Next Steps

Cause No. 46193

Additional questions, comments, and feedback can be sent to

DEIndianaIRP@1898andco.com

Please provide any written feedback by July 10, 2024

The fourth technical and public stakeholders meeting will occur in early August.

Meeting registration will be sent out 4-6 weeks in advance.

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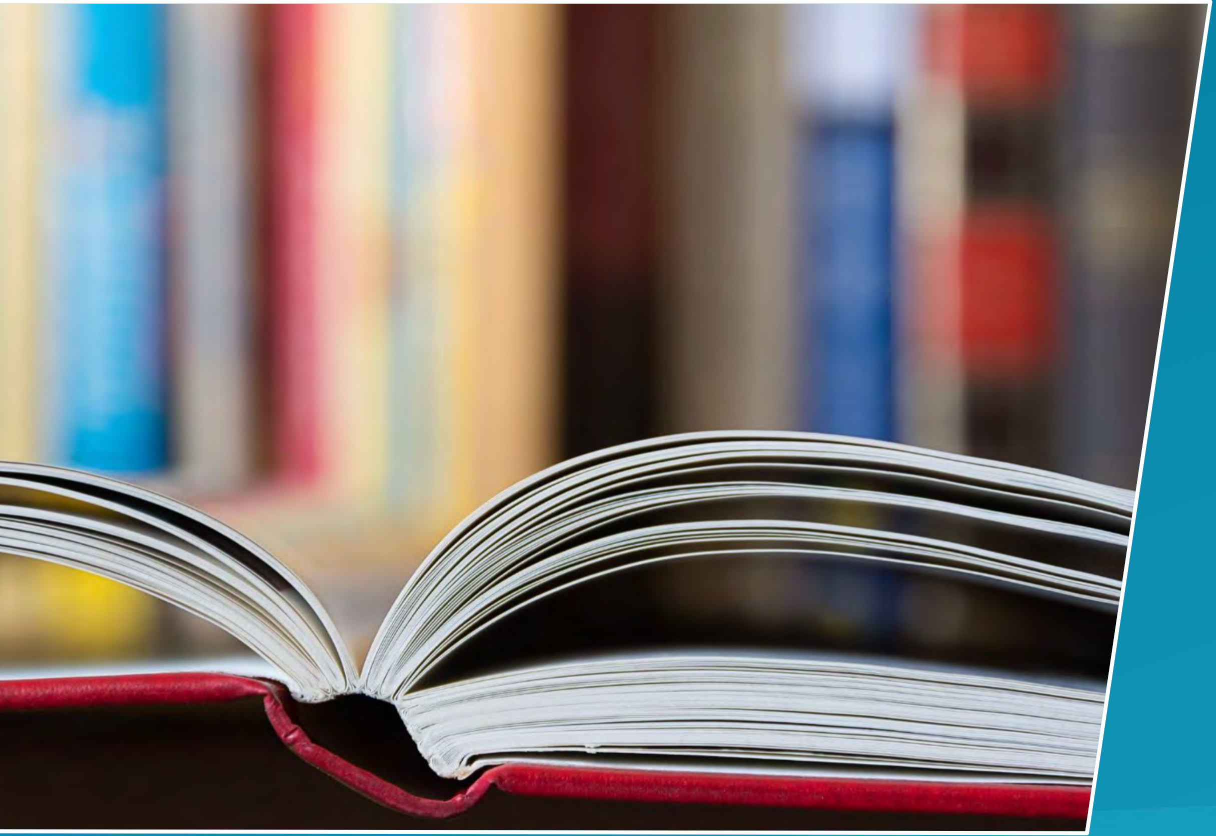
Thank you



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Appendix

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Appendix: Resource Availability

Updates since Meeting 2

Annual Resource Availability (Interconnection Timing, BoY) | Thermal

Resource Type	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation	Basis for Assumption
CT	2031+: Two HA.03 (851 MW)	2031+: Two HA.03 (851 MW) **H_2 fuel**	Reference	Assessment of resource availability and suitable locations
CC	2029+: 1x1 H.03 (664 MW) 2031+: 2x1 H.03 (1,364 MW)	Reference	Reference	Assessment of resource availability and suitable locations
CT PPA	Thru 2028: 600 MW	Reference	Reference	MISO D-LOL implementing in 28/29
Nuclear	2037+: SMR 2039+: Advanced Reactor	Reference	**N/A**	Based on assumption of earliest availability

Note: Differences from reference case marked in **Bold**
BoY: Beginning of Year – Availability begins January 1 of year listed.

No changes to Thermal Resource Availability since Meeting 2

Annual Resource Availability (Interconnection Timing, BoY) | Renewables & Storage

Resource Type	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation	Basis for Assumption
Solar	2026: 199 MW	2026: 199 MW	Reference	Speedway PPA in-flight 2022 RFP awards 2024 RFP proposals pending evaluation
	2027: 300 MW	2027: 300 MW		
	2028: 750 MW	2028: 750 MW		
	2029-2031: 1,000 MW	**2029-2031: 1,500 MW**		Assumes added capacity in future DPP cycles & queue reforms result in expedited study processes
	2032+: 1,200 MW (↑ 200)	**2032+: 1,500 MW**		
Wind	2028: 200 MW	2028: 200 MW	Reference	2024 RFP proposals pending evaluation
	2029: 200 MW	2029: 200 MW		
	2030-2031: 300 MW	**2030-2031: 600 MW**		Assumes added capacity in future DPP cycles, queue reforms expedite study processes & procurement outside of LRZ6
	2032+: 400 MW (↑ 100)	**2032+: 1,000 MW** (↑ 400)		
Storage	2028-2029: 300 MW	2028-2029: 300 MW	Reference	2028-2029: Based on RFP data 2030+: Based on MISO Queue
	2030+: 700 MW	**2030+: 1,200 MW**		
LDES	N/A	**2030+: 100 MW (10-hr) 2032+: 100 MW (100-hr); 500 MW (total)**	Reference	Technology readiness level
SPS	2028-2029: 400 MW Solar; 50% (4-hr)	2028-2029: 400 MW Solar; 50% (4-hr)	Reference	Assumes added capacity in future DPP cycles & queue reforms result in expedited study processes
	2030+: 600 MW Solar; 50% (4-hr)	**2030+: 1,000 MW Solar; 50% (4-hr)**		

Note: Differences from reference case marked in **Bold**
BoY: Beginning of Year – Availability begins January 1 of year listed.

