operation are necessary to model the impacts of battery storage systems on reliability and resilience. The battery characteristics were first detailed in Section 4.3 and are listed again below in Table 5.14. PV system characteristics are also listed, as some of the models assumed that batteries are integrated with PV arrays. Size and capacity assumptions for both types of systems are generally the same as described earlier. However, the reliability/resilience analysis only uses generalized customer type, so there was no variation in the size of the PV or battery systems based on customer size.

Table 5.14 Assumed size for rooftop PV and battery storage systems

DER Technology	Residential	Commercial	Industrial
Rooftop PV	• 8 kW	• 16 kW	N/A
Battery storage	• 7 kW max discharge capacity • 12 kWh storage capacity • 90% roundtrip efficiency • 25% maximum discharge level	• 14 kW max discharge capacity • 38 kWh storage capacity (0.1% of average annual kWh consumption) • 90% roundtrip efficiency • 25% maximum discharge level	N/A

It is important to clarify that this analysis is not based on the six adoption *scenarios* outlined in Section 2, but on the three adoption *levels* for battery storage as indicated below:

- BAU: 0.01% of total customers adopt
- High: 1% of total customers adopt

- Very High: 5% of total customers adopt

These adoption levels were for customers across all clusters, but the actual numbers of customers adopting varied by cluster according to the assumptions outlined in Section 4.3. Figure 5.10 shows the penetration of battery storage among residential and commercial customers by cluster. Residential adoption at the High level ranges from negligible levels for Cluster 6 to roughly 3.5 percent for Cluster 4; the Very High level ranges from less than 0.5% in Cluster 6 to nearly 5% in Cluster 4. As indicated earlier, circuits in Cluster 4 are relatively long, rural, and residential. Commercial adoption was contained to Clusters 1 and 6 at the High level and Clusters 1, 4, and 6 at the Very High level. It is worth noting that adoption levels employed in the reliability analysis reflect year 2040 adoption developed for the power flow analysis (Section 5.1). We apply these adoption levels with 2014-2018 outage data, because resource and time constraints prevented us from projecting outages into the future.

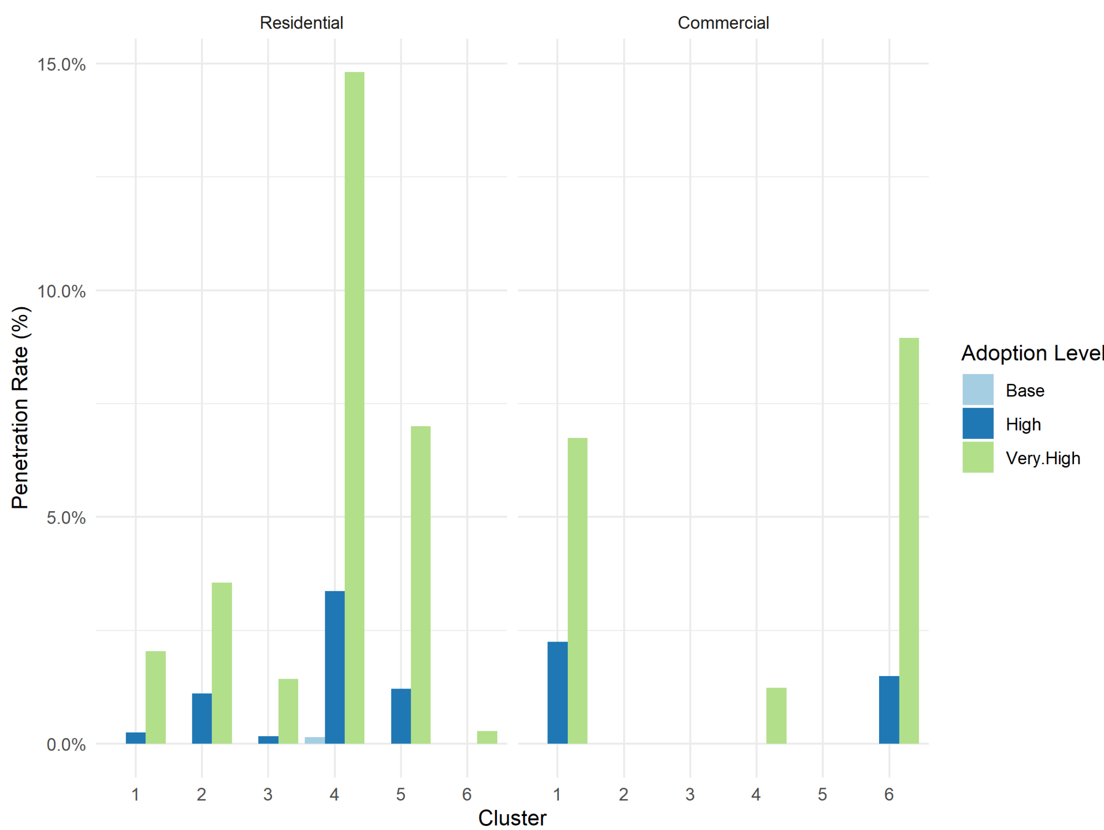

Figure 5.10 Battery storage penetration by customer type and cluster

This analysis assumes that the customer can operate the battery using one of five modes of operation. The modes of operation are purely illustrative and this report does not make any assumptions about policies for encouraging or discouraging one mode of operation over another—or for promoting adoption of DERs in general. The modes of operation are explained in more detail below and Figure 5.11 shows the available charge for mitigating outages by hour of the day for the first four modes.

In the "Full" mode, the battery is only used during interruptions and does not discharge otherwise. The red line in the figure shows that in any hour of the day that an outage could occur, the battery is fully charged and ready to provide its full capacity to the customer premise if an outage occurs. The "Half" mode is similar to the "Full" mode, but a battery only has half of the storage capacity. The green line in the figure shows that the battery has 6 kWh at all hours of the day. This mode of operation functions as a sensitivity analysis of the assumed storage capacity in mitigating the given set of outages.

In the "PV" mode, each battery is assumed to be coupled with a PV system. The PV system primarily provides power for the residence or commercial facility—with excess generation going toward charging the battery during the day. When onsite demand is higher than PV generation, the battery discharges to provide the net demand. The battery continues discharging to supply onsite power until it reaches 25% of capacity, at which point the rest is saved to mitigate nighttime outages and the customer draws power from the grid until PV generation begins on the following day. The purple line in Figure 5.11 shows the available storage capacity for this mode of operation during the summer. The battery remains at its minimum 25% charge until around 9 am, when the PV system generates more electricity than the household uses. The battery reaches its maximum capacity at 1 pm and remains at this level until early evening, when net demand is higher than PV output. The battery continues discharging until it reaches 25% charge around 10 pm. If an outage occurs, the PV system stops generating electricity and the battery supplies power to the customer until it no longer has charge.

The "Peak Times" mode makes the battery charge from the grid and offset demand at the residence or facility during system peak hours of 12 pm to 5 pm. For this analysis, the system peak was defined as hours where load was 90% of the all-time system peak. The light blue line in Figure 5.11 shows the battery charge during summer for this mode of operation. The battery is at full capacity in the morning and begins discharging at noon. It continues discharging until it reaches 25 percent capacity between 4 pm and 5 pm. At 5 pm, it recharges from the grid. When an outage occurs, the battery supplies electricity to the customer until it no longer has charge. While this analysis does not make any assumptions about policy or pricing structures for compelling this (or any) mode of operation, this charge/discharge pattern does reflect one possible way that customer-sited batteries could be operated to mitigate peak demand.

Finally, the "Islanding" mode of operation assumes—similar to the "PV" mode—that each battery storage system works in conjunction with a PV system. The difference for this mode of operation is that the battery can continue to recharge from the PV system during an outage, whereas the PV mode assumes that the PV system does not operate during the outage. Then, the charge profile for a battery operating in Islanding mode is contingent on outage timing.

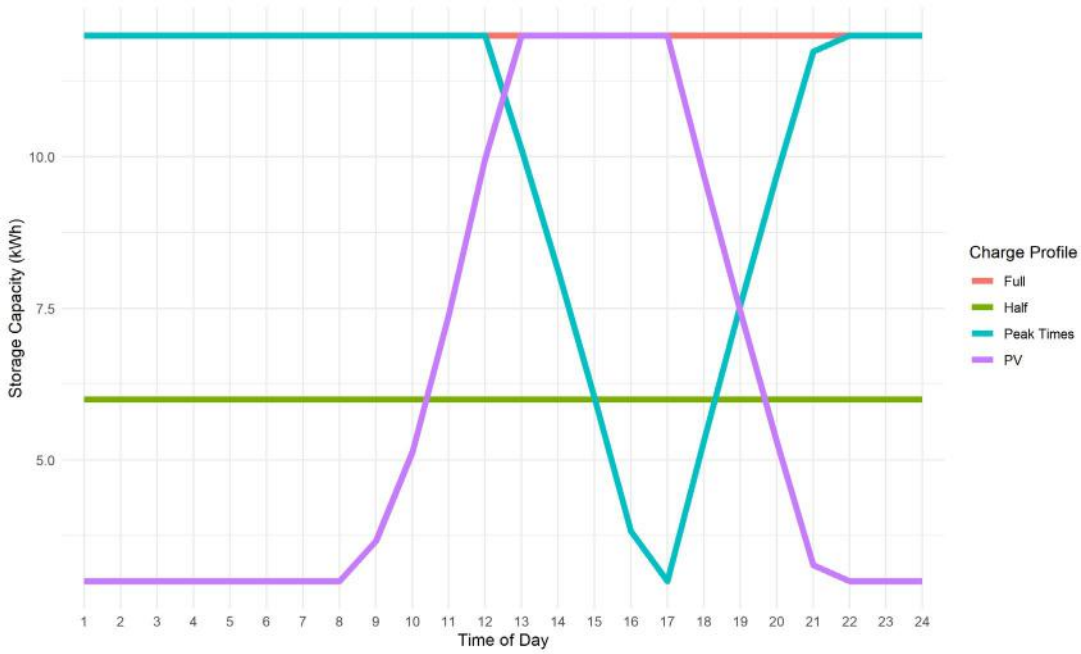

Figure 5.11 Residential storage capacity in summer, by hour of day and operation mode

Batteries are able to eliminate outages of certain durations and reduce outages of longer durations under each mode of operation and set of adoption assumptions. The simulation proceeds systematically through each outage in the dataset. For each outage, we assume that the number of residential and commercial customers impacted was proportional to the overall mix of customer types on the affected circuit, as the outage dataset only provided a total number of customers interrupted and not the number of customers affected by type. Each combination of customer type, season, outage onset hour, and mode of operation was associated with a battery storage capacity that could reduce or eliminate the outage for the percentage of customers that had adopted battery storage systems on that cluster. We reduced the duration of the outage according to the available storage capacity—for the portion of affected customers who would have adopted batteries. If the duration was reduced to zero with a battery, then the number of customers affected by the outage was reduced proportionally. Reducing the outage duration for a portion of the customers in turn reduced the number of customer minutes interrupted for the outage. The next section provides the results of the analysis.

5.3.3 Outage mitigation results

This analysis measures reliability impacts of DER adoption in terms of changes in SAIDI, SAIFI, and CAIDI, which were described in Section 3.2. This analysis examines impacts under two conditions: with MEDs and without MEDs. The reliability metrics are calculated at the cluster level, such that the number of customers N_T in the denominator of the SAIDI and SAIFI equations is equal to the total number of customers in the cluster (calculated by summing the number of customers on each circuit in the cluster). Table 5.15 shows the baseline levels of the metrics for reliability with and without MEDs for each cluster. The table shows some differences when comparing reliability metrics with and without MEDs, but the general trends are the same: reliability metrics for Clusters 1-3 are relatively similar; reliability metrics for Cluster 4 —particularly for SAIDI and SAIFI, are significantly higher than other clusters; reliability metrics for Clusters 5 and 6 are relatively low, which indicates above-average reliability.

Table 5.15 Base case reliability metrics (with and without major event days) by cluster

	Base Case Reliability Metrics (without MEDs)			Base Case Reliability Metrics (with MEDs)		
Cluster	**SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**
CL1	1.68	0.77	2.17	3.41	0.96	3.56
CL2	1.99	0.91	2.19	4.03	1.12	3.59
CL3	1.62	0.80	2.02	3.85	1.04	3.71
CL4	2.97	1.26	2.35	6.03	1.58	3.81
CL5	1.13	0.65	1.74	2.13	0.79	2.69
CL6	0.92	0.58	1.58	2.39	0.71	3.34

Figure 5.12 shows the improvements in SAIDI without MEDs included by mode of operation, adoption level, and cluster (SAIFI changes are very similar, hence not reported). A portion of residential and commercial customers assumed to have installed batteries will have their outages mitigated—as explained earlier. These reductions for particular customers lead to reductions in the total number of customers affected and customer minutes interrupted for each cluster, which in turn reduce cluster-level SAIDI and SAIFI calculations.

Battery adoption levels have more impact on reliability metrics than mode of operation. Cluster 4 has the largest residential battery adoption at 3.5% and 15% for High and Very High levels, respectively. Subsequently, it shows the greatest improvements in SAIDI, ranging from 2%-2.5%for the High level and 9.0%-11.5%for Very High level. The results show that the mode of operation has a modest impact on reliability metrics compared to the battery penetration level. Even a battery with half of the capacity performs relatively well compared to the Full mode. For example, Very High adoption levels in “Half” mode in Cluster 4 improved SAIDI by 9.8% compared to 11.5% for “Full” mode. Doubling the storage capacity led only to a ~15% improvement in reliability metrics.

There are significant differences in reliability impact metrics across clusters. Using the “Full” mode of operation as an example, Cluster 4 had the greatest reduction in SAIDI for High and Very High adoption levels at 2.5% and 11.5%, respectively. Cluster 5 showed a SAIDI reduction of 1% for High adoption and nearly 6% for Very High. Cluster 3 had the lowest impacts, with negligible improvements at the High level and a 1.1% SAIDI reduction at the Very High level. The results appear to be driven by battery adoption assumptions as Cluster 4 has the highest residential adoption and reliability improvement. Clusters 6 and 1 had the highest levels of commercial storage adoption, with negligible commercial adoption for Clusters 2, 3, and 5. Cluster 3 had low residential adoption and negligible commercial adoption and subsequently showed the lowest reliability improvements.

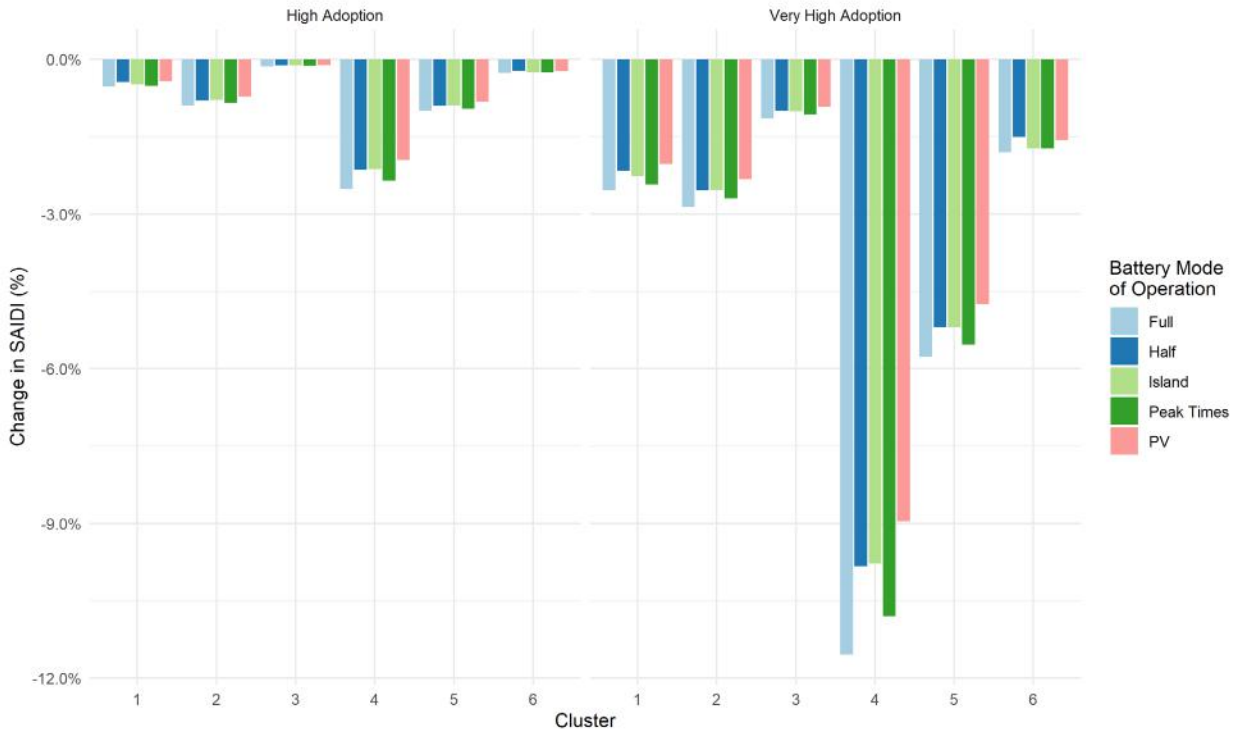

Figure 5.12 SAIDI improvements relative to BAU adoption level by mode of operation – without MEDs

A reason for the comparable performance between modes is likely due to the shape of the statistical distribution of outages in the dataset. As reported in Section 5.3.1, roughly 75 percent of outages are less than two and a half hours. Thus, given the assumptions for average battery capacity (12 kWh for residential and 38 kWh for commercial), using a battery with half of the capacity appears to improve reliability almost as well. In addition, using the battery during the day in tandem with PV, or to reduce peak time demand from the grid, appears to reduce reliability improvements only slightly compared to having a full battery dedicated only to function as a backup power system.

Figure 5.13 shows the results for reliability improvements with MEDs included. The figure displays only the results for SAIDI, as the improvements to SAIFI were larger than those for SAIDI. The SAIDI improvements were more modest across the board, as the pool of outages was larger with the MED outages included, which were longer on average than outage dataset that does not include MEDs. For example, Cluster 4 showed improvements without MEDs of 9.0% for PV and 11.5% for Full, whereas improvements, with MEDs included, were only 6.5% for PV and 9.2% for Full. SAIFI improved more than SAIDI when including MEDs—generally by 20 to 40% in relation to the percent improvement in SAIDI.

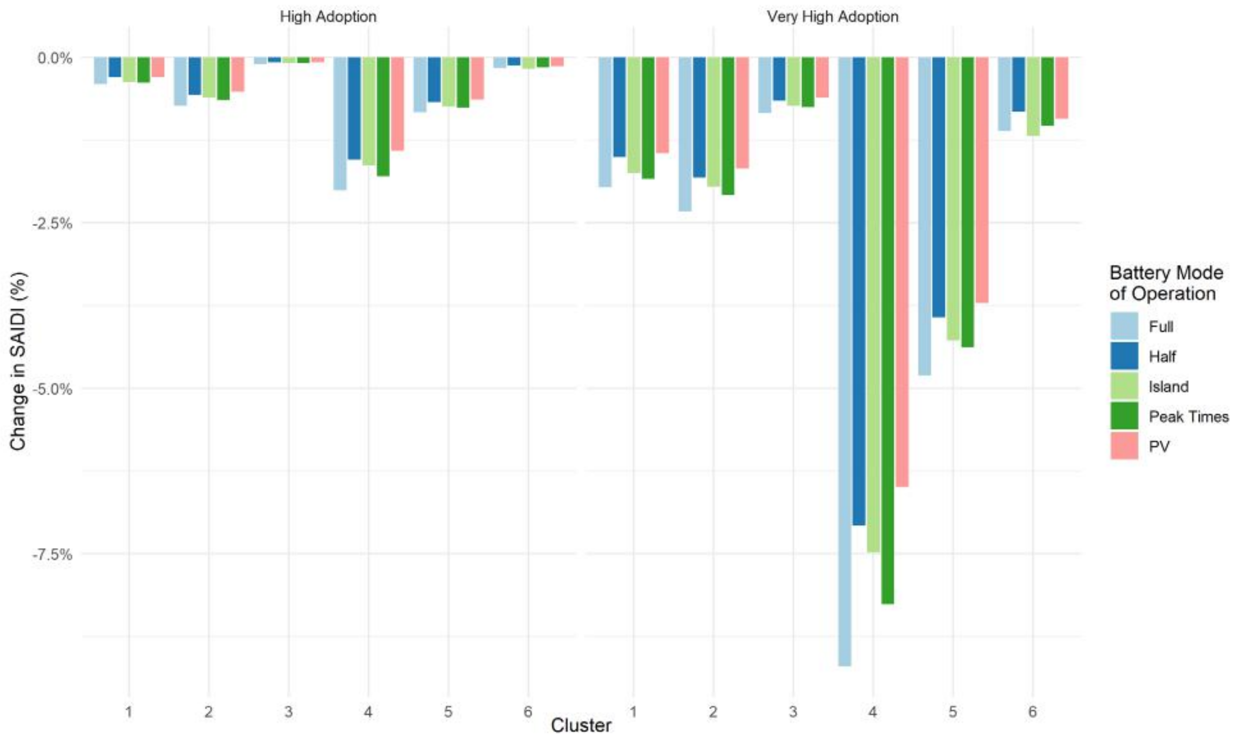

Figure 5.13 SAIDI improvements relative to BAU adoption level by mode of operation – with MEDs

The metrics thus far have shown the reliability impacts from a system-wide perspective. However, in reality, only those customers who installed a battery storage system would benefit from the outage reductions and the remaining customers would not. Figure 5.15 shows the impacts without MEDs to total outage time, outage frequency, and average outage duration for *battery owners only* using the Full mode of operation. It follows that these metrics would translate to cluster-level SAIDI, SAIFI, and CAIDI if all customers in that cluster had batteries. The figure shows that reliability impacts without MEDs to total outage time (equivalent to SAIDI) and outage frequency (equivalent to SAIFI) are very similar, with approximately 90% improvements for each metric in each cluster. Average outage time (equivalent CAIDI) shows increases approaching 30% for Clusters 3 and 6. This counter-intuitive finding is related to the fact shorter duration outages were mitigated by the use of batteries while longer duration outages were still present thus driving up the *average* duration of outages.

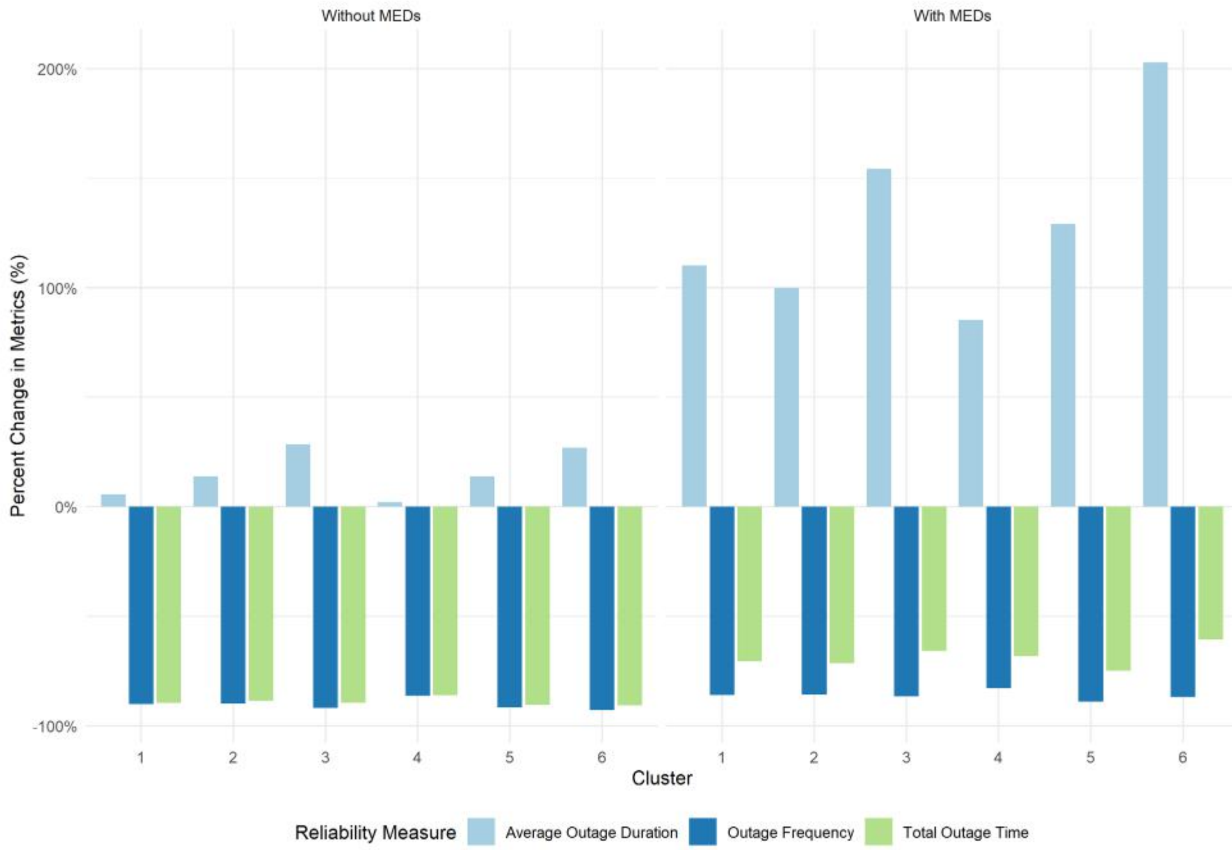

Figure 5.14 Reliability changes relative to the base case for battery storage adopters under full battery mode (with and without MEDs included)

Reliability metric improvements—when MEDs are included—are significant, but more modest when compared to the reliability metrics improvements when MEDs are not included (see Figure 5.14 and Figure A.2, Appendix A). The average outage durations (CAIDI) when MEDs are included is substantially higher relative CAIDI when MEDs are not included—between 100 and 200 percent, depending on the cluster. The results suggest that installing a standard-sized battery can reduce customers' total annual outage durations and frequencies by a significant amount. Overall, we expect significant improvement for the customers that adopt these technologies, but modest system-level reliability improvements across the IOU's distribution systems (see Table 5.16 and Figure A.3, Appendix A).

Table 5.16 Reliability metrics under different behind-the-meter battery storage adoption levels

		Behind-the-meter Battery Storage Adoption Levels			
		BAU	**High**	**Very High**	**Theoretical Limit**
Without MED	**SAIDI**	1.66	1.64	1.58	0.18
	SAIFI	0.81	0.80	0.77	0.08
	CAIDI	2.00	2.00	2.00	2.32
With MED	**SAIDI**	3.09	3.07	2.97	0.96
	SAIFI	0.90	0.89	0.86	0.12
	CAIDI	2.94	2.95	2.97	6.80

5.3.4 Resilience assessment

As discussed earlier, we develop an initial metric of system resilience—the ability to avoid longer-duration (greater than 24 hours) power interruptions. Figure 5.15 shows a histogram of customer-outages lasting longer than 24 hours (1,440 minutes) that occurred for the five IOUs between 2014 and 2018. Recall that a customer-outage is defined as one customer experiencing one outage. The histogram is truncated at 4,000 minutes (2.8 days) to focus on the portion of the histogram with most of the data points. The total number outages in the final dataset lasting longer than 24 hours was 7,612, representing 192,607 customer-outages over the 5-year period.

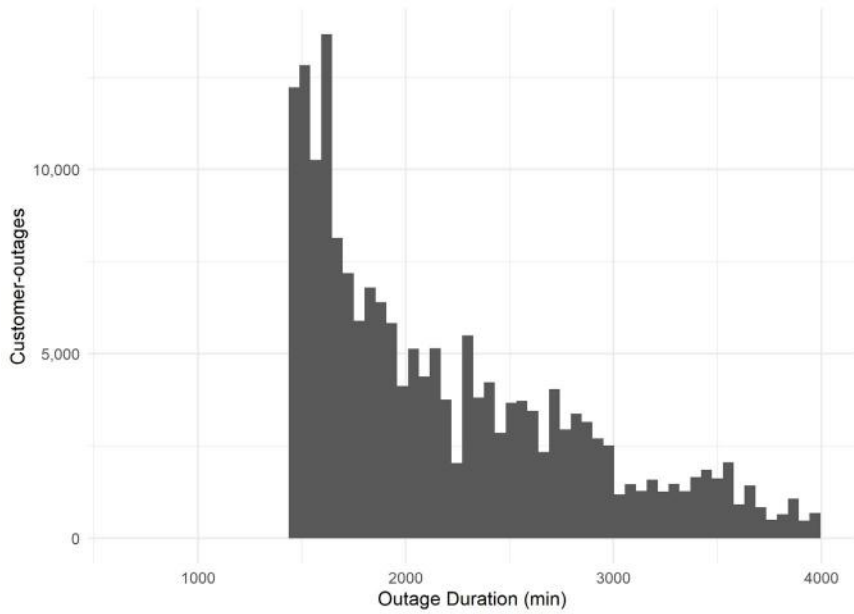

Figure 5.15 Histogram of customer-outages lasting longer than 24 hours (2014-2018)

We follow the same simulated outage mitigation procedure described in Section 5.3.3 to assess the impact of battery storage adoption on the set of long-duration outages. Each of the 7,612 long-duration outages in the dataset is broken down into three outages: (1) a shorter outage affecting the subset of residential customers on the specified circuit who adopted battery storage; (2) another shorter outage affecting the subset of commercial customers who adopted battery storage; and (3) an outage of the original duration, but affecting fewer customers (i.e. the original number of customers affected minus the residential and commercial customers with batteries).

Figure 5.16 shows a histogram representing the impact of the Very High level of battery adoption—operated in Full mode—on the set of long-duration outages (truncated at 4,000 minutes for the figure). The transparent bars outlined in blue represent the histogram of mitigated outages. The graph shows that a number of the outages have shifted left, to durations shorter than 1,440 minutes. It also shows blue bars that are below the original grey level, indicating the mitigated customer-outages (which shifted to shorter durations). The total number of long-duration customer-outages reduces slightly – to 188,879—representing a modest decrease of 2 percent.

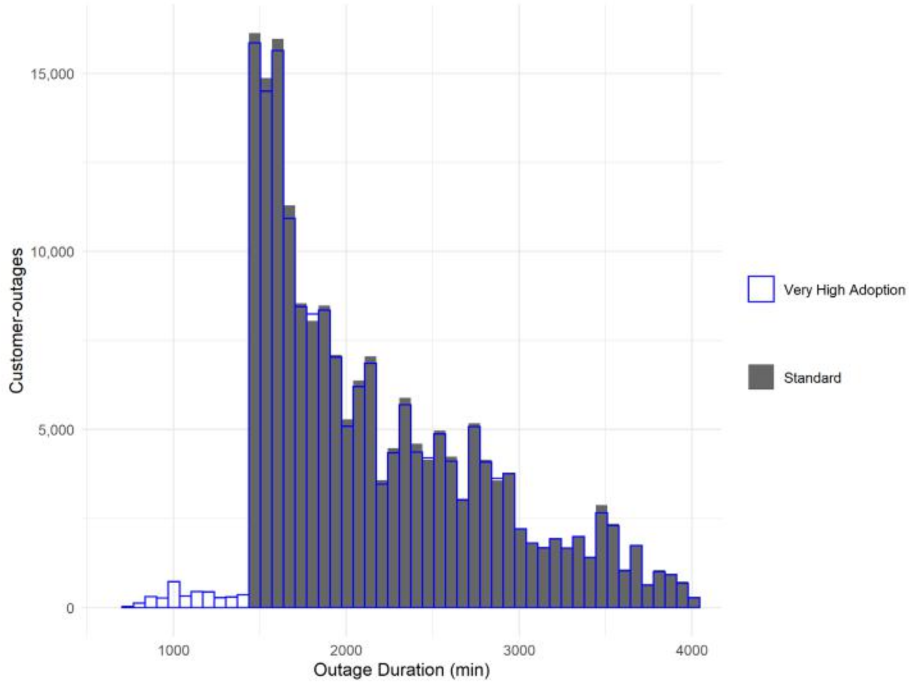

Figure 5.16 Histogram of customer-outages with and without mitigation from Very High level of battery adoption, operated in Full mode (2014-2018)

Using this framework, we examine an illustrative example of the impact on long-duration outages of battery adoption by every residential and commercial customers (Figure 5.17, truncated at 4,000 minutes). Apart from residential and commercial customers, circuits could also contain industrial, agricultural, and/or other customer types. Thus, having all residential and commercial customers adopt battery storage would still leave some customers on each circuit without a battery system. The transparent bars outlined in green in Figure 5.18 represent the histogram of mitigated outages; the grey bars represent the original unmitigated long-duration outages. The graph shows a larger number of customer-outages have shifted left, to durations shorter than 1,440 minutes. The total number of long-duration customer-outages reduces more significantly to 114,831, representing a 40% decrease. This illustrative example shows that even widespread adoption of relatively large battery storage systems would still leave 60% of long-duration outages unmitigated.

The results of this resilience assessment indicate that customer-sited battery storage systems could have an impact on mitigating outages lasting longer than 24 hours. The long tail to right on the duration histogram means that high adoption levels would be needed to shift a substantial portion of customer-outage durations below the somewhat arbitrary threshold of 24 hours. The ability of batteries to mitigate outages longer than 24 hours could be further enhanced by other measures that a customer could take. For example, our approach does not include changing customer behaviors, which could include reducing or eliminating discretionary power consumption (e.g. television) during outages when the battery was providing power. This type of behavior would allow customers to extend the length of time they would be able to power essential electrical appliances, including refrigeration, cell phone chargers, etc. Further research should be conducted to explore how integrating battery storage with other mitigation measures could significantly enhance distribution system resilience.

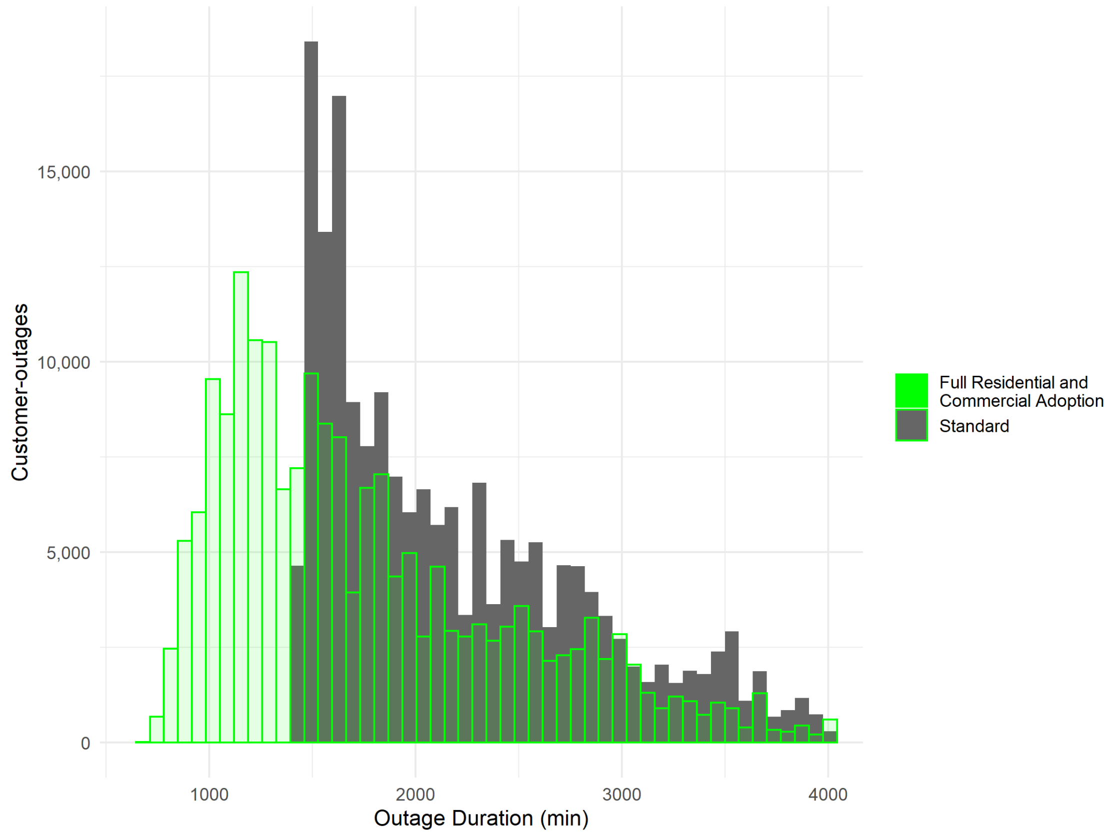

Figure 5.17 Illustrative histogram of customer-outages with and without mitigation from 100% battery adoption for residential and commercial customers, operated in Full mode (2014-2018)

These results account only for the infrastructure requirements to maintain resource adequacy and operational standards, but not the costs of interruptions to customers. For commercial customers, these costs include net revenue losses, equipment damage, and response costs; for residential customers, the costs are primarily due to inconvenience (Sullivan et al., 2018). Over the last few decades, researchers have used survey-based approaches to measure costs of interruptions lasting 24 hours or less. The Interruption Cost Estimation (ICE) Calculator is an interactive online tool for estimating interruption costs using the data from 34 customer interruption cost studies that used similar, survey-based methodologies. Other monetization methods, including the use of regional economic models, could be useful for determining the economic impacts of avoiding longer duration power interruptions as well as the indirect effects to the broader economy (Larsen et al., 2019; Zamuda et al., 2019). Proper accounting of the economic impacts from avoiding power interruptions can help utilities, regulators, and other stakeholders weigh the cost of integrating DERs against these types if benefits. Future research could involve efforts by Indiana IOUs—and their partners—to monetize the customer benefits of reliability and resilience improvements using the ICE Calculator metadata, new customer interruption cost studies, and/or regional economic modeling.

6. Conclusion

In 2019, the Indiana General Assembly enacted House Enrolled Act No. 1278 to explore the impact that fuel transitions and emerging technologies may have on the state's power system. The Act created the 21st Century Energy Policy Development Task Force, whose work will be informed by a comprehensive study of the impacts of fuel transitions and emerging technologies across Indiana. The preceding analysis explores the impacts of emerging technologies that could be deployed in Indiana IOU distribution systems by 2025 and 2040.

We develop six adoption scenarios that combine deployment levels of rooftop solar, electric vehicle charging, and battery storage—collectively referred to as DER—in residential and commercial customers connected to Indiana IOU systems. Five of the adoption scenarios implement a mix of expected and optimistic deployment of these resources, while a sixth scenario is developed as a stress-test with very high adoption levels. For example, rooftop PV adoption by 2040 ranges from 820 MW in the Base case to almost 6.5 GW in the Boundary scenario.

This study develops and employs an empirical framework that measures the impact of emerging distributed technologies on the power system for the six scenarios. The framework measures both the economic value and the reliability impact of DER:

- The economic value of DER is assessed by developing capacity expansion and power flow analysis of the generation and distribution segments, respectively, under future hourly demand assumptions based on the six adoption scenarios. The assessment of generation energy and capacity impacts uses State Utility Forecasting Group (SUFG) modeling platform to simulate optimal production and expansion costs. The assessment of distribution impacts employs the industry-standard Cymdist distribution power flow model with an array of strategies to upgrade feeders to address voltage, line loading, and energy losses issues. A simplified model for transmission expansion measures the economic impact of DER on three power system segments.
- The reliability impact of DER adoption is measured using a pioneering method first developed for this study. We use a data set of over half a million of historical outages across the five Indiana IOUs to inform this measurement. The method simulates the impact of different levels of behind-the-meter battery storage adoption, with several operational strategies, to reduce the frequency and duration of outages from the customer's perspective. This analysis is complemented with an assessment of the impacts of DER on reducing long-duration (more than 24 hours) interruptions as an initial measure of resilience impacts on the distribution system.

This study uses statistical techniques to classify over 2,800 feeders across Indiana into one of six groups that represent different types of feeders based on their customer mix, length, reliability, and other variables. Representative feeders from each group are selected to run power flow analyses for DER impacts on distribution systems, which can then be extrapolated to produce state-wide results.

Results for the distribution system power flow simulations show that voltage violations are relatively rare. Only 159 out of 3,456 simulated hours exhibit voltage violations of the ANSI optimal range levels, generally spanning a relatively small fraction of load nodes in a feeder. The majority of voltage issues arise only in the Boundary case and the violations are relatively small in magnitude. Voltage violations can be mitigated at a very low cost using a combination of smart inverters in future rooftop PV systems and voltage adjustments in the feeder heads. Line loading issues are minimal, with only eight simulation hours showing loading levels above 100% of capacity in about 3% of segments for feeders in clusters 3, 4, and 5. Line loading issues are addressed by upgrading conductors with relatively low costs given the few affected segments. Line losses are ~4%-10% higher than the Base case in the High Electrification and Boundary scenarios and 11% lower than the Base case in the High PV and High PV and Storage scenarios. Energy losses are not mitigated in this analysis, but monetized using the wholesale generation power costs that are output by the SUFG model.

Customer-sited battery storage systems can achieve multiple objectives related to improved reliability/resilience. When sized and operated appropriately, batteries can be used behind-the-meter for peak shaving or mitigating the PV ‘duck curve’ although their ability to mitigate power interruptions is limited. Reliability and resilience improvements are driven more by battery adoption levels than by mode of operation. We study battery storage adoption levels of 0.01% of customers (BAU), 1% of customers (high), 5% of customers (very high), and 100% of residential and commercial customers (theoretical limit). This analysis assumes that the battery discharge could only be consumed behind the meter. It is possible that larger system-wide benefits could be achieved if customer-sited batteries could discharge power back to the grid under direction from utility operations staff.

We estimate that the economic impact on power system investment and operation of increased DER adoption within the IOU service territories will be between -$265 million to +$105 million and -$550 million to +$1.6 billion in 2025 and 2040 relative to the Base case, respectively. In general, scenarios with high adoption of rooftop solar result in system-wide savings, while scenarios with high adoption and charging of electric vehicles result in large peaks that require substantial new generation capacity and higher system costs. The economic impacts of DER in the power system are concentrated in the generation segment, with about 80% of the cost impacts. The impact on the distribution segment is at most 0.12 ¢/kWh by 2040 in the Boundary scenario, while the impacts in generation can reach close to 1 ¢/kWh by 2040 in the same scenario. It is important to note that the results only account for the infrastructure requirements to maintain resource adequacy and operational standards—they do not account for avoided costs of power interruptions to customers.

This report is one of the first manuscripts to estimate the economic impact of increased adoption of distributed technologies across the different segments of the power system—generation, transmission, and distribution—using a forward-looking simulation framework. This study is also novel in that it develops an empirically-based estimation of the impact of behind-the-meter battery storage adoption on reliability indices from the customer and grid operators’ perspective. This report identifies a number of future research opportunities including:

- The investigation of impacts to secondary distribution networks.
- More targeted upgrade assessments for representative feeders that consider a wider range of expansion options to integrated DER.

- Estimating the economic value of avoiding power interruptions due to DER adoption.
- A more thorough examination of the impacts of DER adoption on transmission expansion using an optimization model with explicit transmission representation.
- Development and implementation of additional methods to measure and mitigate impacts on distribution system resilience, including integration of battery storage with demand management processes.

The framework developed for this report can serve as a blueprint for utilities, policymakers, and other stakeholders who may be interested in conducting more targeted and expansive technology adoption impact studies.

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Appendix A. Additional results

The following results complement the cluster-level analysis for voltage violations in section 5.1.1 and reliability results from section 5.3

Table A.1 Number of nodes with voltage violations of the optimal range by simulation hour for Cluster 1

Year	Scenario	Cluster	Load Day Type	Simulation Time	Hour of Day	Number of nodes with high voltage violations	Number of nodes with no violations	Number of nodes with low voltage violations	Percent nodes with high voltage violations	Percent nodes with low voltage violations
2040	Boundary	CL1	max	22874400	18	0	436	6	0.0%	1.4%
2040	Boundary	CL1	max	22878000	19	0	435	7	0.0%	1.6%
2040	Boundary	CL1	max	22881600	20	0	441	1	0.0%	0.2%
2040	Boundary	CL1	min	9712800	10	1	441	0	0.2%	0.0%
2040	Boundary	CL1	min	9716400	11	1	441	0	0.2%	0.0%
2040	Boundary	CL1	min	9720000	12	1	441	0	0.2%	0.0%
2040	Boundary	CL1	min	9723600	13	1	441	0	0.2%	0.0%
2040	Boundary	CL1	min	9727200	14	0	441	1	0.0%	0.2%
2040	Boundary	CL1	min	9730800	15	0	441	1	0.0%	0.2%

Table A.2 Number of nodes with voltage violations of the optimal range by simulation hour for Cluster 2

Year	Scenario	Cluster	Load Day Type	Simulation Time	Hour of Day	Number of nodes with high voltage violations	Number of nodes with no violations	Number of nodes with low voltage violations	Percent nodes with high voltage violations	Percent nodes with low voltage violations
2025	HighElec	CL2	max	23032800	14	0	623	1	0%	0%
2025	HighElec	CL2	max	23036400	15	0	623	1	0%	0%
2040	Base	CL2	max	23032800	14	0	619	5	0%	1%
2040	Base	CL2	max	23036400	15	0	619	5	0%	1%
2040	Base	CL2	max	23040000	16	0	623	1	0%	0%
2040	Boundary	CL2	max	22874400	18	0	370	254	0%	41%
2040	Boundary	CL2	max	22878000	19	0	432	192	0%	31%
2040	Boundary	CL2	max	22881600	20	0	613	11	0%	2%
2040	Boundary	CL2	min	7149600	18	0	605	19	0%	3%

2040	Boundary	CL2	min	7153200	19	0	602	22	0%	4%
2040	HighElec	CL2	max	23032800	14	0	613	11	0%	2%
2040	HighElec	CL2	max	23036400	15	0	613	11	0%	2%
2040	HighElec	CL2	max	23040000	16	0	618	6	0%	1%
2040	HighPV	CL2	max	22874400	18	0	620	4	0%	1%
2040	HighPV	CL2	max	22878000	19	0	623	1	0%	0%
2040	HighPVSto	CL2	max	22874400	18	0	620	4	0%	1%
2040	HighPVSto	CL2	max	22878000	19	0	623	1	0%	0%
2040	Storage	CL2	max	23032800	14	0	619	5	0%	1%
2040	Storage	CL2	max	23036400	15	0	619	5	0%	1%
2040	Storage	CL2	max	23040000	16	0	623	1	0%	0%

Table A.3 Number of nodes with voltage violations of the optimal range by simulation hour for Cluster 3

Year	Scenario	Cluster	Load Day Type	Simulation Time	Hour of Day	Number of nodes with high voltage violations	Number of nodes with no violations	Number of nodes with low voltage violations	Percent nodes with high voltage violations	Percent nodes with low voltage violations
2040	Boundary	CL3	max	22856400	13	274	311	0	46.8%	0.0%
2040	HighPV	CL3	max	22852800	12	272	313	0	46.5%	0.0%
2040	HighPVSto	CL3	max	22852800	12	272	313	0	46.5%	0.0%
2040	Boundary	CL3	max	22860000	14	264	321	0	45.1%	0.0%
2025	Boundary	CL3	max	23022000	11	164	421	0	28.0%	0.0%
2025	Base	CL3	max	23018400	10	162	423	0	27.7%	0.0%
2025	HighElec	CL3	max	23018400	10	162	423	0	27.7%	0.0%
2025	Storage	CL3	max	23018400	10	162	423	0	27.7%	0.0%
2025	Base	CL3	max	23050800	19	153	432	0	26.2%	0.0%
2025	HighPV	CL3	max	23050800	19	153	432	0	26.2%	0.0%
2025	HighPVSto	CL3	max	23050800	19	153	432	0	26.2%	0.0%
2025	Storage	CL3	max	23050800	19	153	432	0	26.2%	0.0%
2025	HighElec	CL3	max	23050800	19	152	433	0	26.0%	0.0%
2025	Boundary	CL3	max	23050800	19	140	445	0	23.9%	0.0%
2040	HighPV	CL3	max	22856400	13	134	451	0	22.9%	0.0%
2040	HighPVSto	CL3	max	22856400	13	134	451	0	22.9%	0.0%

2025	HighPV	CL3	max	23022000	11	131	454	0	22.4%	0.0%
2025	HighPVSto	CL3	max	23022000	11	131	454	0	22.4%	0.0%
2040	Boundary	CL3	min	7124400	11	99	486	0	16.9%	0.0%
2040	Boundary	CL3	min	7131600	13	99	486	0	16.9%	0.0%
2040	Boundary	CL3	min	7135200	14	98	487	0	16.8%	0.0%
2040	Boundary	CL3	min	7120800	10	95	490	0	16.2%	0.0%
2040	Base	CL3	max	23018400	10	88	497	0	15.0%	0.0%
2040	HighElec	CL3	max	23018400	10	88	497	0	15.0%	0.0%
2040	Storage	CL3	max	23018400	10	88	497	0	15.0%	0.0%
2040	Boundary	CL3	max	22867200	16	81	504	0	13.8%	0.0%
2040	HighPV	CL3	max	22860000	14	81	504	0	13.8%	0.0%
2040	HighPVSto	CL3	max	22860000	14	81	504	0	13.8%	0.0%
2040	Base	CL3	max	23050800	19	74	511	0	12.6%	0.0%
2040	Storage	CL3	max	23050800	19	74	511	0	12.6%	0.0%
2025	Boundary	CL3	max	23025600	12	73	512	0	12.5%	0.0%
2040	Boundary	CL3	min	7128000	12	69	516	0	11.8%	0.0%
2040	Boundary	CL3	max	22852800	12	66	519	0	11.3%	0.0%
2040	Boundary	CL3	max	22849200	11	63	522	0	10.8%	0.0%
2040	HighElec	CL3	max	23050800	19	63	522	0	10.8%	0.0%
2040	Boundary	CL3	max	22885200	21	59	526	0	10.1%	0.0%
2025	Base	CL3	max	23047200	18	52	533	0	8.9%	0.0%
2025	HighElec	CL3	max	23047200	18	52	533	0	8.9%	0.0%
2025	HighPV	CL3	max	23047200	18	52	533	0	8.9%	0.0%
2025	HighPVSto	CL3	max	23047200	18	52	533	0	8.9%	0.0%
2025	Storage	CL3	max	23047200	18	52	533	0	8.9%	0.0%
2025	Boundary	CL3	max	23047200	18	50	535	0	8.5%	0.0%
2025	Base	CL3	max	23022000	11	37	548	0	6.3%	0.0%
2025	HighElec	CL3	max	23022000	11	37	548	0	6.3%	0.0%
2025	Storage	CL3	max	23022000	11	37	548	0	6.3%	0.0%
2040	HighPV	CL3	max	22881600	20	31	554	0	5.3%	0.0%
2040	HighPVSto	CL3	max	22881600	20	31	554	0	5.3%	0.0%
2025	HighPV	CL3	max	23025600	12	19	566	0	3.2%	0.0%

2025	HighPVSto	CL3	max	23025600	12	19	566	0	3.2%	0.0%
2025	Boundary	CL3	max	23043600	17	16	569	0	2.7%	0.0%
2040	Base	CL3	max	23047200	18	16	569	0	2.7%	0.0%
2040	Storage	CL3	max	23047200	18	16	569	0	2.7%	0.0%
2040	Boundary	CL3	max	22870800	17	15	570	0	2.6%	0.0%
2025	HighPV	CL3	max	23043600	17	13	572	0	2.2%	0.0%
2025	HighPVSto	CL3	max	23043600	17	13	572	0	2.2%	0.0%
2040	HighPV	CL3	max	22867200	16	5	580	0	0.9%	0.0%
2040	HighPVSto	CL3	max	22867200	16	5	580	0	0.9%	0.0%
2025	Boundary	CL3	max	23029200	13	4	581	0	0.7%	0.0%
2025	Base	CL3	max	23043600	17	3	582	0	0.5%	0.0%
2025	Storage	CL3	max	23043600	17	3	582	0	0.5%	0.0%
2040	Boundary	CL3	max	22845600	10	3	582	0	0.5%	0.0%
2040	HighPV	CL3	max	22849200	11	3	582	0	0.5%	0.0%
2040	HighPVSto	CL3	max	22849200	11	3	582	0	0.5%	0.0%
2025	HighElec	CL3	max	23043600	17	2	583	0	0.3%	0.0%
2040	Base	CL3	max	23022000	11	2	583	0	0.3%	0.0%
2040	HighElec	CL3	max	23022000	11	2	583	0	0.3%	0.0%
2040	Storage	CL3	max	23022000	11	2	583	0	0.3%	0.0%

Table A.4 Number of nodes with voltage violations of the optimal range by simulation hour for Cluster 4

Year	Scenario	Cluster	Load Day Type	Simulation Time	Hour of Day	Number of nodes with high voltage violations	Number of nodes with no violations	Number of nodes with low voltage violations	Percent nodes with high voltage violations	Percent nodes with low voltage violations
2040	Boundary	CL4	max	22874400	18	0	734	877	0%	54%
2040	Boundary	CL4	max	22878000	19	0	747	864	0%	54%
2040	HighElec	CL4	max	23032800	14	0	836	775	0%	48%
2040	HighElec	CL4	max	23036400	15	0	891	720	0%	45%
2040	Base	CL4	max	23036400	15	0	1206	405	0%	25%
2040	Storage	CL4	max	23036400	15	0	1206	405	0%	25%
2040	HighPV	CL4	max	22874400	18	0	1232	379	0%	24%
2040	HighPVSto	CL4	max	22874400	18	0	1232	379	0%	24%

2040	Base	CL4	max	23032800	14	0	1238	373	0%	23%
2040	Storage	CL4	max	23032800	14	0	1238	373	0%	23%
2040	HighElec	CL4	max	23040000	16	0	1251	360	0%	22%
2025	Boundary	CL4	max	22874400	18	0	1268	343	0%	21%
2040	Boundary	CL4	max	22881600	20	0	1279	332	0%	21%
2040	HighPV	CL4	max	22878000	19	0	1298	313	0%	19%
2040	HighPVSto	CL4	max	22878000	19	0	1298	313	0%	19%
2040	Boundary	CL4	min	7149600	18	0	1313	298	0%	18%
2040	Base	CL4	max	23040000	16	0	1314	297	0%	18%
2040	Storage	CL4	max	23040000	16	0	1314	297	0%	18%
2040	Boundary	CL4	min	7153200	19	0	1330	281	0%	17%
2025	HighElec	CL4	max	23036400	15	0	1403	208	0%	13%
2025	Base	CL4	max	23032800	14	0	1417	194	0%	12%
2025	Storage	CL4	max	23032800	14	0	1417	194	0%	12%
2025	HighElec	CL4	max	23032800	14	0	1426	185	0%	11%
2025	Boundary	CL4	max	22878000	19	0	1429	182	0%	11%
2025	Base	CL4	max	23036400	15	0	1455	156	0%	10%
2025	Storage	CL4	max	23036400	15	0	1455	156	0%	10%
2025	HighElec	CL4	max	23040000	16	0	1457	154	0%	10%
2040	HighElec	CL4	max	23043600	17	0	1472	139	0%	9%
2025	Base	CL4	max	23040000	16	0	1473	138	0%	9%
2025	Storage	CL4	max	23040000	16	0	1473	138	0%	9%
2040	Base	CL4	max	23029200	13	0	1473	138	0%	9%
2040	HighElec	CL4	max	23029200	13	0	1473	138	0%	9%
2040	HighPV	CL4	max	22881600	20	0	1473	138	0%	9%
2040	HighPVSto	CL4	max	22881600	20	0	1473	138	0%	9%
2040	Storage	CL4	max	23029200	13	0	1473	138	0%	9%
2025	Base	CL4	max	23029200	13	0	1474	137	0%	9%
2025	HighElec	CL4	max	23029200	13	0	1474	137	0%	9%
2025	HighPV	CL4	max	22874400	18	0	1474	137	0%	9%
2025	HighPVSto	CL4	max	22874400	18	0	1474	137	0%	9%
2025	Storage	CL4	max	23029200	13	0	1474	137	0%	9%

2040	Base	CL4	max	23043600	17	0	1474	137	0%	9%
2040	HighElec	CL4	max	23047200	18	0	1474	137	0%	9%
2040	Storage	CL4	max	23043600	17	0	1474	137	0%	9%
2040	HighPV	CL4	max	22863600	15	0	1526	85	0%	5%
2040	HighPVSto	CL4	max	22863600	15	0	1526	85	0%	5%
2040	Base	CL4	max	23025600	12	0	1528	83	0%	5%
2040	HighElec	CL4	max	23025600	12	0	1528	83	0%	5%
2040	Storage	CL4	max	23025600	12	0	1528	83	0%	5%
2025	Boundary	CL4	max	22881600	20	0	1538	73	0%	5%
2040	Boundary	CL4	max	22863600	15	0	1559	52	0%	3%
2040	Base	CL4	max	23047200	18	0	1600	11	0%	1%
2040	Storage	CL4	max	23047200	18	0	1600	11	0%	1%
2025	HighPV	CL4	max	22863600	15	0	1609	2	0%	0%
2025	HighPVSto	CL4	max	22863600	15	0	1609	2	0%	0%

Table A.5 Number of nodes with voltage violations of the optimal range by simulation hour for Cluster 5

Year	Scenario	Cluster	Load Day Type	Simulation Time	Hour of Day	Number of nodes with high voltage violations	Number of nodes with no violations	Number of nodes with low voltage violations	Percent nodes with high voltage violations	Percent nodes with low voltage violations
2040	Boundary	CL5	max	22874400	18	0	389	119	0%	23%
2040	Boundary	CL5	max	22878000	19	0	396	112	0%	22%
2040	Boundary	CL5	min	7120800	10	215	293	0	42%	0%
2040	Boundary	CL5	min	7124400	11	340	168	0	67%	0%
2040	Boundary	CL5	min	7128000	12	51	457	0	10%	0%
2040	Boundary	CL5	min	7131600	13	396	112	0	78%	0%
2040	Boundary	CL5	min	7135200	14	327	181	0	64%	0%
2040	Boundary	CL5	min	7138800	15	31	477	0	6%	0%

Table A.6 Number of nodes with voltage violations of the optimal range by simulation hour for Cluster 6

Year	Scenario	Cluster	Load Day Type	Simulation Time	Hour of Day	Number of nodes with high voltage violations	Number of nodes with no violations	Number of nodes with low voltage violations	Percent nodes with high voltage violations	Percent nodes with low voltage violations
2040	Boundary	CL6	min	12153600	16	1	237	0	0.4%	0

Table A.7 Total incremental transmission costs by scenario and year

	Simulation Year	
Adoption Scenario	**2025**	**2037**
1 Base	1,077,613,431	1,457,049,154
2 High Electrification	1,093,451,837	1,548,299,883
3 High PV	1,045,216,453	1,385,144,937
4 High PV and Storage	1,045,218,128	1,386,399,530
5 Storage	1,077,614,894	1,457,043,925
6 Boundary	1,105,144,637	2,191,110,968

Table A.8 Line upgrades for cluster 3, Boundary scenario, year 2040

Cluster	Length(ft)	Line	Line Type	Loading	Material	New Ampacity	New Size	New Type
3	51	2107973_2108_OH	Overhead Line	113.1	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	52	1349839_2108_OH	Overhead Line	111	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	158	1956950_2108_OH	Overhead Line	113.1	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	121	2258992_2108_OH	Overhead Line	111	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	247	1804292_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	98	1198047_2108_OH	Overhead Line	112.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	128	1500660_2108_OH	Overhead Line	119.3	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	116	1980686_2108_OH	Overhead Line	103.5	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	58	1197568_2108_OH	Overhead Line	119.3	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	134	2283272_2108_OH	Overhead Line	101	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	92	1373954_2108_OH	Overhead Line	109.4	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	73	1349597_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	80	1956400_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	87	1980711_2108_OH	Overhead Line	109.4	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	107	2107409_2108_OH	Overhead Line	113.1	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	204	2107615_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	55	1222320_2108_OH	Overhead Line	109.4	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	78	1980317_2108_OH	Overhead Line	101	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	103	1501183_2108_OH	Overhead Line	111	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	82	1652450_2108_OH	Overhead Line	119.3	ALUMINIUM_ALLOY	200	1 AWG	AAAC 1 AWG
3	136	1501186_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	254	1501372_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	50	1349642_2108_OH	Overhead Line	111	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	139	1349641_2108_OH	Overhead Line	100.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	95	1804287_2108_OH	Overhead Line	112.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	96	1804286_2108_OH	Overhead Line	112.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	220	1198053_2108_OH	Overhead Line	104.1	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
3	100	1652939_2108_OH	Overhead Line	112.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	151	1350232_2108_OH	Overhead Line	111	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL

3	173	1350230_2108_OH	Overhead Line	113.1	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
3	96	1350231_2108_OH	Overhead Line	113.1	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL

cluster	Phases	Previous Ampacity	Previous Size	Previous Type	Ratio	Steps	Unit Cost ($/ft)	Total Cost ($)
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	6630
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	6760
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	20540
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	15730
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	23465
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	12740
3	C	128	2 AWG	#2_AAAC_BR	0.563	1	95	12160
3	A	128	2 AWG	#2_AAAC_BR	0.563	1	95	11020
3	C	128	2 AWG	#2_AAAC_BR	0.563	1	95	5510
3	A	128	2 AWG	#2_AAAC_BR	0.563	1	95	12730
3	A	128	2 AWG	#2_AAAC_BR	0.563	1	95	8740
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	6935
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	7600
3	A	128	2 AWG	#2_AAAC_BR	0.563	1	95	8265
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	13910
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	19380
3	A	128	2 AWG	#2_AAAC_BR	0.563	1	95	5225
3	A	128	2 AWG	#2_AAAC_BR	0.563	1	95	7410
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	13390
3	C	128	2 AWG	#2_AAAC_BR	0.563	1	95	7790
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	12920
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	24130
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	6500
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	13205
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	12350
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	12480

3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.132	1	95	20900
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	13000
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	19630
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	22490
3	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	12480

Table A.9 Line upgrades for cluster 4, Boundary scenario, year 2040

Cluster	Length(ft)	Line	Line Type	Loading	Material	New Ampacity	New Size	New Type
4	155.7	PRIOH36034657-17	Overhead Line	113.8	COPPER	180	4 AWG	CCC 4 A
4	173.5	PRIOH36034657-12	Overhead Line	105.7	COPPER	160	5 AWG	CCC 5 A
4	164	PRIOH36034657-19	Overhead Line	119.9	COPPER	180	4 AWG	CCC 4 A
4	163.6	PRIOH36034657-14	Overhead Line	109.6	COPPER	160	5 AWG	CCC 5 A
4	6.9	PRIOH36034657-13	Overhead Line	108.1	COPPER	160	5 AWG	CCC 5 A
4	11.9	PRIOH36034977	Overhead Line	122	COPPER	180	4 AWG	CCC 4 A
4	172.6	PRIOH36034669-2	Overhead Line	103.8	COPPER	160	5 AWG	CCC 5 A
4	301.9	PRIOH36034657-15	Overhead Line	112.1	COPPER	180	4 AWG	CCC 4 A
4	220.4	PRIOH36034657-20	Overhead Line	122	COPPER	180	4 AWG	CCC 4 A
4	239.6	PRIOH36034657-11	Overhead Line	102.7	COPPER	160	5 AWG	CCC 5 A
4	170.5	PRIOH36034657-16	Overhead Line	116.1	COPPER	180	4 AWG	CCC 4 A
4	393.8	PRIOH36034669-1	Overhead Line	101.3	COPPER	160	5 AWG	CCC 5 A
4	211.8	PRIOH36034657-18	Overhead Line	117.1	COPPER	180	4 AWG	CCC 4 A
4	39.8	PRIUG38005501	Cable	123.3	COPPER	475	450 kcmil	IEEE 600V-5KV NONSHIELDED 450KCMIL SR 1C CU
4	17.1	PRIUG38019283	Cable	123.3	COPPER	475	450 kcmil	IEEE 600V-5KV NONSHIELDED 450KCMIL SR 1C CU

cluster	Phases	Previous Ampacity	Previous Size	Previous Type	Ratio	Steps	Unit Cost ($/ft)	Total Cost ($)
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	30361.5
4	A	140	26.248 kcmil	#6A-CW_BARE	0.143	1	142.5	24723.75
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	31980
4	A	140	26.248 kcmil	#6A-CW_BARE	0.143	1	142.5	23313
4	A	140	26.248 kcmil	#6A-CW_BARE	0.143	1	142.5	983.25
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	2320.5
4	ABC	140	26.248 kcmil	#6A-CW_BARE	0.143	1	142.5	24595.5
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	58870.5
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	42978
4	A	140	26.248 kcmil	#6A-CW_BARE	0.143	1	142.5	34143
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	33247.5
4	ABC	140	26.248 kcmil	#6A-CW_BARE	0.143	1	142.5	56116.5
4	A	140	26.248 kcmil	#6A-CW_BARE	0.286	2	195	41301
4	ABC	382	350 kcmil	12KV_350CU_1/C_TAPE_SHIELD	0.243	2	120	4776
4	ABC	382	350 kcmil	12KV_350CU_1/C_TAPE_SHIELD	0.243	2	120	2052

Table A.10 Line upgrades for cluster 3, Boundary scenario, year 2040

Cluster	Length(ft)	Line	Line Type	Loading	Material	New Ampacity	New Size	New Type
5	198	2268221_2854_OH	Overhead Line	101.8	ALUMINIUM	645	556.5 kcmil	AAC DAHLIA 556.5 KCMIL
5	220	1813448_2854_OH	Overhead Line	130	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	194	1816870_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	51	1661550_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	97	1813574_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	205	2116482_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	223	2268149_2854_OH	Overhead Line	130	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	202	1509873_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	192	1816645_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	212	1513395_2854_OH	Overhead Line	130	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	195	1816689_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL

5	36	151080124_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	203	1510149_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	96	2271306_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	188	2271307_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	193	1510354_2854_OH	Overhead Line	122.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	44	1358439_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	192	1510316_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	97	2271305_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	60	151570492_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	156	2116518_2854_OH	Overhead Line	119.5	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	121	1813603_2854_OH	Overhead Line	122.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	99	1965598_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	185	1965135_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	203	2268150_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	181	1210203_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	96	1665149_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	211	1510275_2854_OH	Overhead Line	130	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	182	1210246_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	177	1210247_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	192	1813209_2854_OH	Overhead Line	122.4	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	204	1661844_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	95	1968614_2854_OH	Overhead Line	138.6	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	206	1358440_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	97	1358486_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	191	2116076_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	191	2116075_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	62	1510323_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	209	1665083_2854_OH	Overhead Line	130	ALUMINIUM	800	875.5 kcmil	AAC ANEMONE 874.5 KCMIL
5	205	1206743_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	100	1965204_2854_OH	Overhead Line	119.9	ALUMINIUM	750	715.5 kcmil	AAC NASTURTIUM 715.5 KCMIL
5	57	1362103_2854_UG	Cable	119.7	COPPER	695	2000 kcmil	ENERGYA 15KV IEC 500MM 3C CU UA

5	115	1816518_2854_UG	Cable	119.7	COPPER	695	2000 kcmil	ENERGYA 15KV IEC 500MM 3C CU UA

cluster	Phases	Previous Ampacity	Previous Size	Previous Type	Ratio	Steps	Unit Cost ($/ft)	Total Cost ($)
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.132	1	95	18810
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	38060
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	33562
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	6630
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	12610
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26650
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	38579
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26260
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	33216
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	36676
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	33735
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	4680
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26390
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	16608
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	32524
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	25090
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	5720
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	24960
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	16781
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	7800
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	20280
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	15730
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	12870
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	24050
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26390
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	31313
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	16608

5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	36503
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	31486
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	30621
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	24960
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26520
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	16435
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26780
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	12610
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	24830
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	24830
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	8060
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.404	3	173	36157
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_PE	0.316	2	130	26650
5	ABC	570	397.5 kcmil	397.5_KCMIL_AL_BR	0.316	2	130	13000
5	ABC	660	211.6 kcmil	3P_750_KCMIL_CU_15KV_QUAD	0.053	0	120	6840
5	ABC	660	211.6 kcmil	3P_750_KCMIL_CU_15KV_QUAD	0.053	0	120	13800

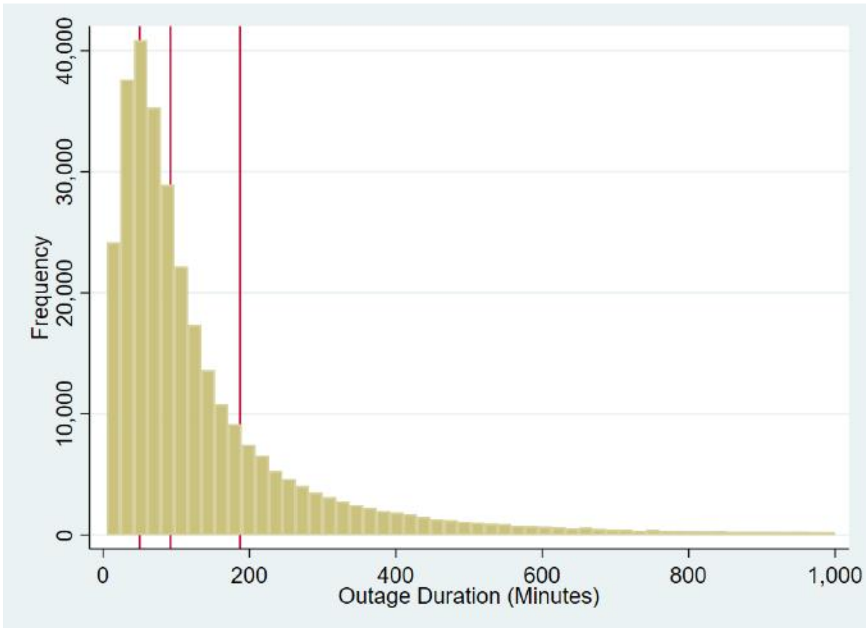

Figure A.1 Frequency of outages by duration including MEDs (truncated at 1,000 minutes) (2014-2018)

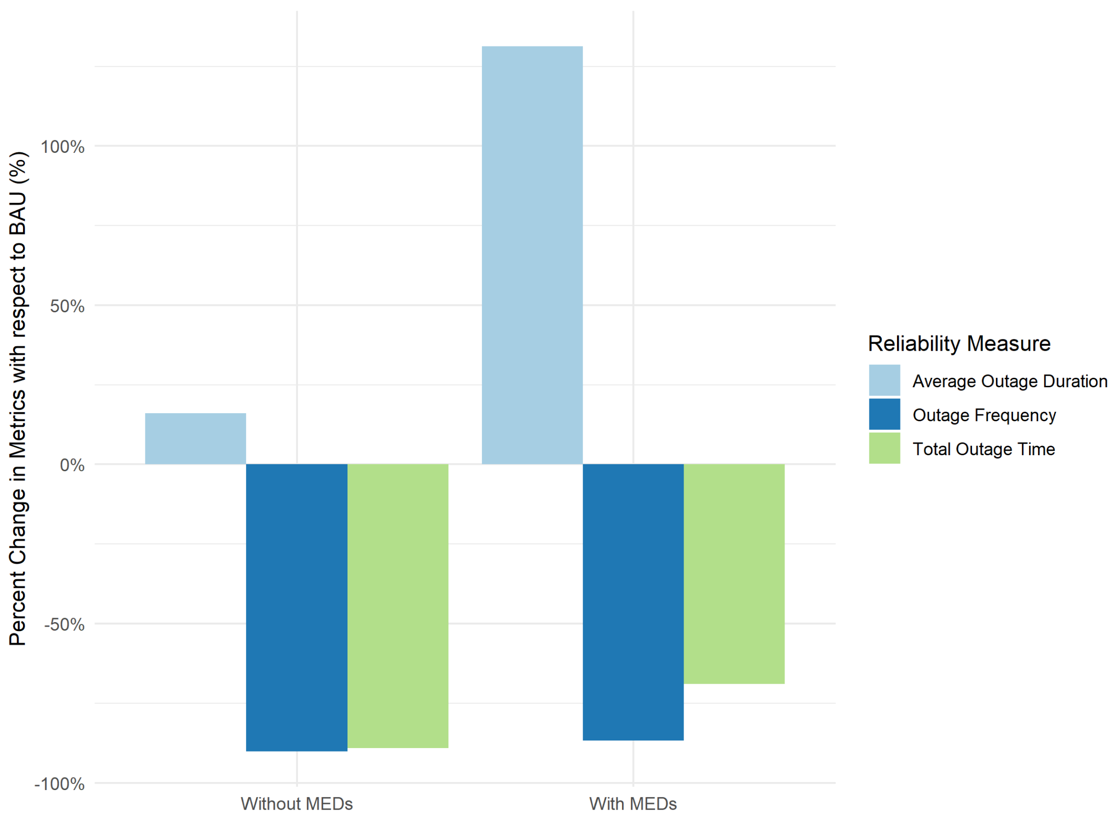

Figure A.2 State-wide reliability changes relative to the base case for battery storage adopters under full battery mode (with and without MEDs included)

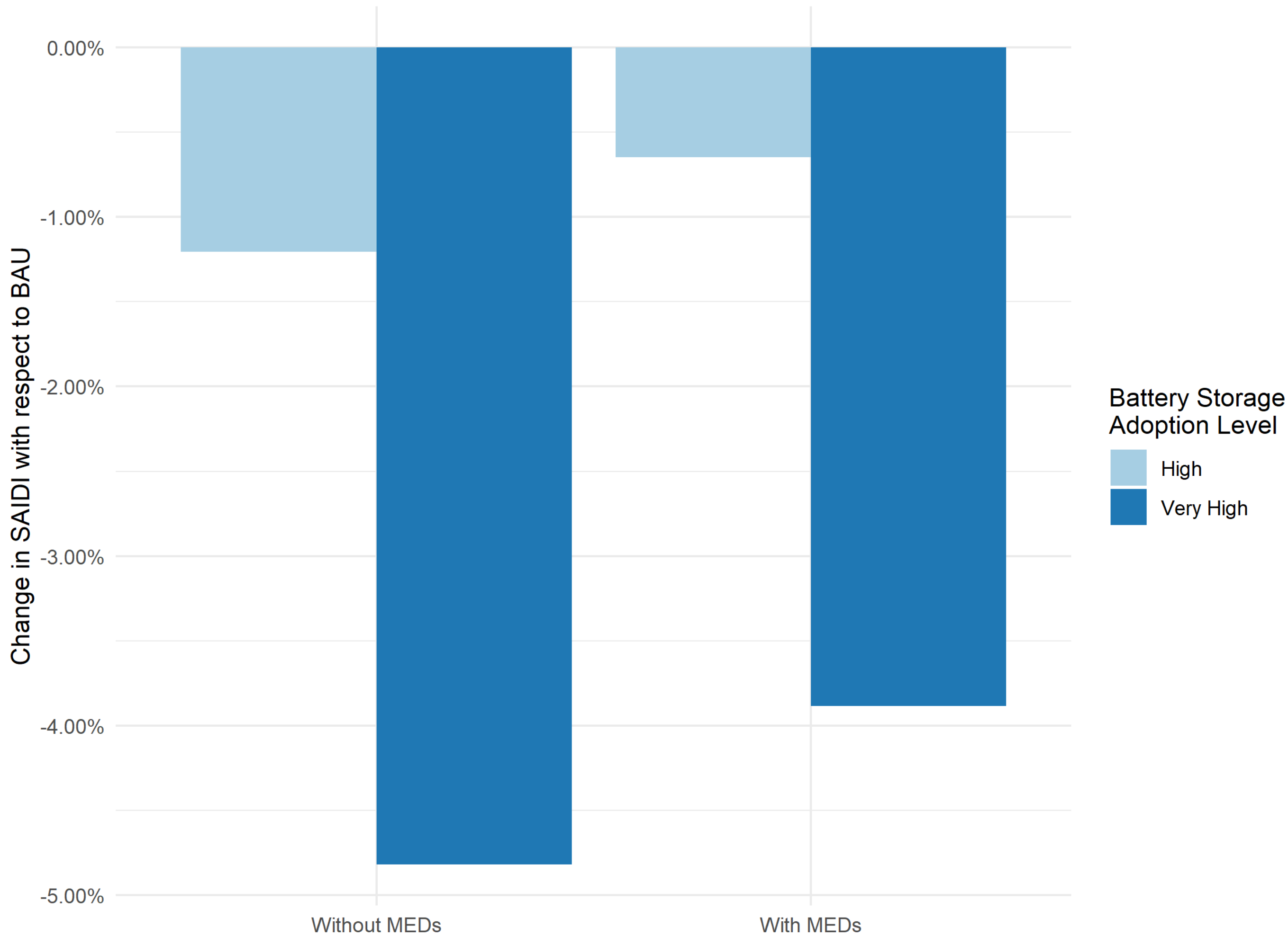

Figure A.3 Average state-wide SAIDI changes with respect to BAU with and without MEDs.

Appendix B. Technical Appendix

B.1. Feeder clustering methodology

This subsection reports the method used to preprocess the feeder dataset using Principal Component Analysis (PCA)

B.1.1. Transforming the data using PCA

Data transformation is a pre-processing step intended to extract useful information from an otherwise noisy and possibly redundant dataset. Outliers need to be identified and cleaned or removed to make sure the critical differences and similarities between feeders are evident and lead to better clustering. Reducing the complexity of the dataset leads to an improved and computationally tractable analysis of large datasets.

In the case of feeder metrics, potential correlation between parameters can hinder appropriate clustering. For example, the aggregate transformer capacity in a feeder and its peak demand may be highly correlated. Including both in the analysis may give inappropriate weight to these two parameters, preventing important information from other parameters to be considered.

We transformed the data employing Principal Component Analysis. PCA is a method designed to extract and display the systematic variation in a data set (Broderick and Williams, 2013). Technically speaking, PCA seeks to express the feeder metrics on a different basis, such that the variance across parameters is maximized and their covariance is minimized (Cale et al., 2014). As stated by Shlens (2005), "PCA provides a roadmap for how to reduce a complex data set to a lower dimension to reveal the sometimes hidden, simplified structure that often underlie it."[9]

The resulting data allows us to express each feeder as a combination of the transformed variables. For example, in Figure B.1, each dot represents a single feeder characterized by their first two standardized principal components. The condensation of data in several areas of the plot suggests how clusters can be formed, and the dots that are farther from the center (0, 0) are candidates for outliers.

[9] Technical details on the method are out of the scope of this study, but an accessible tutorial is available from Shlens (2005).

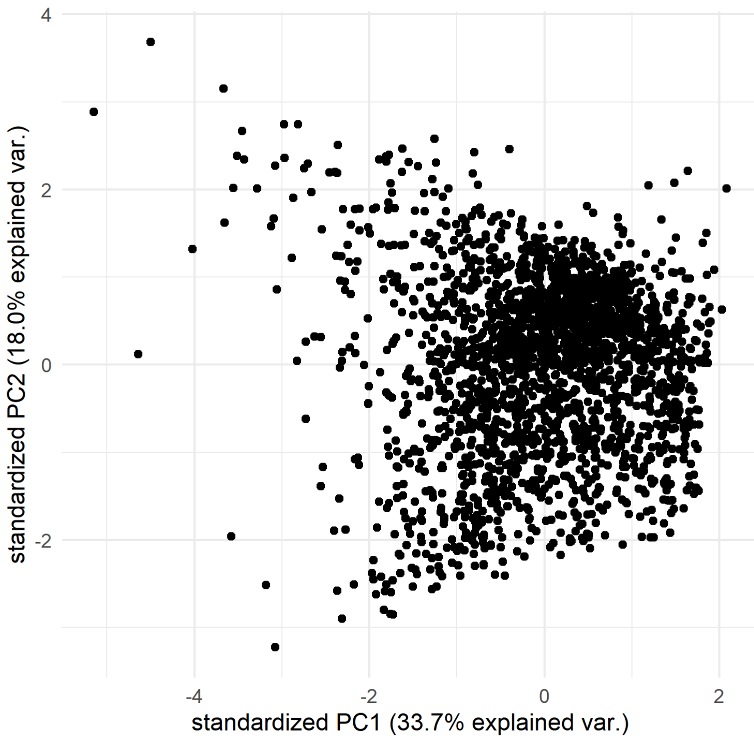

Figure B.1 Indiana feeder data expressed in its first two principal components

Sampling techniques are very sensitive to the presence or exclusion of outliers. A genuine outlier – a data point that is most likely wrong – should be excluded when possible to minimize distortion of the outcome. However, feeder metrics that are extreme may signal an unusual type of feeder whose properties should be captured by the clustering algorithm and not discarded.

This study employs the Mahalanobis distance (D^2) to identify outliers within the dataset (McLachlan, 1999). Outliers are usually analyzed within individual dimensions (for example, the 99th percentile of the number of poles for each feeder). However, a feeder with many poles could represent a long feeder with many customers, hence being a "typical" feeder from a multivariable perspective. The D^2 metric measures the "distance" between a point and the center of its distribution (Ruefer, 2016). In this case, it allows to measure the distance of a set of feeder parameters to their joint distribution, allowing the identification of true outliers that avoid the issue presented before.

The application of the D^2 method to the dataset did not remove a substantial number of data points. This is due, in part, to the cleaning described earlier, but also because we used a conservative threshold to classify outliers in order to preserve a reasonable amount of variation within the dataset. The final dataset used for determining feeder clusters was composed of 12 parameters representing over 2,250 feeders across the Indiana IOU service territories.

B.1.2. Determining the number of clusters

After the dataset is transformed, scaled, and cleaned of outliers, the next step is to classify these feeders according to common features and produce "representative" clusters of feeders. This clustering step was performed in two stages.

First, a clustering technique is applied iteratively and performance metrics are calculated for each iteration. These performance metrics identify the optimal number of clusters from a statistical perspective. We employ the Partitioning Around Medoids (PAM), which was used by (Cale et al., 2014) as a more robust method than the well-known k-means cluster algorithm. Second, we manually examine the clusters and iterate further to produce a final set of clusters. The definitive clusters can be represented by its two principal components by assigning the corresponding cluster to each dot in Figure B.1 (see Figure B.2 below). The figure shows clusters forming on the two left quadrants (purple and orange), two interior clusters closer to the center (green and blue), and two clusters in the right quadrants (red and yellow).

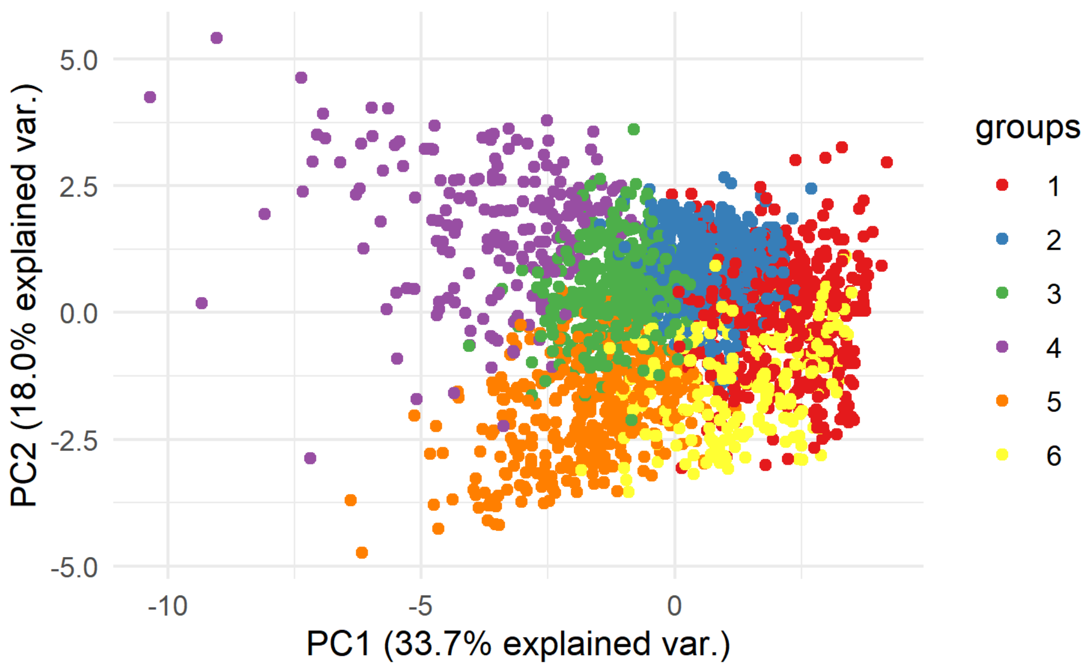

Figure B.2 Result of PAM algorithm on the first two principal components (PC1 and PC2, respectively).