Changes since Meeting 2 are highlighted

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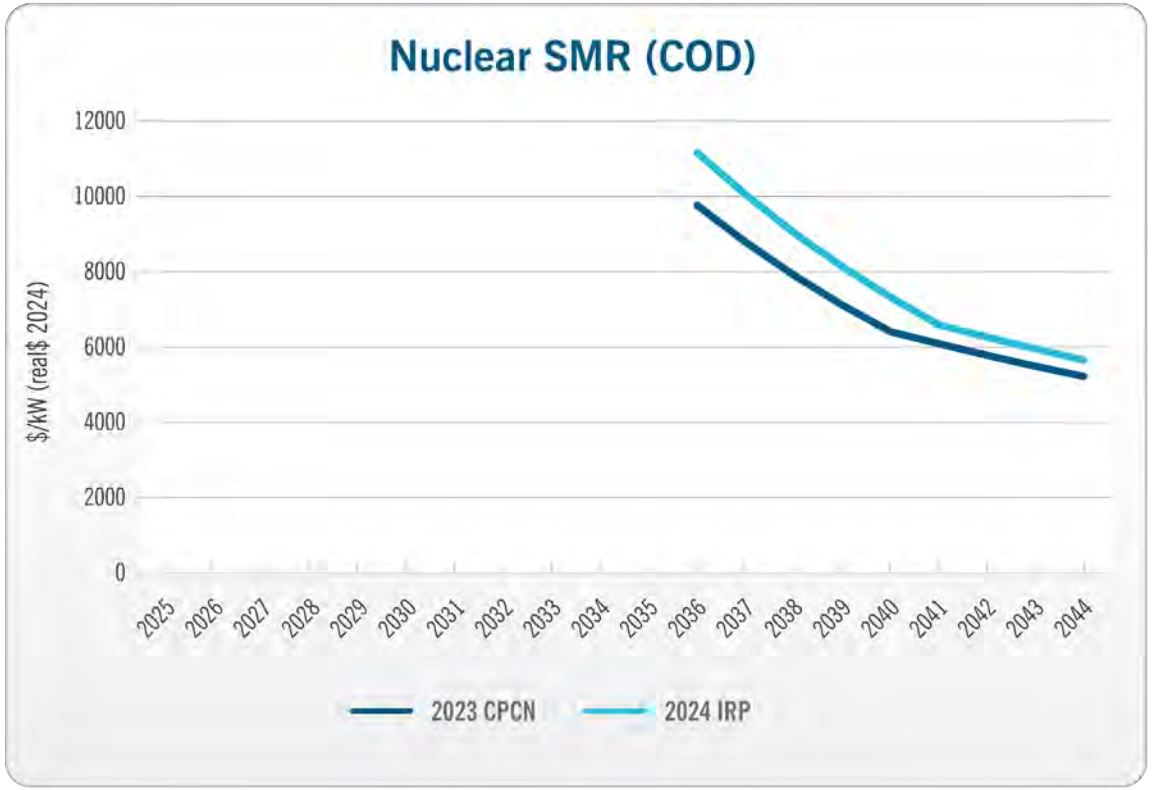
Appendix:
Nuclear SMR Costs

Nuclear SMR Cost Curve



SMR Advantages Relative to Traditional Nuclear:

- Modularized section for containment fabricated offsite
  - Reduces quantity of concrete, rebar
  - Majority of welding done offsite
- Modularized equipment rooms fabricated offsite and installed in sections
- Reactor vessel below grade
  - Passive shutdown and cooling
  - Fewer moving parts (pumps, valves, motors, etc.) required
- Greater use of commercially available components
- Smaller site footprint
- Proven reactor technology should result in reduced licensing costs

Costs can be expected to decline as designs, manufacturing processes, and construction processes are refined and improved.

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Appendix: Demand-Side Management Market Potential Study

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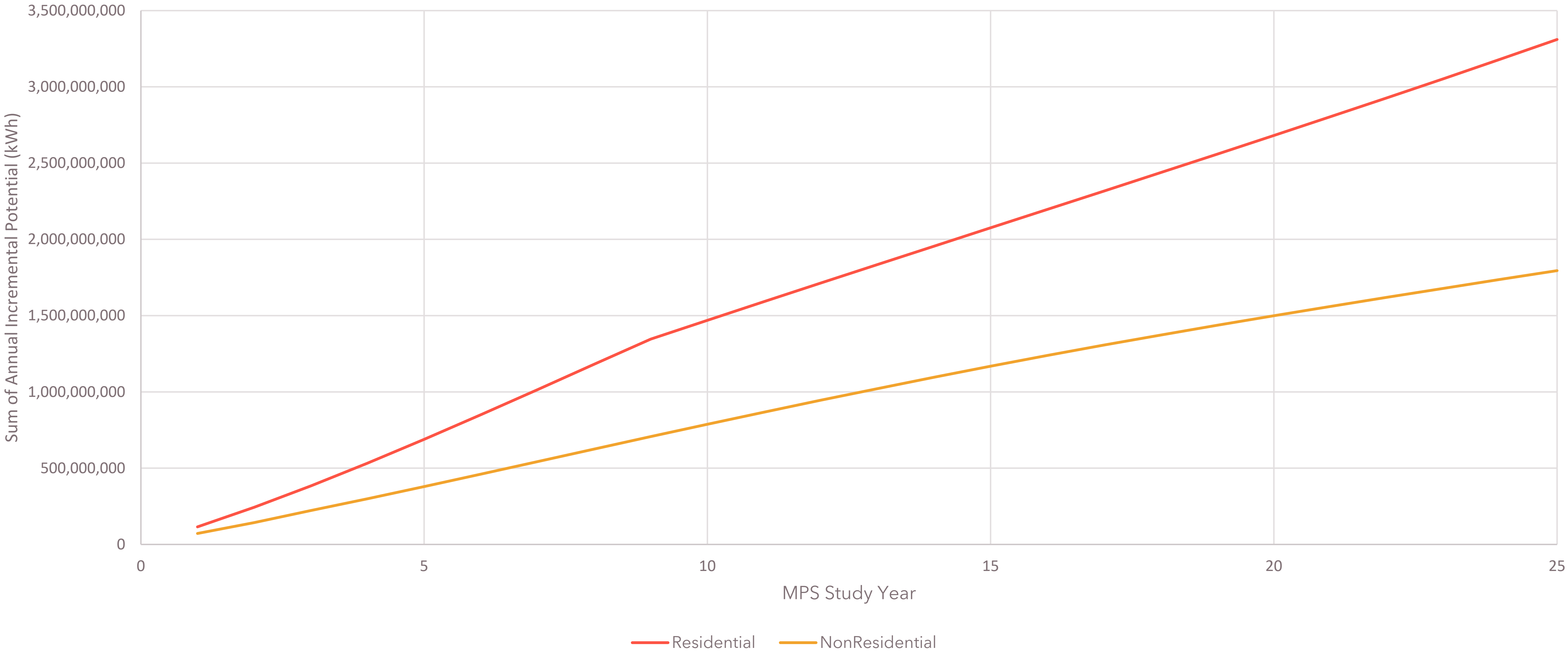
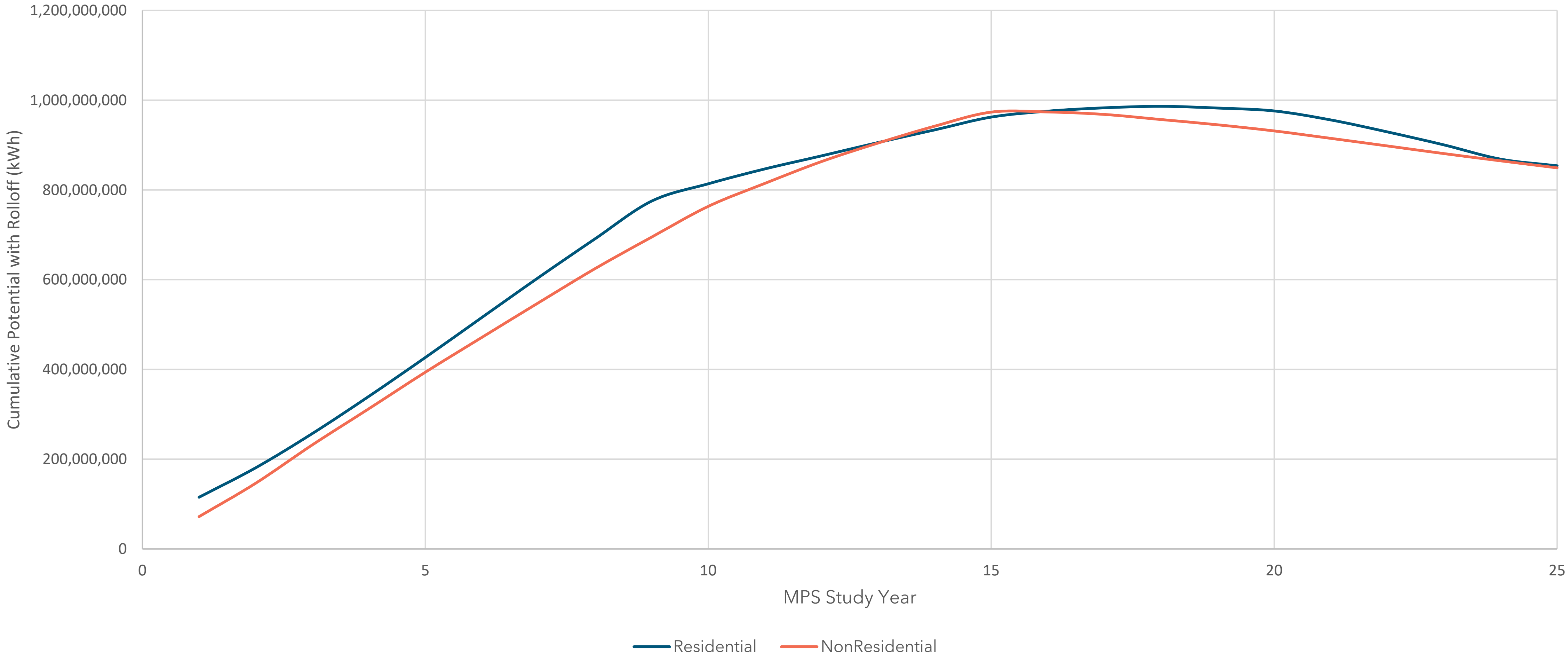
Total Energy Saved (Sum of Annuals) – Base Case w/ IRA