B.1.3. Selecting representative feeders

We used again the D^2 distance defined in subsection B.1.1 to choose a representative feeder for each cluster, which will be then used for the power flow simulations in the next stage of the analysis. The D^2 distance identifies the center of the "cloud" of data points, and then reports the distance of each actual data point (in this case, feeder) to that center value. The feeders with the shortest distance to this median value are then the ones that most closely represent an average feeder within a cluster. This is the method used to select representative feeders for simulation.

B.2. Distribution system power flow simulation results

This appendix includes a deeper analysis of voltage violations for each individual cluster.

Cluster 1: 442 total nodes

The representative feeder for cluster 1 has less than seven nodes compromised on a few simulation hours, all of them in the Boundary scenario and the year 2040 (Table A.1, Appendix A). Low voltage issues exist on up to seven nodes over five hours, and high voltage issues on a single node over four additional hours. Cluster 1 is one of the least impacted feeders, probably due to its short length and its larger share of commercial customers which have a relatively high load factor.

Cluster 2: 624 total nodes

In year 2040, the representative feeder for cluster 2 has only low voltage issues (Table A.2, Appendix A). Most hour-scenario combinations have few nodes with voltage violations. However, there are two simulation hours in the Boundary scenario where 31% and 41% of nodes exhibit low voltage issues. These voltage issues occur at 6 pm and 7 pm on a maximum load day. A topology map of this feeder shows low voltage levels at the points farther from the source node, at times of the day when PV voltage support declines due to reduced production (Figure 5.2). In the figure, small dots represent nodes colored according to their voltage level in p.u., and yellow dots represent location of PV systems in this feeder.

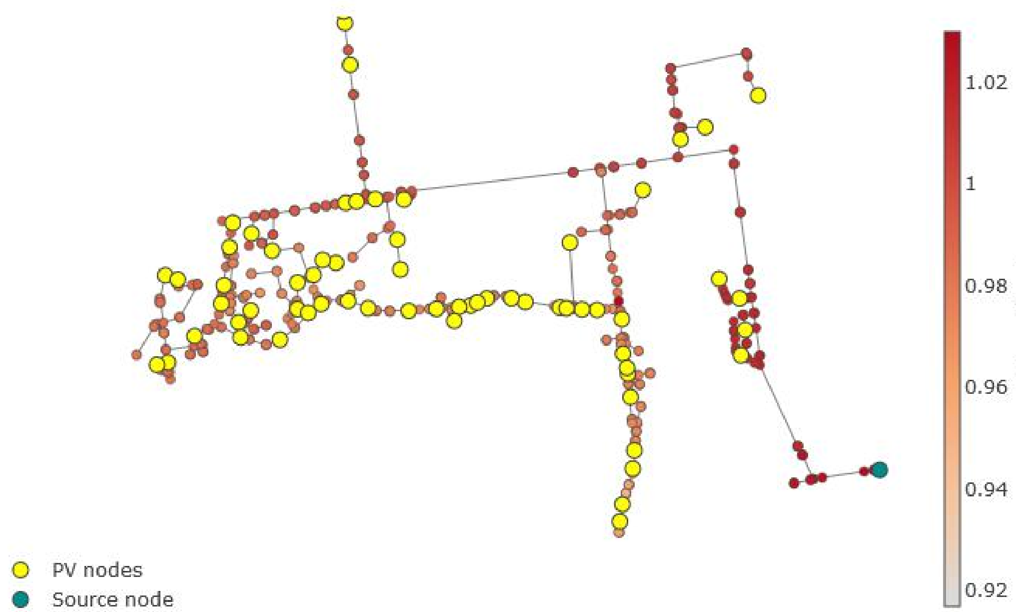

Figure B.3 Depiction of voltage levels for Cluster 2 in 2040 under the Boundary scenario

Cluster 3: 585 total nodes

The representative feeder for cluster 3 exhibited voltage issues during 67 simulation hours out of 576—the most recorded for all clusters (Table A.3, Appendix A). It should be noted that there are only high voltage anomalies in this cluster. About 20% of the nodes exhibited high voltage issues. The majority of these high voltage issues occurred in the middle of the day, which likely correlates with increased PV production and is expected with the Boundary and High PV scenarios.

However, further analysis of the high voltage anomalies reveal that the base voltage set point at the feeder header is set at 1.045 p.u. in the Cymdist feeder model submitted by the utility. The absolute minimum voltage in any node in this feeder is 0.982 p.u., which is high for a relatively long feeder. Even scenarios with low PV adoption including the 2025 Base scenario exhibit high voltage issues in over 15% of the nodes. Furthermore, this is the only feeder with a similar number of voltage violations in 2025 and 2040; voltage violations in other feeders happen almost exclusively in 2040. Our analysis suggests that about half of the responsibility for high voltage issues can be attributed to the current base voltage set point at feeder header, and the other half to DER adoption.

Cluster 4: 1,611 total nodes

The representative feeder for cluster 4 exhibited low voltage issues only, in about 50 simulation hours out of 576 (Table A.4, Appendix A). This feeder also exhibits the widest range of node voltages among clusters, most likely due to its length.

The low voltage issues appear to be correlated with high demand during the middle of the day. About half of the nodes have low voltage issues in the worst four simulation hours. These correspond to the Boundary scenario, at 6 pm and 7 pm; and to the High Electrification scenario, at 2 pm and 3 pm. The timing of the two worst hours in the Boundary scenario suggests that high PV adoption is indeed contributing to the improvement in low voltage issues exhibited in this feeder. Not surprisingly, the two worst simulation hours correspond to the High Electrification scenario, which has a high net demand due to electric vehicle charging. It is possible that, with lower PV adoption, these two hours in the High Electrification scenario would also exhibit the highest levels of voltage violations.

Cluster 5: 508 total nodes

The representative feeder for cluster 5 has only eight simulation hours out of 576 with voltage issues (Table A.5, Appendix A). However, this feeder is unique in that it exhibits *both* low and high voltage issues affecting a reasonably large number of nodes (20% of notes exhibited low voltage issues and 75% exhibited high voltage issues). However, all voltage issues in this feeder occur in the Boundary scenario.

This cluster has the highest PV adoption per customer node—more than double the next closest cluster. It is possible that higher PV adoption correlates to relatively more affluent residential customers, who are more likely to take advantage of PV incentives and be served by higher shares of underground circuits (Barbose et al., 2020). It follows that high voltage violations occur during very low load hours, which is when PV production can have the most significant impact on voltage increases. This suggests that most voltage issues in this feeder may be solved by smart inverters that can consume reactive power at specific times to prevent voltage increases.

Cluster 6: 238 total nodes

As with the feeder in cluster 1, the representative feeder in cluster 6 is essentially not impacted by DER adoption. There is a single simulation hour with voltage issues, which takes place on a single node out of the 238 nodes in the feeder (Table A.6, Appendix A). The relatively high share of industrial customers on nodes in cluster 6—who do not adopt DER in our study—as well as the relative short circuit length make feeders in this cluster less prone to develop voltage issues, even in the Boundary scenario.

Economic, Fiscal, and Social Impacts of the Transition of Electricity Generation Resources in Indiana

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EXECUTIVE SUMMARY

At the request the Indiana Utility Regulatory Commission (IURC), Indiana University researchers from the Public Policy Institute, the Indiana Business Research Center (IBRC), and the Paul H. O'Neill School of Public and Environmental Affairs prepared this analysis of the local economic, fiscal, and social impacts of the transition of electricity generation from coal to new and emerging technologies.[1] The study focused on the effects of anticipated 2021–2028 closures or partial closures of the Schahfer, Michigan City, Petersburg, and Rockport coal-fired generating plants, and was informed by an extensive review of literature on the transition and closing of power plants in other communities across the United States. Similar analyses were conducted on each plant. The requirements of this study also included interviews with stakeholders from two communities. The communities and regions around the Schahfer and Petersburg plants were selected for this purpose.

Several findings are provided in this report and the key findings are summarized below. Readers are encouraged to examine the detailed findings beginning on page 23. It important to note, however, that the findings in this report—as well as summaries of conversations with community stakeholders, where applicable—were prepared largely before the pandemic impacted our state and national economies. There is no consensus about the duration of our current recession or any long-lasting effects resulting from it; therefore, the timing and long-term effects of plant closures or changes in operations may be substantially different than those presented in this report.

Indiana's electricity sector is part of the broader national energy transition. Indiana, like the nation, is shifting from producing electricity from carbon-intensive fossil fuels to more efficient low-carbon sources such as natural gas, solar photovoltaics, wind turbines, and demand-side management approaches. Based on an extensive literature review, the Indiana energy transition is expected to come with a mix of benefits and costs. Expected benefits include improved health from cleaner air, increased jobs in the clean energy field, and reduced greenhouse gas emissions. Expected costs include job losses in traditional fossil fuel industries, localized tax revenue losses, potential changes in the social makeup of affected communities, and potentially unwanted land uses.

The statewide direct economic impacts of the four plant closures may affect as many as 652 jobs, $77.5M in employee compensation, and $345.0M in GDP. The economic ripple effects may affect an additional 1,732 jobs, $98.4M in employee compensation, and $184.7M in state GDP. These direct and ripple effects represent 0.05 percent and 0.06 percent of Indiana's 2018 GDP and total employment, respectively. The continued demand for skilled labor in maintenance and construction occupations is expected to mitigate some of these effects (see the Force Account discussions in each of those sections and the full analysis in Appendix B).[2]

1 Please see 2019 House Enrolled Act 1278 (IC 8-1-8.5-3.1(b) et seq.), which directed the IURC to undertake this study.

2 This report does not address the potential change in energy prices due to transition because potential price effects have been analyzed by the State Utility Forecasting Group in a companion report, Scenario analyses for the IURC report to the 21st Century Policy Task Force (2020).

While these impacts are not substantial in a statewide context, the closures are expected to have considerable impacts on the communities in which the plants are located. Among the four plants, the Schahfer plant closure is expected to have the biggest direct regional employment impact, a loss of almost 300 jobs. The other plants are expected to lose approximately 120 jobs each.

Job loss also is likely to be mitigated by tight labor markets and open positions in the regions surrounding each of the plants. The Schahfer and Petersburg stakeholders generally expressed that skilled workers would be absorbed immediately and semi-skilled workers with some additional training. In both regions, they indicated that management and administrative workers would find fewer replacement opportunities regionally and may need to relocate as a result. In addition, several stakeholders indicated that having available workers in these regions also provides an opportunity to attract new firms and to diversify the local economy and tax base.

The four plants pay substantially more in wages and compensation than the average wages and compensation in the counties in which they are located. Stakeholders believe that these wages and benefits generally may be difficult for local displaced workers to replace.

Many stakeholders suggested that households in rural Indiana are locally rooted and will likely be willing to commute within their region for new jobs. However, there also is concern, particularly in Pike County, about potential employee relocation and population loss that can further exacerbate the existing challenges in rural communities.

NIPSCO, IPL, and I&M reported buying goods and services (excluding coal) in half of Indiana's counties. The partial closure of the Petersburg plant is expected to have the greatest regional ripple employment impacts at 470 jobs, in part, because it is the only one of the four plants that uses Indiana coal.

The loss of assessed value from the three plant closures in rural settings has or will have a profound impact on the affected local governments, particularly townships and school corporations. The impact of the Michigan City plant closure, the only one located in an urban setting, is mitigated somewhat by a larger and more diverse tax base.

Stakeholders reported being confident that local officials generally understand the nature and scale of the upcoming impacts and that resource organizations are poised to assist. They commonly expressed, however, that communities and local resource organizations need more specific information about assessed value losses, the occupations of transitioning employees, and the goods and services firms that will be affected.

The communities near the Schahfer and Petersburg plants have undertaken a substantial set of local efforts to mitigate the effects of plant closures. For example, Pike County officials have developed the Southwest Indiana Megasite—a large shovel-ready industrial park—and the Entrepreneurial and Technology Center near I-69. Jasper County convened a community task force which made a number of recommendations about how to diversify the local tax base, including facilitating development around the I-65 interchanges by extending infrastructure and adopting tax increment financing districts. The county economic development organization is working with partners to implement the recommendations.

The development of wind and solar resources provides opportunities to mitigate both job and tax base loss. While the literature suggests that communities facing the loss of a coal-fired plant are not always suitable for replacement capacity development, community stakeholders in Pike and Jasper counties shared that IPL and NIPSCO have been working to develop solar projects in those counties. Jasper County also is suitable for wind development, but local preferences have limited such development.

This Executive Summary highlights only key findings and issues faced by communities where plants are scheduled to close or reduce operations of coal-fired generators. Readers are strongly encouraged to read the remainder of this report for more detailed information, implications from current literature, and analysis of individual communities' economic, fiscal, and social impacts from the transition away from coal-fired power generation.

INTRODUCTION

2019 House Enrolled Act 1278 (IC 8-1-8.5-3.1(b) et seq.) directed the Indiana Utility Regulatory Commission (IURC) to conduct a comprehensive study of the short- and long-term statewide impacts of (1) transitions in the fuel sources and other resources used to generate electricity by electric utilities; and (2) new and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure on electric generation capacity, system reliability, system resilience, and the cost of electric utility service for consumers. The IURC also is required to issue the findings of these studies to the Governor, the Legislative Council, and the 21st Century Energy Policy Development Task Force (IC 2-5-45-2) by July 1, 2020. The due date for the IURC report was extended to on or before August 14, 2020, by the Governor's Executive Order 20-31 issued June 3, 2020.

As part of this effort, the IURC approached Indiana University to prepare an analysis of the local economic, fiscal, and social impacts of the transition in generation resources, particularly on rural communities. This work was conducted by a team of researchers from the IU Public Policy Institute, the Indiana Business Research Center (IBRC), and the Paul H. O'Neill School of Public and Environmental Affairs at Indiana University.

The report that follows provides state and local policymakers information about the potential impact of retiring coal-fired generation and how building replacement generation will affect local communities and regions. These impacts are important to economic development, workforce development, and other civic leaders as they craft community, regional, and state responses.

This report is organized into five principal sections:

- A detailed methodology for each of the report's analytical elements
- Literature reviews on the local economic and social impacts of the ongoing energy transition in the United States and Indiana
- An assessment of potential impacts, along with regional and selected statewide analyses, of retiring four coal-fired power plants—Schahfer, Michigan City, Petersburg, and Rockport
- An analysis of the employment effects of planned near-term investments in wind, solar, and natural gas generation

The document also includes a bibliography and three appendices:

- Appendix A contains a short discussion about the potential effects of the pandemic on the study results.
- Appendix B contains the complete county-level and force account input-output modeling analyses.
- Appendix C contains a brief summary of wind farm operations data.

A special note: The estimates provided in this report do not consider potential residual effects from the current economic downturn because as discussed more fully in Appendix A the full extent of economic adjustment from the current downturn will not be known for several months, or longer. Therefore, the actual effects of plant closures on any county or region cannot be estimated with a high degree of confidence in the current economic environment.

METHODOLOGY

This section provides the detailed methodology used by the research team to produce each element in the report.

Literature reviews

The research team conducted two literature reviews synthesizing current literature on the local economic and social impacts of the ongoing energy transition in the United States and in Indiana.

State and local impacts of selected near-term retirements of coal-fired generation

To evaluate the nature and intensity of potential impacts of a full or partial closure of four coal-fired generating stations—Schahfer, Michigan City, Petersburg, and Rockport—the research team completed an analysis for each. First, they assessed plant data on employment, wages and compensation, and goods and services purchased. Second, the team conducted a cursory analysis of tax impacts. Third, they created an input-output analysis of direct and spin-off economic activity. Fourth, the team interviewed stakeholders in the regions affected by the closing of the Petersburg and Schahfer plants. Lastly, researchers analyzed three additional scenarios using input-output modeling: statewide impact of the plant closures, impact on the counties where the plants are located, and a force account scenario exploring the potential absorption of released workers. Additional detail is provided for each of these activities in the sections that follow.

The assessments for the Michigan City and Schahfer plants assumes a full closure of these coal-fired facilities, resulting in scenarios in which all direct jobs and spending are lost to their respective regions. On the other hand, the Petersburg and Rockport plant assessments consider only partial closures. This means only a portion of the economic activity created by these plants will be lost. The research team did not have data on the number of direct jobs or amount of supply chain spending that is at risk from these partial closures. Instead, the team used the expected decrease in net electricity generation—based on an average of the past three years—as a proxy for the reduction of jobs and spending. In Petersburg, for instance, the units slated for closure have accounted for approximately 40 percent of the total electricity generated at this plant. Therefore, analysts assumed that there would also be a 40 percent decrease in employment, wages and benefits, and spending. The effects of any closures also are assumed to occur proportionally across demographics, geography, etc. These adjustments were not made to property tax data.

Direct economic and tax effects

The first two analyses use data provided by each company including the number of employees and their distribution by zip code of residence, employee age, gender, and race, employees by occupation type, the type and geographic distribution of goods and services purchased by the plant, and net electricity generation. This data provides important information about the communities affected by closure and the nature and relative intensity of those impacts.

The property and income tax analysis uses data collected by county assessors, the Indiana Department of Local Government Finance (DLGF), and the Indiana State Budget Agency (ISBA).

Input-output modeling

The economic impact analysis measures the direct economic effects of Indiana's electricity generation industry using the number of facility employees, the compensation they earn, and the Gross Domestic Product (GDP) they contribute to the economy (i.e., the total value of the electricity generated after subtracting the cost of production inputs).

The impacts do not end there. The economic ripple effects of these activities cascade throughout the economy. For instance, power plant operators engage with other local businesses to purchase the goods and services needed to maintain and operate their facilities. Additionally, employees at these plants—as well as workers throughout the electricity generation supply chain—trigger more economic activity when they spend their earnings on food, clothing, health care, entertainment, and other goods and services. The contributions from both of these spending streams—the supply chain purchases and the household spending by employees—are referred to as the economic ripple effects of electricity generation industry activities.

To estimate these impacts, the research team used detailed data provided by each company on staffing, payroll, capital expenditures, and supply chain spending from the relevant electricity generation companies. Several companies provided specifics on supply chain spending by industry, as well as the amount of money paid to Indiana-based vendors. This level of detail allowed the analysts to fine-tune the modeling approach and improve the accuracy of the resulting estimates.

The research team used the IMPLAN economic modeling software to generate the impact estimates. IMPLAN draws from a variety of secondary data sources to create a detailed model of a local economy that reflects the unique dynamics of the geographic region selected for analysis.

Table 1 summarizes several key details used for modeling each facility. The process for defining the regions was taking the county in which a given plant is located, adding any bordering counties within Indiana. The Michigan City plant, for instance, is located in LaPorte County, which is bordered by Porter, Starke, and St. Joseph counties within Indiana. The lone exception to this rule was the addition of Sullivan County to the Petersburg region since this generating station buys a portion of its coal from suppliers in this county.

TABLE 1. Regional modeling details

GENERATING STATION	COUNTIES IN MODELING REGIONS	PERCENT REDUCTION IN NET GENERATION	PERCENTAGE OF COAL FROM INDIANA
Schahfer	Benton, Jasper, Lake, Newton, Porter, Pulaski, Starke, White	100%	0%
Michigan City	LaPorte, Porter, Starke, St. Joseph	100%	0%
Petersburg	Daviess, Dubois, Gibson, Knox, Pike, Sullivan, Warrick	40%	100%
Rockport	Dubois, Perry, Spencer, Warrick	47%	0%

The research team completed modeling for three additional scenarios:

Statewide: This scenario calculates the combined statewide effects of the four plant closures or partial closures. It also uses similar data to the regional modeling described above. Direct effects are the same as the aggregate of the direct effects in the regional modeling for the four plants. The model, however, accounts for ripple effects that occur within Indiana but outside the four local regions.

County-level: This scenario calculates the economic effects for the counties in which each plant is located. The analysis of the effects of the Schahfer plant uses a two-county region (Jasper and Porter counties). The direct effects again are identical to those in the regional models. The models account only for the ripple effects in each county, excluding economic activity that occurs in the local region and throughout the state.

Force account: This scenario considers that the portion of plant employment associated with the construction and repair of structures—as well as the goods, materials, and services purchased for specialty construction—would transition to construction and maintenance activities of the remaining coal-fired production and non-coal electricity production. To provide perspective on the potential retention of this economic activity, this model calculates the effects of closure assuming that 30 percent of plant construction workers and 50 percent of goods and services purchased from specialty contractors would transition.

Stakeholder interviews

The research team interviewed representatives from local and regional government, economic development, and business organizations for local perspectives on the expected economic, tax, and social effects of closure, local responses, and any gaps in needed assistance and other challenges. The interviews were conducted in March and early April 2020. Tables 2 and 3 show the stakeholders who provided perspectives on the closure of the Schahfer Generating Station and the partial closure of the Petersburg Generating Station. Figure 1 shows the interview questions.

FIGURE 1. Stakeholder interview questions

1. How significant do you expect the impacts of these changes to be in your community?
2. Have you observed signs of these changes in your community? If so, how?
3. How optimistic are you that government and economic development officials understand the severity of your local challenges?
4. How do you think these changes will affect individuals within your community personally?
5. What support systems are in place to help people cope and adapt to these changes?
6. How do you think the closure will affect the local economy?
7. How do you think the closure will affect local taxes used by local governments and school districts to provide services?
8. What efforts are the [nonprofit, private, public] sector planning or taking to help relieve these impacts? How are you or your organization helping affected communities?
9. Are there any gaps in needed assistance?
10. Overall, how effectively has your community planned for this event to date?

Northern Indiana Public Service Company (NIPSCO) and Indianapolis Power & Light (IPL) were given the opportunity to provide information about their strategies for transitioning employees upon closure. While the Rockport plant was not one of those chosen for stakeholder interviews, Indiana Michigan Power (I&M) also was given the opportunity to provide similar information.

TABLE 2. Local and regional stakeholders—Schahfer Generating Station

NAME	TITLE	ORGANIZATION
Debi Baughman	Chair	Northwest Indiana Workforce Investment Board (Region 1)
Edwin Buswell	Executive Director	Kankakee-Iroquois Regional Plan Commission (KIRPC)
Kendell Culp	Commissioner	Jasper County
Stephen Eastridge	Executive Director	Jasper County Economic Development Organization
Heather Ennis	President and CEO	Northwest Indiana Forum
Kathy Luther	Chief of Staff and Director of Environmental Programs	Northwestern Indiana Regional Plan Commission (NIRPC)
Rex Richards	Executive Director	Valparaiso Economic Development Corporation/Greater Valparaiso Chamber of Commerce
Matt Sheafer	Farmer/business owner	N/A
Linda Woloshansky	President and CEO	WorkOne Northwest Indiana (Region 1)

TABLE 3. Local and regional stakeholders—Petersburg Generating Station

NAME	TITLE	ORGANIZATION
Makenzie Coulter	Chair	Grow Southwest Indiana Workforce Investment Board (Region 11)
Lisa Gelhausen	Executive Director	Indiana 15 Regional Planning Commission
Jill Hyneman	Director	Pike County Chamber of Commerce
R.C. Klipsch	Mayor	City of Petersburg
Bryant Niehoff	Executive Director	Daviess County Economic Development Corporation
David Rhoads	Mayor	City of Washington
Jeff Quyle	President and CEO	Radius Indiana
Ashley Willis	Executive Director	Pike County Economic Development Corporation
Sara Worstell	Executive Director	Grow Southwest Indiana/WorkOne (Region 11)

Employment impacts of near-term solar, wind, and natural gas generation investments in Indiana

The research team collected data from selected solar, wind, and natural gas facilities—including the number of employees, employee wages and compensation, goods and services purchased (total and in Indiana), capital expenditures, and net electricity generation. Six energy companies provided data on seven operating wind farms. Two energy companies provided data on three solar farms in development. IPL provided data for the Eagle Valley Generating Station, a natural gas facility.

The research team performed statewide input-output modeling to estimate the impacts of the solar, wind, and natural gas investments described in current utility Integrated Resource Plans (IRP) submitted to IURC. The direct employment factors for wind and solar energy come from an analysis of U.S.-based projects by the National Renewable Energy Laboratory (NREL) (Steinberg et al, 2012). The direct employment factor for natural gas also is derived from an analysis of Indiana facilities. The indirect employment factors for the alternative energy sources are based on IMPLAN multipliers for these industries.

The research team evaluated the data provided by energy companies when selecting the direct employment factors for solar and wind energy. The Indiana data shows a slightly lower, but similar, jobs per 100 megawatts of wind energy capacity. From 2014 to 2018, Indiana data shows that every 100 megawatts (MW) of wind energy capacity translates to 4.7 jobs. In 2014 and 2018, Indiana wind farms reported 5.0 or more jobs per 100 MW-capacity. While much of the literature consistently shows a relatively high direct employment factor for solar energy, data gathered on three proposed solar energy projects in Indiana show much smaller direct employment effects. Specifically, the factor for solar energy reflected substantially fewer jobs per 100 MW-capacity than the average for projects in the NREL study (EDP Renewables North America, 2020; Invenergy, 2020a; Invenergy, 2020b). The team contacted the NREL study authors but was unable to identify a reason for the difference. Given this uncertainty and the non-disclosure limitation on the Indiana solar data, the NREL direct employment factor for solar is labeled as a high estimate.

AN ENERGY TRANSITION—A LITERATURE REVIEW

The energy transition from a fossil-fuel based economy to one powered by advanced, efficient, and low- to no-carbon sources is occurring in the United States and across the world. In general terms, an energy transition is a shift in dependence on one set of energy resources to another (Sovacool, 2016). The current energy transition in the U.S. is a shift from producing electricity from carbon-intensive fossil fuels, such as coal, to using more efficient, lower-carbon sources, such as natural gas, solar photovoltaics, wind turbines, and demand-side management approaches.

Energy transitions tend to be gradual. On average, it can take 50 years for a sector to partially transition from one energy source to another, shifting as little as 5 percent of its energy or as much as 80 percent during that time. Historical examples from the 19th century include the transition from burning of animal fat candles to kerosene lamps, as well as the transition from burning wood to burning coal to heat homes (Fouquet, 2016).

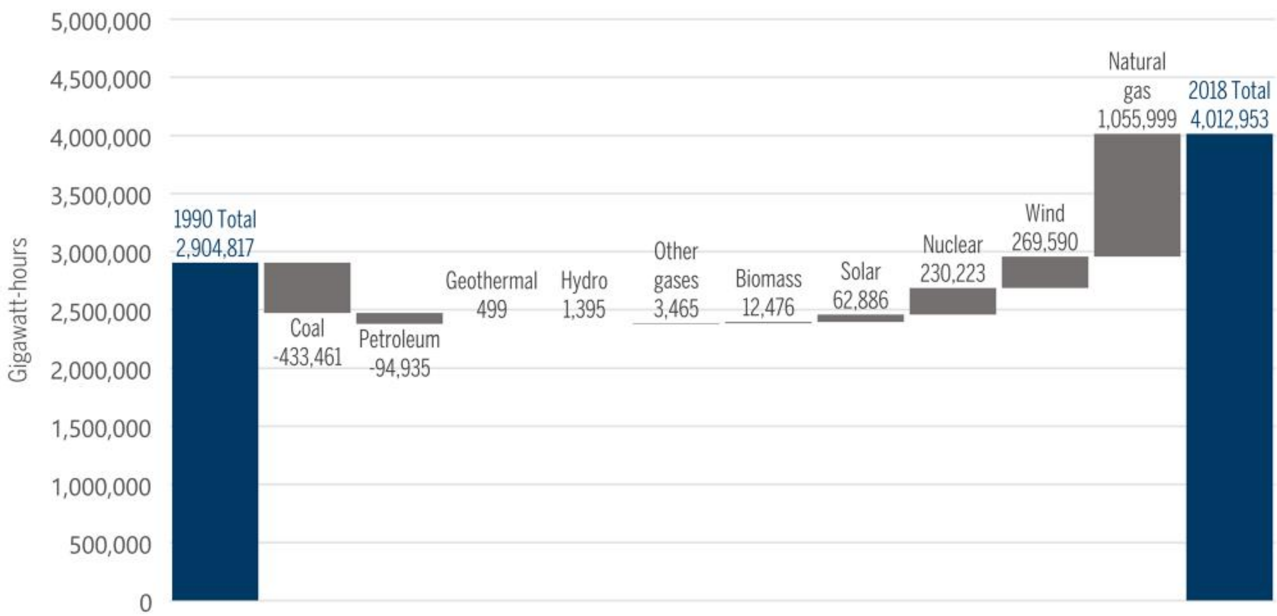
While the shift in energy resources is gradual, both the short-term and long-term effects of the transition will be significant. In some places, the localized impacts are already evident. Such impacts include benefits, costs, and a mixture of both. These effects vary from community to community, and within regions. Benefits of the transition include improved health from cleaner air, increased jobs in the clean energy field, and reduced greenhouse gas emissions. However, there are costs to making the change, including job losses in traditional fossil fuel industries, localized tax revenue losses, and potential unwanted land uses.

This report covers only topics of economic and social impacts of the energy transition. A discussion of the environmental and health benefits is outside of the scope of our analysis. The environmental and health effects of an energy transition toward low- to no-carbon sources could be immense. For example, climate scientists strongly urge an energy transition as a key strategy to reduce greenhouse gas emissions and mitigate the most serious effects of climate change (Intergovernmental Panel on Climate Change, 2018).

Coal use increased between 1990 and 2007, when it produced as much as 50 percent of the country's electricity. The decline in coal as an electricity generation resource began in 2008. By the 2010s, coal use began decreasing gradually at first but more rapidly in recent years. In 2015, the U.S. retired 15 GW of coal use capacity, the largest capacity retirement to that date. In 2018, the U.S. retired another 13 GW of capacity. By 2019, coal generation only accounted for 25 percent of the nation's electricity. During that same 30-year period, the use of natural gas, wind, and solar photovoltaics (PV) for electricity generation has increased. Natural gas use increased the most, producing 1 million more GWh[3] in 2018 than in 2017. These various trends are reflected in Figures 2 and 3, which display the change in electricity sources between 1990 and 2018 (U.S. EIA, 2019a).

3 Utilities often report the electricity we use in kilowatt-hours (kWh) on monthly electricity bills. When aggregating electricity use on a national scale, experts use gigawatt-hours (GWh). A GWh is 1 million kWhs, which is roughly the amount of energy needed to power 110 million LED lightbulbs for 1 hour. Power is the rate at which electricity is used or produced in any given moment. Some units of power are kilowatts (kW), megawatts (MW), and gigawatts (GW), where 1 GW = 1,000 MW = 1,000,000 kW. Power plants have maximum power ratings (i.e. maximum rates at which the plant can produce energy), and these power ratings are often referred to as capacities.

FIGURE 2. Change in electricity production by source (1990–2018)



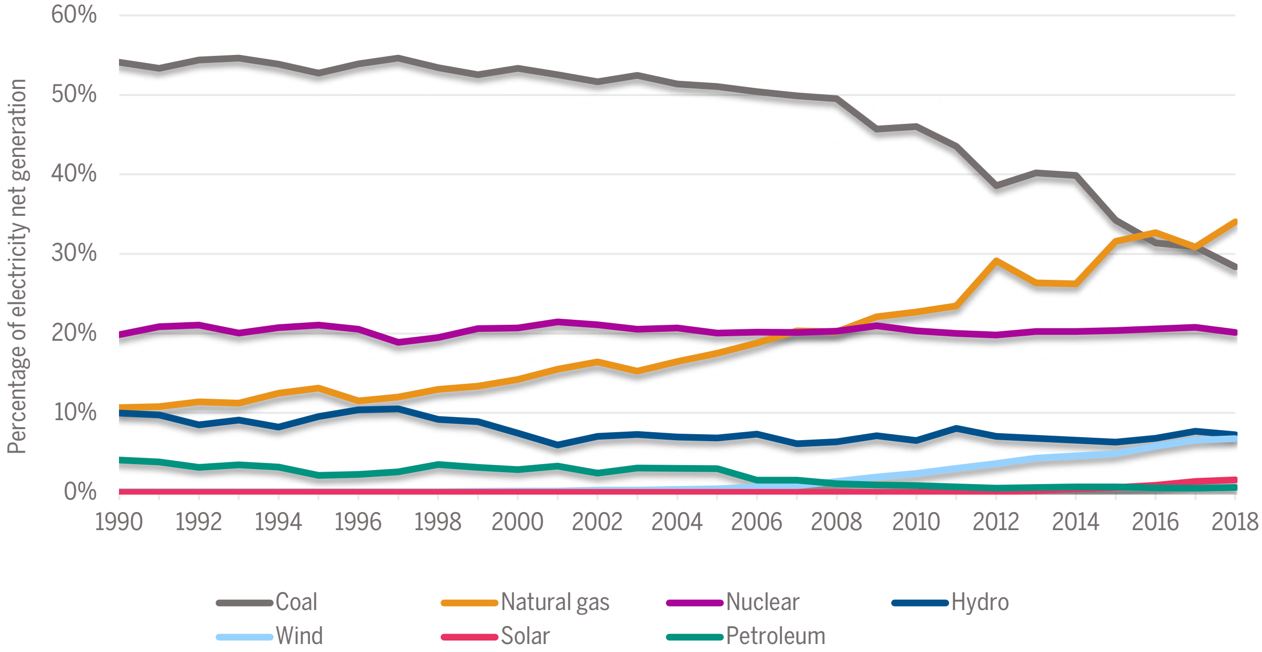
Source: U.S. EIA, 2019a.

Before 2015, most of the retired coal plants were small, old, and in need of retirement. Since 2015, lower cost substitutes, such as natural gas and renewables, have driven retirements as opposed to the age or condition of the plant (Houser et al., 2017). Retired coal units in 2018 were, on average, 10 years younger, 46 years old versus 56 years old. They also were twice as large as the coal plants retired before 2015, with a capacity of 350 MW versus 130 MW (Johnson & Chau, 2019).

Economic pressures have contributed to these trends. Prices for natural gas, for example, remain consistently lower than coal due to technological advancements in the extraction of unconventional oil and gas, and the resulting increased domestic supply (Hodge, 2018). Driven by government mandates for renewable energy and subsidies, renewable energy markets also are rapidly maturing. For example, between 2009 and 2019 costs for onshore wind turbines and utility-scale solar declined by 70 percent and 89 percent, respectively (Lazard, 2019). Even without government subsidies, onshore wind and utility-scale solar are becoming the lowest cost options, based on the levelized cost of electricity, for new power generation (U.S. EIA, 2019b).

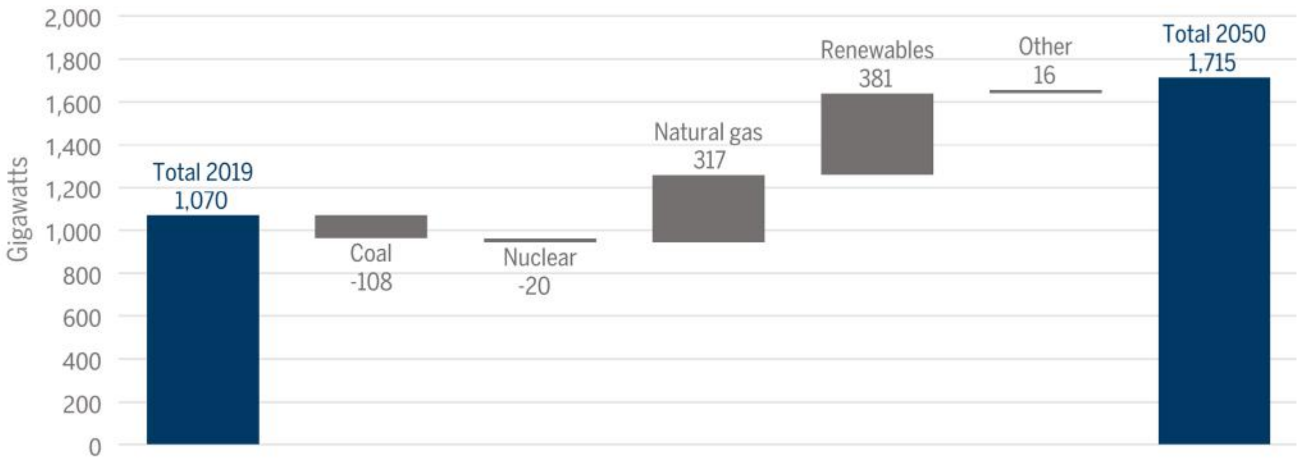
Analysts predict that the trend in coal plant retirements and increased reliance on renewables and natural gas will continue. The U.S. Energy Information Administration's (U.S. EIA) 2020 *Annual Energy Outlook* predicts that all new generating capacity built between now and 2050 will come primarily from wind, solar, and natural gas facilities. These estimates are reflected in Figure 4, which shows projections in generation sources between 2019 and 2050. The U.S. EIA also forecasts a retirement of 108 GW of coal capacity between now and 2050 (U.S. EIA, 2020). The rate of coal retirements likely will accelerate if governments adopt more stringent policies to reduce greenhouse gas emissions.

FIGURE 3. Electricity generation by resource (1990–2018)



Source: U.S. EIA 2019a.

FIGURE 4. Change in electricity capacity by source (2019–2050)



Source: U.S. EIA, 2020.

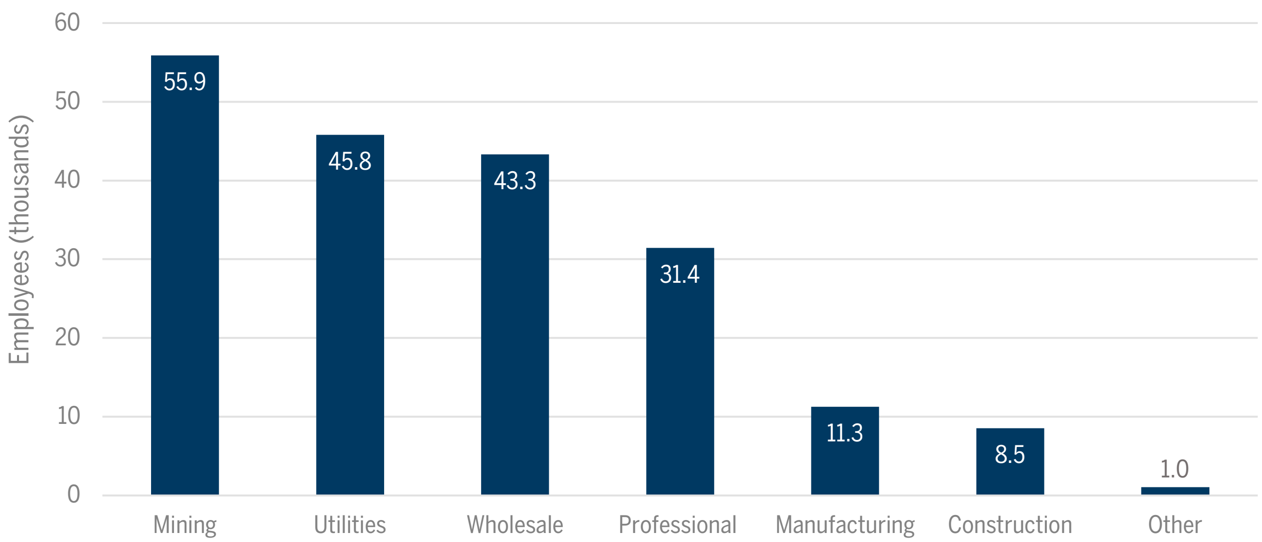
Impacts associated with the decline of coal

As the United States transitions electricity markets away from coal, it will experience a loss of direct jobs in industries that produce and use coal and indirect jobs in the broader community surrounding coal operations, a loss of tax revenue from coal facility closures, and changes to the social makeup of communities, among other possible effects. The majority of these impacts will be local and will disproportionately affect some communities more than others.

Employment

The National Association of State Energy Officials (NASEO)[4] estimates that the coal industry employed 197,400 people across all sectors in 2018 (National Association of State Energy Officials [NASEO], 2019). Figure 5 shows the distribution of these jobs into North American Industrial Classification System (NAICS) categories. As displayed, the largest share of coal employment in 2018 was in coal mining (28 percent), followed by utilities (23 percent), and wholesale trade (22 percent). Professional services, manufacturing, and construction firms accounted for smaller shares: 15 percent, 6 percent and 4 percent, respectively (NASEO, 2019).

FIGURE 5. Coal employment by sector (2018)



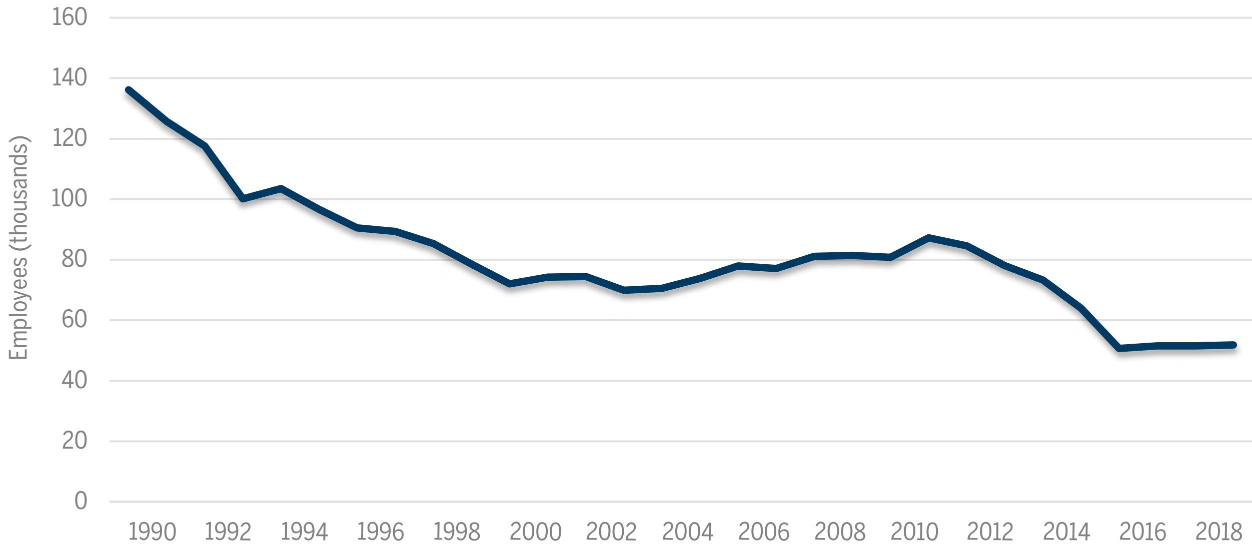
Source: NASEO, 2019.

Figure 6 presents employment in the coal-mining sector from 1990 to 2019, as published by the U.S. Bureau of Labor Statistics. The peak employment for coal miners in the last 30 years was in 2011, when 89,000 individuals worked in the profession (U.S. Bureau of Labor Statistics [U.S. BLS], 2018). Coal-mining employment has declined since 2011 as improvements to mining techniques, such as mountaintop removal,

4 It is challenging to find comprehensive employment statistics for the entire coal industry because government reporting does not distinguish jobs associated with the coal industry from those that otherwise fall into other government reported categories. Therefore, the National Association of State Energy Officials supplemented the Bureau of Labor Statistics' Quarterly Census of Employment and Wages with employer surveys to estimate total energy-related employment across all sectors.

make mining less labor intensive (Betz et al., 2015). Between 2011 and 2019, coal mining employment fell more than 40 percent to 53,000 miners. Decreases in coal employment also closely follow the closure of coal mines. Half of the coal mines open in 2008 (1,435 mines) closed by 2019, leaving a total of 671 mines still in operation (Berry, 2019).

FIGURE 6. U.S. coal-mining employment (1990–2019)



Source: U.S. BLS, 2018

Communities with power plants and mining operations often are unprepared with alternative plans for retraining workers, economic development, and revitalization (Jolley et al., 2019). These industries are typically located in remote areas of counties with few alternative job opportunities (Haggerty et al., 2018), and that exhibit higher income volatility and a higher proportion of adults without a college degree (Betz et al., 2015). Further, the cyclical boom-and-bust nature of the coal industry may suppress entrepreneurship and small business formation (Betz et al., 2015). Replacement job opportunities for former coal employees can come with sacrifices—they may have to take a pay cut, acquire new skills (Jolley et al., 2019), or commute long distances from their homes to find a job (Carley et al., 2018). These sacrifices also depend on the type of coal job replaced. Through a comparison of reported skills in coal employment and emerging job opportunities in Adams County, Ohio, researchers found that white-collar coal plant workers were more likely to have to acquire new skills compared to blue-collar workers if they were to transition into a new job. Through further comparison of reported wages in coal employment and emerging occupations, the researchers also found blue-collar workers were more likely to have to take a pay cut (Jolley et al., 2019).

Tax revenue losses

Coal-mining operations and power plants typically are located in areas without significant economic diversification. In such locations, coal-related economic activity often contributes a large portion of the local tax base and funds critical public services. Therefore, when coal industry closures occur, they will have greater economic consequences than individual job losses (Betz et al., 2015; Haggerty et al., 2018; Tierney, 2016).

Most articles and reports on tax revenue impacts focus on cases from Appalachia and the Western United States. Very few studies focus on the Midwest. Susan Tierney's 2016 study, for example, presented the case of Boone County, West Virginia, located in the Central Appalachia coal basin. Formerly, the county received a portion of the coal severance tax[5] from the state of West Virginia, which it used to fund municipal services such as trash pick-up, the health department, county jail, and public transportation (Tierney, 2016). Local property taxes from coal, which fund the county government and school system, brought in about 30 percent of the Boone County general fund. A 70 percent decline in coal production in Boone County in 2017, however, led to a decrease in local tax revenue, and subsequently prompted cuts in solid waste services and school closures (Morris et al., 2019). In another example, the two coal power plants in Adams County, Ohio, paid tangible personal property taxes—taxes on property that can be physically moved or relocated—to the county. When the two plants closed, Adams County lost $8.7 million in property tax revenue, representing a 10 percent decrease in total revenue (Jolley et al., 2019).

Social

In addition to economic losses, the sharp decline in coal-mining jobs has profound social and cultural implications. Through semi-structured interviews and focus groups, residents from coal-mining regions of West Virginia, Kentucky (Carley et al., 2018), and Utah (Olson-Hazboun, 2018) revealed how the decline in coal threatened their cultural identity and sense of community. In some Appalachian families, coal mining is ancestral. When families are no longer able to work in the profession, they experience some loss of identity. Some people also experience a decline in a sense of community, as day-to-day activities—such as children's sporting events, parades, and potlucks that are sponsored by the coal industry—disappear as the industry shrinks. Changing job opportunities may also force families to renegotiate social structures when new job opportunities necessitate greater time away from the home and family, or additional family members must take up new employment to help support the family.

Impacts associated with the increase of renewable energy

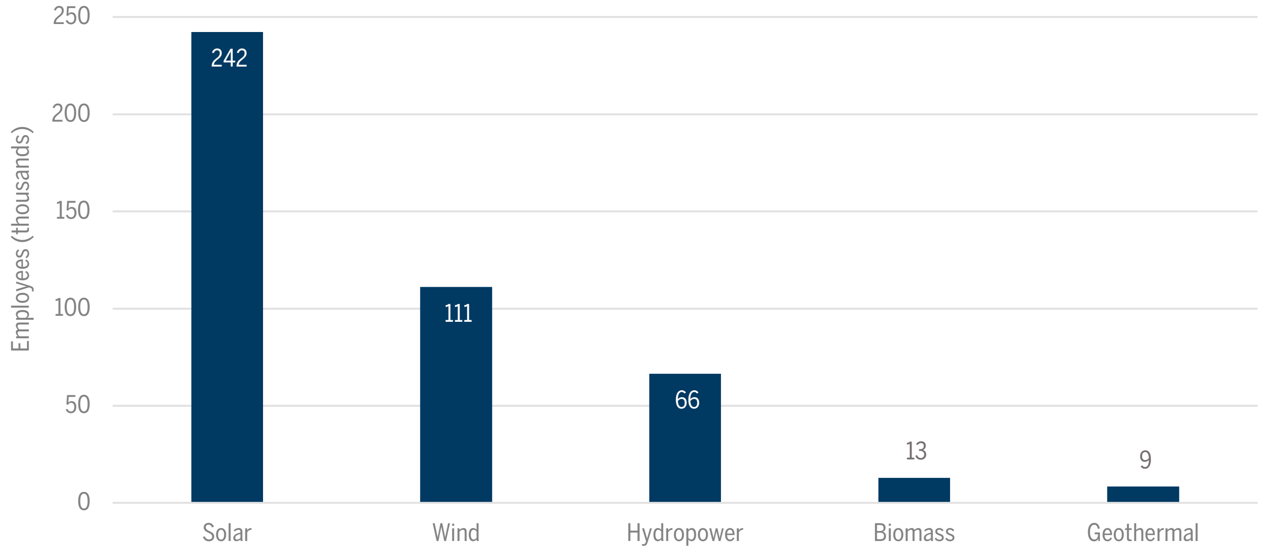
While coal-dependent communities may be affected adversely from the energy transition, there are also opportunities—beyond direct environmental improvements—for communities to benefit. This section discusses the employment and tax benefits of renewable projects as well as how effects vary across and within communities.

Employment

In 2018, there were an estimated 441,459 U.S. jobs in solar, wind, hydropower, biomass, and geothermal electric power generation (NASEO, 2019). The distribution of these jobs is shown in Figure 7. Solar (55 percent) and wind (25 percent) represented the largest share of these jobs. The U.S. Bureau of Labor Statistics also forecasts that solar photovoltaic installers and wind turbine service technicians will be the two fastest growing occupations in the next decade, with a projected 63 percent and 57 percent increase in employment, respectively (U.S. BLS, 2019a).

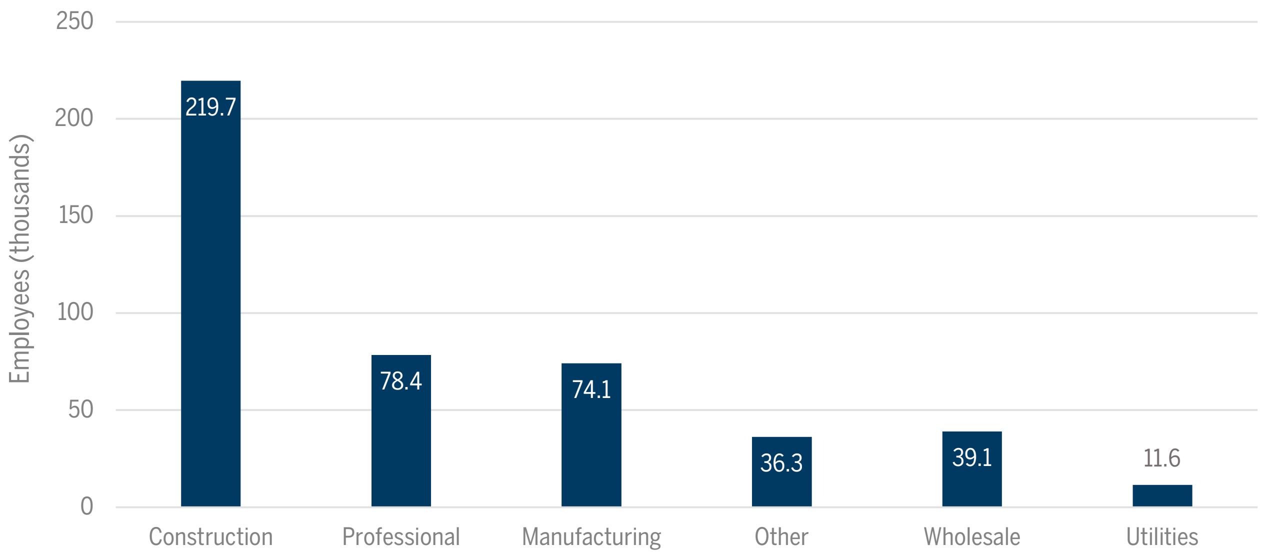
5 A severance tax is a tax on the extraction of a natural resource such as coal or oil. Severance taxes are often collected by states for resources extracted within their state.

FIGURE 7. Employment in renewable power generation (2018)



Source: NASEO, 2019.

FIGURE 8. Renewable energy employment by industry sector (2018)



Source: NASEO, 2019.

Figure 8 shows the full distribution of 2018 renewable energy jobs across sectors. The construction industry (NASEO, 2019) makes up the largest portion of renewable energy jobs, at 45 percent. Construction offers short- to medium-term employment compared to professional (17 percent) and wholesale trade (9 percent), both of which offer more permanent employment.

Many studies quantify the employment impacts of renewable energy projects using employment factors (Cameron & van der Zwaan, 2015; Wei et al., 2010).[6] In 2015, Cameron and van der Zwaan conducted a literature review of reported employment factors for renewable energy projects. For onshore wind, the researchers found the median employment factors for manufacturing, construction and installation, and operations and maintenance to be 4 person-years/MW, 2 person-years/MW, and 0.3 jobs/MW, respectively. For solar, the median employment factors for the same three categories of jobs were 18.8 person-years/MW, 11.2 person-years/MW, and 0.3 jobs/MW, respectively (Cameron & van der Zwaan, 2015). These estimates are summarized in Table 4. Differing methodologies, locations of study, and project sizes account for the large standard deviations in employment factors.

Many entry-level construction and installation jobs, such as solar photovoltaic installer, do not require any postsecondary certificate or degree (U.S. BLS, 2019b). However, renewable energy operation and maintenance jobs, such as wind turbine technician, tend to require a postsecondary certificate or degree (U.S. BLS, 2019c). To prepare local residents for these positions, community colleges across the country have started offering certificate and degree programs in operations and maintenance for renewable energy (U.S. DOE Wind Energy Technologies Office, n.d.; U.S. DOE Office of Energy Efficiency & Renewable Energy, n.d.).

TABLE 4. Median direct employment factors for wind and solar PV projects

EMPLOYMENT FACTOR STATISTICS	MANUFACTURING (PERSON-YEARS/MW)	CONSTRUCTION AND INSTALLATION (PERSON-YEARS/MW)	OPERATIONS AND MAINTENANCE (JOBS/MW)
Wind			
Median	4	2	0.3
Standard deviation	3.3	2.4	0.2
Solar PV			
Median	18.8	11.2	0.3
Standard deviation	9.3	9.7	0.4

Note: Cameron & van der Zwaan (2015) derived employment factor statistics from renewable energy employment factors published in public sector studies, private sector studies, and journal articles.
Source: Adapted from Cameron, L. & van der Zwaan, B. (2015, 160-172).

6 One conventional method of reporting employment factors for renewable energy is in jobs per megawatt for operations and maintenance jobs and in person-years per megawatt for manufacturing and construction and installation jobs. Operations and maintenance jobs refer to jobs that are needed over the operational lifetime of the renewable energy project (often 20–25 years). A person-year—synonymous with a job-year or full-time equivalent—refers to full-time employment for one person over the course of one year. The difference in units is necessary since the construction and installation of renewable energy projects may support many jobs but only for a short period of time (e.g., a year or less).

Tax revenue

Renewable energy projects typically raise property values and also can change the property use classification for a parcel from agricultural to commercial use, which in turn can increase property tax revenue for local communities. In the North Carolina Sustainable Energy Association (NCSEA) evaluation of North Carolina utility-scale solar projects installed in 2017, they found the state and counties received almost $10.6 million in property taxes the year after solar installation, compared to only $513,000 on the same parcels of land the year prior to the installations. That is a nearly 2,000 percent increase (Carson et al., 2019). While this gain is significant for the state of North Carolina, tax systems with maximum property tax levy controls, such as Indiana, will only experience increased revenue from renewables if county revenues are below the maximum levy (Accelerating Indiana Municipalities, 2019).

It can be difficult to analyze local tax revenue since there is no national database of local government finances or revenue from renewable energy projects (Haggerty et al., 2014). The majority of studies on the topic focus on individual counties and projects. For example, a 2014 study found that the extent of property tax revenue in the western U.S. could vary considerably, with revenue ranging between $32,000 and $850,000 one year after the installation of a hypothetical renewable energy project. Revenue estimates in this study were dependent on the size of the project, tax rates, tax abatement policies, and other local or state policies (Haggerty et al., 2014). A 2013 study estimated property tax rates for solar developments across several states (Barnes et al., 2013). The property tax rates ranged from as low as $2,500/MW per year in states with solar specific tax-exemptions to more than $100,000/MW per year in other states. The researchers noted that the price of electricity and cost to build the projects affected the potential tax revenue. Local revenue benefits are most pronounced in communities with a small tax base and high tax rates since such communities can raise a consistent and relatively significant revenue stream (Haggerty et al., 2014). Another study estimated that the 600-MW Rush Creek Wind Farm in Colorado will produce around $62.5 million in 2016 dollars in property tax revenue across four counties during its lifetime from 2018–2043 (Stefek et al., 2019).

Landowner payments

Studies on landowner payments from renewable energy developers primarily focus on wind, possibly due to the fact that utility-scale wind projects have a longer history than solar. In the case of wind farms, which are predominantly located on ranges or farms (Xiarchos & Sandborn, 2017), landowner payment arrangements typically include an annual lease per turbine as well as royalty payments based on total electricity production. These payments can offer significant financial compensation to the landowner, as well as long-term boosts to the local economy. For example, researchers estimated the Rush Creek Wind Farm will provide more than $1.8 million dollars in payments annually, and result in a total of $45 million (in 2016 dollars) in transfers to local landowners in four counties in Colorado (Stefek et al., 2019). Landowner payments also are more stable than farming income, which is susceptible to drought or other weather conditions.

One survey analysis linked wind landowner payments to an increase in farmer retention and a decrease in rural migration to urban areas. The increase in income from wind turbine payments made farmers less likely to sell their properties, and thus lose their farmland to the urban fringe (Mills, 2015). In some contexts, this decline in migration from rural to urban areas also could reverse structural economic declines in rural communities by restoring local populations to sustainable levels and creating diverse income sources (Berka & Creamer, 2018).

The literature has documented that, in some cases, landowners reinvest payments from developers into their properties (Mills, 2017). Yet, this finding does not hold across all studies. A statistical analysis of the overall impacts of energy payments in the U.S., for example, found that those receiving energy payments, on average, were no more likely to invest them back into their farms than those who did not receive the payments (Grout, 2018). The author of this study noted, however, that farms that receive such energy payments are more likely to be profitable in the long run.

There also are distributional issues associated with renewable energy payments. Some studies find that the majority of such payments go to individuals who already own large amounts of land (Brannstrom et al., 2015). These payments, therefore, may reinforce pre-existing landowner advantages, where wealthier landowners benefit the most from payments and non-landowners or less wealthy landowners receive fewer or no benefits.

Variation in local impacts from renewable energy projects

Renewable energy projects typically have a short-term construction period of one to two years and an operating and maintenance period of around 20–30 years. In the short-term, renewable energy projects exhibit some of the same dynamics as other major infrastructure projects. That is, the majority of the economic activity occurs within the construction period (Stefek et al., 2019). Such a short-term and relatively rapid influx of people into rural areas can create strains on housing markets and infrastructure. During the Rush Creek Wind Farm construction period, for instance, there were anecdotal reports of rent increasing more than 300 percent in some areas and local residents who could not afford to pay being displaced (Stefek et al., 2019). In the long-term, wind energy projects can provide a long-lasting and predictable stream of income and employment for some individuals within the community. The pattern of development is relatively predictable, compared to fossil fuel extractive industries, and reports are optimistic that lessons from the industry can help inform local communities on how to best prepare and benefit from the economic activity generated by renewable energy projects (Stefek et al., 2019).

The impacts of renewable energy projects on local economies is highly dependent upon the amount of local economic inputs and the degree of local ownership, as well as the specific location of the project. For example, a project built with out-of-town labor, imported inputs, and sited on public land—where there are no payments to local landowners or local payments of taxes—will have minimal local economic impacts. As many renewable energy projects take large amounts of capital and technical expertise, they are often financed by multinational conglomerates and developed by large energy firms (Berka & Creamer, 2018). Such conditions make local ownership challenging since local areas often do not have the capital or expertise needed to implement these large-scale projects. It follows that local and municipal ownership is rare. However, such cases exist and the literature finds that in those cases, municipal ownership greatly increase the local value of the project (del Río & Burguillo, 2009).

Employment transitions from fossil fuels to renewables

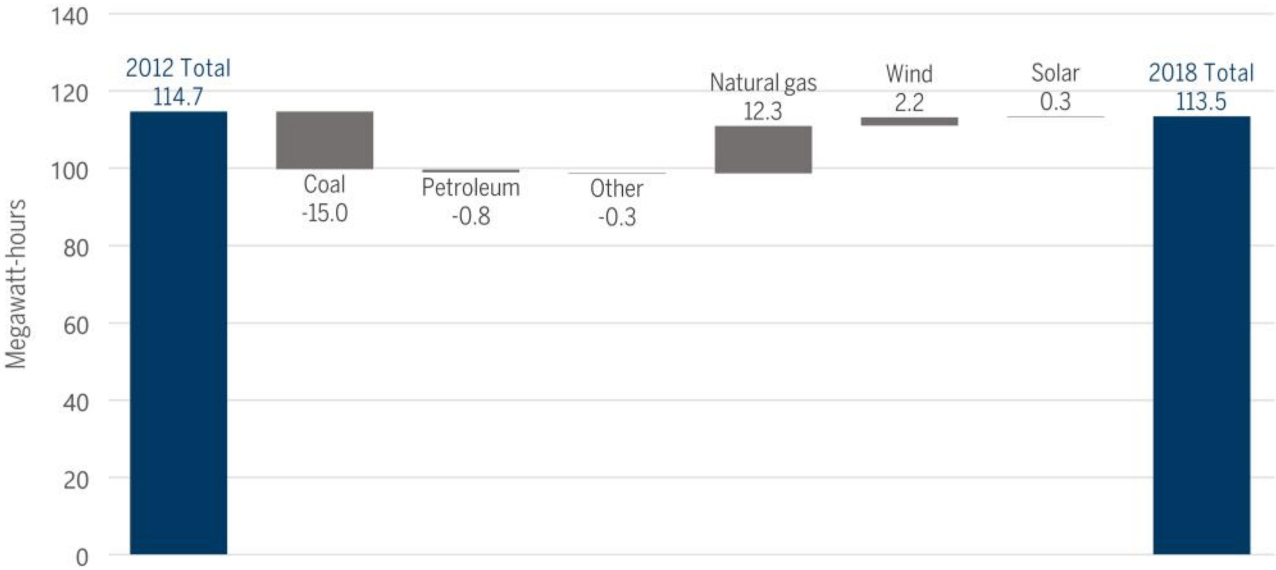
One may question whether lost coal or other fossil fuel jobs can be replaced with clean energy jobs. One study addressed this question with an analysis of employment trends between 2008 and 2012. It found that in most parts of the country—the Northeast, Carolinas, Midwest, and West—employment losses in the fossil fuel industry were more than offset by growth in solar, wind, and natural gas industries. However, counties that lost coal-mining and coal-fired power plant jobs were not typically the same as the counties that gained renewable energy jobs. Appalachia and parts of Wyoming and Colorado experienced greater job losses from coal than employment gains from clean energy (Haerer & Pratson, 2015).

More recently, in a 2020 peer-reviewed article, researchers evaluated whether coal-mining communities were suitable for wind and solar, as well as how many megawatts of wind or solar would need to be deployed to replace local coal-mining jobs. The study found 71 percent of U.S. coal-mining communities had either the solar irradiance or wind speeds necessary for utility-scale solar or wind. The study also estimated that each U.S. coal-mining community with suitable solar potential would need to install, on average, 320 MW of solar to replace all estimated lost coal-mining jobs. Each U.S. coal-mining community with suitable wind potential would need to install, on average, 180 MW of wind to replace all estimated coal-mining jobs (Pai et al., 2020).

INDIANA'S ENERGY TRANSITION—A LITERATURE REVIEW

Indiana's electricity sector is a part of the nationally occurring energy transition. In Indiana, coal's share of total electric generation declined from 94 percent in 2008 to 68 percent in 2018. During the same time, natural gas and renewables increased from 3 percent and 1 percent to 24 percent and 6 percent, respectively (U.S. EIA, 2019d). These trends are displayed in Figure 9. The publicly available Integrated Resource Plans (IRPs) of Indiana's electric utilities and more recent announcements from some utilities indicate the shift away from coal will continue. By 2023, Indiana's electric utilities plan to retire 3,300 MW of coal-fired power in Indiana, with an additional 1,700 MW committed to retirement between 2023 and 2028. All coal-fired units at the NIPSCO Schahfer Generating Station, the IPL Petersburg Units 1 and 2, and the Hoosier Energy Merom Generating Station are planned to retire by 2023 (Northern Indiana Public Service Company [NIPSCO], 2018; Indianapolis Power and Light [IPL], 2019; Morehouse, 2020). I&M's Rockport Unit 1 and NIPSCO's Michigan City plant will retire by 2028 (NIPSCO, 2018; Kuykendall et al., 2019).

FIGURE 9. **Renewable energy employment by industry sector (2018)**



Note: EIA data does not include generation resources owned by Indiana utilities and used to serve Indiana customers but located out of state. For example, Cook Nuclear Plant in Michigan has approximately 66 percent of its output going to I&M retail customers located in Indiana. Also, the Indiana Municipal Power Agency (IMPA) owns portion of two coal units located in Kentucky and portions of two units in Illinois.
Source: U.S.EIA, 2019d.

As this energy transition continues in Indiana, some communities may experience gains in economic opportunities and increases in government revenue, while others may face economic declines. In its 2018 IRP, NIPSCO projected it will terminate 276 full-time jobs and pay $74 million less in property taxes by following through with its 2018 IRP compared to its 2016 IRP. NIPSCO estimated its plan for replacement capacity will provide fewer than 30 permanent NIPSCO jobs (NIPSCO, 2018). However, there could be private jobs outside of NIPSCO spurred by NIPSCO's investments in renewables, storage, and demand-side management. Currently, 220 individuals work full time at the Rockport power plant,[7] and it is uncertain how many individuals will remain employed after the retirement of Rockport 1 in 2028 (Lyman, 2019). The Hoosier Energy Merom Generating Station currently employs 185 people (Kuykendall et al., 2019). The closure of these coal-fired power plants likely will result in job losses, property tax revenue declines, and reduced economic activity to varying degrees in LaPorte, Jasper, Sullivan, Pike, Spencer, and surrounding counties.

Natural gas combined-cycle, solar, and wind will largely replace retiring coal capacity and generation in Indiana. In their latest IRP, I&M estimated adding 1,700 MW of solar, 1,800 MW of wind, 2,695 MW of natural gas, and 50 MW of battery storage by 2037 (Indiana Michigan Power [I&M], 2019). In IPL's latest IRP, they estimated renewables, storage and demand-side management will meet 87 percent of their new capacity needs in 2037, with natural gas meeting the remaining 13 percent (IPL, 2019). NIPSCO plans to meet 97 percent of its 2037 capacity deficit with renewables, storage, and demand side management, with MISO market purchases meeting the remaining 3 percent (NIPSCO, 2018).

NIPSCO has received approval from the IURC for a number of wind farm projects with a total capacity of 1,104 MW (IURC, 2019a, 2019b, 2019c, 2020). The developers of these projects plan to locate them in White, Warren, Benton, and Montgomery counties. EDP Renewables, the developer of a collective 1,000 MW of wind in Indiana, claims that these projects have supported 674 short-term construction jobs (EDP Renewables North America LLC [EDPR], 2019a). This equates to 6.74 construction jobs per 100 MW of capacity. Using this employment factor, NIPSCO's planned wind projects could result in 741 construction jobs. In addition, developers have proposed roughly 520 MW of power from three solar farms in Randolph, Shelby, and Madison counties (EDPR, 2019b; Speedway Solar, n.d.; Invenergy, n.d.). The project developers estimate more than 100 short term construction jobs and several permanent jobs will result from each project, as well as millions in landowner payments and property taxes (EDPR, 2019b; Speedway Solar, n.d.; Invenergy, n.d.; Associated Press [AP], 2019). These proposed renewable projects are in Central and Northwest Indiana, whereas coal-power plant closures will occur in Northwest and Southwest Indiana. Although the proposed solar projects are not in coal-mining counties, a recent study estimated 100 percent of coal-mining communities in Indiana are suitable for solar power due to the communities' solar irradiance. However, in Indiana, no coal-mining community was suitable for wind (Pai et al., 2020).

7 The data reported in the next section of the report reflects employment data provided by I&M for 2014–2018. The research team began data collection in late 2019 and requested data for the five full years that were available at that time. The employment reported in the cited article were for mid-2019.

STATE & LOCAL IMPACTS OF SELECTED NEAR-TERM RETIREMENTS OF COAL-FIRED GENERATION IN INDIANA

As described in the previous section, the closure or partial closure of coal-fired power plants may have a variety of impacts, affecting individuals, businesses, communities/local governments, and regions. Plant closures or partial closures may result in job losses that affect workers and their households. Utilities may be able to absorb some employees in the remaining local operations or within the companies more broadly. Older workers may be able to take retirement. The remaining workers potentially face full or partial income loss in the event that they take another job in the local community or region. Workers may need to complete skills training/retraining to access new jobs. Employees and their households may face relocation or more extensive commutes.

Plant closure or partial closure will result in lost sales to firms that provide goods and services directly to these plants. Local businesses that provide goods and services to workers may also lose sales. When in sufficient concentrations, these losses could affect the viability of these businesses and their ability to maintain current workers.

Local communities in and around these plant closures may be affected in a number of ways. In communities in which the plants are located, local governments face significant reductions in industrial assessed value and the shifting of property tax burdens to the remaining property owners. They could also lose property tax revenues if lost assessed value increases property tax rates to levels exceeding statutory tax rate caps. Lost revenues also may result in service reductions for the affected counties, townships, municipalities, school districts, and other local governments. The viability of the communities in which affected employees live—particularly rural communities—may experience population loss when the employees have to move to other areas or regions for work. Further, labor markets in Indiana are tight. For local communities and their regions, a diminished local workforce may affect the ability to attract new industries that provide jobs for new and existing workers and support local income and property tax revenues.

This section evaluates the nature and intensity of potential impacts of a full or partial closure of four coal-fired generating stations—Schahfer, Michigan City, Petersburg, and Rockport—on individuals, communities/local governments, and regions. State and local leaders can use this information to plan for closure by crafting economic development, workforce development, and other responses.

The research team completed four analyses for each plant. First, was an assessment of plant data on employment, wages and compensation, and purchased goods and services. Second, was an input-output analysis of direct and spin-off economic activity. Third, was a cursory analysis of tax impacts. Fourth, the team conducted stakeholder interviews in the regions affected by the closing of the Petersburg and Schahfer plants. The research team also conducted additional input-output analyses for three additional scenarios: statewide impact of the closure of the four plants, the impact on the county where each plant is located, and a force account scenario that adjusts the estimates to account for the construction-type workers that the utility would continue to employ following a plant closure.

Schahfer Generating Station

The R.M. Schahfer Generating Station is owned and operated by NIPSCO. It is located in a rural setting in Jasper County near Wheatfield and the Kankakee River. The annual average generation, from 2014 through 2018, was 5.8 million MWh. Generation in 2018 was 6.8 million MWh (NIPSCO, 2020).

NIPSCO plans to close the four coal-fired units by the end of 2023. The facility also has two natural gas units that will remain open. With the exception of local property tax data, all data reported here covers only the activity associated with the coal-fired units.

Employment

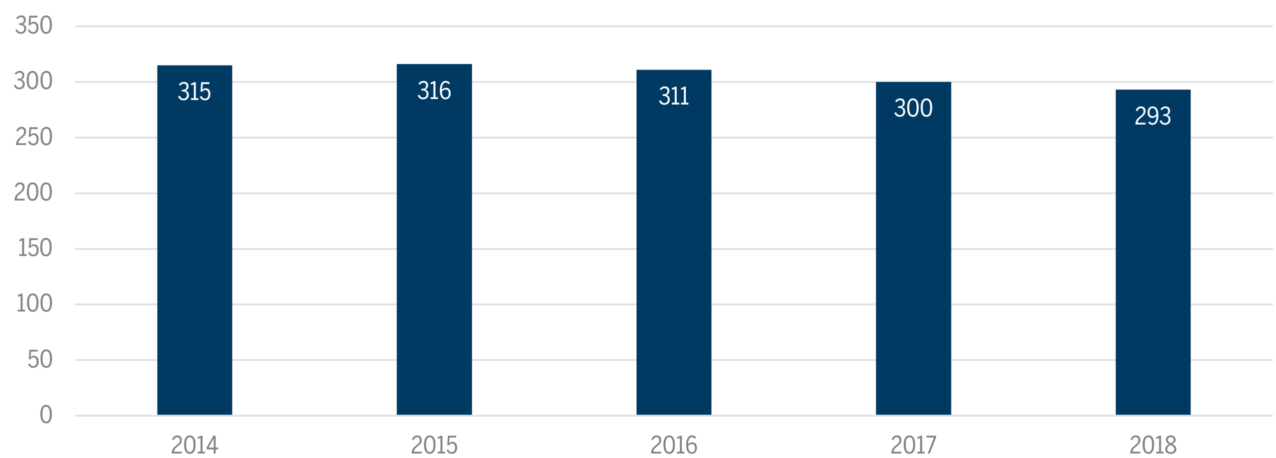
The coal-fired units planned for closure employed 293 workers in 2018. A closure would put those jobs in jeopardy. Employment at the plant already dropped 7 percent from 2014 through 2018 (Figure 10). The facility accounted 2.9 percent of private sector jobs in Jasper County (Indiana Business Research Center [IBRC], 2020).

Employees who work at the Schahfer Generating Station live throughout Northwest Indiana. In 2018, employees commuted from Lake, Porter, LaPorte, Newton, Jasper, Starke, Marshall, Elkhart, and White counties (Figure 11). More than a third of employees lived in Porter County while only one-sixth lived in Jasper County where the plan is located. Five other counties had five or more employees working at the plant.

As mentioned above, the Northwest Indiana region has a tight labor market with low unemployment. Stakeholders who serve the region believe that skilled and semi-skilled employees can be absorbed readily but that administrative jobs may be harder to absorb.

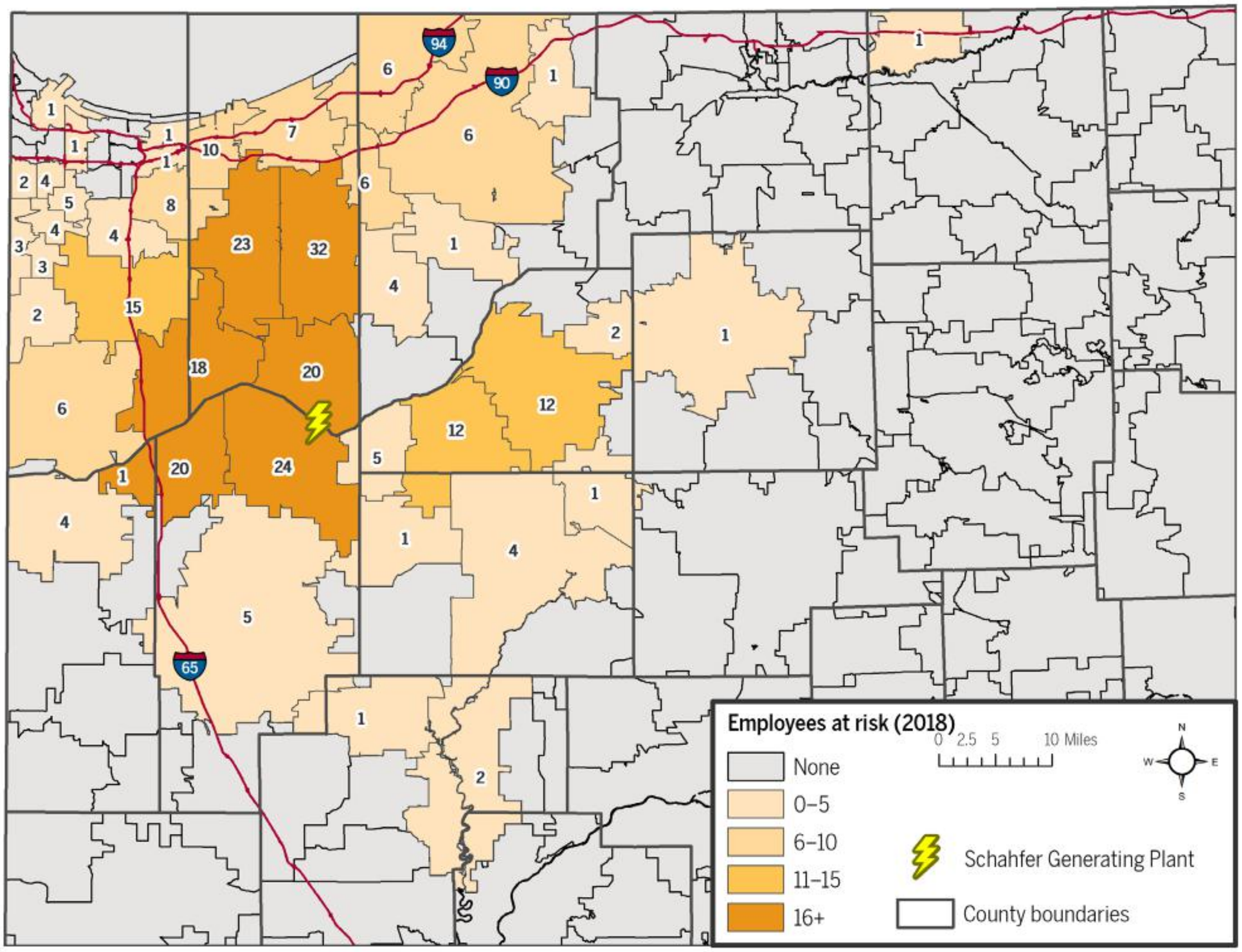
Jasper County has a relatively small industrial base, a tight labor market, and low unemployment. Employees who live there could potentially access jobs within the county, within neighboring urban communities to the north and west, and in surrounding rural communities. Stakeholders suggested that county residents often commute to jobs outside Jasper County.

FIGURE 10. Schahfer Generating Station potential employment losses (2014–2018)



Source: NASEO, 2019.

FIGURE 11. Schahfer Generating Station potential employment losses in Indiana from closure by zip code of employee residence (2018)



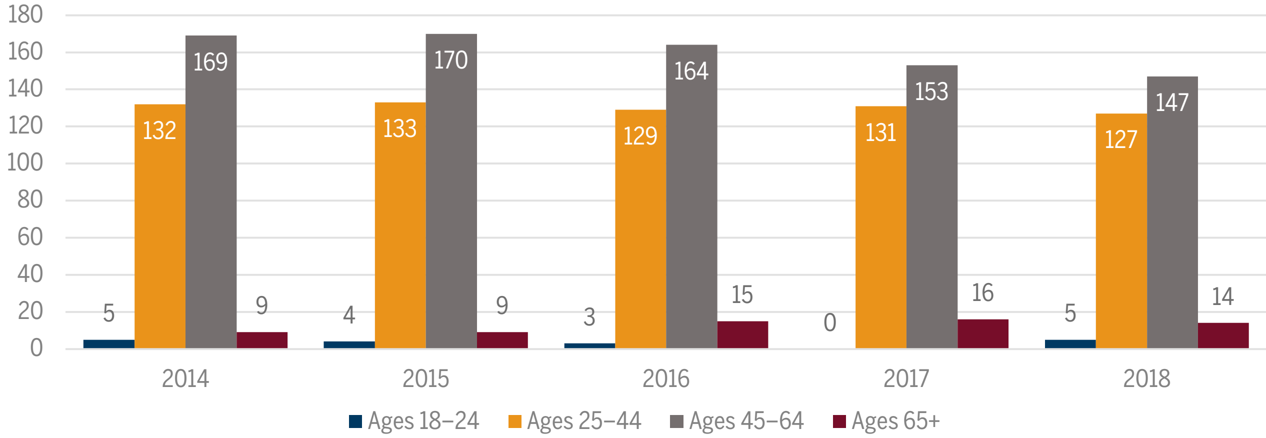
Source: NIPSCO, 2020; IndianaMAP Data Portal.

Employee demographics

In 2018, the vast majority of employees for the coal-fired units were white (90.1 percent) and male (89.1 percent). More than half of employees were ages 45–64. More than two-fifths of employees, however, were ages 25–44. The company reported having a few employees ages 18–24 in all years except 2017 (Figure 12).

Age may influence employee responses to job loss. Older employees may have the option to retire when the plant closes. In some cases, other employees may be able to relocate within the company. People ages 45–64 may be more likely to remain in their current communities and commute to other jobs, while younger employees may be more likely to relocate.

FIGURE 12. Schahfer Generating Station employees for coal-fired units by age (2014–2018)



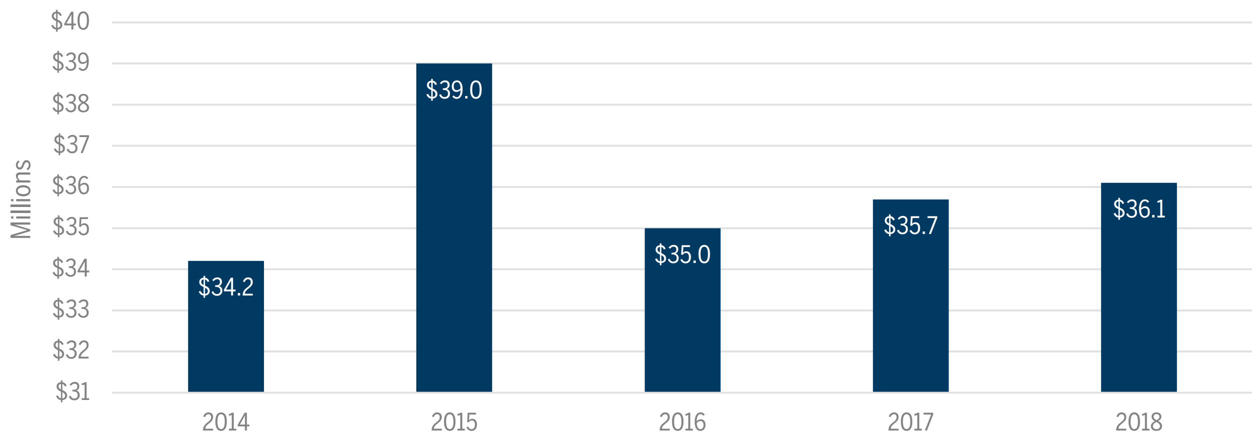
Source: NIPSCO, 2020.

Wages and compensation

Plant employees earned $25.3 million in wages and $36.1 million in compensation (wages and benefits) in 2018 (Figure 13). Employees at the Schahfer plant earn higher wages and benefits relative to the average wages and compensation in Jasper and Porter counties. Average wages and the estimated average compensation per employee were $86,273 and $123,072 at the plant. By comparison, the averages for private sector wages in Jasper and Porter counties were $42,401 and $46,392. The total estimated average employee compensations were $55,079 and $60,263 in these counties (IBRC, 2018; U.S. BLS, March 19, 2020).[8] Figure 14 shows the distribution of compensation by zip code of employee residence.

The premium wages and benefits paid by NIPSCO may be difficult to match for transitioning employees. Stakeholders suggested that some opportunities to match these higher wages may exist in the regional steel industry and by relocating to the Chicago area and within the Northwest Indiana region.