Cumulative Savings with Rolloff – Base Case w/ IRA



First-Year Impacts by Measure (top 20, Ach.)

Residential

Measure Name	Cumul Savings	% of Savings
Behavior Modification Home Energy Reports	59,196,860	51%
Air Sealing	6,936,905	6%
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	6,284,225	5%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	5,427,951	5%
Energy Star Door	3,627,491	3%
HVAC ECM Motor	3,056,869	3%
Behavior Modification Pre-pay plan	2,953,816	3%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	2,797,874	2%
Ceiling Insulation	1,759,343	2%
Low-E Storm Window	1,603,068	1%
Air Handler Filter Clean	1,602,695	1%
Energy Star Desktop Computer	1,147,601	1%
1.5 GPM Kitchen Faucet Aerators	1,128,331	1%
1.60 GPM Low-Flow Showerhead	1,115,559	1%
RealTime Information Monitoring Residential	1,010,861	1%
Energy Efficiency Education in Schools	761,950	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	754,596	1%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	715,751	1%
Programmable Thermostat Residential	656,944	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	616,151	1%

Non-Residential

Measure Name	Cumul Savings	% of Savings
VFD on HVAC Fan	7,352,262	10%
VFD on Cooling Tower Fans	3,992,913	6%
Air Compressor Optimization	3,294,232	5%
Time Clock Control	2,909,462	4%
SP to ECM Evaporator Fan Motor (Walk-In_ Refrigerator)	2,888,236	4%
VFD on process pump	2,777,933	4%
Demand Defrost	2,554,470	4%
LED Linear - Lamp Replacement	2,361,680	3%
Indoor daylight sensor	1,911,288	3%
Evaporator Fan Motor Control	1,538,962	2%
LED High Bay_LF Baseline	1,339,403	2%
Energy Star PCs-Desktop	1,284,783	2%
High Bay Occupancy Sensors_ Ceiling Mounted	1,233,247	2%
Refrigeration Economizer	1,167,224	2%
Energy Star Monitors	1,161,185	2%
1.5 GPM Low-Flow Showerhead	1,043,923	1%
Cogged Belt on 40hp ODP Motor	1,023,237	1%
High Volume Low Speed Fan (HVLS)	997,605	1%
Cogged Belt on 15hp ODP Motor	996,482	1%
VFD on HVAC Pump	993,656	1%

Five-Year Cumulative Impact by Measure (Ach.)

Residential

Measure Name	Cumul Savings	% of Savings
Behavior Modification Home Energy Reports	62,799,748	15%
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	48,660,929	11%
Air Sealing	44,430,929	10%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	40,164,710	9%
Energy Star Door	23,436,278	5%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	22,222,860	5%
HVAC ECM Motor	19,751,682	5%
Ceiling Insulation	11,364,616	3%
Low-E Storm Window	10,382,557	2%
Energy Star Desktop Computer	7,457,980	2%
1.60 GPM Low-Flow Showerhead	7,322,591	2%
1.5 GPM Kitchen Faucet Aerators	7,277,588	2%
Air Handler Filter Clean	6,949,655	2%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	5,866,852	1%
RealTime Information Monitoring Residential	5,692,702	1%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	5,574,108	1%
Energy Efficiency Education in Schools	4,888,956	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	4,661,804	1%
CEE Tier 3 Refrigerator	4,301,277	1%
Programmable Thermostat Residential	4,269,971	1%