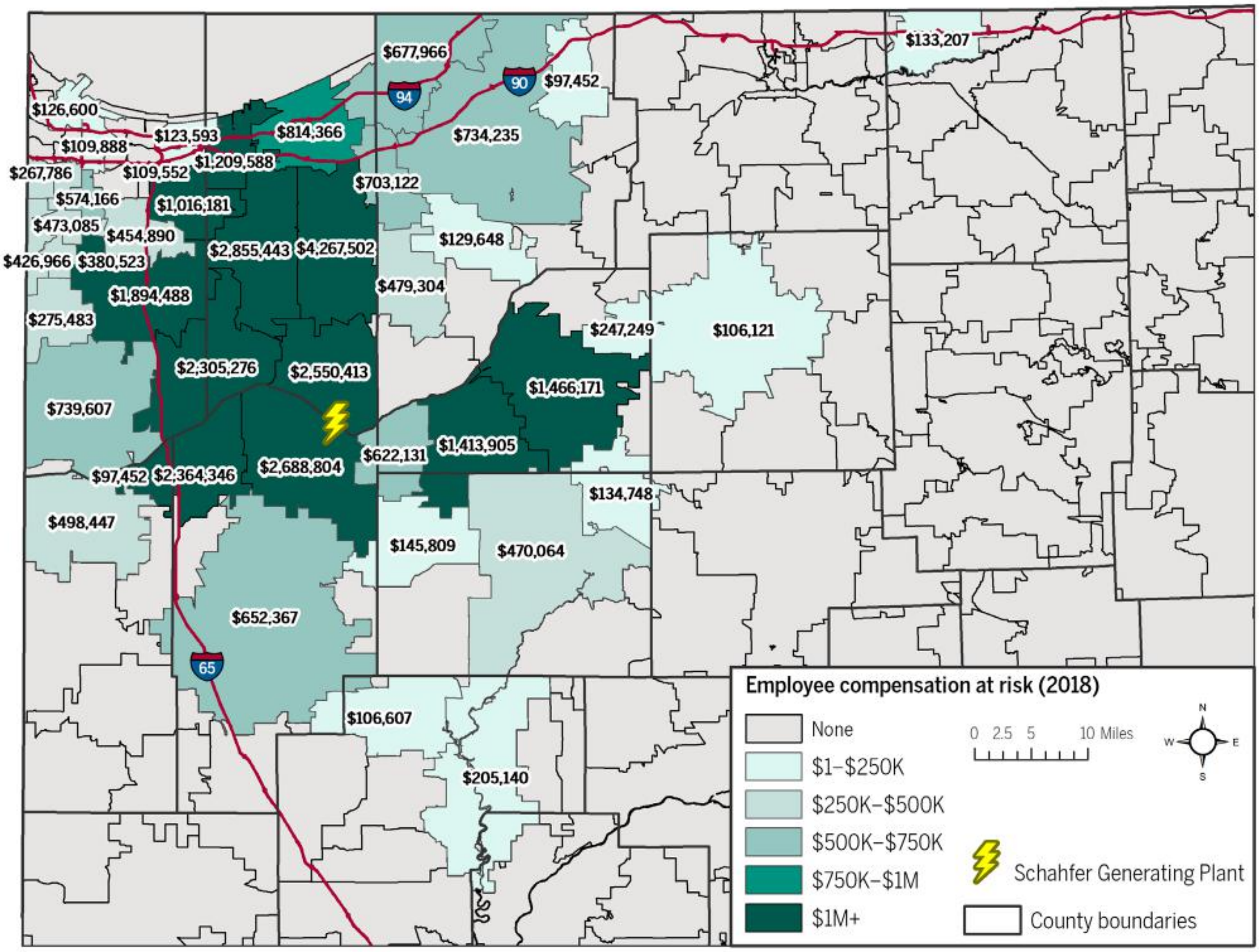
FIGURE 13. Schahfer Generating Station potential employee compensation (2014–2018)



Source: NIPSCO, 2020.

8 Estimated compensation was calculated using county average wage data from IBRC (2020) and U.S. Bureau of Labor Statistics survey data regarding compensation (March 19, 2020).

FIGURE 14. Schahfer Generating Station potential employee compensation losses in Indiana from closure by zip code of employee residence (2018)



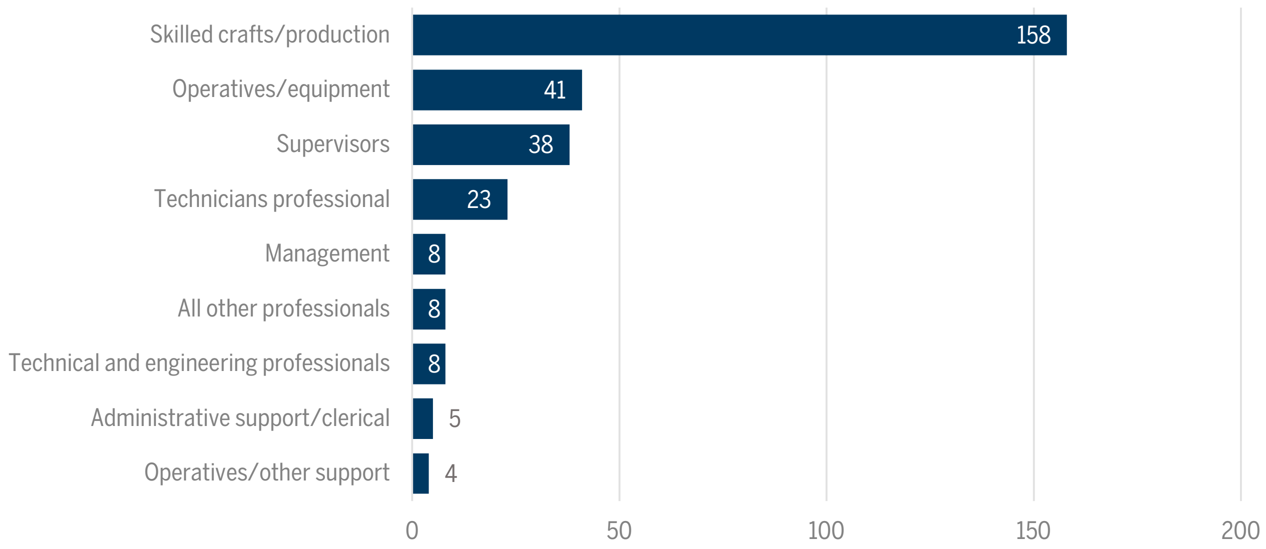
Source: NIPSCO, 2020; IndianaMAP Data Portal.

Occupations

Occupations at the plant are 82.6 percent technical/mechanical and 17.4 percent and management/administrative. More than half of the employees at the plant were classified as skilled (skilled crafts/production). About 15 percent were classified as semi-skilled (operatives/equipment and operatives/other support), and about 13 percent of employees were classified as professional technicians, technical and engineering professionals, and other professionals (Figure 15) (NIPSCO, 2020).

As the result of a robust industrial base and tight labor market with low unemployment in Northwest Indiana, stakeholders believe that skilled and semi-skilled employees can be absorbed readily either directly or with some training. They suggested that administrative jobs may be harder to absorb in the region and that opportunities may be better in the South Bend and Lafayette areas.

FIGURE 15. Schahfer Generating Station worker occupations (2018)



Source: NIPSCO, 2020.

Goods and services purchases

NIPSCO reported $69.2 million and $15.3 million in average annual goods and services purchases, excluding coal, total and in Indiana, respectively (Figure 16). Figure 17 shows the five largest expenditures by type. NIPSCO purchased $146.1 million in out-of-state coal on average annually during this same period.

FIGURE 16. Schahfer Generating Station potential goods and services losses, excluding coal (2015–2018)

Source: NIPSCO, 2020.

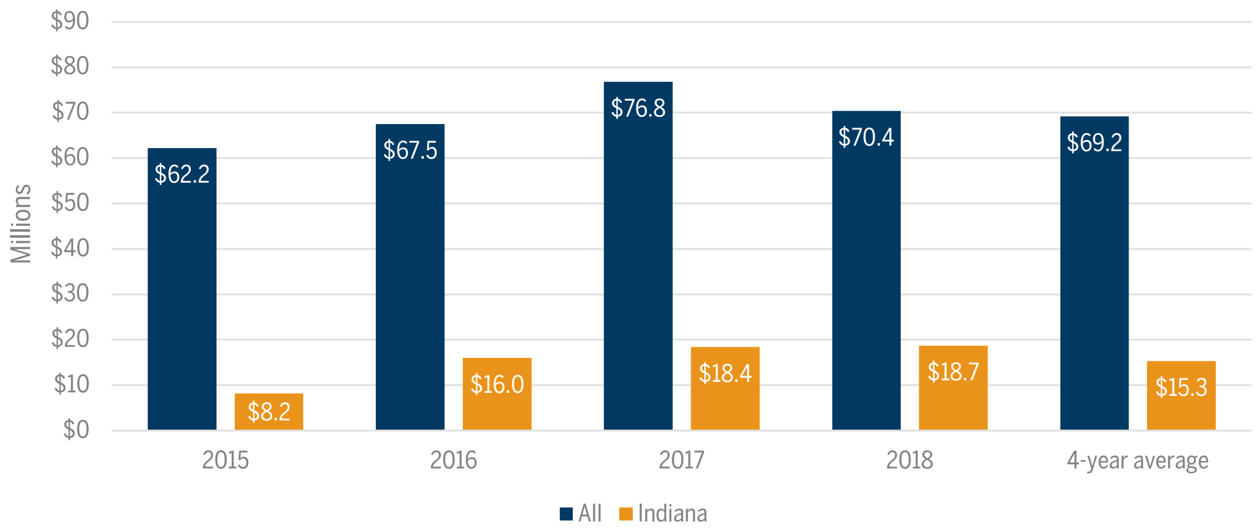
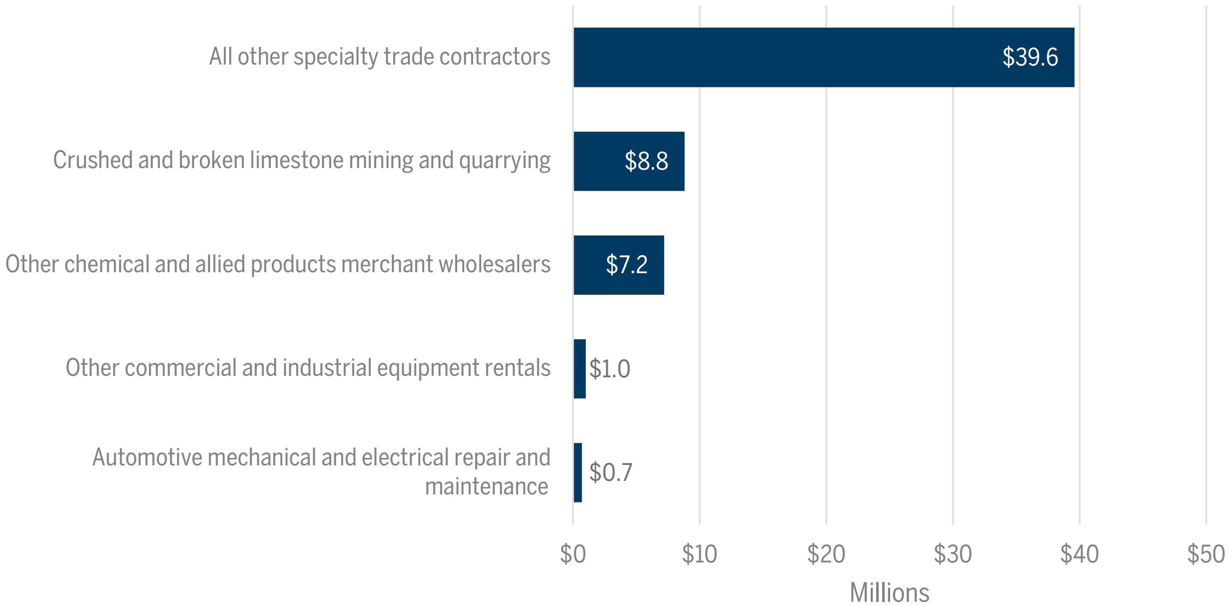


FIGURE 17. Schahfer Generating Station annual average goods and services purchases—Five largest categories, excluding coal (2015–2018)

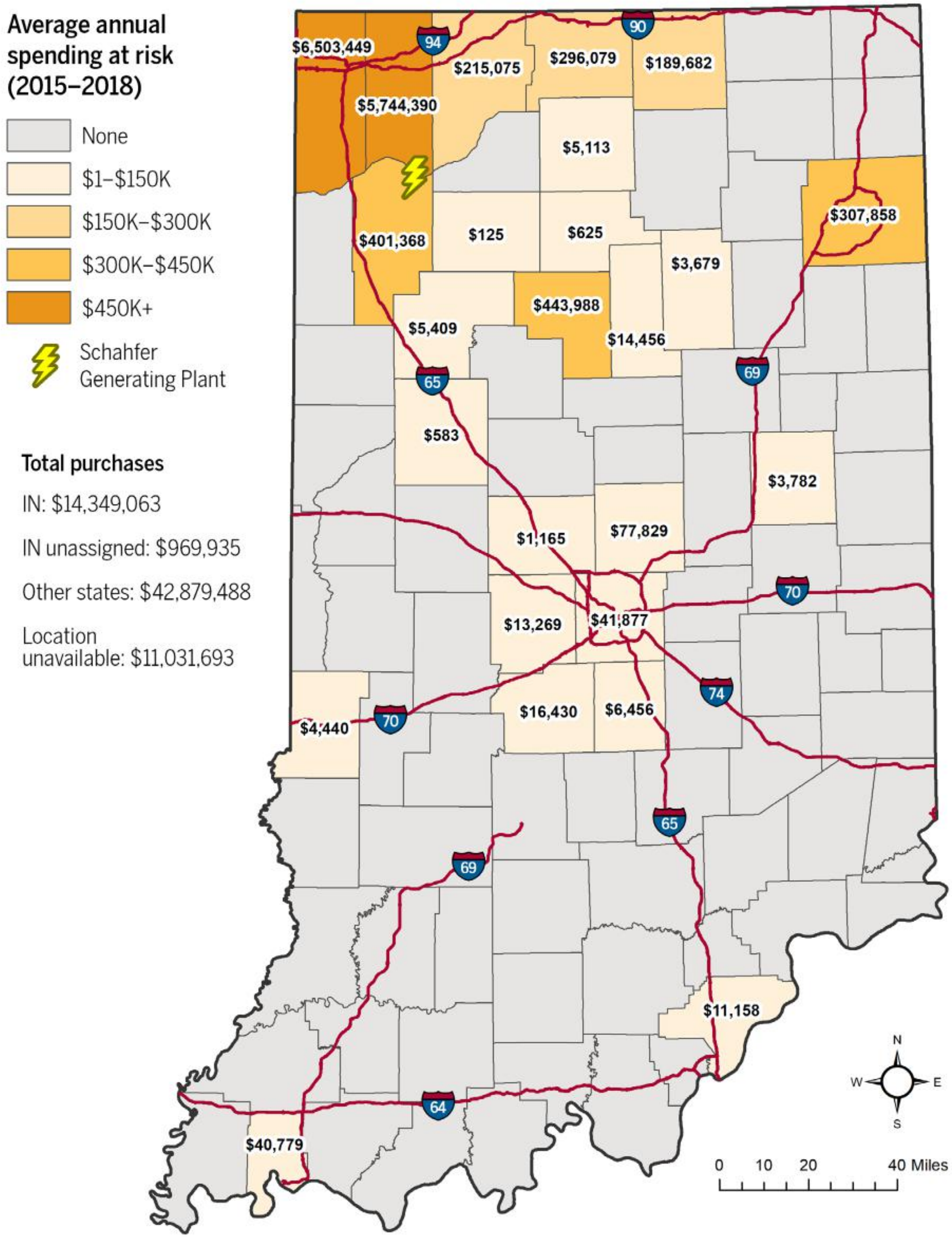


Source: NIPSCO, 2020.

Figure 18 shows the distribution by county of plant expenditures purchased from Indiana firms. NIPSCO reported purchasing goods and services from firms in 25 Indiana counties. Jasper County firms could lose more than $400,000 on average annually. Firms in Lake and Porter counties are most at risk from the loss of purchased goods and services, with more than $5.5 million going to firms in each county on average annually. Firms in these counties also had substantial sales from the Schahfer plant. Sufficient information was not available to know how much overlap might exist.

Lost sales could affect firms and their employees negatively. Firms may face viability issues if sales to the plant represent a large portion of overall sales and they are not able to establish new customers. Laid-off workers likely would face some of the same issues that plant employees will when transitioning. Additional detail about the scale of these ripple effects are described in the regional economic analysis section below.

FIGURE 18. Schahfer Generating Station potential goods and services losses, excluding coal, in Indiana from closure by county (2015–2018)



Notes:

1. *County totals were aggregated from zip code data.*
2. *The Schahfer plant purchases only out-of-state coal. These purchases are not reflected in the total shown for purchases from other states.*

Sources: NIPSCO, 2020; IndianaMAP Data Portal.

Local income and property taxes

Property taxes and local option income taxes are fundamental resources for local governments. The most fundamental component of local government property tax revenues and fiscal well-being is assessed value. The loss of a significant proportion of assessed value can have traumatic impacts on local taxing units.

Tables 5 and 6 show total assessed value for Jasper County, Kankakee Township, and Kankakee Valley School Corporation, and the assessed value of selected plant parcels, particularly those with improvements or substantial land assessed value, and the State Distributable (personal property) Assessed Value. The Schahfer Generating Station makes up a substantial portion of the property tax base for these three local governments.

TABLE 5. Total assessed value for selected local governments (assess 2019, pay 2020)

	CERTIFIED ASSESSED VALUE
Jasper County	$2,472,597,647
Kankakee Township	$471,689,407
Kankakee Valley School Corporation	$1,440,040,785

Source: DLGF, Feb. 19, 2020.

TABLE 6. Schahfer Generating Station assessed value as a share of assessed value for selected parcels and taxing units (assess 2019, pay 2020)

	TOTAL ASSESSED VALUE	SHARE OF JASPER COUNTY ASSESSED VALUE	SHARE OF KANKAKEE TOWNSHIP ASSESSED VALUE	SHARE OF KANKAKEE VALLEY SCHOOL CORPORATION ASSESSED VALUE
Parcel 006-00324-00	$38,620,400	1.6%	8.2%	2.7%
Real property improvements	$30,764,200	1.2%	6.5%	2.1%
Parcel 006-00326-00	$7,943,500	0.3%	1.7%	0.6%
Parcel 006-00327-02	$4,052,100	0.2%	0.9%	0.3%
Real property improvements	$3,205,100	0.1%	0.7%	0.2%
Personal property improvements	$352,777,190	14.3%	74.8%	24.5%
Total assessed value	$419,247,470	17.0%	88.9%	29.1%
Real and personal property improvements	$386,746,490	15.6%	82.0%	26.9%

Notes:

1. *The total and personal property assessed values reported here are from the Jasper County Assessor and may include assessed value for additional parcels.*
2. *The certified total assessed values in Table 5 for the county, township, and school districts were used to calculate the percentages in this table.*

Sources: DLGF, Feb. 20, 2020; Jasper County, 2020; Jasper County Assessor, 2020.

The loss of assessed value that will result from closure is unknown, but could be substantial for these units. The property tax assessment of utilities is complex. The exact effects also are dependent on the complex dynamics among levy controls, mix of property types and property tax caps, property tax replacement strategies, etc.

Property tax records show that substantial assessed value changes are already occurring. For example, the value of the real property improvements on parcel 006-00324-00 already has been reduced from $69,022,100 from assessments for the assess 2018, pay 2019 property tax cycle. The Jasper County Assessor and stakeholders indicated that NIPSCO has appealed their county assessments a number of times in the past.

These losses, however, will challenge local governments with, all else the same, increases in property tax rates and potential property tax increases for county, township, and school taxpayers. The county's relatively high local option income tax rate limits raising local option income tax rates as an option for mitigating the likely increases in property taxes as a result of the closure. Local leaders also may consider changes to public services to offset increases.

County leaders convened a task force to develop strategies to mitigate potential losses. In addition, county leaders have asked NIPSCO to develop alternative solar generation within the county in order to replace, in part, the anticipated losses.

Among the counties that have five or more plant employees in residence, Jasper, Porter, Lake, Starke, and LaPorte counties utilize local options income taxes (Table 7) (Indiana State Budget Agency [ISBA], 2019). The number and distribution of employees across these counties and the relative income tax rates, suggest a minimal direct effect on local revenues. Jasper County historically has used local option income taxes to offset property taxes.

TABLE 7. County local income tax rates for final CY 2020 certified distribution

LOIT RATES	JASPER COUNTY	PORTER COUNTY	LAKE COUNTY	STARKE COUNTY	LAPORTE COUNTY
Certified shares	1.364%	0.000%	0.000%	0.500%	0.500%
Public safety	0.250%	0.000%	0.250%	0.000%	0.000%
Economic development	0.250%	0.500%	0.250%	0.000%	0.450%
Property tax relief	0.850%	0.000%	1.000%	0.060%	0.000%
Special purpose	0.150%	0.000%	0.000%	0.650%	0.000%
Total	2.864%	0.500%	1.500%	1.710%	0.950%

Note: None of these counties has adopted a correctional facility local income tax rate.
Source: ISBA, Nov. 18, 2019.

Regional economic analysis[9]

From the perspective of direct effects alone, the potential Schahfer plant closure represents the largest loss of jobs and GDP. The expected direct employment effect of this closure would be approximately 290 jobs (NIPSCO, 2020). With a nearly equal number of ripple-effect jobs likely to be lost, the full employment impact would stand at roughly 570 lost jobs and $54.1 million in lost compensation for the region (Table 8). Meanwhile, the total lost GDP would reach nearly $200 million.

TABLE 8. Estimated regional effects of Schahfer Generating Station closure

	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Employment	293	280	573	1.96
Compensation	$36.1M	$18.0M	$54.1M	1.50
GDP	$170.4M	$28.8M	$199.2M	1.17
State and local tax revenue	$7.5M	$2.2M	$9.7M	N/A

Sources: NIPSCO, 2020; IBRC, using the IMPLAN economic modeling software.

A helpful way to interpret these potential losses is to look at the multiplier. The ratio of total effects for employment to the direct effects yields a multiplier of 1.96, meaning that every direct job lost at the power plant could lead to the loss of nearly one additional job in other industries in the region. Likewise, the compensation multiplier of 1.50 suggests that every dollar of direct pay generates another $0.50 in employee compensation for other workers in the region.

The Schahfer plant also produces state and local government revenues. The IMPLAN model estimates the tax collections from corporate profits, indirect business taxes (e.g., sales, property and excise taxes), personal taxes (e.g., income and property taxes), and employee and employer contributions to social insurance. The combined lost economic activity created by the plant closing would translate into an estimated loss $9.7 million in state and local government revenues.

With a large share of the supply chain spending for this plant going to out-of-state vendors, industries that benefit from household spending will experience the largest impacts. As with the other facilities, however, the big exception is the region's maintenance and repair construction industry, which could lose nearly 90 jobs from this closure (Table 9).

The force account scenario in Appendix B lays out whether some share of construction workers directly employed at the plant—as well as some of the labor and spending associated with specialty contractors—will continue to be employed in the region by NIPSCO. These workers and contractors could be redeployed to other activities such as building and maintaining transmission and distribution systems or other types of production infrastructure. Assuming that 30 percent of plant construction workers and 50 percent of labor

9 This analysis was conducted for the region that includes Jasper County in which the Schahfer plant is located, along with bordering counties of Benton, Lake, Newton, Porter, Pulaski, Starke, and White counties. A separate analysis for the effects on Jasper and Porter counties solely is available in Appendix B.

and purchases for specialty contractors remain engaged with the utility, the full employment effects of this closure would improve from a loss of 573 jobs to 539 jobs, while the full GDP losses would improve from an estimated $199.2 million in value added to $166.5 million.

TABLE 9. Schahfer Generating Station regional employment ripple effects—Top 10 industries

	JOBS
Maintenance and repair construction of nonresidential structures	87
Hospitals	19
Limited-service restaurants	14
Wholesale trade	14
Full-service restaurants	14
Real estate	13
General merchandise stores	9
Physician offices	9
Food and beverage stores	7
All other food and drinking places	7

Source: IBRC, using the IMPLAN economic modeling software.

Stakeholder input

Stakeholder perceptions about the impact expected from closure and local preparations for these changes are provided below.

Expected economic impacts

Stakeholders indicated that the economic effects of the Schahfer retirement would be mixed. In the short-term, they recognize that there will be negative impacts, principally potential job losses or wage reductions for employees as they find other employment opportunities. Stakeholders do not perceive that many workers are leaving their jobs in anticipation of closure. Most stakeholders indicated needing more information about the company's plans in order to understand the nature and scale of impacts for plant workers. There generally is uncertainty among stakeholders about whether NIPSCO will absorb employees within the company.[10] If transfers are offered, employees may have to move. Employees that choose to remain in their current homes may have to find new jobs or change professions. While the Northwest Indiana economy should absorb most skilled workers, matching current wages and benefits may be a challenge.

10 NIPSCO provided the following statement when asked to provide their plans for transitioning employees. "NIPSCO is working internally to determine workforce transition and training opportunities. We have a number of activities and milestones that we have to complete over the next months and years in order to finalize our workforce transition plans. The goal, as we develop our future plans, is to create the least amount of disruption for our employees" (T. McElmurry, email communication, May 4, 2020).

Those interviewed currently have limited knowledge of the type and scale of goods and services that local firms provide to the plant. More information is needed from NIPSCO to identify the nature and scale of those effects. Stakeholders specifically identified potential effects on the railroad companies that deliver coal. Jasper County officials expect that the plant retirement will have some effect on local businesses near the plant, particularly if Jasper County residents relocate.

Jasper County officials perceive residents as anchored to their communities. They do not expect many local employees to relocate. Commuting to jobs is already common. In the past, these communities have placed a focus on housing to attract residents.

Jasper County officials are thinking about the disposition of the retired elements at the NIPSCO facility. No specific plans have been shared by NIPSCO. Some officials expect that the site will be used, in part, as an electricity distribution facility. Reusing the site may be challenging because of environmental issues, particularly the coal ash landfill.

Regional stakeholders believe that there will be positive long-term impacts as communities work through these broader economic transitions. Jasper County is well-positioned geographically to benefit from opportunities in both the Northwest Indiana and Lafayette regions. Stakeholders believe Porter County's location, diversity, and the resilience of its economy will offset some of these effects.

They identified a number of mitigating factors that may lessen negative impacts for skilled workers: a modest number of employees affected, open jobs as a result of the tight labor market and low unemployment, demand for high-skilled and well-trained workers, and training made available by NIPSCO and a variety of providers in the region. The expansion of the steel industry in the northwest region may provide opportunities. Administrative jobs may be harder to absorb in the immediate area. Additional opportunities for these workers may be available in South Bend or Lafayette.

Expected local tax impacts

Jasper County has a small industrial property tax base and projects a substantial loss of assessed value that will likely affect property tax revenue to the county, the township, and Kankakee Valley School Corporation. Local stakeholders are concerned that the assessment of the plant is not fair. Jasper County already has suffered assessed value losses due to changes in the plant's assessed value including as a result of tax appeals. There is a mismatch between the company's definition of the value of a soon-to-be-retired operation and the community's perception of the value of a plant that is still operating. County officials indicated that the state-distributed value process is challenging. Per state law, the value of plant equipment is self-assessed by NIPSCO and approved the DLGF. The details are confidential. The county has negotiated with NIPSCO in past years about assessed value and property taxes generated by the plant.

Jasper County officials also expressed concern about the potential loss of a gypsum plant that manufactures wallboard using fly ash from NIPSCO generating facilities and is located in northern Jasper County. The company has assured officials they will continue to operate.

Previous and anticipated losses in light of an accelerated retirement timeline have contributed to two local governments postponing or canceling capital projects. Kankakee Valley School Corporation has postponed later phases of a planned building project. The uncertainty also caused the township adjacent to the most directly affected township to cancel building a new fire station. In spite of securing an Indiana Office of Community Affairs Community Development Block Grant, the township was not able to make the economics work without bonding and chose to cancel the project.

Local recognition of challenges and adequacy of planning to date

Stakeholders who work regularly with the county and communities in Jasper County generally are confident that local officials recognize the general potential impact of the plant closure and will understand it more specifically when information is available. As mentioned above, stakeholders recognize that more details are needed about company plans for employees, the affected goods and services firms, and assessed value reductions. Some suggested that it is not possible to be completely prepared and that communities must be able to adapt as needed.

NIPSCO reported five years in advance that the plant would close, giving communities time to respond. Some reported that NIPSCO has been active in communicating the changes through the community advisory panels (CAPs) in Lake, Porter, and LaPorte counties. Communication in Jasper County has been both directly with local elected officials and through the recent county task force. There is no Jasper County-specific CAP.

Resources and efforts to address impacts

Stakeholders identified many resources that are available to address the impacts identified above:

Workforce development and training

- The Center for Workforce Innovations serves Northwest Indiana.
- WorkOne Northwest Indiana provides services in Jasper, Lake, LaPorte, Newton, Porter, Pulaski, and Starke counties. Each county has at least one WorkOne office.
- NIPSCO has developed energy academies/centers that provide training in renewable energy occupations.
- Local high schools and career and technical education programs.
- Postsecondary institutions including Ivy Tech and Indiana University Northwest.

Economic development

- The Northwest Indiana Forum serves Lake, Porter, LaPorte, Newton, Jasper, Starke, and Pulaski counties.
- The Greater Valparaiso Chamber of Commerce serves much of Porter County. It is co-located with the Valparaiso Chamber of Commerce.
- The Valparaiso Economic Development Corporation serves Valparaiso. It is co-located with the Greater Valparaiso Chamber of Commerce.
- Jasper County Economic Development Organization (Jasper County EDO).
- Kankakee-Iroquois Regional Planning Commission (KIRPC) serves Jasper, Benton, White, Newton, Starke, and Pulaski counties.

- Northwest Indiana Regional Planning Commission serves Lake, Porter, and LaPorte counties
- Jasper County commissioners and council.

Social services

- United Ways
- Community foundations
- Food banks
- Child care
- KIRPC provides public transit (Jasper, Newton, Pulaski, and Starke counties)
- KIRPC provides Head Start (Jasper, Newton, and Pulaski counties)

Efforts to mitigate impacts

Stakeholders identified a number of efforts local communities and other stakeholders have or plan to undertake related, in part, to the expected effects of the Schahfer retirement.

- Jasper County convened a community task force to make recommendations about diversifying the local base. The report, "Preparing for Growth after 2023," was led by the Jasper County EDO and completed in the first half of 2019. The committee recommended updating the county comprehensive plan and unified development ordinance (combined zoning and subdivision control), investing in quality-of-life projects, facilitating development around the Interstate 65 interchanges within the county by extending utilities to those areas and adopting tax increment finance (TIF) districts, revisiting the county tax abatement policy, and pursuing grant funding to support county efforts. The EDO is leading implementation. Purdue Extension and other county offices are working on the initial phases of the comprehensive plan update. The commissioners are working on developing the TIF districts.
- Jasper County is working with neighboring rural counties (Benton, White, Newton, Starke, and Pulaski) to attract value-added agricultural industries.
- Jasper County asked NIPSCO to invest in renewable energy near the retiring plant. The company released a request for proposals and received a number of responses. To date, one large solar farm has been approved locally. Another project has been proposed. A proposal for a wind farm was rejected by county residents.
- The NWI Forum released its report "Ignite the region: A regional strategy for economic transformation" in 2018. The plan addresses five pillars: entrepreneurship and innovation, business development and marketing, infrastructure, placemaking, and talent.
- KIRPC will undertake a new Community Economic Development Strategy in the summer/fall 2020.
- DeMotte is considering extending drinking water and sewer utilities out to Interstate 65.
- Wheatfield is considering a stormwater project and plans to meet with KIRPC regarding the closure.

Gaps and other issues

Stakeholders also were asked to identify any gaps in the services necessary to respond to the effects of closures and for any additional issues that were not covered by other interview questions.

- While the stakeholders interviewed generally perceive NIPSCO positively, there is some community mistrust within Jasper County.

- Stakeholders are concerned about having ample electric service at reasonable cost in the region to support the regional economy. One Jasper County stakeholder indicated some concern that large industrial customers may install their own generation if sufficient and price competitive replacement resources are not identified within the region. This could limit the development of that capacity in Jasper County.
- Only a small part of Jasper County is served by NIPSCO. The Jasper County REMC is the principal provider in the county.
- There is a bit of a geographic mismatch between employees who live in Jasper County and the bulk of training resources.
- A few stakeholders expressed concern that the language and debate around 2020 HEA 1414 may be interpreted by local officials and residents as forestalling closure and may hinder efforts to build support for the next iteration of the local economy.
- Local communities need more mental health resources to address the psychological effects of job loss on workers.
- More standardization is needed in the property tax assessment of wind and solar facilities. There is variation across the state that affects the fairness of the playing field.

Summary

The Schahfer Generating Station is owned and operated by NIPSCO. The plant is located in a rural setting in northern Jasper County. NIPSCO plans to close the four coal-fired units at this location by the end of 2023.

As stakeholders mentioned, the effects of the closing plant are likely to be mixed. Jasper and surrounding counties face a number of challenges. The Schahfer plant has the biggest potential employment losses—about 300—among the locations studied. Employees live in nine counties. More than a third of them live in Porter County. Both the average wage and the total compensation at the Schahfer plant are substantially more than the average wages and compensation in Porter and Jasper counties and may be hard to match, although stakeholders suggested that some high wage opportunities may be available in Northwest Indiana and Chicago. Firms in Lake and Porter counties potentially will be affected most by lost sales of goods and services to the Schahfer and Michigan City plants.

The loss of assessed value for Jasper County and taxing units that serve the northeast part of the county will be profound. Taxpayers could face increasing property tax rates with an already high local option income tax rate, historically used to offset property taxes.

On the positive side, stakeholders identified that the region was economically robust with a tight labor market and low unemployment. They added that many companies with open positions would mitigate the effects of the closure on employees, particularly those with skilled occupations. They also identified that the transition to new energy sources and available employees would provide new opportunities for the local economy including attracting new firms.

Stakeholders are confident that local officials generally understand the nature and scale of the coming impacts. They commonly expressed that communities and resource organizations need more specific information about the assessed value losses, the occupations of transitioning employees, and the goods and services firms that will be affected. Resource organizations are poised to assist the impacted employees, businesses, and communities through the transition.

Jasper County has undertaken several efforts to address the potential assessed value losses and their impact on local taxing units. First, Jasper County convened a community task force in 2019 to make recommendations about diversifying the local base. The committee recommended updating the county comprehensive plan and unified development ordinance (combined zoning and subdivision control), investing in quality of life projects, facilitating development around the I-65 interchanges within the county by extending utilities to those areas and adopting tax increment finance (TIF) districts, revisiting the county tax abatement policy, and pursuing grant funding to support county efforts. Second, the county asked NIPSCO to invest in renewable energy near the retiring plant. The company released a request for proposals and received a number of responses. To date, one large solar farm has been approved locally with additional facilities in development. Third, the county is partnering with neighboring rural counties to attract value-added agricultural industries. Fourth, DeMotte and Wheatfield, communities in northern Jasper County, are considering infrastructure investments, in part, to support economic development.

Michigan City Generating Station

The Michigan City Generating Station is located in Michigan City in LaPorte County and is adjacent to Lake Michigan. It is the only plant in the study that is located in an urban context and within a municipality. The annual average generation for Unit 12 (coal-fired), 2014–2018, was 1.9 million MWh. Generation in 2018 was 2.0 million MWh (NIPSCO, 2020). NIPSCO has announced plans to close its coal-fired unit at the Michigan City plant by 2028.

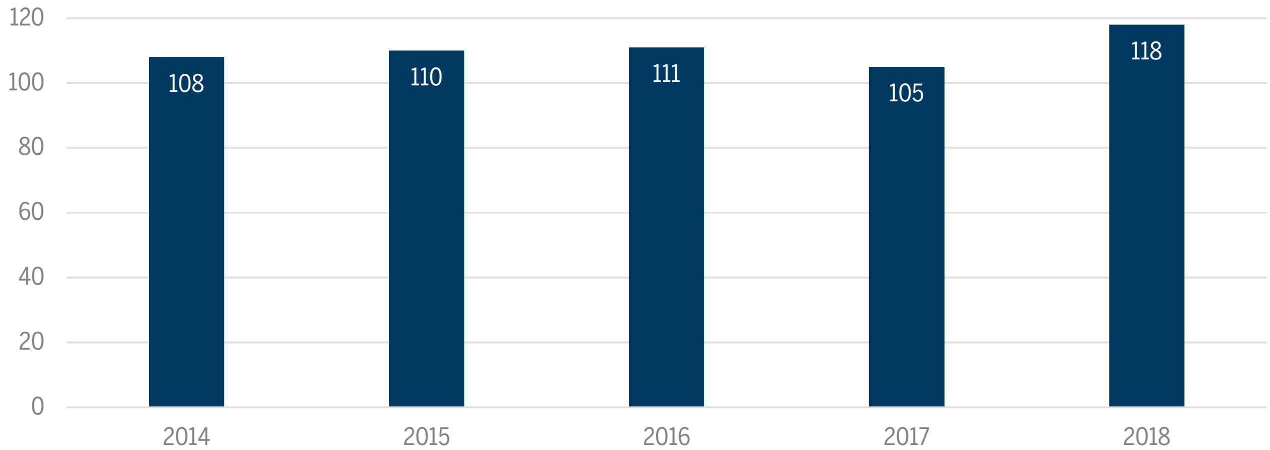
Employment[11]

The Michigan City Generating Station employed 118 employees to operate Unit 12 in 2018. Unit 12 employment accounted for just 0.35 percent of private sector jobs in LaPorte County in 2018 (IBRC, 2020). During the last five years (2014–2018), plant employment varied from 105 to 118 employees (Figure 19) (NIPSCO, 2020).

Less than half of the plant's employees live in LaPorte County. The remaining employees commute from Elkhart, Lake, Marshall, Porter, St. Joseph, and Starke counties (Figure 20) (NIPSCO, 2020).

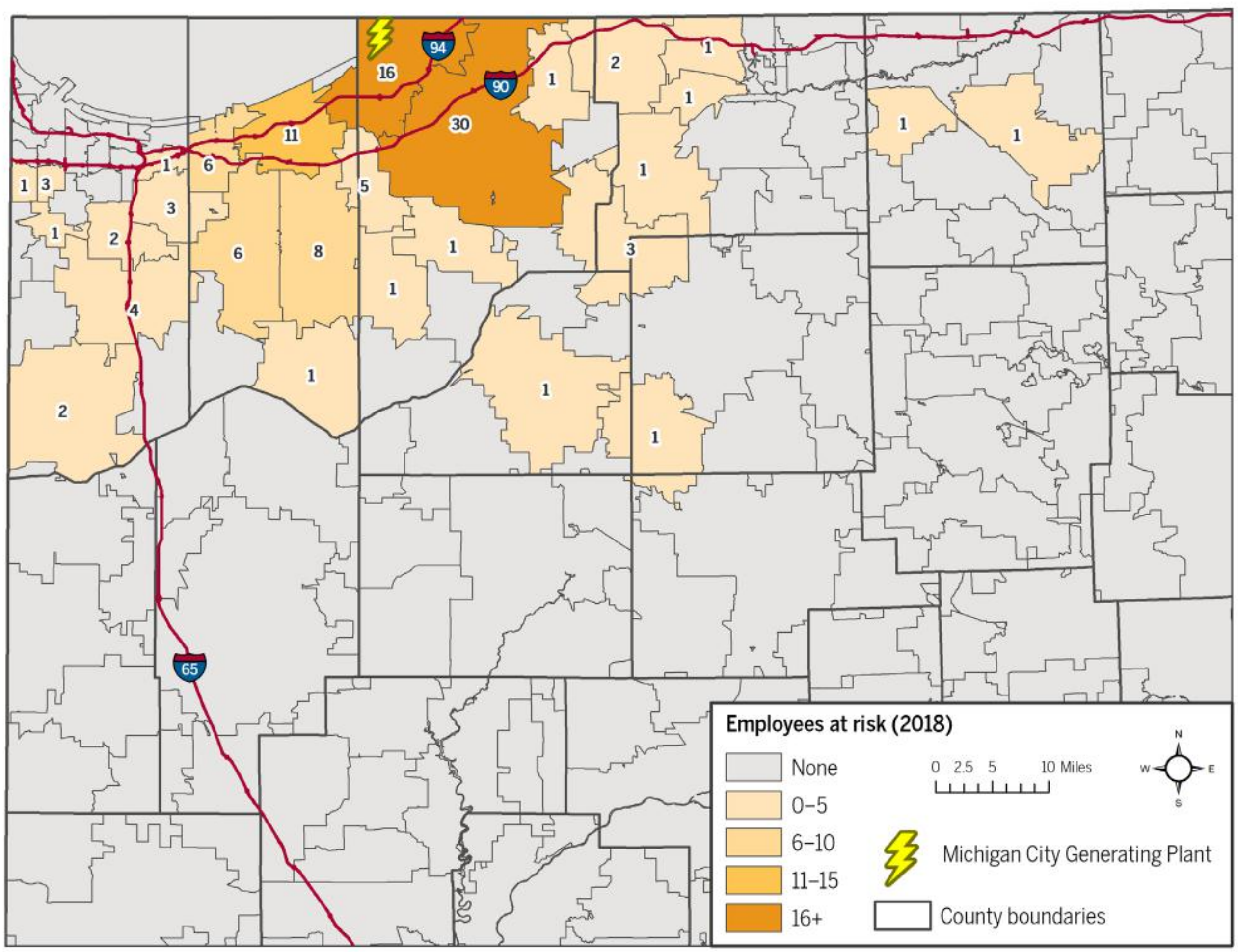
11 NIPSCO provided the following statement when asked to provide their plans for transitioning employees. "NIPSCO is working internally to determine workforce transition and training opportunities. We have a number of activities and milestones that we have to complete over the next months and years in order to finalize our workforce transition plans. The goal, as we develop our future plans, is to create the least amount of disruption for our employees" (T. McElmurry, email communication, May 4, 2020).

FIGURE 19. Michigan City Generating Station potential employment losses from closure (2014–2018)



Source: NIPSCO, 2020.

FIGURE 20. Michigan City Generating Station potential employment losses in Indiana from closure by zip code of employee residence (2018)



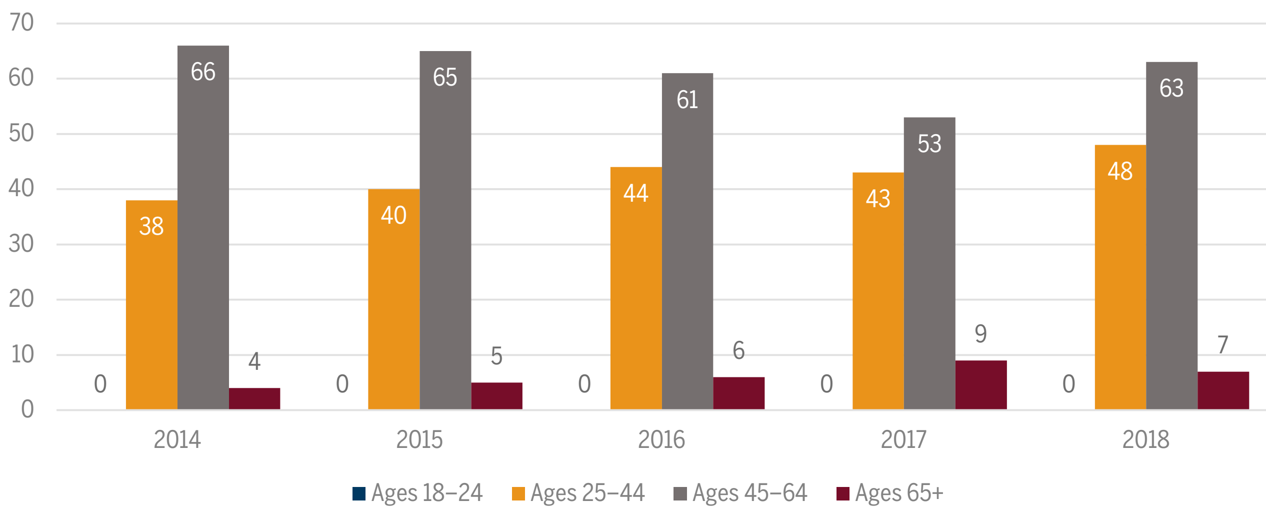
Sources: NIPSCO, 2020; IndianaMap Data Portal.