Non-Residential

Measure Name	Cumul Savings	% of Savings
VFD on HVAC Fan	38,040,493	10%
VFD on Cooling Tower Fans	19,367,860	5%
LED Linear - Lamp Replacement	18,570,268	5%
SP to ECM Evaporator Fan Motor (Walk-In_ Refrigerator)	15,658,092	4%
Time Clock Control	14,937,553	4%
VFD on process pump	12,821,992	3%
Demand Defrost	12,350,938	3%
Air Compressor Optimization	11,222,465	3%
Indoor daylight sensor	10,202,862	3%
Energy Star PCs-Desktop	9,103,834	2%
Evaporator Fan Motor Control	8,640,233	2%
LED High Bay_LF Baseline	8,217,258	2%
Energy Star Monitors	8,118,564	2%
Cogged Belt on 40hp ODP Motor	6,473,042	2%
High Volume Low Speed Fan (HVLS)	6,347,322	2%
Refrigeration Economizer	6,328,728	2%
Cogged Belt on 15hp ODP Motor	6,286,779	2%
LED Linear - Fixture Replacement	6,091,651	2%
1.5 GPM Low-Flow Showerhead	5,733,126	1%
High Efficiency PTHP	5,719,880	1%

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Ten-Year Cumulative Impacts by Measure (Ach.)

Residential

Measure Name	Cumul Savings	% of Savings
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	106,826,536	13%
Air Sealing	88,571,505	11%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	86,909,606	11%
Behavior Modification Home Energy Reports	68,337,152	8%
Energy Star Door	48,473,157	6%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	47,717,581	6%
HVAC ECM Motor	28,910,574	4%
Low-E Storm Window	24,279,271	3%
Ceiling Insulation	22,478,750	3%
1.60 GPM Low-Flow Showerhead	16,033,832	2%
1.5 GPM Kitchen Faucet Aerators	16,026,965	2%
Air Handler Filter Clean	13,934,967	2%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	13,514,124	2%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	12,626,502	2%
RealTime Information Monitoring Residential	11,947,835	1%
Energy Star Desktop Computer	11,142,404	1%
CEE Tier 3 Refrigerator	10,290,267	1%
ASHP - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2 (from elect resistance)	9,542,473	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	9,484,123	1%
Smart Thermostat Residential	8,416,472	1%

Non-Residential

Measure Name	Cumul Savings	% of Savings
VFD on HVAC Fan	76,462,762	10%
LED Linear - Lamp Replacement	45,226,201	6%
VFD on Cooling Tower Fans	37,846,844	5%
SP to ECM Evaporator Fan Motor (Walk-In_ Refrigerator)	32,213,547	4%
Time Clock Control	24,275,272	3%
VFD on process pump	24,227,492	3%
Demand Defrost	23,463,931	3%
Indoor daylight sensor	21,037,384	3%
Evaporator Fan Motor Control	18,380,204	2%
LED High Bay_LF Baseline	17,949,982	2%
LED Linear - Fixture Replacement	14,708,107	2%
Cogged Belt on 40hp ODP Motor	14,223,456	2%
High Volume Low Speed Fan (HVLS)	13,994,054	2%
Cogged Belt on 15hp ODP Motor	13,800,387	2%
Heat pump water heater 50gallon	13,500,199	2%
Energy Star PCs-Desktop	13,419,513	2%
Refrigeration Economizer	12,925,657	2%
High Efficiency PTHP	12,379,547	2%
Air Compressor Optimization	11,928,408	2%
Energy Star Monitors	11,887,261	2%

Twenty-Five-Year Cumulative Impacts by Measure (Ach.)

Residential

Measure Name	Cumul Savings	% of Savings
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	93,082,360	11%
Behavior Modification Home Energy Reports	87,370,432	10%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	75,601,752	9%
Air Sealing	46,378,643	5%
Low-E Storm Window	37,482,555	4%
Energy Star Door	35,780,120	4%
HVAC ECM Motor	33,084,255	4%
Energy Star Desktop Computer	24,499,572	3%
CEE Tier 3 Refrigerator	23,222,336	3%
Ceiling Insulation	22,831,933	3%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	20,966,078	2%
Air Handler Filter Clean	19,761,469	2%
Energy Star Air Purifier	18,996,523	2%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	16,777,552	2%
Properly Sized CAC	15,567,709	2%
ASHP - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2 (from elect resistance)	15,326,162	2%
Energy Star Freezer	15,176,376	2%
Energy Star LED Directional Lamp Residential	15,037,609	2%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	14,149,398	2%
1.60 GPM Low-Flow Showerhead	13,967,484	2%

Non-Residential

Measure Name	Cumul Savings	% of Savings
LED Linear - Lamp Replacement	80,966,254	10%
VFD on HVAC Fan	64,366,072	8%
VFD on Cooling Tower Fans	34,517,140	4%
LED High Bay_LF Baseline	32,249,159	4%
LED Linear - Fixture Replacement	31,770,409	4%
SP to ECM Evaporator Fan Motor (Walk-In_ Refrigerator)	28,392,268	3%
Heat pump water heater 50gallon	26,780,547	3%
Energy Star PCs-Desktop	24,708,748	3%
Cogged Belt on 40hp ODP Motor	23,988,820	3%
Cogged Belt on 15hp ODP Motor	23,254,687	3%
Energy Star Monitors	21,882,581	3%
VFD on process pump	20,954,691	2%
High Efficiency PTHP	18,967,808	2%
Solar Thermal Water Heating System Commercial	18,398,817	2%
Custom Measure - Non-Lighting_65	17,843,078	2%
High Volume Low Speed Fan (HVLS)	17,205,033	2%
Evaporator Fan Motor Control	14,541,982	2%
High Efficiency Welder	14,226,094	2%
Ductless Mini-Split HP	13,189,186	2%
Synchronous Belt on 75hp ODP Motor	11,874,879	1%

Cause No. 46193

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Appendix: Acronyms

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Acronyms

Cause No. 46193

AMI	Advanced Metering Infrastructure
APS	Achievable Potential Study
ASHP	Air Source Heat Pump
BOY	Beginning of Year
CAA 111	Clean Air Act 111
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CEE	Center for Energy and Environment
CHP	Combined Heat and Power
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbine
DE&I	Diversity, Equity, & Inclusion
DEI	Duke Energy Indiana
DER	Distributed Energy Resources
D-LOL	Direct Loss of Load
DR	Demand Response
DSM	Demand Side Management

ECM	Electronically Commutated Motor
EE	Energy Efficiency
EOY	End of Year
EPA	Environmental Protection Agency
GPM	Gallons per Minute
GW	Gigawatt
HSPF	Heating Seasonal Performance Factor
HVLS	High Volume Low Speed
HEA	House Enrolled Act
ICAP	Installed Capacity
ICCT	International Council on Clean Transportation
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan

Acronyms

Cause No. 46193

IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
LMP	Locational Marginal Pricing
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MW	Megawatt
MWh	Megawatt-hour
NG	Natural Gas
ODP	Open Drip-Proof
OSB	Oversight Board
PTHP	Packaged Terminal Heat Pump
RES	Residential
RFP	Request for Proposal
SEER	Seasonal Energy Efficiency Ratio
SMR	Small Modular Reactor
T&D	Transmission & Distribution
TWh	Terawatt-hour
UCAP	Unforced Capacity
UCT	Utility Cost Test
VFD	Variable Frequency Drives

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PART OF BURNS & McDONNELL

Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

AUGUST 13, 2024, MEETING SUMMARY

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Meeting Information

On Tuesday, August 13, 2024, Duke Energy Indiana convened the fourth stakeholder meeting to inform the development of the 2024 Duke Energy Indiana Integrated Resource Plan ("IRP"). The meeting was held virtually. Approximately 63 external individuals representing over 38 organizations participated in this session.

Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other**:
  Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve a better understanding and develop robust solutions.
- **Focus on today's topics**:
  Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**
  Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

Session Participation

This virtual event was facilitated by 1898 & Co., and the session included presentations and robust conversations on the following topics:

- Feedback from the Third Public Engagement Session
- RFP Update
- Updated Portfolio Modeling
- Preliminary Scorecard
- Energy Market Interaction and Stochastic Modeling

Virtual attendees used the "raise hand" feature in Teams to ask a question or make a comment aloud or submitted questions through the "Q&A" feature. Virtual attendees had access to the "chat" feature in Teams to share links to information and communicate with each other. Staff from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to DEIndianaIRP@1898andco.com.

Access to Meeting Materials

Meeting materials for the August 13, 2024 engagement session were posted to Duke Energy Indiana's IRP website at duke-energy.com/IndianaIRP August 6, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders via email as the website is updated with materials for each session.

Meeting Notes

This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed. Similar summaries will be prepared following each public engagement session throughout this process.

Safety

Karen Hall, Duke Energy Resource Planning Director

Ms. Hall provided a safety moment on cybersecurity attacks and the potential threats of vishing, smishing, and quishing.

Welcome

Stan Pinegar, Duke Energy Indiana State President

Mr. Pinegar opened the meeting by welcoming attendees, thanking them for their participation, and encouraging active engagement in the 2024 IRP process.

Introductions

Karen Hall, Duke Energy Resource Planning Director

Ms. Hall introduced the Duke Energy teammates who are supporting the 2024 IRP.

Meeting Guidelines & Agenda

Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Mr. Burczyk discussed the ground rules for the virtual meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

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Stakeholder Feedback and Incorporation

Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Mr. Burczyk provided an overview of stakeholder feedback that was received and incorporated into the agenda for the fourth Public Engagement Session and when this feedback would be discussed in the meeting. He then covered additional feedback and the responses from Duke Energy Indiana, which included topics such as resource availability assumptions, firm gas transportation, and other IRP modeling questions.

Q&A related to Stakeholder Feedback and Incorporation

1. Question: Is Duke Energy Indiana planning able to provide additional details on the build-up of firm natural gas transportation costs?
    a. The total costs for firm natural gas transportation are included in the modeling and have been provided to technical stakeholders. Some of the details of the build-up are confidential, so Duke Energy Indiana is unable to disclose them at this time.
2. Question: Is Duke Energy Indiana considering running a sensitivity that would include potential significant increases in load due to data centers?
    a. Yes, the high load sensitivity includes economic development for data centers.
3. Question: Is the storage capacity in the model the maximum for each year or incremental?
    a. It is the maximum for each year.

RFP Update

Robert Lee, Vice President, Charles River Associates

Mr. Lee provided an overview of Duke Energy Indiana's all-source Request for Proposal (RFP). He explained that the RFP accepted bids for power purchase agreements (PPA), build transfer agreements (BTA), and existing asset sales. Mr. Lee outlined the evaluation criteria, including proposal economics, reliability and deliverability, development, and asset-specific benefits/risks. He presented the RFP results by technology type and noted that most projects were in MISO LRZ 6, which was preferred as part of the RFP. Mr. Lee then reviewed the pricing of the RFP proposals. Mr. Lee explained how the IRP and RFP studies are separate but are both parts of the asset selection process.

Q&A related to RFP Update

1. Question: Can you provide more information on the updates to the IRP modeling regarding the RFP bids?
    a. EnCompass was initially evaluating and selecting from a large number of very similar resources, which increases the complexity of the solution that the model must solve. So, we have updated the model to select from generic resources for the different technologies. The costs for the generic resources are still informed by the data from the RFP.

2. Question: What is the difference between RFP bids previously modeled and the resources being modeled now?
    a. The projects modeled previously were an aggregate of RFP bids, and now the model is selecting the generic resources.
3. Question: Please explain how a single tranche by resource type is created?
    a. Benchmarking is done to ensure that the generic curves fall in the range of the costs from the RFP bids. Additional RFP cost information, including the benchmarking of the generic curves, has been provided to technical stakeholders subject to an NDA.
4. Question: Regarding the thermal resource RFP, what types of generation bids were submitted.
    a. There were shorter term Power Purchase Agreements for a few different resources outside of Local Resource Zone 6 and several self-build options including Combined Cycle Gas Turbines (CCGTs) with different in-service dates.
5. Question: Were all the thermal resources natural gas resources?
    a. Yes, all the thermal resources were natural gas.
6. Question: What is the total nameplate capacity for each technology?
    a. The total installed capacity (ICAP) for Solar projects is 5,145 MW, while proposals account for 14,308 MW. Solar + Storage projects contribute 4,612 MW, with proposals adding up to 6,954 MW. Wind projects have an installed capacity of 1,777 MW, and proposals contribute 3,507 MW. Thermal projects provide 5,105 MW, with proposals amounting to 11,116 MW. Finally, Storage projects contribute 2,001 MW, with proposals adding up to 4,400 MW. In total, the combined ICAP for all technologies is 18,602 MW by project and 40,254 MW by proposal.
7. Question: Are the MWs provided for seasonal accredited capacity?
    a. No, those numbers represent the installed capacity.
8. Question: How is a project defined?
    a. A project is an individual site.
9. Question: What stage are the RFP projects in?
    a. Some RFP projects are in development, and most are already in the MISO queue, though that was not a requirement of the RFP.
10. Question: How would the passage of the Barrasso/Manchin Energy Permitting Act of 2024 affect the RFP with respect to solar and wind capacity?
    a. The Barrasso/Manchin Energy Permitting Act of 2024 is still a bill and is not current legislation, so it would not be considered in the RFP at this stage. However, the Aggressive Policy & Rapid Innovation scenario in the IRP assumes transmission and queue reforms are enacted that enable higher annual interconnection (“resource availability”) of renewable resources in the IRP modeling. The effect of permitting reform would be captured by proxy, along with other uncertainties, through the scenario analysis.
11. Question: Are the RFP asset sale prices shown in the RFP summary table on slide 23 a $/kW basis or an LCOE basis?

   a. These are on a $/kW basis and are calculated by dividing the costs of purchasing the asset by the capacity of the resource.