In recent years, the Northwest Indiana region had a tight labor market with low unemployment. Stakeholders who serve the region believe that employees in skilled and semi-skilled occupations can be absorbed readily into other companies, either directly or with some training. They suggested that administrative jobs may be harder for the region to absorb.

Employee demographics

In 2018, 94.1 percent of plant employees were white male. Most employees were ages 45–64. Two-fifths of employees, however, were ages 25–44. No employees were younger than 25 (Figure 21) (NIPSCO, 2020).

FIGURE 21. Michigan City Generating Station employees by age (2014–2018)



Note: NIPSCO reported no employees ages 18–24 during this period.
Source: NIPSCO, 2020.

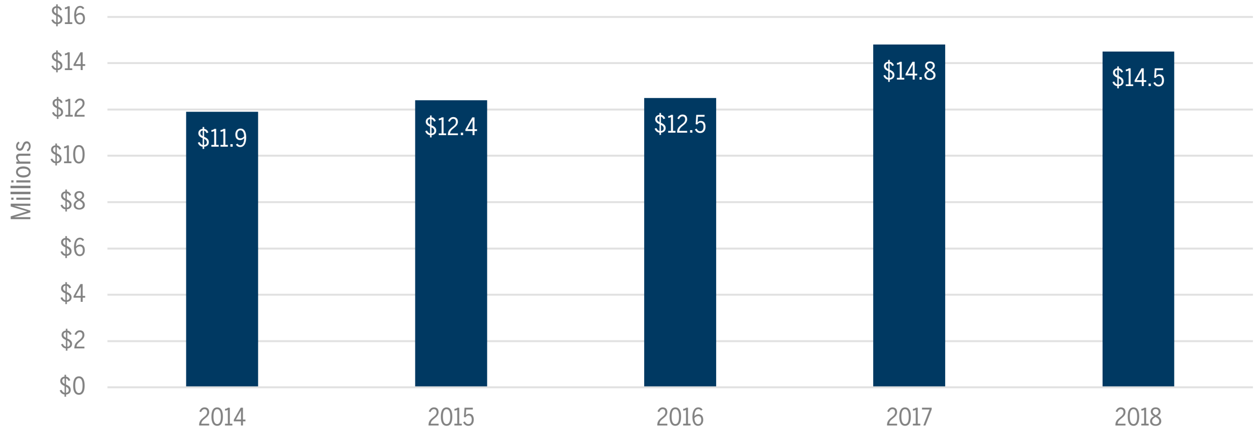
Wages and compensation

Plant employees earned $10.2 million in wages and $14.5 million in compensation (wages and benefits) in 2018. The average wages and compensation per employee were $85,508 and $126,710, respectively (Figure 22) (NIPSCO, 2020). The average wages and estimated compensation for LaPorte County were $40,810 and $52,013 (IBRC, 2020; U.S. BLS, March 19, 2020).[12] Figure 23 shows the geographic distribution of employee compensation.

The premium wages and benefits paid by NIPSCO may be difficult to match for transitioning employees. Some stakeholders interviewed about the Schahfer closure and who operate in Northwest Indiana suggested that there may be opportunities to match these higher wages in the steel industry and by relocating to the Chicago area.

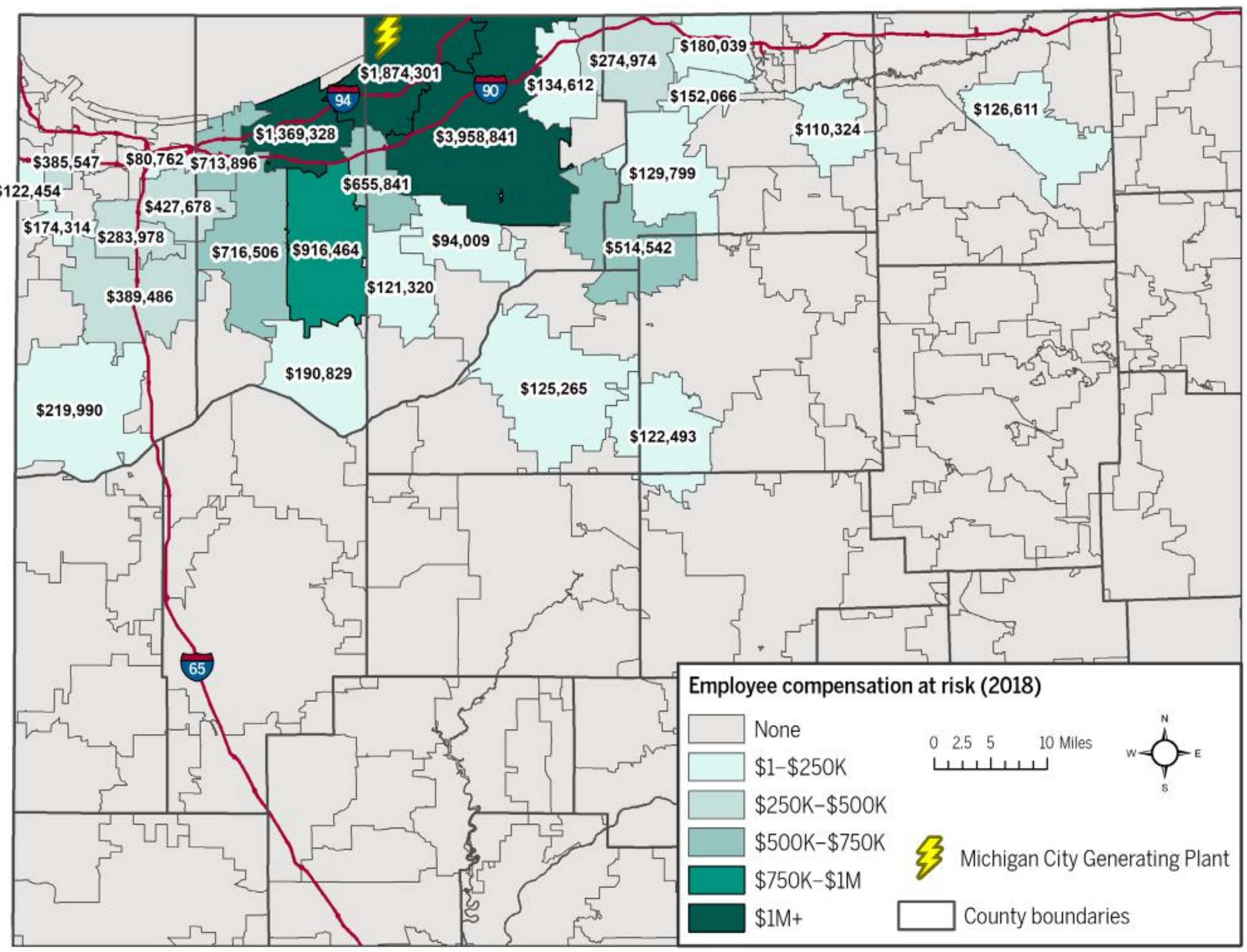
12 Estimated compensation was calculated using wage data from IBRC (2020) and U.S. Bureau of Labor Statistics survey data regarding compensation (March 19, 2020).

FIGURE 22. Michigan City Generating Station potential employee compensation losses (2014–2018)



Source: NIPSCO, 2020.

FIGURE 23. Michigan City Generating Station potential employee compensation losses in Indiana from closure by zip code of employee residence (2018)

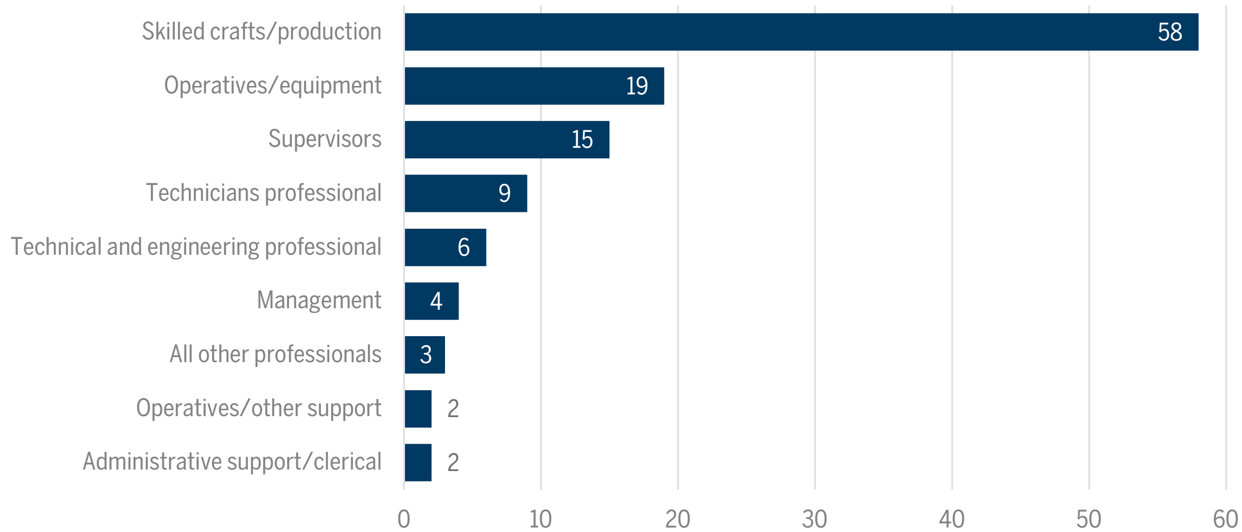


Source: NIPSCO, 2020; IndianaMap Data Portal

Occupations

Occupations at the plant are 81 percent technical/mechanical positions and 19 percent management/administrative positions. Nearly 50 percent of plant employees were classified as skilled (skilled crafts/production). About 20 percent were classified as semi-skilled (operatives/equipment and operatives/other support) and about 15 percent were classified as professional technicians, technical and engineering professionals, and other professionals (Figure 24) (NIPSCO, 2020).

FIGURE 24. Michigan City Generating Station worker occupations (2018)



Note: NIPSCO, 2020.

As mentioned above, stakeholders who serve the region believe that employees skilled and semi-skilled can be absorbed readily in to other companies, either directly or with some training. They suggested that administrative jobs may be harder for the region to absorb, but that these employees may be able to find opportunities in the South Bend and Lafayette areas.

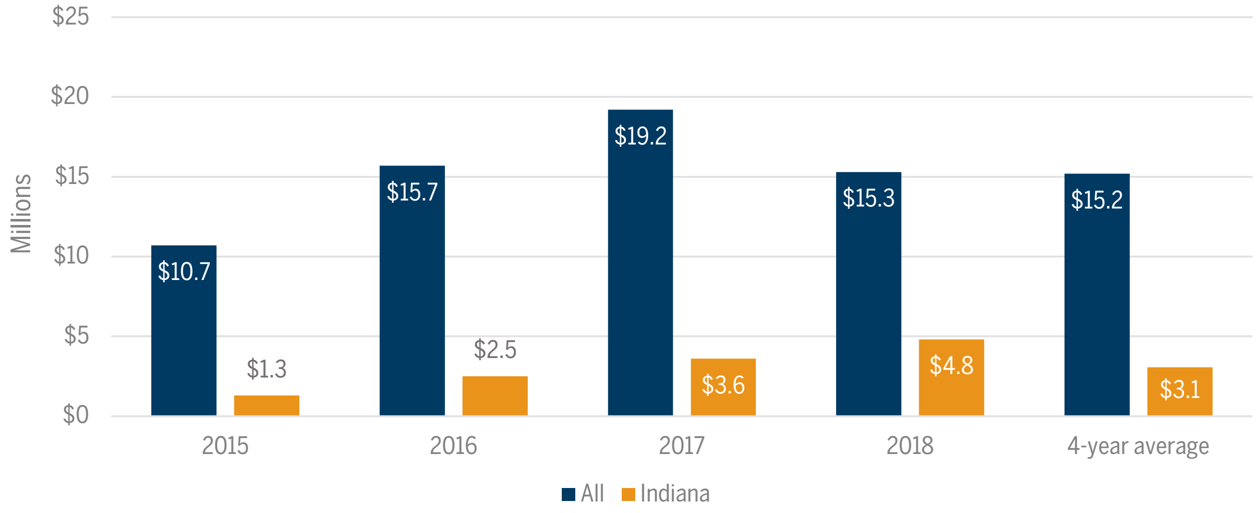
Goods and services purchases

NIPSCO reported its average annual spending on goods and services, excluding coal, was $15.2 million overall and $3.1 million in Indiana from 2015–2018 (Figure 25). Figure 26 shows the five sectors, excluding coal, from which NIPSCO buys the most goods and services. NIPSCO purchased $40.5 million in out-of-state coal on average annually during this same period.

NIPSCO reported purchasing goods and services from 14 Indiana counties (Figure 27). Firms in Lake and Porter counties could lose the most business as a result of the plant closure (NIPSCO, 2020).

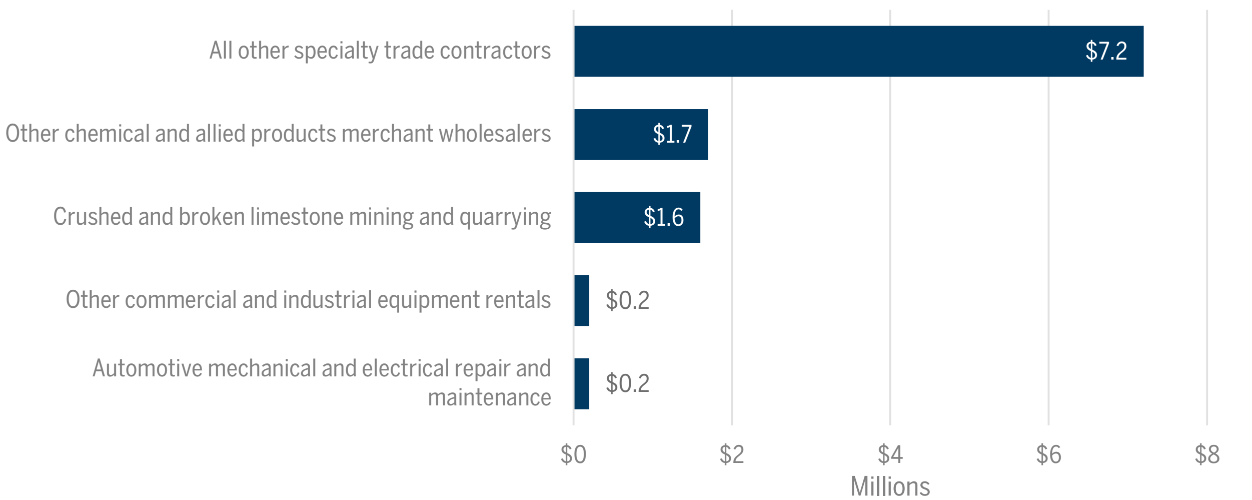
While the potential loss of goods and services purchases from Indiana firms are modest, some of these same firms may be affected by the Schahfer closure as well. We do not have sufficient data to know how much overlap might exist. Additional detail about the scale of these ripple effects are described in the regional economic analysis section below.

FIGURE 25. Michigan City Generating Station potential goods and services losses, excluding coal (2015–2018)



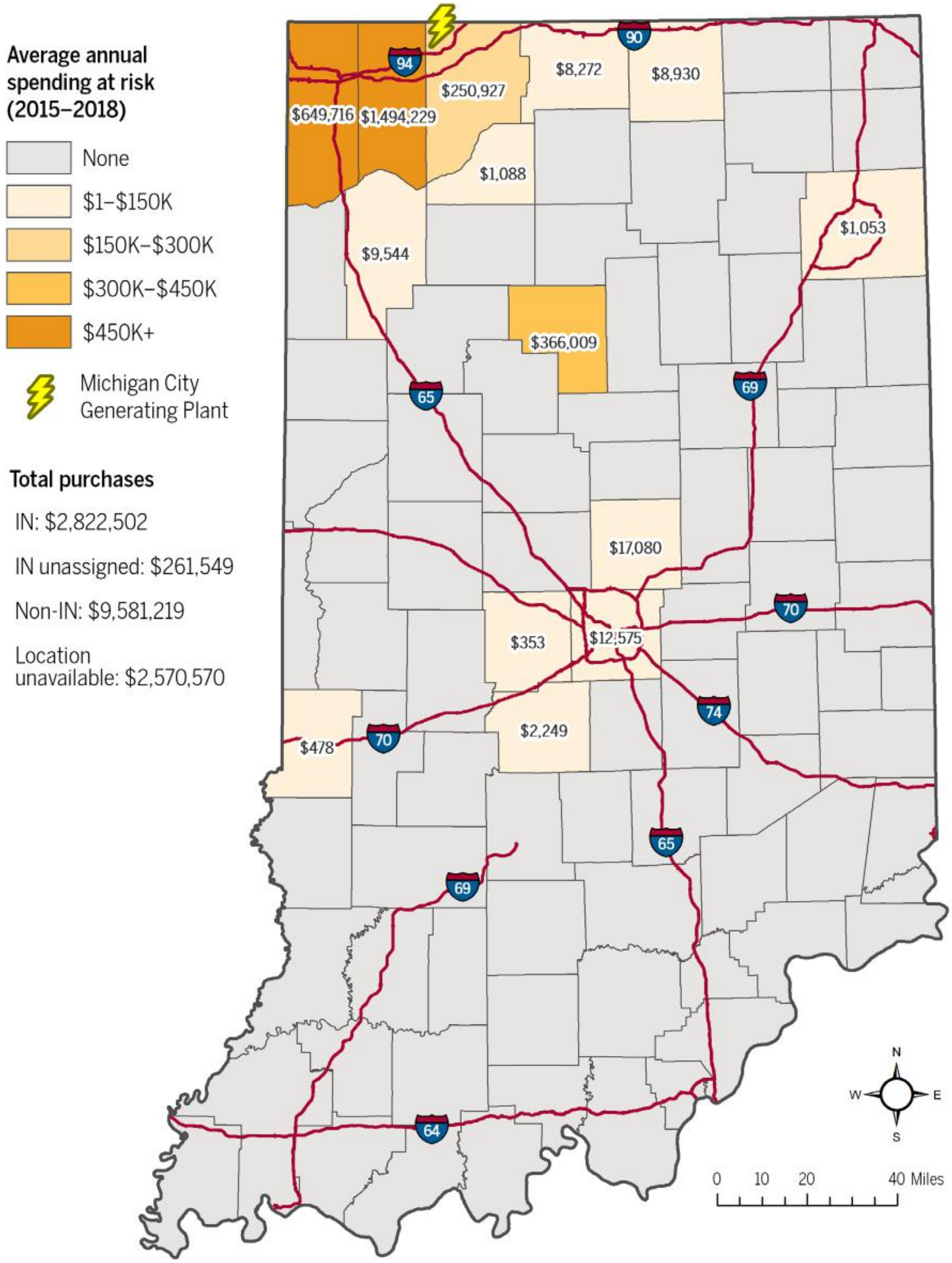
Source: NIPSCO, 2020.

FIGURE 26. Michigan City Generating Station average annual goods and services purchases—Five largest categories, excluding coal (2015–2018)



Source: NIPSCO, 2020.

FIGURE 27. Michigan City Generating Station potential goods and services losses, excluding coal, in Indiana from closure by county (2015–2018)



Notes:

1. *County totals were aggregated from zip code data.*
2. *The Michigan City plan purchases only out-of-state coal. These purchases are not reflected in the total shown for purchases from other states.*

Sources: NIPSCO, 2020; IndianaMAP Data Portal.

Local income and property taxes

Table 10 shows total assessed value for LaPorte County, Michigan Township, Michigan City, and Michigan City Area Schools. Table 11 shows the assessed value of selected plant parcels, particularly those with improvements or substantial land assessed value. The selected parcels for the Michigan City plant make up almost 10 percent of the assessed value in Michigan City. The proportions for the other taxing units are more modest. All generally are less than the proportion of assessed value represented by the other plants located in rural locations.

TABLE 10. Total certified assessed value for selected local governments (assess 2019, pay 2020)

	CERTIFIED ASSESSED VALUE
LaPorte County	$5,575,472,955
Michigan Township	$1,818,012,184
Michigan City	$1,372,013,562
Michigan City Area Schools	$2,694,187,503

Source: DLGF, Dec. 20, 2019.

TABLE 11. Michigan City Generating Station assessed value for selected parcels as a share of assessed value for selected taxing units (assess 2019, pay 2020)

PARCEL	ASSESSED VALUE	SHARE OF LAPORTE COUNTY ASSESSED VALUE	SHARE OF MICHIGAN TOWNSHIP ASSESSED VALUE	SHARE OF MICHIGAN CITY ASSESSED VALUE	SHARE OF MICHIGAN CITY SCHOOLS ASSESSED VALUE
46-01-29-151-006.000-022	$8,099,300	0.2%	0.5%	0.6%	0.3%
Real property improvements	$6,892,800	0.1%	0.4%	0.5%	0.3%
46-01-29-101-001.000-022	$1,249,900	0.0%	0.1%	0.1%	0.1%
46-01-29-151-007.000-022	$1,173,800	0.0%	0.1%	0.1%	0.0%
Personal property improvements	$118,245,920	2.1%	6.5%	8.6%	4.4%
Total assessed value	$135,661,720	2.4%	7.5%	9.9%	5.0%
Real and personal improvements	$126,345,220	2.3%	7.0%	9.2%	4.7%

Note: The certified total assessed value for the county, township, city, and school districts in Table 10 were used to calculate the percentage in this table.
Sources: DLGF, Dec. 20, 2019; DLGF, 2020; LaPorte County, 2020.

13 Tax bill data shows that personal property assessed value increased by approximately $50 million for NIPSCO-owned properties in LaPorte County between Assess 2018, Pay 2019 and Assess 2019, Pay 2020 property tax years.

The property tax assessment of utilities is complex, and the exact loss of assessed value that will result from closure is unknown.[13] These losses, however, will challenge local governments with, all else the same, increases in property tax rates and potential property tax increases for county, township, city, and school taxpayers. Because the plant is located inside a municipality, there is an increased likelihood of property cap losses.

Among the counties with five or more plant employees who reside there, LaPorte, Porter, Lake, and Elkhart counties utilize local option income taxes (Table 12) (ISBA, 2019). The number and distribution of employees across these counties, and the relative income tax rates, suggest a minimal effect on local revenues. The relatively low local income tax rate for LaPorte County provides an option for replacing potential property tax losses.

TABLE 12. County local income tax rates for final CY 2020 certified distribution

LOIT RATES	LAPORTE COUNTY	PORTER COUNTY	LAKE COUNTY	ELKHART COUNTY
Certified shares	0.500%	0.000%	0.000%	1.000%
Public safety	0.000%	0.000%	0.250%	0.250%
Economic development	0.450%	0.500%	0.250%	0.250%
Property tax relief	0.000%	0.000%	1.000%	0.250%
Special purpose	0.000%	0.000%	0.000%	0.250%
Total	0.950%	0.500%	1.500%	2.000%

Note: None of these counties has adopted a correctional facility local income tax rate.
Source: ISBA, Nov. 18, 2019.

Regional economic analysis[14]

As mentioned above, the power plant at Michigan City employs nearly 120 workers who earn a combined $14.5 million in compensation (Table 13) (NIPSCO, 2020). In addition to these direct effects, the supply chain purchases for this facility along with the household spending of the employees combined to support another 150 additional ripple-effect jobs for other businesses in the region. All told, the Michigan City plant's full employment footprint in the region stands at an estimated loss of 268 jobs with a total compensation loss of $21.8 million.

TABLE 13. Estimated regional effects of the Michigan City Generating Station closure

	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Employment	118	150	268	2.27
Compensation	$14.5M	$7.3M	$21.8M	1.50
GDP	$65.3M	$11.2M	$76.5M	1.17
State and local tax revenue	$3.6M	$0.9M	$4.5M	N/A

Sources: NIPSCO, 2020; IBRC using the IMPLAN economic modeling software.

14 This analysis was conducted for the region that includes LaPorte County in which the Michigan City plant is located, along with bordering counties including Porter, Starke, and St. Joseph counties. A separate analysis for the effects on only LaPorte County is available in Appendix B.

In terms of contributions to the broader economy, the combined effects of the Michigan City plant's activities created an estimated $76.5 million to total GDP for the region. The multiplier of 1.17 indicates that every dollar of GDP directly generated by the facility spurs an additional $0.17 in economic activity in the region.

The combined economic activity created by this plant contributes an estimated $4.5 million to annual state and local government revenues.

Table 14 lists the industries that will likely take the hardest hits from a Michigan City plant closure, with maintenance and repair construction leading the way with an estimate loss of 35 jobs in the region. The only other industry on this list that would be considered part of the plant supply chain would be wholesale trade. A decline in household spending as a result of lost employee compensation will drive the impacts to the remaining industries on the list.

TABLE 14. Michigan City Generating Station regional employment ripple effects—Top 10 industries

	JOBS
Maintenance and repair construction of nonresidential structures	35
Hospitals	7
Full-service restaurants	6
Limited-service restaurants	6
Real estate	5
Wholesale trade	4
General merchandise stores	4
Physician offices	4
Food and beverage stores	3
Colleges, universities, and professional schools	3

Source: IBRC, using the IMPLAN economic modeling software.

The force account scenario in Appendix B contemplates that some share of construction workers employed at the plant, as well as some of the labor and spending associated with specialty contractors, will continue to be employed in the region by NIPSCO. These workers and contractors could be redeployed to other activities such as building and maintaining transmission and distribution systems or other types of generation infrastructure. Assuming that 30 percent of plant construction workers and 50 percent of labor and purchases for specialty contractors remain engaged with the utility, the full employment effects of this closure would change from a gross loss of 268 jobs (with no force account adjustment) to a net loss of 225 jobs (with the force account adjustment) while the full GDP impact would change from a gross loss $76.5 million drop in value added to a less severe net-loss of $64.8 million.

Summary

The Michigan City Generating Station is owned and operated by NIPSCO. The plant is located in Michigan City on Lake Michigan. It is a small plant relative to Schahfer and Petersburg. It is the only plant in the study that is located in an urban and municipal setting.

Within the region, LaPorte County potentially will be affected most in terms of employment. Loss of assessed value is likely to have a substantial effect on local taxing units, including Michigan City, Michigan Township, Michigan City Area Schools, and—to a lesser degree—LaPorte County. Lake and Porter counties will be affected most by lost sales of goods and services. Specialty trade contractors in the goods and services industry are most likely to be affected by the plant closures for all regions.

Petersburg Generating Station

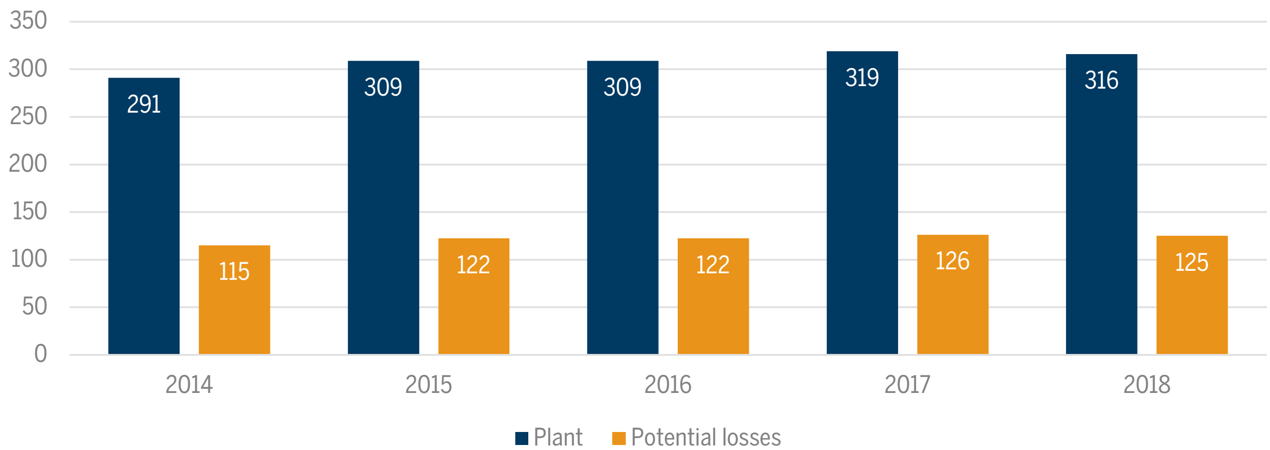
The Petersburg Generating Station is owned and operated by IPL. It is located in a rural setting near Petersburg in Pike County. The annual average net generation between 2014 and 2018 was 9.6 million MW (IPL, 2020a).

IPL has announced the closure of two of the four generating units by 2023. Units 1 and 2 account for 39.6 percent of the plant's average annual net generation 2016–18 (IPL, 2020a). For the analysis that follows, plant data—employment, wages and compensation, purchased goods and services, etc.—has been parsed using this proportion. The effects of closure also are assumed to occur proportionally by demographics, geography, etc.

Employment

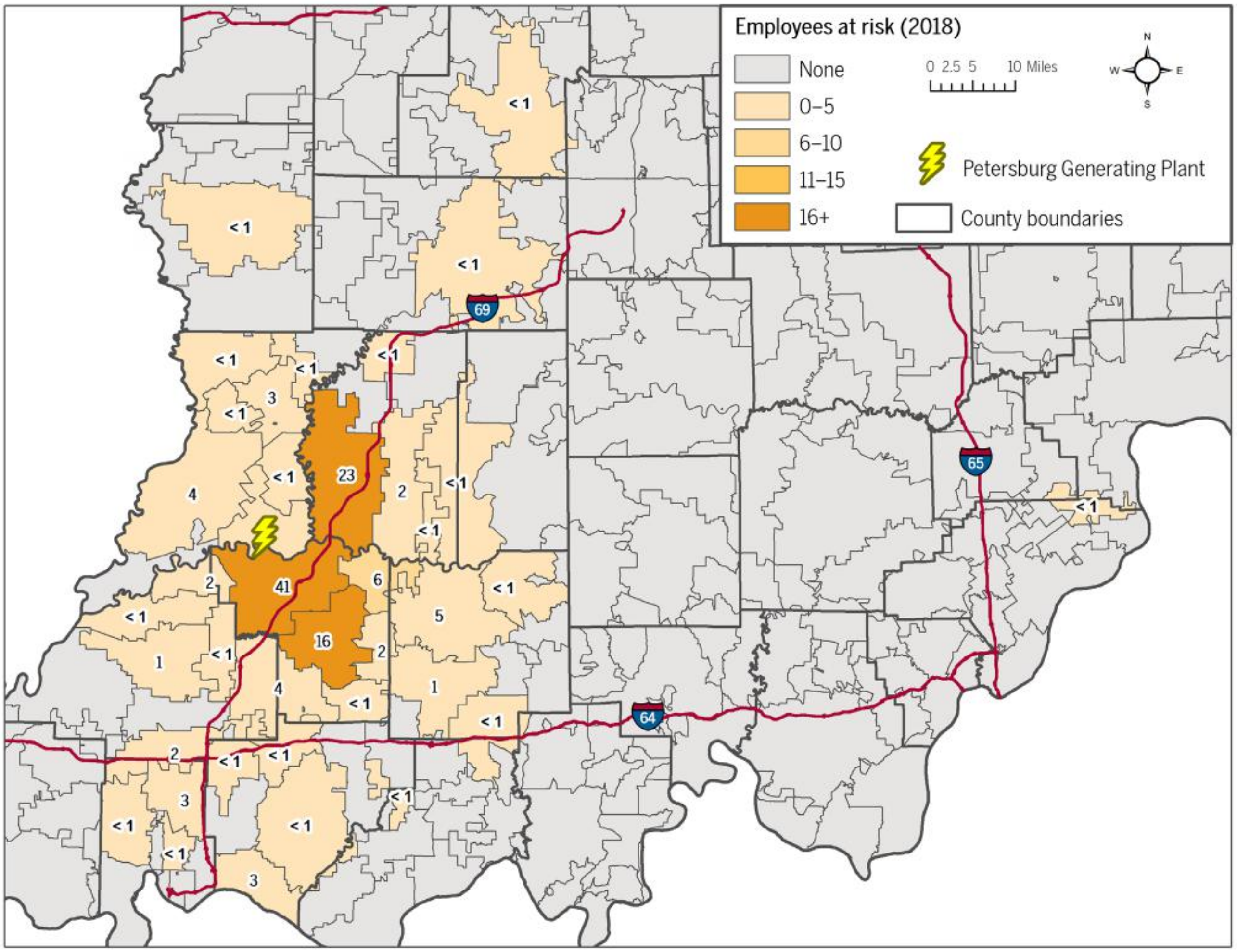
Employment at the Petersburg plant increased from 2014 through 2018. In 2014, the plant had 291 employees. In 2018, the plant had 316 employees (IPL, 2020a). An estimated 125 employees could be at risk with the partial closure (Figure 28). These lost jobs account for 4.6 percent of the private sector jobs in Pike County in 2018 (IBRC, 2020)

FIGURE 28. Petersburg Generating Station total employees and estimated lost employment from partial closure (2014–2018)



Note: Estimated job losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: IPL, 2020a.

FIGURE 29. Petersburg Generating Station potential job losses in Indiana from partial closure by zip code of employee residence (2018)



Notes:

1. *Estimated job losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.*
2. *Zip codes represented by less than one employee equivalent are displayed as <1. All others are rounded to the nearest whole number.*

Sources: IPL, 2020a; IndianaMAP Data Portal.

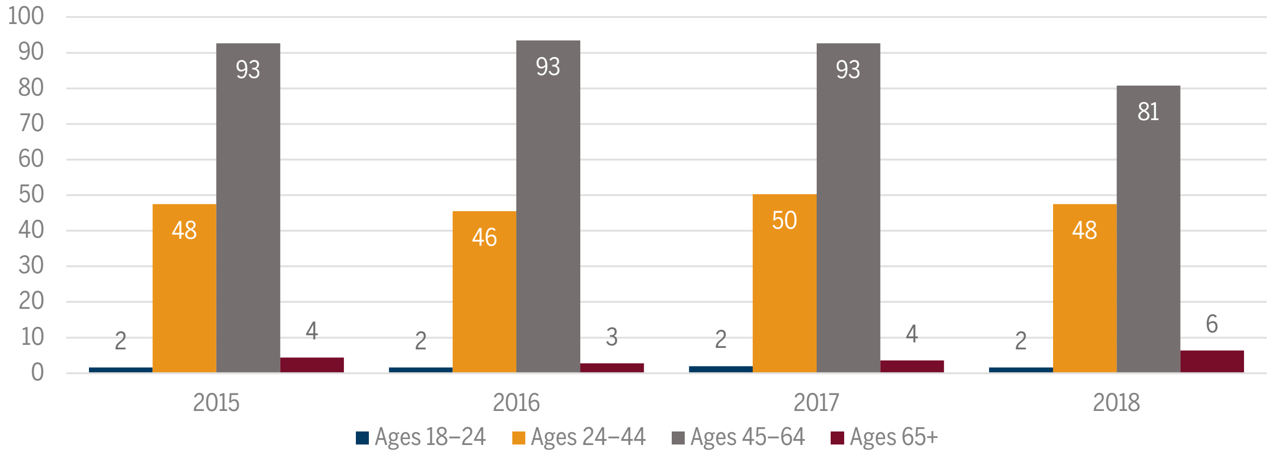
Most of the employees who work at the plant live in Pike and Daviess counties. Employees also commute to the plant from Dubois, Gibson, Greene, Knox, Martin, Owen, Spencer, Sullivan, Switzerland, Vanderburgh, and Warrick counties. Figure 29 shows potential job losses in Indiana by zip code based on where employees live (IPL, 2020a).

Pike County has a relatively small industrial base. The regional industrial base is more robust. Both Pike County and the region have a tight labor market and low unemployment. Stakeholders believe that skilled and semi-skilled workers can be absorbed into the many open positions in the region.

Employee demographics

A strong majority of employees in 2018 were white (97.9 percent) and male (96.2 percent). Figure 30 shows potential job losses by employee age. More than half of plant employees were ages 45–64, and more than one-third of employees were 25–44. The plant employed just a small proportion of employees ages 18–24 and age 65 and older (IPL, 2020a).

FIGURE 30. Petersburg Generating Station potential job losses from partial closure by employee age (2014–2018)



Note: Estimated job losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: IPL, 2020a.

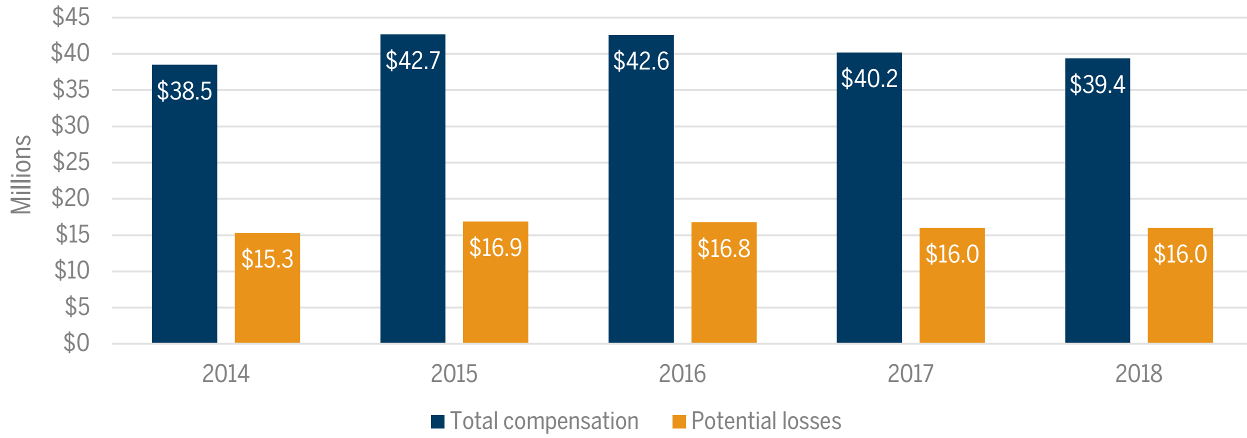
If employees are not able to stay in the continuing operations or transfer within the company, stakeholders believe that many employees are settled in their communities and will commute to new jobs, if possible. There is some worry in Pike County about potential population loss if employees choose to relocate.

Wages and compensation

With a partial closure, an estimated $16 million in employee compensation is potentially at risk. Figure 32 shows the geographic distribution of employee compensation. In 2018, the average wages for a plant employee was $122,059 and the average compensation—which includes wages and benefits—was $183,919 (IPL, 2020a). This is more than twice the estimated average compensation in Pike and Daviess counties in 2018 (Figure 31) (IBRC, 2020). In Pike County, the average private-sector wage was $54,205 and the average compensation—including wages and benefits—was $70,412. In Daviess County, the average private-sector wage and estimated total compensation were $35,965 and $46,719, respectively (IBRC, 2020; U.S.BLS, March 19, 2020).[15] Stakeholders believe that the premium wages and benefits paid by IPL may be difficult to match for transitioning employees.

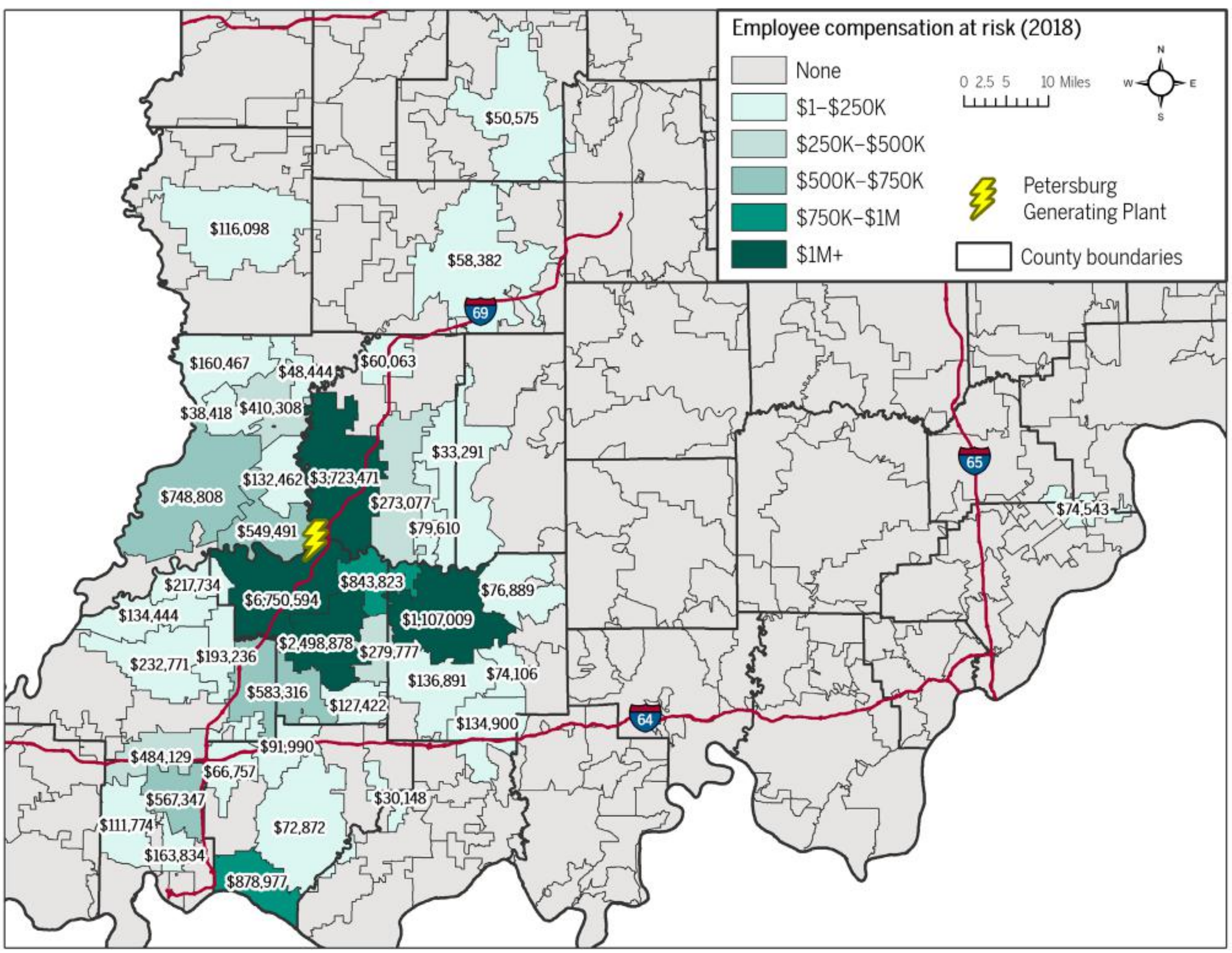
15 Estimated compensation was estimated using wage data from IBRC (2020) and U.S. Bureau of Labor Statistics survey data regarding compensation (March 19, 2020).