12. Question: What does the count of asset sales represent on slide 23?
    a. That count represents the number of different options available, including self-build options.

Updated Portfolio Modeling

Nate Gagnon, Managing Director Midwest IRP
Matt Peterson, Lead Resource Planning Analyst

Mr. Gagnon provided an overview of the analytical framework for the IRP, which includes the generation strategies and worldviews (Reference, Aggressive Policy & Rapid innovation, and Minimum Policy & Lagging Innovation), resulting in 18 scenario portfolios. He added that with additional strategy variations, portfolio sensitivities, production cost sensitivities, and a supplemental stakeholder portfolio, the total number of resource portfolios modeled exceeds 40. Mr. Gagnon then reviewed the different generation strategies—convert/co-fire coal, retire coal, convert Cayuga, co-fire Gibson, incremental generation, exit coal earlier, and “No EPA 111”—and specifically addressed how they relate to the Cayuga, Gibson, and Edwardsport units in terms of retirement, co-firing, and natural gas conversion. He emphasized that while these strategies have unit-specific assumptions in the IRP, detailed studies will be conducted before the execution phase to validate these assumptions.

Mr. Gagnon then presented preliminary results for the strategies under the reference scenario, covering unforced capacity (UCAP), energy mix, and preliminary PVRRs. He highlighted that renewables make up a sizable portion of total energy across all cases, but in most portfolios, a substantial portion of the accredited capacity is thermal resources. He also discussed that in strategies involving the converted and co-fired units, these units become less competitive in the energy market, leading to the use of MISO energy market purchases to reduce costs. Additionally, he noted that the PVRRs for the generation strategies are generally close, except for the “No EPA 111” strategy, which is not necessarily directly comparable to the others.

Mr. Peterson provided a summary of the individual generation strategies, focusing on the Reference, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation worldviews. He shared results related to installed capacity, carbon emissions, and energy mix over time and offered an overview of each strategy.

Mr. Gagnon discussed the preliminary high-load sensitivity analysis and mentioned that a low-load sensitivity analysis is also underway. He pointed out that the forecasted peak load shape changes in the high load sensitivity due to assumptions around industrial load and data centers.

Mr. Gagnon then reviewed the IRP planning process, emphasizing that uncertainty increases over time within the planning period. He also discussed the key considerations and sources of uncertainty in developing the short-term action plan for the 2024 IRP, including balancing the retirement, natural gas conversion, and co-firing of existing coal units, as well as balancing the five IRP pillars when considering new resource additions. He outlined a few sources of uncertainty, including regulatory, demand, market, and supply chain assumptions.

Q&A related to Updated Portfolio Modeling

1. Question: Is Duke Energy considering burning natural gas instead of coal at Edwardsport?
    a. In all the EPA 111-compliant strategies, the conversion of Edwardsport to natural gas takes place in 2030, and in the "No EPA 111" strategy, that conversion takes place in 2035. Edwardsport can burn gas, but the unit is optimized to burn syngas, so its maximum unit output is lower when Edwardsport burns natural gas. With the projected load growth in zone 6, derating Edwardsport in the near term increases the need for capacity.
2. Question: Is there an expected capacity derate when converting the Cayuga and Gibson units to natural gas?
    a. No. Derates for those units are not expected.
3. Question: Are batteries being considered in the model, and can they provide system reliability benefits similar to thermal resources?
    a. Yes. Batteries can provide several benefits to a resource portfolio, and they increase as part of the UCAP mix over the planning period. However, batteries do not generate energy, so, while they can provide system reliability benefits, there are significant differences between batteries and thermal generators in terms of contributions to the system.
4. Question: What is the discount rate assumption for PVRR calculations?
    a. It is assumed to be the utility's weighted average cost of capital, which is 7.07%.
5. Question: Is the rate base investment of the coal capacity included in the PVRR?
    a. No, because depreciation of existing assets is consistent across all generation strategies and portfolios. The cost of converting units to natural gas or enabling them to co-fire is reflected in PVRR. The PVRR metric is intended to help show the differences in cost between the generation strategies.
6. Question: What is IVVC?
    a. IVVC is Integrated Volt/VAR Control, which manages voltage and power factor on distribution circuits.
7. Question: Is a carbon capture and sequestration (CCS) investment being made and included in the analysis?
    a. CCS will be evaluated at Edwardsport, but the generation strategies themselves do not include CCS. There are selectable combined cycle resources with CCS available for selection in the model, but the model is not currently selecting them.
8. Question: What does the negative ICAP represent in the generation strategy summaries?
    a. The negative ICAP shows retired unit capacity.
9. Question: Why do the CO_2 emissions over time appear higher in the short-term and comparable in the long-term between the Retirement and Co-Fire/Conversion scenarios?
    a. All strategies will have similar resources in the first few years of the planning period. In the late 2020's this starts to deviate across the strategies as there are changes in the existing resource assumptions. The co-fire and conversions in the EPA 111-compliant strategies will take place by 2030. Under the retire coal

strategy, the Gibson units continue to operate on coal and retire by 1/1/2032. These differences in existing resource retirement, conversion, and co-firing timing as well as the resource mix, leads to the emission results varying in the middle of the planning horizon. Later in the planning period, coal is replaced by more efficient combined cycles and/or renewables, resulting in similar reductions across all generation strategies.

10. Question: Is consideration being given to the effects of continuing cost increases as it impacts rates in the PVRR modeling?
    a. Rate impact calculations are a metric in the scorecard. However, in those rate impact calculations, the costs will reflect the impacts within the scope of the IRP. Other system costs that are the same across strategies will not be included in the calculation.
11. Comment: Commenter is concerned that the rate-based value of existing coal units is not fully considered in this analysis.
12. Comment: Commenter does not believe that the comparison of relative NPVs provides a good indication of affordability.
13. Question: Why are CO_2 equivalent emissions not included for transport and methane leakage from natural gas pipes?
    a. We do not have data specific to each potential resource portfolio, nor do we have a means of projecting upstream emissions over the planning horizon, so we've not included these metrics in the IRP
14. Question: Will Duke Energy Indiana share its assumptions around power purchase pricing?
    a. The methodology and results for power price development were discussed at Stakeholder Meetings 2 and 3. The modeling files and data for the National Database used to develop the power price assumptions were also provided to technical stakeholders on the DataSite, subject to non-disclosure agreements.
15. Question: How much data center load is included in the high load sensitivity?
    a. The high load sensitivity includes 507 MW of new data center load by 2031.
16. Question: How much does EV adoption impact your storage projections?
    a. The EV forecast contains assumptions around EV charging, but there is still a lot of uncertainty around vehicle-to-grid technology at enough scale to impact storage projections so it is a bit early for that to be included in the IRP.