FIGURE 31. Petersburg Generating Station total compensation and potential losses (2014–2018)



Note: Potential wage losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: IPL, 2020a.

FIGURE 32. Petersburg Generating Station potential employee compensation losses in Indiana from partial closure by zip code of employee residence (2018)



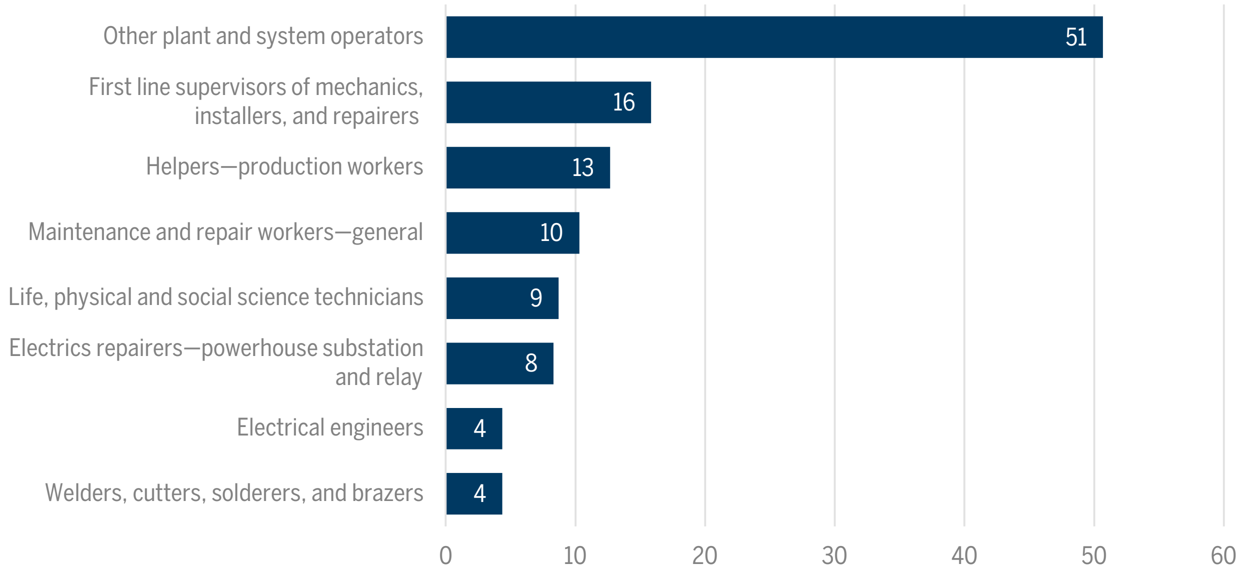
Note: Potential job losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: IPL, 2020a; IndianaMAP Data Portal.

Occupations

In 2018, more than three-quarters of employee occupations at the plant were skilled/semi-skilled. More than 10 percent of employees were classified as supervisors and about 10 percent were classified as helpers. The company did not list any administrative staff (Figure 33) (IPL, 2020). Anecdotal information from stakeholders suggest that the plant human resources unit was closed in the last few years.

Stakeholders believe that skilled and semi-skilled workers can be absorbed by the regional economy. They expressed concern that management and administrative jobs may be more difficult to absorb.

FIGURE 33. Petersburg Generating Station worker occupations associated with predicted job losses (2018)



Note: Potential job losses by occupation were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: IPL, 2020a.

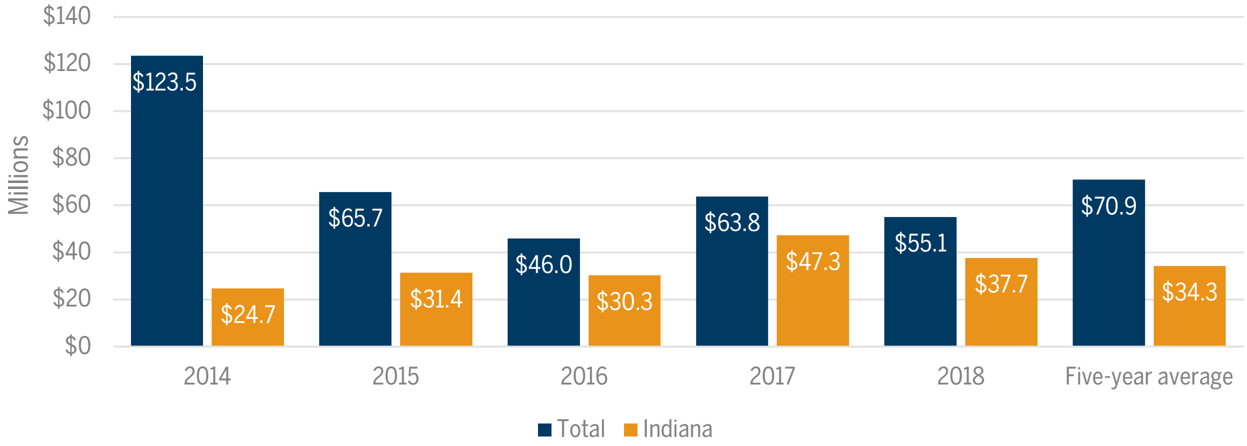
Goods and services purchases

From 2014–2018, the Petersburg plant purchased an annual average of $179 million of inputs—goods and services, excluding coal—from all firms. The plant purchased $74.1 million on average annually from firms in Indiana. Those Indiana firms could lose $34.2 million in annual average sales from the partial closure (Figure 34). Specialty trade contractors account for about half of these losses (Figure 35).

Figure 36 shows the geographic distribution of potential losses. IPL reported making purchases from firms in 34 counties. The largest potential losses are possible in Marion, Vanderburgh, and Knox counties.

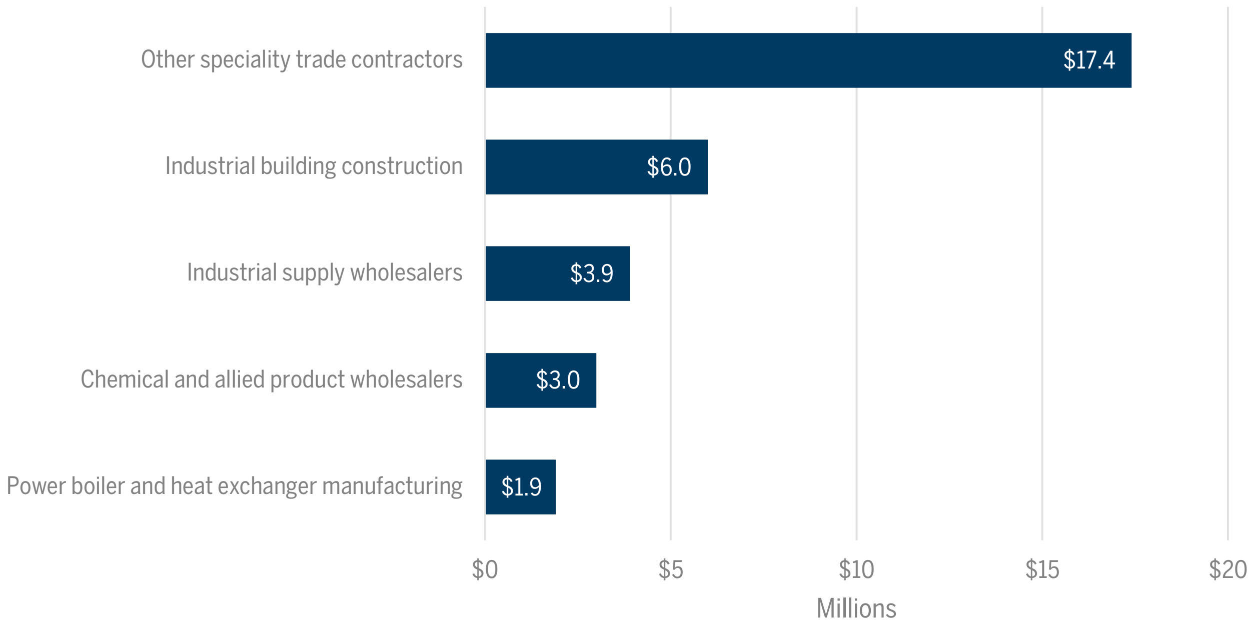
During the last five years (2014–2018), the Petersburg plant purchased an average of 4.5 million tons of coal annually with an average value of $215.8 million (IPL, 2020). The partial closure puts the purchase of 1.8 million tons of coals at an approximate value of $85.5 million at risk. In 2018, more than half of coal purchases came from mines in Gibson County. The plant also purchased coal from mines in Sullivan, Knox, Daviess, and Dubois counties (EIA, 2019c).

FIGURE 34. Petersburg Generating Station estimated loss of goods and services sales from partial closure, excluding coal (2014–2018)



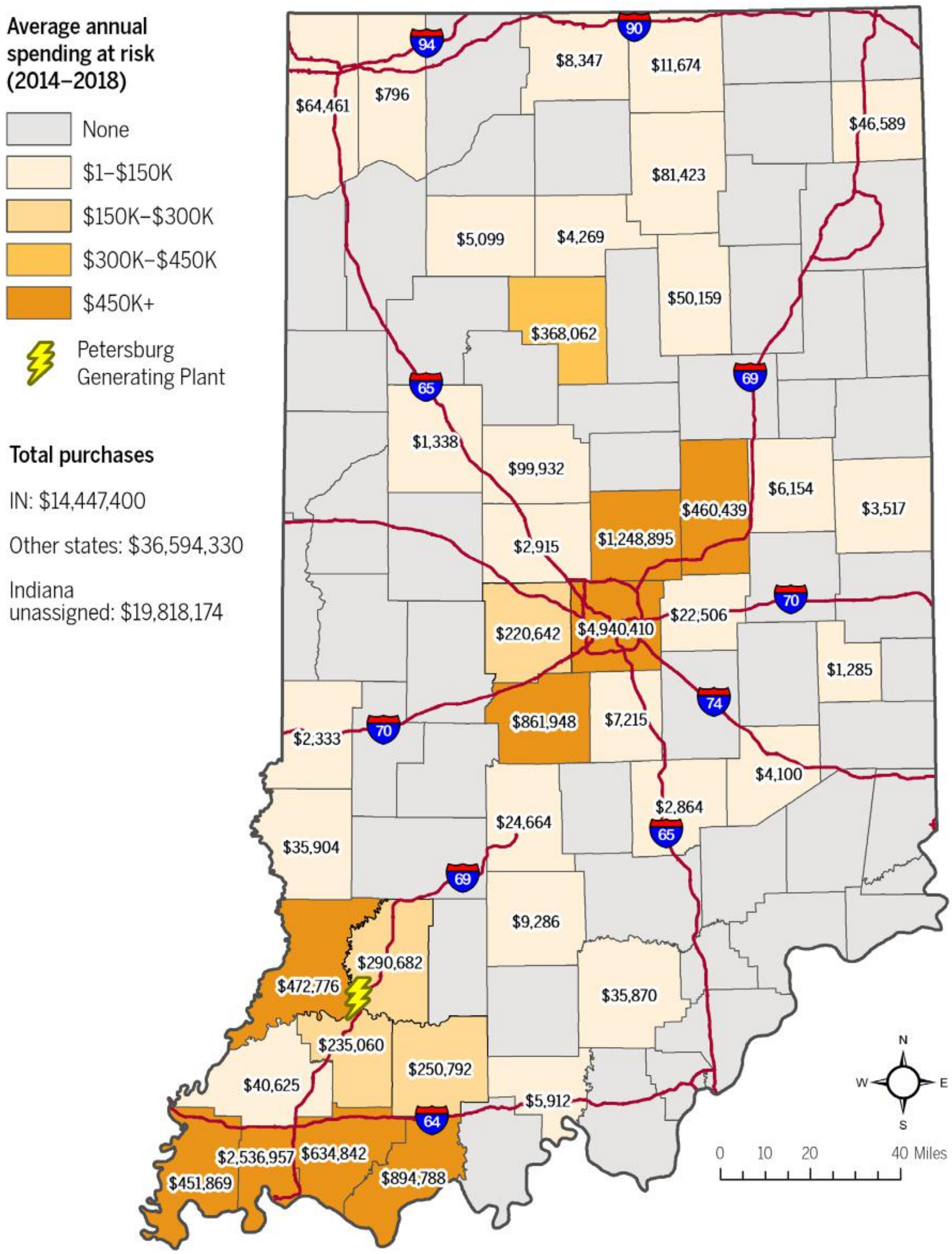
Note: Potential losses in goods and services sales were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: IPL, 2020.

FIGURE 35. Petersburg Generating Station top five types of goods and services purchased, excluding coal, and potential sales losses from partial closure (2018)



Source: IPL, 2020a.

FIGURE 36. Petersburg Generating Station potential annual goods and services losses, excluding coal, in Indiana from partial closure by county (2014–2018)



Notes:

1. *Potential sales losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.*
2. *County totals were aggregated from zip code data.*
3. *The Petersburg plant purchases Indiana coal. These purchases are not reflected in the Indiana goods and services sales reported here.*

Source: IPL, 2020; IndianaMAP Data Portal.

IPL makes substantial purchases in Indiana of coal and other goods and services. Among the companies in our analysis, IPL purchases touch firms in the broadest set of counties. Some of these same firms may be affected by the Rockport partial closure as well. We do not have sufficient data to know specifically how much overlap might exist.

Additional detail about the scale of these ripple effects are described in the regional economic analysis section below.

Local income and property taxes

Tables 15 and 16 show total assessed value for Pike County, Washington Township, and Pike County School Corporation, and the assessed value of selected parcels owned by IPL, particularly those with real and personal improvements or substantial land assessed value.

TABLE 15. Total assessed value for selected local governments (assess 2019, pay 2020)

	CERTIFIED ASSESSED VALUE
Pike County	$625,655,419
Washington Township	$273,440,242
Pike County School Corporation	$625,655,419

Sources: DLGF, Dec. 13, 2019.

TABLE 16. Schahfer Generating Station assessed value as a share of assessed value for selected parcels and taxing units (assess 2019, pay 2020)

	ASSESSED VALUE	SHARE OF PIKE COUNTY ASSESSED VALUE	SHARE OF WASHINGTON TOWNSHIP ASSESSED VALUE	SHARE OF PIKE COUNTY SCHOOL DISTRICT ASSESSED VALUE
63-02-12-700-014.000-011	$1,501,400	0.2%	0.5%	0.2%
Real property improvements	$1,060,400	0.2%	0.4%	0.2%
63-02-12-800-008.000-011	$1,459,000	0.2%	0.5%	0.2%
Real property improvements	$926,900	0.1%	0.3%	0.1%
63-02-12-900-006.000-011	$31,720,700	5.1%	11.6%	5.1%
Real property improvements	$27,621,800	4.4%	10.1%	4.4%
Personal property improvements	$98,026,310	15.7%	35.8%	15.7%
Total assessed value	$132,707,410	21.2%	48.5%	21.2%
Real and personal property improvements	$127,635,410	20.4%	46.7%	20.4%

Notes:

1. *These numbers were not adjusted using the proportion of retiring capacity with partial closure.*
2. *The certified total assessed value for the taxing districts in Table 15 were used to calculate the percentages in this table*

Sources: DLGF, Dec. 12, 2019; DLGF, 2020. Pike County, 2020.

Based on the value of these selected parcels, the Petersburg Generating Station makes up a substantial portion of the property tax base for these three local governments. The personal and real property improvements for these parcels make up one-fifth of the certified assessed value for the county and the school district. The proportion is almost double that for Washington Township. These units experienced property tax reductions in the past with the closure of the Hoosier Energy Ratts Generating Station. They also experienced a significant assessed value reduction for the Petersburg plant, about $94 million in the plant's assessed value from the 2019 to the 2020 budget year. Stakeholders indicated that for the recent substantial reduction units were able to raise property tax rates and generally were able to maintain the previous level of services.

The additional losses of assessed value that will result from closure are unknown, and may be particularly devastating for these units, particularly devastating given the recent reduction. These losses will be very challenging with likely some increases in tax rates and property taxes for county, township, and school taxpayers. These increases will likely be mitigated for taxpayers by property tax caps. Local leaders also may consider changes to public services to offset increases.

Among the counties that have five or more plant employees who reside there, Pike, Daviess, Dubois, Knox, and Vanderburgh counties utilize local options income taxes (Table 17) (ISBA, 2019). The number and distribution of employees across these counties and the relative income tax rates, suggest a minimal effect on local revenues. Pike County's relatively low income tax rate provides an option for replacing potential property tax losses.

TABLE 17. County local income tax rates for final CY 2020 certified distribution

LOIT RATES	PIKE COUNTY	DAVIESS COUNTY	DUBOIS COUNTY	KNOX COUNTY	VANDERBURGH COUNTY
Certified shares	0.0000%	1.0000%	0.6000%	0.6000%	0.9035%
Public safety	0.2500%	0.0000%	0.0000%	0.0000%	0.2000%
Correctional facility	0.0000%	0.0000%	0.2000%	0.2000%	0.0000%
Economic development	0.5000%	0.2500%	0.4000%	0.4000%	0.0000%
Property tax relief	0.0000%	0.2500%	0.0000%	0.0000%	0.0965%
Special purpose	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Total	0.7500%	1.5000%	1.2000%	1.2000%	1.2000%

Source: ISBA, Nov 18, 2019.

Regional economic analysis

The estimated economic effects from the partial closure of the generating station in Petersburg stand out from the other facilities in this analysis since it is the only facility using Indiana coal. A partial closure of this plant would lead to an estimated loss of approximately 125 direct employees (IPL, 2020). With the loss of associated supply chain purchases and household spending, the total job loss could rise as high as 595 jobs in the region worth an estimated $44.4 million in employee compensation (Table 18). To provide some context, the U.S. Bureau of Economic Analysis reports that this region had a total of nearly 139,000 jobs in 2018, meaning the total estimated effect of this partial closure would represent 0.4 percent of total employment in the area.

Other potential economic effects from this partial closure include a total of nearly $146 million in GDP in the region and $9.6 million in annual state and local government revenues.

TABLE 18. Estimated regional effects of Petersburg Generating Station partial closure

	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Employment	125	470	595	4.76
Compensation	$15.3M	$29.1M	$44.4M	2.90
GDP	$71.7M	$74.1M	$145.8M	2.03
State and local tax revenue	$3.4M	$6.2M	$9.6M	N/A

Sources: IPL, 2020; IBRC, using the IMPLAN economic modeling software.

Even with the coal sourced locally, the maintenance and repair construction industry would sustain the biggest losses with an estimated 127 jobs (Table 19). The decrease in demand for coal would lead to the loss of an estimated 106 jobs in the Southwest Indiana region including Daviess, Dubois, Gibson, Knox, Warrick, and Sullivan counties. The IMPLAN model indicates that this region has a total of nearly 2,220 jobs in the coal-mining industry, an estimated impact that translates to 4.8 percent of total coal jobs in the region.

The force account scenario in Appendix B contemplates that some share of construction workers directly employed at the plant, as well as some of the labor and spending associated with specialty contractors, will continue to be employed in the region by IPL. These workers and contractors could be redeployed to other activities such as building and maintaining transmission and distribution systems or other types of production infrastructure. Assuming that 30 percent of plant construction workers and 50 percent of labor and purchases for specialty contractors remain engaged with the utility, the full employment effects of this partial closure would improve from a loss of 595 jobs to 476 jobs, while the full GDP losses would improve from an estimated $145.8 million in value added to $128.0 million.

16 This analysis was conducted for the region that includes Pike County in which the Petersburg plant is located, along with bordering counties including Daviess, Dubois, Gibson, Knox, and Warrick counties. Sullivan County also was included in this region because the plant buys a portion of its coal from suppliers in this county. A separate analysis for the effects on Pike County solely is available in Appendix B.

TABLE 19. **Petersburg Generating Station employment ripple effects—Top 10 industries**

	JOBS
Maintenance and repair construction of nonresidential structures	127
Coal mining	106
Wholesale trade	16
Limited-service restaurants	10
Real estate	10
Full-service restaurants	9
Architectural, engineering, and related services	8
General merchandise stores	8
Hospitals	7
Miscellaneous store retailers	7

Source: IBRC, using the IMPLAN economic modeling software.

Stakeholder Input

Stakeholder perceptions about the impact expected from partial closure and local preparations for these changes are provided below.

Expected economic impacts

Most stakeholders indicated that the economic effects of the partial retirement at Petersburg will be very negative for Pike County and the surrounding region. More specifically, they identified potential job losses and wage reductions for employees, an impact on the plant's goods and services suppliers, and effects on local service industry. Stakeholders indicated that coal mines already have begun closing and laying off employees.

IPL is one of the two biggest employers in Pike County. Most stakeholders do not believe that workers are leaving their jobs in anticipation of closure. A few indicated that some may be starting to look around and that some people will not plan ahead. The Washington mayor indicated they are getting more applications for city positions. Stakeholders shared that the partial closure will be a "big transition for workers" and that the loss of a job can be "devastating, like losing a loved one."

Most stakeholders indicated that communities need more information about the company's specific plans for employees to understand the nature and scale of impacts for plant workers and tailor assistance to those specific needs. The recent WARN[17] notice will allow WorkOne to survey IPL workers. There is some expectation among stakeholders that IPL will address early job cuts through transfers, retirement, and attrition.[18] Younger workers may have to find new jobs and possibly relocate. The partial closure may also

17 Refers to a notice under the Worker Adjustment and Retraining Notification Act of 1988.

18 IPL provided the following statement when asked about their plans for transitioning employees. "With regard to the public information around Petersburg employee retraining, Indianapolis Power & Light Company continues to develop and analyze its staffing projections and potential training opportunities associated with the two planned retirements at Petersburg Generating Station in 2021 and 2023, respectively" (A. Baker, email communication, May 17, 2020).

affect part-time workers at the plants, potentially including some local firefighters who work part time in the plant's safety department.

Stakeholders indicated that the negative effects of layoffs will be mitigated to a degree by the tight labor market with a substantial number of open positions in the surrounding region. They mentioned the region is becoming an automotive cluster. There are open jobs at Toyota in neighboring Gibson County. They also identified open jobs with Dubois County manufacturers. They suggested that many employers are willing to provide training.

Officials believe that employees with production jobs will be able to find new positions directly. They suggested that employees with technician positions may need some training. Employees with administrative jobs are expected to be harder to absorb within the regional economy. One stakeholder mentioned that IPL closed the Petersburg human resources unit a few years ago.

Stakeholders indicated that matching current wages and benefits often including overtime is likely to be a challenge. One stakeholder provided an example of a recent closure of a legacy industry that resulted in a \$6–\$10/hour reduction in wages for those workers in new positions.

Stakeholders perceive that residents in the region generally are settled in their communities where they have connection to churches, schools, childcare, etc. They expect that some of the displaced workers will commute to other jobs in the region. Some believe that workers who leave IPL in the first wave of the partial closure will stay, but they are less confident that workers who leave in the second wave of potential layoffs will stay.

Pike County officials are particularly worried that employees who live in the county will leave. Population loss is a common challenge in rural areas, affecting the communities' ability to maintain the critical mass of people and business needed to thrive. They also expressed concern that the partial closure would have a negative impact on the already tight housing market.

Stakeholders believe that the challenges will filter down to goods and services providers as well as to the local service economy. They noted that IPL has continued to make investments in the plant. More information is needed from IPL to identify the nature and scale of likely effects. Stakeholders identified specifically potential effects on the railroad companies that deliver coal. Officials also identified known suppliers that provide welding, fabricating, fuel, and limestone. Stakeholders suggested effects on local businesses such as restaurants, although they disagreed about the likely severity. In Pike County some proprietors were identified to be spouses of plant employees, creating additional potential challenges for those families.

Pike County officials are thinking about the disposition of the retired elements at the IPL facility. No specific plans have been shared yet.

While IPL does not provide local electricity, officials are concerned about the effects of the transition on the power industry and on the availability and price of electricity locally. Power is an important input for potential replacement employers.

Expected local tax impacts

Pike County has a small industrial property tax base and projects a substantial loss of assessed value that will affect property tax revenue in 2023 to Pike County, Washington Township, the Petersburg Fire Territory, the Pike County School Corporation, and the Pike County Library. These taxing units already faced reductions in assessed value with the retirement of the Hoosier Energy Ratts Generating Station and more recently as a result of the depreciation and reallocation of IPL assets. Local governments were able to maintain services by raising tax rates. With the announcement that the partial closure will happen sooner than previously expected, taxing units are trying to be frugal. The Pike County Library is concerned about funding building expansion that is underway. Some stakeholders are concerned that the Pike County landscape does not lend itself well to development that can mitigate these losses. The reuse of old mine land is challenging.

Pike and Daviess county officials expect some impact on local option income taxes from job and wage losses for plant and supplier workers. Pike County officials hopes that those losses will not be as bad as for property taxes.

Local recognition of effects and adequacy of planning to date

Stakeholders that work regularly with the county and communities in Pike County generally are confident that local officials recognize the potential changes generally and will understand more specifically when information is available. Several indicated that IPL reported several years in advance that the plant would close, giving communities time to respond. Officials mentioned that a few local leaders are new and might have a bit of a learning curve.

Stakeholders indicated that the affected communities have put substantial energy into preparing for the anticipated effects of partial closure. They believe, however, that a new urgency and more planning is needed with the recent announcement of a compressed timeline for partial closure and as more specific information is available from IPL about their plans for employees and the affected goods and services firms.

One stakeholder suggested thinking creatively and looking at case studies from other areas of the country that have dealt with the decline of the coal industry, including Appalachia.

Resources to address impacts

Stakeholders identified many nonprofit and public sector organizations that are working on or serve as resources to address the effects identified above.

Workforce development and training

- WorkOne Region 8 (South Central) serves Brown, Daviess, Greene, Lawrence, Martin, Monroe, Orange, and Owen counties. All counties have a local office.
- WorkOne Region 11 (Southwest) provides services in Dubois, Gibson, Knox, Perry, Pike, Posey, Spencer, Vanderburgh, and Warrick counties. There are no local offices in Pike, Posey, Spencer, and Warrick counties. They reported an upcoming meeting with the Pike County library about a location for service hours in the county.
- IPL training.
- The Patoka Valley Career and Technical Cooperative includes the following high schools: Jasper, Pike County, Northeast Dubois, Southeast Dubois, Southwest Dubois,

North Spencer, East Gibson, Tell City, Perry Central, and Cannelton. These schools work together to cover a variety of CTE specialties.
- Washington High School.
- Postsecondary institutions including Ivy Tech and Vincennes.

Economic development
- Pike County Economic Development Corporation.
- Daviess County Economic Development Corporation.
- Radius Indiana serves Crawford, Daviess, Dubois, Greene, Martin, Orange, Lawrence, and Washington counties.
- Indiana 15 Regional Plan Commission provides assistance to communities with studies and applying for funding.
- Pike County Chamber of Commerce provides technical assistance to entrepreneurs.
- Southwest Indiana Development Council (SWIDC) is a coalition of local economic development organizations from Crawford, Daviess, Dubois, Knox, Martin, Orange, Perry, Pike, and Spencer counties.

Social services
- Worship sector for food support and other services.
- Township relief.

Efforts to mitigate impacts

Stakeholders identified a number of efforts local communities and other stakeholders have or plan to undertake related, at least in part, to the expected effects of the partial closure.
- The Pike County Economic Development Corporation has developed the Southwest Indiana Megasite, a 4,000-acre industrial park near I-69. The site is shovel-ready with electric (Win Energy and Hoosier Energy), water (Petersburg), sewer (Petersburg), and natural gas available. The site also is served by rail. Pike County EDC has completed a marketing study for the site. The city and county are working to market sites. Recently, stakeholders reported having some heavy industrial prospects.
- The development is on reclaimed mine land. The 2020 HEA 1065 allows mine reclamation sites to be designated as eligible for redevelopment tax credits. This incentive will be helpful in marketing the Megasite.
- Some new and relocating companies want to market to investors and customers that they use sustainable energy. Some want on-site generation, while others want to say that energy used at their sites comes from renewables.
- The Pike County Progress Partners is developing the Entrepreneurship and Technology Center also near I-69 that will provide support for entrepreneurs with coworking, training, and makers' spaces. It will open in late 2020.
- The Pike County Chamber of Commerce provides technical assistance services for local entrepreneurs.
- The Pike County Commissioners and Council are collaborating with nearby communities on a number of efforts, including working with Ivy Tech and Vincennes University on training and retraining.

- Pike County updated its comprehensive plan in the last couple of years.
- Petersburg is working on a wastewater upgrade using a U.S. Department of Agriculture grant and is preparing the engineering for a drinking water project.
- Representatives of the U.S. Economic Development Administration recently visited the region. The agency will provide access to the Assistance to Coal Communities program, which is available to communities with a WARN notice. These funds have been used for Entrepreneurship and Technology Center. They also can be used for water and sewer improvements.
- Petersburg joined the Main Street program in 2016.
- WorkOne Region 11 will survey IPL employees about needs as a result of the WARN notice.
- The community is applying for a Lilly Endowment grant to support retraining.
- The Daviess County Economic Development Corporation had planned a recent job fair, but it was cancelled due to the pandemic.
- Pike County EDC and Daviess County EDC were among the partners that participated in the Southwest Indiana Technology and Collaboration Hub Network Feasibility Study known as the SWITCH Study, launched in late 2018 and focused on entrepreneurship in the technology and defense sectors. Additional partners included nine additional local economic development organizations (Crawford, Daviess, Dubois, Greene, Knox, Lawrence, Martin, Monroe, Orange, Pike and Washington counties), three regional planning commissions (SIDC, River Hills and IN 15), two regional economic development organizations (Radius Indiana and the Southwest Indiana Development Council), Regional Opportunity Initiatives, Inc., and the Indiana Economic Development Corporation.
- The Pike County Economic Development Corporation, Farm Bureau, the Pike County Soil and Water Conservation District, and Purdue Extension hosted a workshop in March 2020 about the local tax impacts from partial closure. The speaker was Purdue University Professor Larry DeBoer.
- Several solar projects have been proposed in Pike County, including one resulting from an IPL request for proposals issued in late 2019 regarding the competitive procurement of replacement capacity.
- Daviess County EDC created the Daviess County Quality of Place and Workforce Attraction Plan through the Regional Opportunity Initiatives, Inc. Ready Communities Program. The program encourages investment in quality of life and in the skills gap for STEM careers in defense, technology, medical devices, and advanced manufacturing.
- Washington High School is working to launch a College and Career Academy, a career pathways strategy. The program will connect students with local and regional employers to establish local talent pipelines.
- In addition to services provided to member counties, Radius Indiana has invited Pike County to participate in a number of programs and is open to additional collaborations.

Gaps and other issues

Stakeholders identified service and resources gaps, as well as a number of miscellaneous issues.

- More resources are needed to address the local skills gap.
- One stakeholder would like to see more activity from the U.S. Small Business Administration to support small business startups locally and more partnerships run through the new technology and entrepreneurial center.

- Some local leaders across the state, including a number of city councils, have called for retiring coal-fired generation and moving to renewable sources. One stakeholder hoped that those communities would be a bit more sensitive about the effects of the transition directly on the affected communities.
- Regional definitions can be limiting in crafting solutions.
- One stakeholder suggested that the federal Opportunity Zone program could be helpful if there was more flexibility about the drawing of zones. Rural residences and needed investments are not as compact as in more urban areas.
- More guidance is needed for assessors about the assessment of wind and solar facilities. There are varied treatments across the state.

Summary

The Petersburg Generating Station is owned and operated by IPL. The plant is located in a rural setting in Pike County. IPL plans to close Units 1 and 2 by 2023.

Most stakeholders indicated that the partial closure of the IPL plant will affect Pike County and the region negatively. They specifically identified job and wage losses for employees, loss of sales for mining and other goods and services firms, and the effects on the local service industry. Within the region, Pike County and its communities will be the most profoundly affected by the partial closure and the resulting job losses, sales losses to the local service industry, and loss of property tax base.

Stakeholders believe that job losses will be mitigated by available jobs in the robust regional industrial economy. They believe that production workers will be absorbed quickly, while technician-level positions may require some training. Firms in the region often are willing to provide training. Other occupations may be harder to absorb.

Many stakeholders identified households in southern Indiana as locally rooted and that they will be willing to commute to new jobs. There also is concern, particularly in Pike County, about employee relocation and potential population loss that can further exacerbate the challenges of a rural community.

Petersburg is the only plant in our analysis that uses Indiana coal. Firms in five counties in the region are at risk for loss of coal sales, while firms in Marion, Vanderburgh, and Hamilton counties are most at risk for other goods and services. The greatest potential ripple-effect job losses are in the specialty trades and in mining.

Pike County has a small industrial property tax base and projects a substantial loss of assessed value that will affect property tax revenue in 2023 to Pike County, Washington Township, the Petersburg Fire Territory, the Pike County School Corporation, and the Pike County Library. These taxing units suffered assessed value losses in the current budget year as a result of the depreciation and reallocation of IPL assets. Local governments have been able to maintain services by raising tax rates. In anticipation of further losses, the affected taxing units are trying to be frugal. Pike and Daviess county officials expect some impact on local option income taxes from job and wage losses for plant and supplier workers.

Stakeholders generally are confident that local officials recognize the potential changes generally given available information. They mentioned that some new elected officials may have a bit of a learning curve. All agreed that more specific information is needed to refine local efforts and that a new urgency and more planning are needed with the recent announcement of a compressed timeline. The WARN notice will allow workforce development officials to survey current employees.

Affected communities in Pike and Daviess counties have put substantial effort into planning for closure, including the selected efforts below:

- The Pike County Economic Development Corporation worked with its partners to develop the Southwest Indiana Megasite, a 4,000-acre industrial park near I-69. It is served fully by utilities and rail service. A marketing study has been completed and Pike County EDC is marketing the site.
- The Pike County Progress Partners is developing Entrepreneurship and Technology Center also near I-69 that will provide support for entrepreneurs with coworking, training, and makers' spaces. It will open in late 2020.
- The Pike County Economic Development Corporation, Farm Bureau, the Pike County Soil and Water Conservation District, and Purdue Extension hosted a workshop in March 2020 about the local tax impacts from partial closure. The speaker was Purdue University Professor Larry DeBoer.
- The Daviess County EDC created the Daviess County Quality of Place and Workforce Attraction Plan.
- Petersburg joined the Main Street Program in 2016.
- The Pike County and Daviess County EDCs worked with other partners on in the Southwest Indiana Technology and Collaboration Hub Network Feasibility Study (SWITCH Study) that launched in late 2018 and focused on entrepreneurship in the technology and defense industries.
- The U.S. Economic Development Administration has visited the area and provided access to resources available as a result of the WARN notice through the Assistance to Coal Communities Program.
- Communities and educational institutions are working on a variety of training efforts.
- Resource organizations are poised to assist the impacted employees, businesses, and communities through the transition. Some concern was expressed that WorkOne does not have a local office in Pike County. WorkOne is exploring options for co-locating with a local organization to provide in-person services locally.

Rockport Generating Station

The Rockport Generating Station is operated by I&M. It is located in a rural setting near Rockport in Spencer County and is near the Ohio River. The annual average generation at the plant was 12.7 million MWh (2014–2018).

I&M has announced the closure of Unit 1 by the end of 2028. Current plans are that Unit 2 will remain operational.[19] Unit 1 accounts for 46.9 percent of the plant's net generation (2016–2018). For the analysis that follows, plant data—employment, wages and compensation, purchased goods and services, etc.—

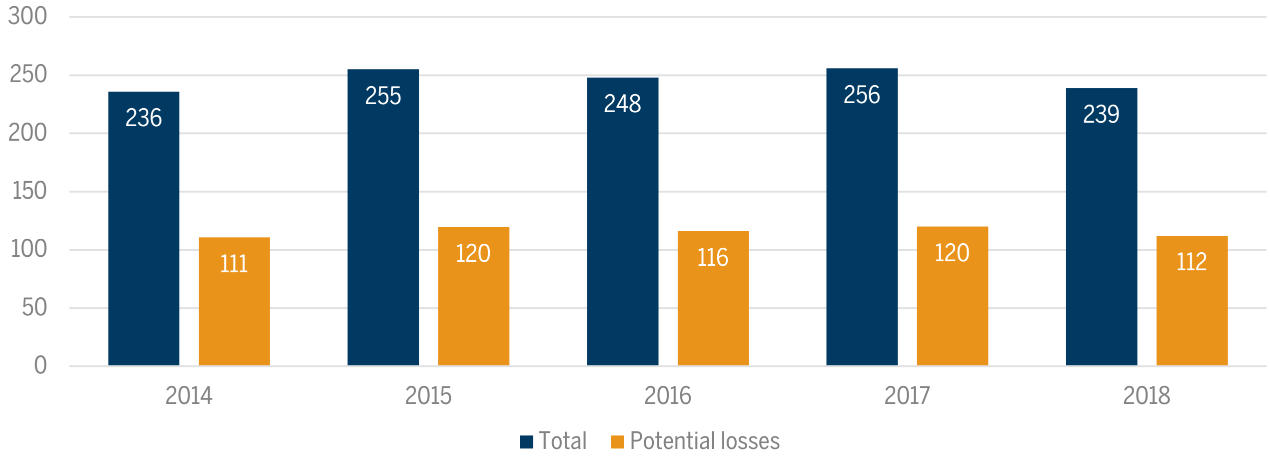
19 I&M's lease of Rockport 2 is scheduled to end December 2022. Currently, it is uncertain if I&M will renew the lease.

has been parsed using this proportion. The effects of closure also are assumed to occur proportionally by demographics, geography, etc.

Employment[20]

The Rockport plant had 239 employees in 2018. The partial closure potentially puts 112 employees at risk (Figure 37) (I&M, 2020), accounting for 1.9 percent of private sector jobs in Spencer County in 2018 (IBRC, 2020).

FIGURE 37. Rockport Generating Station total employees and estimated job losses from partial closure (2014–2018)



Source: I&M, 2020.

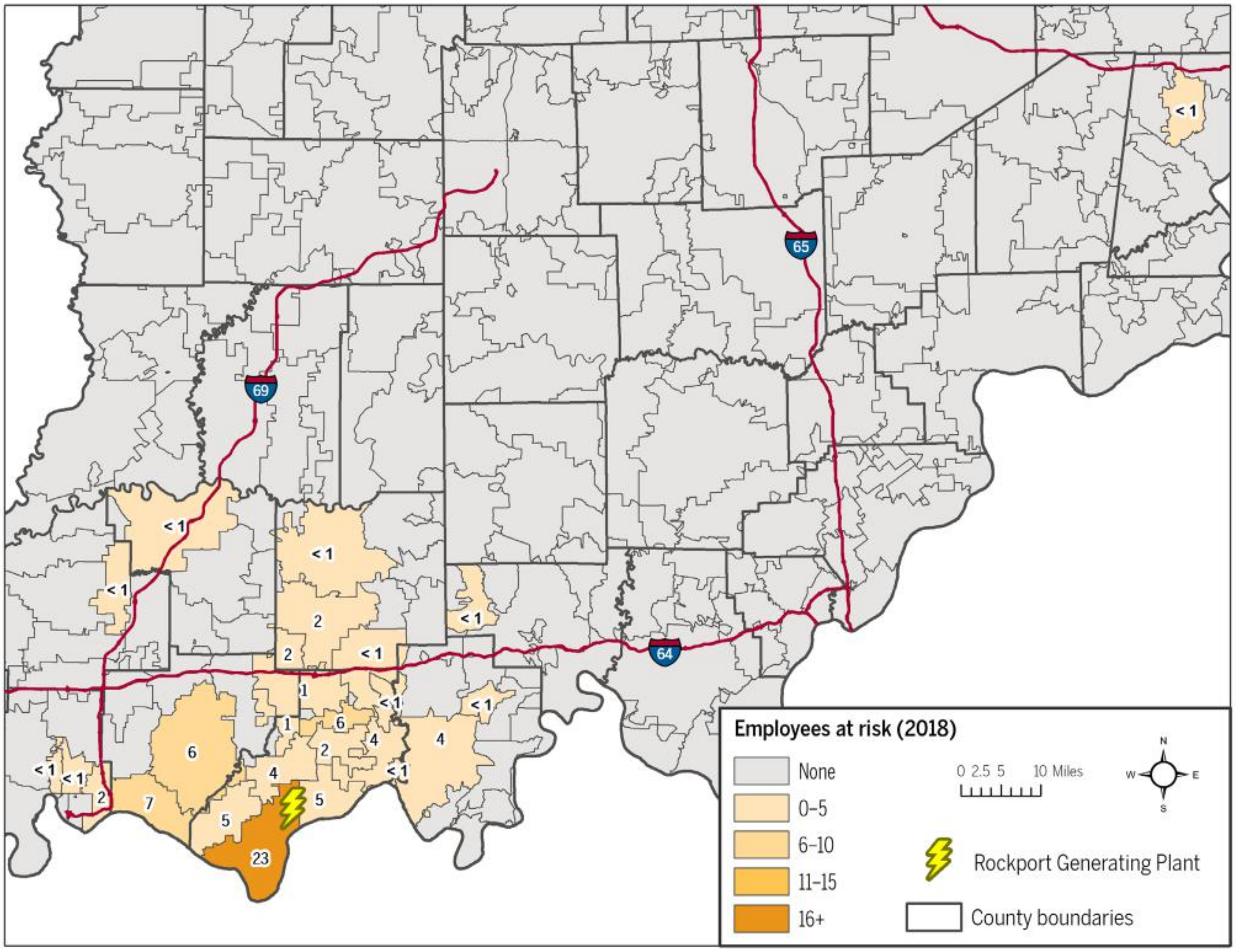
Most of the employees who worked at the Rockport plant live in Spencer and Warrick counties (2018). The remaining employees commute to the plant from Vanderburgh, Perry, Dubois, Gibson, Pike, Crawford, and Dearborn counties (Figure 38).