Preliminary Scorecard

Nate Gagnon, Managing Director Midwest IRP

Mr. Gagnon started by providing an explanation of each scorecard metric and how they are calculated and emphasized that the purpose of these metrics is to assist in distinguishing between the IRP portfolios. He then requested that scorecard feedback be emailed to DEIndianaIRP@1898andco.com for consideration. He also reviewed potential updates to the fast start, spinning reserve, and environmental metrics based on stakeholder feedback.

Mr. Gagnon then provided a detailed look at PVRR and initial observations. He emphasized that in the Aggressive Policy & Rapid Innovation worldview, variables such as increased fuel costs and implementation of a CO2 tax result in higher PVRRs for all strategies, with the opposite being true for the Minimum Policy & Lagging innovation worldview. He also pointed out that preliminary results for the Reference worldview suggest limited variability in total portfolio costs.

Mr. Gagnon reviewed preliminary results for CO2 emissions reduction for both 2035 and 2044. He also emphasized that the energy market purchases also influence the total portfolio CO2 emissions.

Q&A related to Preliminary Scorecard

1. Question: Why do the reliability metrics drop below 100% for the Retire Coal and Exit Coal Earlier portfolios when all portfolios have market purchases?
    a. This metric looks at MW (capacity), not the MWh (energy). It looks at the capacity of thermal and energy storage resources on the system as a percentage of the summer peak load in 2035.
2. Question: Is the Herfindahl–Hirschman index calculated using installed capacity or UCAP?
    a. This calculation is based on installed capacity.
3. Question: Why are the reliability metrics based on installed capacity?
    a. Installed capacity is used because both energy and capacity are needed and installed capacity provides a better sense of the total scale of the system.
4. Comment: I think the execution risk metrics should use both installed capacity and UCAP.
5. Question: Has Duke Energy Indiana considered producing a 10-year and 20-year NPV?
    a. The Customer Bill Impact CAGR will be shown in 2030 and 2035. This should provide a sense for the portfolio costs at the midpoint of the study period. Annual revenue requirements will be included in the final IRP document as well.

Energy Market Interaction & Stochastic Modeling

Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co
Ameya Deoras, Manager of Quantitative Analytics
Nate Gagnon, Managing Director Midwest IRP

Mr. Burczyk provided an overview of the MISO energy market, explaining the process of selling and purchasing energy within the market. He described the two-part simulation used in the IRP model: capacity expansion and production cost. The capacity expansion model requires Duke Energy Indiana to serve 75% of its customers' energy needs with its own generation. However, the production cost model does not impose any targets for meeting customer energy needs. The production cost step inherits the portfolio from the capacity expansion step but dispatches the portfolios more granularly, based on economics, like the real-world MISO energy market and unit dispatch.

Mr. Deoras gave an overview of the stochastic modeling methodology used in the IRP, emphasizing that the goal is to simulate quantifiable uncertainties based on historical

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observations or forward-looking market data. He explained that SERVM is used for reliability modeling, creating historical load data that is then fed into PowerSIMM to simulate hourly power prices. He presented data from these simulations, including Henry Hub and Indiana Hub hourly gas prices, as well as the market-implied heat rate. He noted that in these simulations, power price increases do not keep pace with gas price increases.

Mr. Deoras then shared the generation and net purchases results from the stochastic modeling. He pointed out that while net purchases appear high, this reflects the market's potential to offer more economic prices for customers rather than an inability to generate the necessary power.

Q&A related to Energy market interaction & Stochastic Modeling

1. Question: Please describe, in detail, the EnCompass assumptions regarding MISO Capacity.
    a. Technical stakeholders have received access to the National Database, which has full visibility into these assumptions. Additionally, these assumptions were discussed in the second public stakeholder meeting, and the results were shared at the third public stakeholder meeting.
2. Question: Why is data displayed in the 10^{th} to 90^{th} percentile range?
    a. This range is standard for statistical graphs because of potential outliers. The mean will still include all data points.
3. Question: How are the risks of data center load considered as part of the stochastic analysis?
    a. Higher loads typically result in higher prices, which is considered in the stochastic analysis.
4. Question: What is driving the overall shift beginning in 2028, where Duke Energy generation produces lots of energy, to the company purchasing significant amounts of energy later in the study period?
    a. The shift from Duke Energy Indiana's units generating significant energy in 2028 to purchasing power later in the study period is driven by many factors. Power prices come out of the National Database modeling, which looks at the entire Eastern Interconnect. Over time, there is a greater saturation of renewables across the Eastern Interconnect, which drives the implied market heat rate down. Also, depending on the generation strategy, the steam units have been converted to natural gas units or co-fire in several cases. These converted units are expected to operate differently in the market than in the early years of the planning period when they operate on coal.
5. Question: Is anything from the consumer side factored into these models?
    a. The impact is seen in the load. If customers generate more, the load that the Duke Energy Indiana system must serve decreases. Behind-the-Meter (BTM) solar is one of the considerations in the Aggressive Policy & Rapid Innovation worldview.

2024 Duke Energy Indiana Integrated Resource Plan

Stakeholder Meeting 4

August 13, 2024

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Safety

Safety Moment: Preventing Cybersecurity Attacks

Cyberattacks are not Limited to Email

Phishing is a social engineering attack attempting to trick you into revealing sensitive information. Voice phishing, or **vishing,** using phone calls. Text phishing, or **smishing**, leverages text messages. QR phishing, or **quishing**, involves QR codes that direct you to a bad actor's website, which may appear legitimate.

Avoid falling victim by following these tips:

- **Don't trust caller ID**. Cybercriminals use a tactic called ID spoofing to have the call appear to be originating from a trusted source.
- If you suspect that a call is from an illegitimate source, **hang up**.
- If a text message seems suspicious, avoid replying and **block the number**.
- **Do not scan QR codes** from untrusted emails, posters, or other physical locations.
- Join the Federal Trade Commission's National Do Not Call Registry at **donotcall.gov**

Sources: https://www.uspis.gov/news/scam-article/quishing
https://www.cisecurity.org/insights/newsletter/vishing-and-smishing-what-you-need-to-know

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Welcome

Stan Pinegar

State President, Duke Energy Indiana

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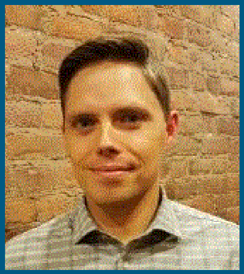
Introductions

Duke Energy Team

Integrated Resource Planning Team

Matt Kalemba
Vice President, Integrated Resource Planning



Nate Gagnon
Managing Director, Midwest Integrated Resource Planning

Matt Peterson
Resource Planning Manager

Emma Goodnow
Market Strategy & Intelligence Director

Karen Hall
Resource Planning Director

Chris Hixson
Principal Engineer, Resource Modeling

Josh Paragas
Engineer, Resource Modeling

Tyler Cook
Engineer, Resource Modeling

Indiana Regulatory and Legal Team

Kelley Karn
Vice President, Indiana Regulatory Affairs and Policy

Beth Heneghan
Deputy General Counsel

Liane Steffes
Associate General Counsel

RFP

Dan Sympson
Generation and Regulatory Strategy Director

1898 & Co.