The southwest region has a robust industrial base and a tight labor market with low unemployment. Similar to Petersburg, skilled and semi-skilled workers likely can be absorbed within the regional economy either directly or with some training. Employees in other position types may find it more challenging to find replacement employment.

20 I&M provided the following statement about their plan for transitioning employees: "I&M's practice when we have reduced our workforce is to offer a severance package to affected employees. The value of that package is reviewed periodically and is revised as required by our Human Resources and Benefits personnel. We also offer, under certain circumstances, employees the opportunity look elsewhere in the company and apply for positions for which they are qualified. For example, in preparation for the retirement of several of coal-fired generating facilities in 2014, employees who would be affected by the retirements were able to apply for positions that we anticipated would be coming open at other facilities.

"Because the approach to a reduction in force depends on the circumstances driving the reduction, it is not possible to predict what we will do in the future, but I&M has a commitment to treating its employees fairly and with respect and we expect to do the same in the future." (R. Sitevaris, email communication, May 1, 2020).

FIGURE 38. Rockport Generating Station potential job losses in Indiana from partial closure by zip code of employee residence (2018)



Notes:

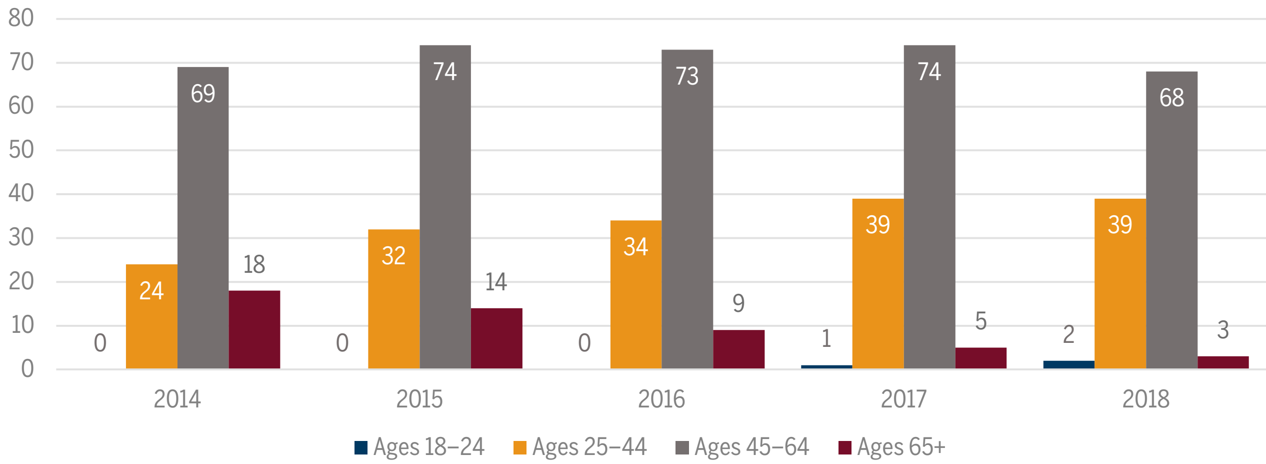
1. *Estimated job losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.*
2. *Zip codes represented by less than one employee equivalent are displayed at <1. All others are rounded to the nearest whole number.*

Sources: I&M, 2020; IndianaMap Data Portal.

Employee demographics

Most employees are white (95.5 percent) and male (90.2 percent). More than half of employees at the plant are ages 45–64, while about one-third of employees are ages 25–44. The plant employs just a few employees who are ages 18–24 or 65 and older (Figure 39) (I&M, 2020).

FIGURE 39. Rockport Generating Station potential job losses by employee age (2014–2018)



Source: I&M, 2020.

Wages and compensation

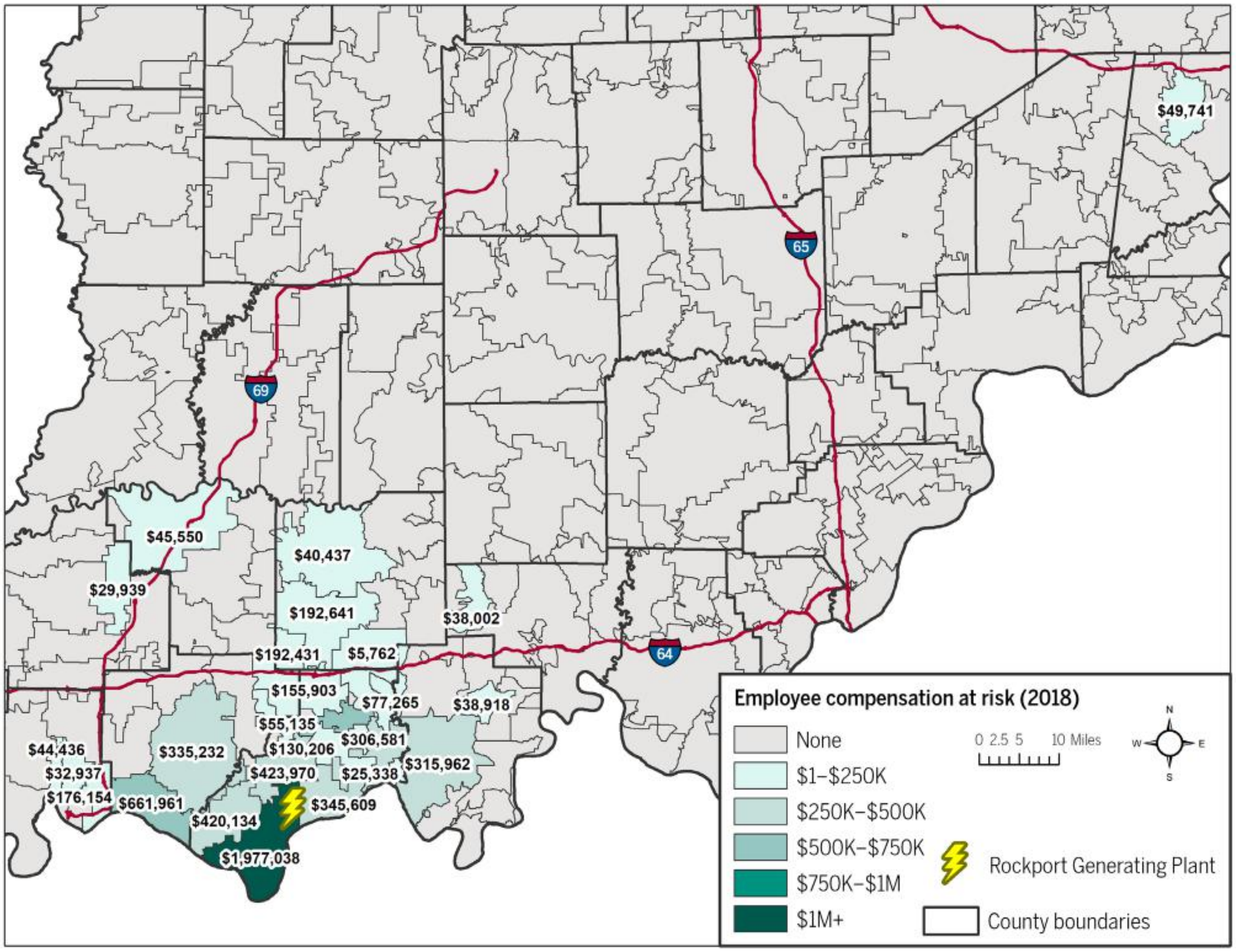
The wages and compensation in 2018 associated with estimated job losses were $9.4 million and $11.9 million, respectively (Figure 40). Employee average wages and compensation at the plant were more than double those in Spencer County. On average, employees at the plant earned $83,710. The average compensation—including both wages and benefits—at the plant was $106,088. That is substantially more than Spencer County's average wage of $41,075 and its estimated average compensation of $53,356 (I&M, 2020; IBRC, 2020).[21] Figure 41 shows the geographic distribution of potential losses in compensation. The premium wages and benefits paid by I&M may be difficult for transitioning employees to match.

FIGURE 40. Rockport Generating Station employee compensation (wages and benefits) and potential losses from partial closure (2014–2018)

Source: I&M, 2020.

21 Estimated compensation was estimated using wage data from IBRC (2020) and U.S. Bureau of Labor Statistics survey data regarding compensation (March 19, 2020).

FIGURE 41. Rockport Generating Station potential employee compensation losses in Indiana from partial closure by zip code of employee residence (2018)



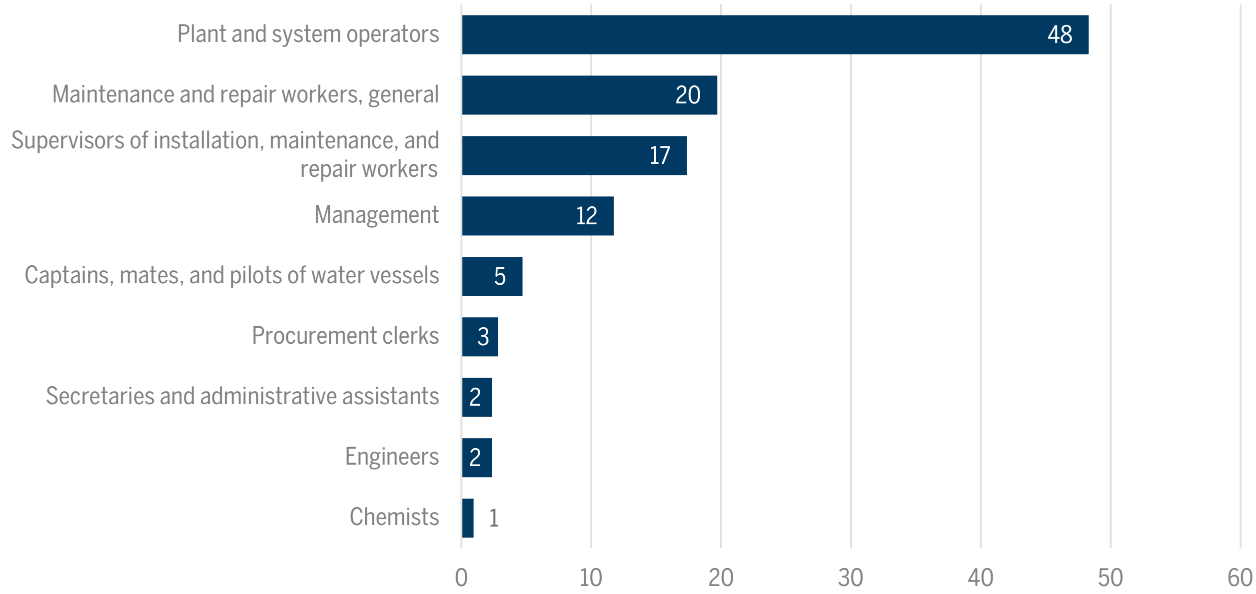
Note: Estimated compensation losses were calculated using the proportion of anticipated plant capacity reduction from partial closure.
Source: I&M, 2020.

Occupations

Figure 42 shows the types of positions that potentially are at risk from the partial closure. Occupations at the plant are 84.9 percent skilled/semi-skilled and 15.1 percent management/administrative (2018) (I&M, 2020).

As mentioned above, the tight labor market in Southwest Indiana make it likely that skilled and semi-skilled workers can find new positions. Administrative and other types of workers may experience more challenges finding new employment regionally.

FIGURE 42. Rockport Generating Station worker occupations associated with potential job losses (2018)

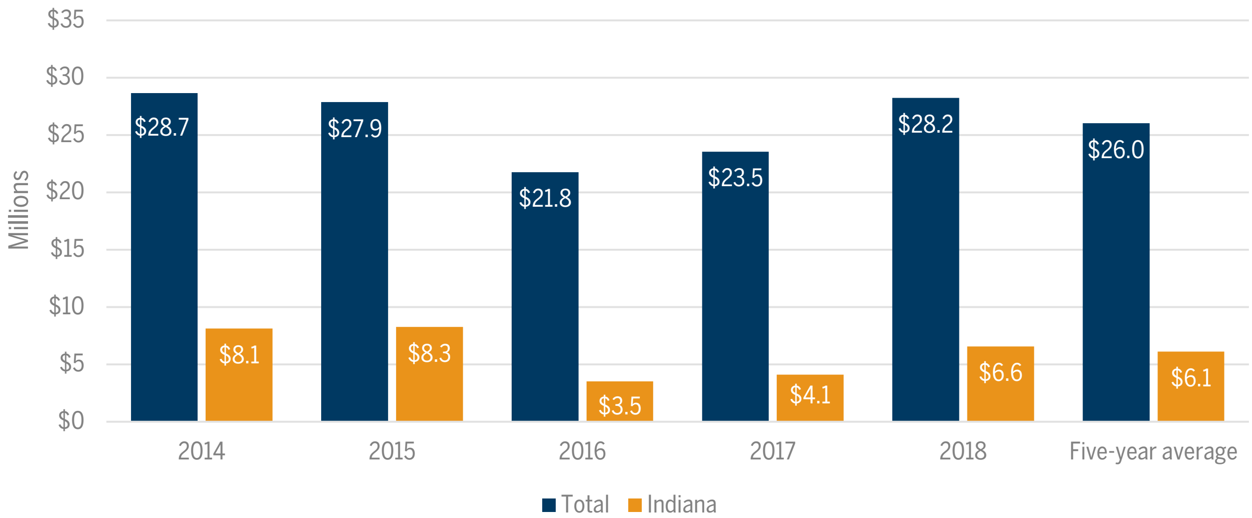


Source: I&M, 2020.

Goods and services purchases

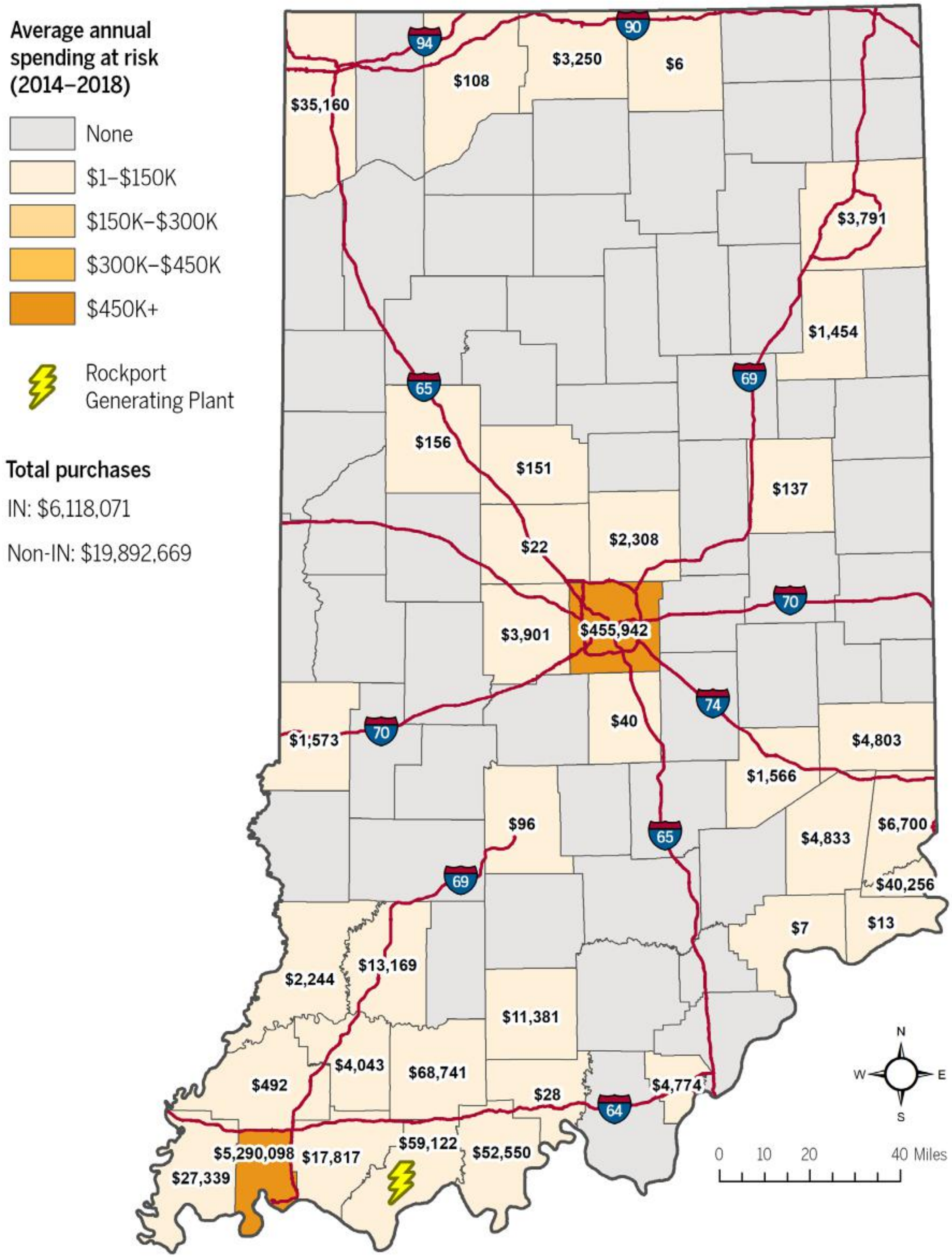
Figure 43 shows the estimated average annual loss of $26.0 and $6.1 million in total and Indiana purchases of goods and services, excluding coal (2014–2018). Data on goods and services purchased by sector were not available in an aggregated format. Figure 44 shows the location of estimated lost goods and services purchases in Indiana (I&M, 2020). I&M also purchased $326.1 million in out-of-state coal on average annually during the same period (I&M, 2020). A portion of these sales are at risk from the partial closure.

FIGURE 43. Rockport Generating Station potential goods and services losses, excluding coal, from partial closure (2014–2018)



Source: I&M, 2020.

FIGURE 44. Rockport Generating Station potential goods and services losses, excluding coal, in Indiana from partial closure by county (2014–2018)



Notes:

1. *Estimated losses were calculated using the proportion of anticipated plan capacity reduction from partial closure.*
2. *County total were aggregated from zip code data.*
3. *The Rockport plan purchases only out-of-state coal. These purchases are not reflected in the total show here for purchases from other states.*

Source: I&M, 2020.

I&M purchased goods and services from firms in 35 Indiana counties (Figure 44). Firms in Vanderburgh and Marion counties are most at risk for these losses (I&M, 2020).

Local income and property taxes

Property taxes and local option income taxes are fundamental resources for local governments. Table 20 shows total assessed value for Spencer County, Ohio Township, and South Spencer School Corporation. Table 21 shows assessed value of selected plant parcels owned by I&M/AEP, particularly those with improvements or substantial land assessed value.

TABLE 20. Total assessed value for selected local governments (assess 2019, pay 2020)

	CERTIFIED ASSESSED VALUE
Spencer County	$1,790,414,104
Ohio Township	$608,031,221
South Spencer School Corporation	$734,366,856

Sources: DLGF, Dec. 6, 2019.

TABLE 21. Rockport Generating Station assessed value as a share of assessed value for selected parcels and taxing units (assess 2019, pay 2020)

	ASSESSED VALUE	SHARE OF SPENCER COUNTY ASSESSED VALUE	SHARE OF OHIO TOWNSHIP ASSESSED VALUE	SHARE OF SOUTH SPENCER SCHOOL CORPORATION ASSESSED VALUE
74-15-11-900-005.000-017	$4,016,300	0.2%	0.7%	0.6%
Real property improvements	$1,667,300	0.1%	0.3%	0.2%
74-15-12-900-001.000-017	$43,875,300	2.5%	7.2%	6.0%
Real property improvements	$38,986,500	2.2%	6.4%	5.3%
74-15-13-900-001.000-017	$4,724,100	0.3%	0.8%	0.6%
Real property improvements	$2,385,700	0.1%	0.4%	0.3%
74-15-02-800-004.000-017	1,240,300	0.1%	0.2%	0.2%
Real property improvements	$571,300	0.0%	0.1%	0.1%
Personal property improvements	$342,576,700	19.1%	56.3%	46.7%
Total assessed value	$396,432,700	22.1%	65.2%	54.0%
Real and personal property improvements	$386,187,500	21.6%	63.5%	52.6%

Notes:
1. *These numbers were not adjusted using the proportion of retiring capacity with partial closure.*
2. *The certified total assessed value for the county, township, city, and school districts in Table 20 were used to calculate the percentage in this table.*

Sources: DLGF, Dec. 6, 2019; Spencer County, 2020.

Based on the value of these selected parcels, the Rockport plant makes up a substantial portion of the assessed value for Spencer County, Ohio Township, and the South Spencer School Corporation. The exact losses of assessed value from partial closure is unknown due to the complexities of the property tax assessment of utilities and the dynamics among levy controls, mix of property types and property tax caps, and property tax replacement strategies. These losses will be challenging with possible increases in tax rates and property taxes for taxpayers.

Among the counties that have five or more plant employees who reside there, Spencer, Dubois, and Vanderburgh counties utilize local option income taxes (Table 22) (ISBA, 2019). The number and distribution of employees across these counties and the relative income tax rates suggest a minimal effect on local revenues. Spencer County's relatively low income tax rate provides an option for replacing potential property tax losses.

TABLE 22. County local income tax rates for final CY 2020 certified distribution

LOIT RATES	SPENCER COUNTY	DUBOIS COUNTY	VANDERBURGH COUNTY
Certified shares	0.2611%	0.6000%	0.9035%
Public safety	0.0000%	0.0000%	0.2000%
Correctional facility	0.0000%	0.2000%	0.0000%
Economic development	0.5000%	0.4000%	0.0000%
Property tax relief	0.0389%	0.0000%	0.0965%
Special purpose	0.0000%	0.0000%	0.0000%
Total	0.8000%	1.2000%	1.2000%

Source: ISBA, Nov. 18, 2019,

Regional economic analysis[22]

The estimated regional direct employment effect of partial closure at the Rockport Generating Station is the potential loss of nearly 120 jobs and $11.6 million in compensation. The ripple effects from these reductions would bring the total effects to an estimated 256 lost jobs and nearly $18 million in lost wages and benefits (Table 23). Other potential impacts include a $56.1 million contribution to the region's GDP and $3.8 million in state and local tax collections.

More than one-third of the expected employment ripple effects would be realized in the maintenance and repair construction industry. Industries such real estate, food service, health care, and retail will also see some impact from the loss of household spending (Table 24).

22 This analysis was conducted for the region that includes Spencer County in which the Rockport plant is located, along with bordering counties including Dubois, Perry, and Warrick counties. A separate analysis for the effects on Spencer County solely is available in Appendix B.

TABLE 23. Estimated effects of Rockport Generating Station partial closure

	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Employment	116	140	256	2.21
Compensation	$11.6M	$6.3M	$17.9M	1.54
GDP	$46.6M	$9.5M	$56.1M	1.20
State and local tax revenue	$2.9M	$0.9M	$3.8M	N/A

Source: IBRC, using the IMPLAN economic modeling software.

TABLE 24. Rockport Generating Station regional employment ripple effects—Top 10 industries

	JOBS
Maintenance and repair construction of nonresidential structures	51
Real estate	5
Full-service restaurants	5
Limited-service restaurants	4
Hospitals	4
Wholesale trade	4
Miscellaneous store retailers	3
General merchandise stores	3
Monetary authorities and depository credit intermediation	3
Nonstore retailers	3

Source: IBRC, using the IMPLAN economic modeling software

Summary

The Rockport Generating Station is operated by I&M. Unit 1 is owned by I&M and Unit 2 is owned by an investor group. The plant is located in a rural setting in Spencer County on the Ohio River. I&M has announced the retirement of Unit 1 by 2028.

Within the region, Spencer County potentially will be most affected by the loss of employment. The potential loss of assessed value could have a substantial effect on Ohio Township and the South Spencer School Corporation, and to a lesser extent Spencer County. Based on the amount of purchases, firms in Vanderburgh and Marion counties are most at risk for losses in goods and services from partial closure.

Statewide economic impact analysis

Table 25 summarizes the combined statewide effects of the four closures and partial closures under consideration. The numbers listed in the direct effects column are simply a sum of the direct effects shown previously for the individual facilities. The ripple effects, however, are all larger than the sum of the individual plants since a portion of the economic activity created by a given generating station will occur elsewhere in Indiana outside of its region. The combined total employment effect of these closures stands at an estimated 2,382 jobs, while the total GDP impact is nearly $539 million.

TABLE 25. Summary of statewide effects of the closures and partial closures of four coal-fired generating stations

	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Employment	652	1,730	2,382	3.65
Compensation	$77.5M	$98.4M	$175.9M	2.27
GDP	$354.0M	$184.7M	$538.7M	1.52
State and local tax revenue	$16.1M	$15.2M	$31.3M	N/A

Source: IBRC, using the IMPLAN economic modeling software.

Maintenance and repair construction and coal mining are the industries expected to take the largest hit in terms of employment (Table 26). According to the IMPLAN model, the employment impact in the maintenance and repair construction industry represents slightly more than 1 percent of all jobs in this industry statewide, while the impact in coal mining translates into 4.7 percent of employment in this industry.

TABLE 26. Statewide summary of employment effects—Top 10 industries

	JOBS
Maintenance and repair construction of nonresidential structures	346
Coal mining	106
Wholesale trade	78
Full-service restaurants	62
Hospitals	51
Limited-service restaurants	48
Real estate	46
Employment services	45
Retail—general merchandise stores	31
Physician offices	27

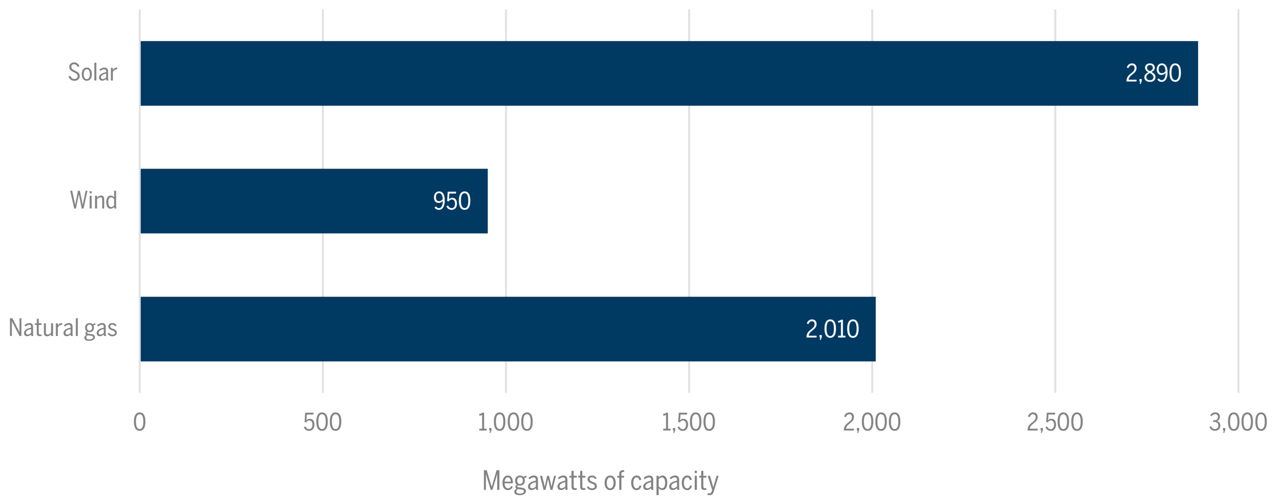
Source: IBRC, using the IMPLAN economic modeling software.

EMPLOYMENT IMPACTS OF NEAR-TERM SOLAR, WIND, & NATURAL GAS GENERATION INVESTMENTS IN INDIANA

While several Indiana electric utilities are set to cut some of their coal-fired generation in the state, many have plans to expand their generation capacity for other energy sources during the next decade. This section of the report explores the potential effects of these investments.

The state's investor-owned electricity producers expect that Indiana's combined generation capacity of wind, solar, and natural gas energy will expand by an estimated 5,850 MW between 2023 and 2030 (Figure 45).

FIGURE 45. Projected increase in alternative energy generation capacity in Indiana (2023–2030)



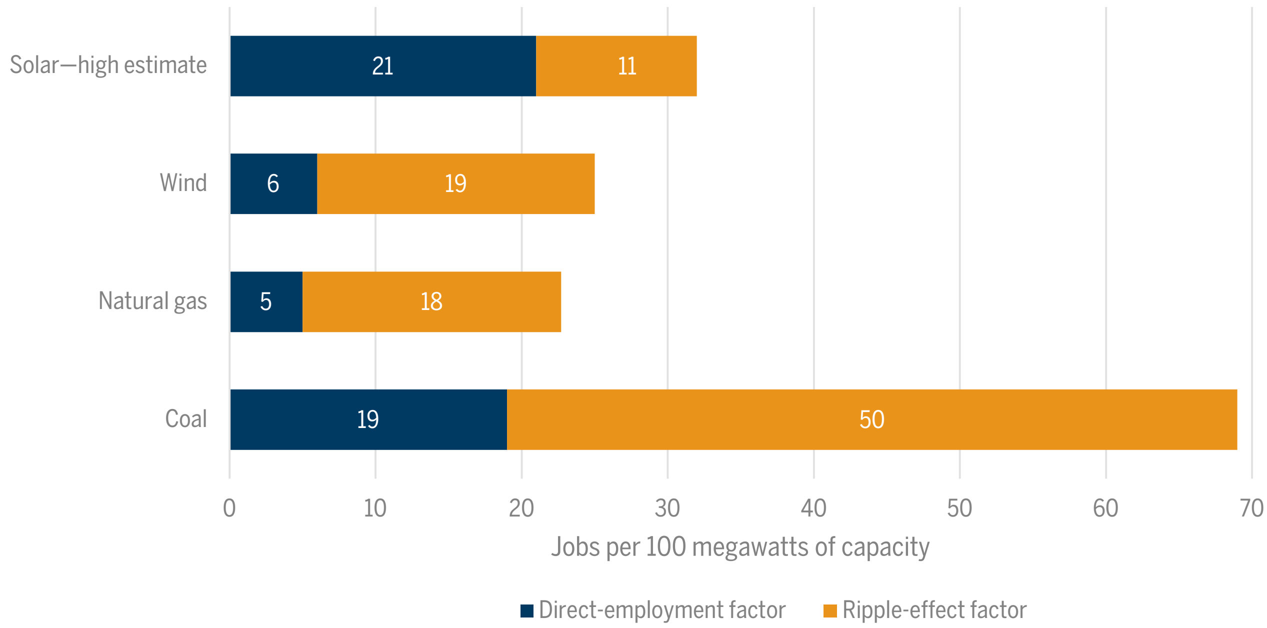
Source: IURC

This expected expansion in alternative energy sources will generate new jobs that will partially offset the job losses associated with coal-fired plant closures, although there is some uncertainty surrounding the potential size of these impacts as described above.

Figure 46 highlights the potential employment effects—either an expansion or contraction—of changes in energy production by type, with employment factors standardized by the number of jobs per 100 MW of capacity.

The direct employment factor for solar energy high estimate is 21 direct jobs for every 100 MW of capacity. With an employment multiplier of 1.5, the full employment impact for solar energy generation could range as high as 32 jobs per 100 MW. Meanwhile, the direct employment factors for wind and natural gas are comparatively small, but with employment multipliers greater than four for each industry, the total employment factors for these sources are 25 jobs and 23 jobs, respectively.

FIGURE 46. Estimated employment factors for operation and maintenance per 100 megawatts of capacity



Notes:

1. *The numbers for coal production originate from our analysis of the four Indiana facilities covered in earlier in this report.*
2. *The employment factor reported by three prospective Indiana solar farms is substantially less than the high estimate reported here. We are not able to report the specific factor due to non-disclosure issues.*

Sources: Steinberg et al., 2012; IPL, 2020b; and IBRC, using the IMPLAN modelling software.

TABLE 27. Potential employment effects of increased alternative energy generation

ENERGY TYPE	EXPECTED CHANGE IN CAPACITY 2023–2030 (MW)	TOTAL EMPLOYMENT FACTOR (PER 100 MW CAPACITY)	EMPLOYMENT CHANGE 2023–2030
Solar	2,890	up to 32	up to 930
Wind	950	25	240
Natural gas	2,010	24	480
Total	5,850	N/A	up to 1,650

Source: IBRC, using the IMPLAN economic modeling software.

Table 27 highlights the potential impacts when these total employment factors are applied to the projections of expanded alternative energy capacity in the state. If Indiana experiences an expansion of alternative energy capacity in the neighborhood of 5,850 MW between 2023 and 2030, this would likely support up to 1,650 jobs in the state. If the employment impacts of these alternative energy sources reach this upper limit, it would represent 69 percent of the estimated statewide job losses linked to the four coal plant closures shown in Table 25.

CONCLUSION—IMPLICATIONS FOR INDIANA

An energy transition from carbon-intensive fossil fuels, such as coal, to low- and no-carbon sources of energy (e.g., wind, solar, natural gas, and demand-side management) is occurring across the globe. As coal plants and coal mines close and the use of renewable energy increases, communities in Indiana will be affected directly. Many communities depend on the tax revenue and employment provided by coal power plants and mines in their community. As the energy transition continues, these communities are likely to experience social and economic losses to varying degrees based on the particular local and regional circumstances, such as losses of jobs, tax revenue, a sense of community, and cultural identity. While historically coal-reliant communities have not been the same communities to gain renewable energy benefits, there are opportunities for renewable energy projects in these communities. Renewable energy projects offer a large amount of short-term employment, as well as tax revenue and payments to landowners. State government and local communities can take steps to plan for the retraining of workers, the stabilization of local government revenue, and local economic development to minimize the costs and maximize the local benefit of the energy transition.

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APPENDIX A—EFFECTS OF COVID-19 PANDEMIC ON ECONOMIC IMPACT ASSESSMENTS

Estimates of economic impacts, tax revenue effects, labor, and community response were based on data and interviews conducted before the release of employment and GDP data related to the current COVID-19 pandemic. While the impacts of the pandemic are not yet fully understood, the fundamental concepts of the risks associated with the closure of the plants and the potential for alternative energies remain in place. The full effects of this crisis are yet to be realized at the national, state, or local level. Even though data that has been released is very specific for the nation and for individual states, it does not imply a known level of impact at the regional or county level.

Plant closures are scheduled to start in 2021 with more scheduled for 2023 and others scheduled for as late as 2028. The timing and magnitude of any economic recovery in counties where plant closures are scheduled cannot be estimated with high confidence at this time. This report is based on assumptions about generation/consumption from pre-pandemic static consumption patterns that still apply in the current economic downturn. Current events related to COVID-19, however, imply a possible upending of the entire cost model of electricity generation and distribution. For example, if there is lower generation and usage levels because of a longer term (beyond a few months) economic slowdown and recovery, utilities must spread the capital cost of the distribution and generation infrastructure over fewer units of electricity used by existing consumers and industries. As a result, costs per unit of generated electricity may increase (subject to approved rate adjustments) even as usage per household increases because of stay-at-home orders. This may result in higher consumer energy bills for everyone, not just those who can work from home and have not been furloughed.

From a resiliency perspective, there may be some good news for communities in which power companies currently operate. Because of the inelasticity of demand for electricity, combined with the vertical structure of the largest power companies, power generation companies may be affected less severely in the economic downturn than other industries. This implies that in the short-term power plants are better-positioned to weather an economic downturn; thus, even at lower levels of demand, power companies may help localities weather better than communities without these plants. In the long term, however, unless replaced by other industries or forms of power generation, local economies will certainly become less resilient.

Finally, long-term demand for electricity may be changed by reconfiguration of supply chains. This is particularly true for products deemed essential to national security but that currently are largely produced overseas, such as pharmaceuticals, medical devices and equipment, defense-related materials and products, etc. If there is substantial re-shoring of industries, the demand for electricity will increase beyond assumptions discussed in this report.

The estimates provided in this report do not consider potential residual effects from the current economic downturn because, as discussed above, the full extent of economic adjustment will not be known for several months or longer. Therefore, the actual effects of plant closures on any county or region cannot be estimated with a high degree of confidence in the current economic environment.

APPENDIX B—ADDITIONAL ECONOMIC EFFECTS SCENARIOS

The research team conducted two additional modeling analyses—county level estimates and a force account scenario.

County-level estimates

Tables B1 and B2 outline the estimated employment and GDP effects within just the counties in which the coal-fired generating stations are located. However, it is important to note that the Schahfer station is located in Jasper County, but researchers treated it as a two-county region since a large share of its employees live in Porter County. For these county-level estimates, the direct effects of these power plants are identical to those listed in the previous section. As a rule, however, the ripple effect estimates will always be smaller than those reported for a larger region since some portion of the household spending and supply chain purchases related to a given facility will be spent in other communities in the region.

TABLE B1. County-level employment effects

COUNTY (GENERATING STATION)	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
LaPorte (Michigan City)	118	80	198	1.68
Pike (Petersburg)	125	130	255	2.04
Spencer (Rockport)	116	70	186	1.60
Jasper/Porter (Schahfer)	293	240	533	1.82

Source: IBRC, using the IMPLAN economic modeling software.

On a proportional basis, the estimated employment impact is greatest in Pike County as the total employment effect represents roughly 6 percent of the county's 4,209 total jobs in 2018, as reported by the U.S. Bureau of Economic Analysis. The impact in Spencer County translates to nearly 2 percent of its total jobs, while the effects in LaPorte County and the Jasper/Porter area represent 0.4 percent and 0.5 percent of all jobs, respectively.

TABLE B2. County-level GDP effects

COUNTY (GENERATING STATION)	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Jasper/Porter (Schahfer)	$170.4M	$18.2M	$188.6M	1.11
LaPorte (Michigan City)	$65.3M	$5.5M	$70.8M	1.08
Pike (Petersburg)	$71.7M	$11.1M	$82.8M	1.15
Spencer (Rockport)	$46.6M	$4.2M	$50.8M	1.09

Source: IBRC, using the IMPLAN economic modeling software.

Force account scenario

The average consumer usually thinks about the economy in terms of producers and consumers. A consumer rarely thinks in terms of how a product or service is made. The average guest at a hotel considers lodging as one service, never mind that making a bed is much different than making an omelet. However, those two production activities—accommodation in contrast to a restaurant—are separated in the national economic accounting production table, the same sort of input-output table that is used to estimate the employment and supply chain ripple effects of a plant closing or opening. The "how" of economic production—which includes the type of labor, supplies, and technology—is the organizing principle for classifying industries. Industry classification is based on production.

It so happens that utilities in general share some similarities with lodging in terms of production activities; they both produce two different things with two different production functions. Lodging produces a place to sleep and a place to eat at the same address. The labor force at electricity generation plants produce electricity, but many of the workers at the plant build and repair structures. They are construction workers. In national industry analysis at places like the BEA and the U.S. Bureau of Labor Statistics, these construction workers are called force account.

As the research team approached the question of the effects of closing coal plants and utilizing other sources of electricity, they considered the separate effects of plant closings on coal-plant operators—those managing the fuel and waste as well as those monitoring the electricity generation—and the construction workers employed by the utilities. While the operators would most likely be displaced as a result of a closing, the force account construction workers still employed by the utility are still needed to build and maintain the electricity transmission and distribution infrastructure. The utilities' purchase of goods, materials, and services for the specialty construction needs of an electricity transmission and distribution system would also still be needed.

Thus, not all labor will be displaced because of a coal plant closing or because multiple units within a plant close. As a result, the economic impacts estimated and presented in the main body of the report are the worst-case scenarios. The actual economic ripple effects will be smaller.

Pursuant to a more accurate picture of the economic ripple effects, the research team created an alternative scenario. There could be several scenarios ranging from the displacement of all force account construction workers, as modeled above, to different proportions of those force account workers who ultimately become redundant with the plant closures. This also holds for the purchased specialty labor inputs mentioned above. No direct data or research was available to select the proportion of absorption.

In the selected scenario, the research team assumed that 30 percent of workers attached to any given plant are force account and would transition frictionlessly to other construction and maintenance activities of non-coal electricity production. We also assumed that only 50 percent of the labor and purchased materials associated with specialty contractors working for the coal plants would also become redundant or discontinued.

A comparison of the employment results in the individual tables for each generating station closing reveals that the direct employment effects—those who are no longer on the plant payroll—are reduced by about 100 statewide (652 versus 554). The ripple effect job losses associated with the spending of the redundant workers together with jobs related to the supply chain are reduced by about 155 (1,040 versus 885) (Table B3). In all, the number of jobs lost is estimated to be reduced by about 250 with the alternative scenario of utility construction workers still holding their jobs after the plant closure. We see the same pattern for the change in state GDP (Table B4) and, while not presented, the in-state and local tax revenue.

Under this scenario, the expected total net change in employment in these regions is closer to 1,450 than to 1,700.

TABLE B3. Employment effects under force account scenario

GENERATING STATION	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Schahfer	249	290	539	2.16
Michigan City	100	125	225	2.25
Petersburg	106	370	476	4.49
Rockport	99	100	199	2.01

Source: IBRC, using the IMPLAN economic modeling software.

TABLE B4. GDP effects under force account scenario

GENERATING STATION	DIRECT EFFECTS	RIPPLE EFFECTS	TOTAL EFFECTS	MULTIPLIERS
Schahfer	$144.8M	$21.7M	$166.5M	1.15
Michigan City	$55.3M	$9.5M	$64.8M	1.17
Petersburg	$60.8M	$67.2M	$128M	2.11
Rockport	$39.8M	$6.6M	$46.4M	1.17

Source: IBRC, using the IMPLAN economic modeling software.

APPENDIX C—WIND FARM DATA SUMMARY

Table C1 summarizes operations data provided by Indiana wind farms.

TABLE C1. Data summary for selected Indiana wind farms (2014–2018)

	AGGREGATED TOTAL PER 100 MWH CAPACITY	AVERAGE ANNUAL
Annual nameplate capacity	7,769 MWh (2018)	N/A
Electricity generation	18,890,826 MW	N/A
Capacity factor	29.23%	N/A
Employment	107 (2018)	4.7
Compensation	$31.8M	$0.4M
Good and services purchased (minus lease payments to landowners)	$230.7M	$3.0M
Good and services purchased in Indiana (minus lease payment to landowners)	$109.2M	$1.4M
Initial capital expenditures	$3.4B	$189.0M (one-time)
Ongoing capital expenditures	$48.2M	0.6M

Note: Calculations were made using annual data provided by wind farm companies and account for both years of operation and missing data.
Sources: BP Wind Energy [BP], 2020a, BP, 2020b: EDPR, 2020a; EDPR, 2020b; NextEra Energy Resources, 2020; Pattern Energy, 2020; RWE Renewable Americas, 2020.