Drew Burczyk
Consultant, Resource Planning & Market Assessments

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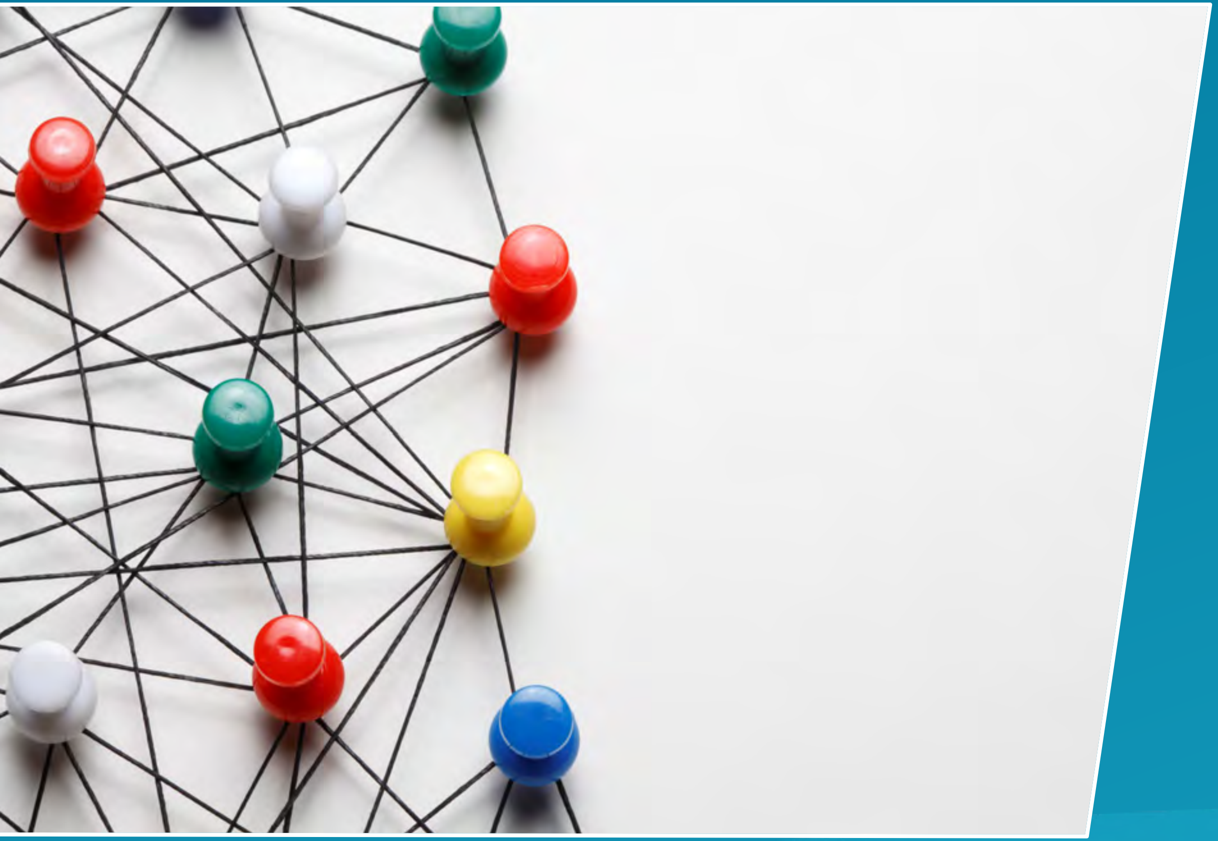

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Agenda

Public Stakeholder Meeting #4 Agenda

Cause No. 46193

Time	Duration	Present | Q&A	Topic	Presenter
9:30	5	5 | 0	Welcome & Safety	**Stan Pinegar,** Duke Energy Indiana State President **Karen Hall,** Duke Energy Resource Planning Director
9:35	5	5 | 0	Meeting Guidelines & Agenda	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:40	25	15 | 10	Stakeholder Feedback & Incorporation	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:05	25	15 | 10	RFP Update	**Robert Lee,** Vice President, Charles River Associates (CRA)
10:30	10	-	BREAK	
10:40	60	30 | 30	Updated Portfolio Modeling	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP **Matt Peterson,** Duke Energy Lead Resource Planning Analyst
11:40	40	-	BREAK	
12:20	30	15 | 15	Updated Portfolio Modeling (cont.)	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP
12:50	30	15 | 15	Preliminary Scorecard	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP
1:20	5	-	BREAK	
1:25	25	15 | 15	Preliminary Scorecard (cont.)	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP
1:50	25	15 | 10	Energy Market Interaction & Stochastic Modeling	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co. **Ameya Deoras,** Duke Energy Manager Quantitative Analytics
2:15	40	0 | 40	Open Q&A	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
2:55	5	5 | 0	Next Steps	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
3:00			Adjourn	

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Meeting Guidelines

Meeting Ground Rules

Respect each other:

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone’s wisdom to achieve better understanding and develop robust solutions.

Focus on today’s topics:

Please respect the scope of today’s meeting to make the most of our time. Pending legal issues are outside the scope of today’s meeting.

Chatham House Rule:

Empower others to voice their perspective by respecting the “Chatham House Rule;” you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

Participation

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There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

- **Q&A:** Please use the "Q&A" feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the "raise hand" feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.

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Stakeholder Feedback and Incorporation

Cause No. 46193

Stakeholder Feedback Received & Incorporated into Meeting #4 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
What do market purchases in the results represent?	Market Purchases Overview
In terms of the market being less expensive than generation in house, is that the case now?	Market Purchases Overview
Can the model add more resources to the portfolio in order to decrease energy market purchases, even if the capacity is not needed in the portfolio?	Market Purchases Overview
How does the RFP inform the IRP modeling?	RFP Update
Is there a revised timeline for responses to the RFP?	RFP Update

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Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
Will any future meetings be held in person?	The third meeting was shifted to a hybrid meeting (in person and virtual options). We initially planned to hold the 5th meeting as a hybrid meeting. Asking for your feedback given in-person attendance of meeting 3. Please provide additional input on what meeting format works best, so we can accommodate preferences on how we can make this process most successful.
What costs are included in your firm transport assumptions for natural gas?	Our FT cost assumption includes all costs associated with delivering firm gas to the site in question. This is inclusive of expected pipeline upgrades and construction or upgrading of the lateral and achieving required delivered pressures (compression and/or regulation and heating).
Are combined cycles assumed to be dual fuel capable?	Yes, generic combined cycles included in the modeling are dual fuel capable and have on-site ultra-low sulfur diesel storage on-site.
What is the first year that storage resources are allowed to be selected in the model?	Battery energy storage resources can be selected in the model beginning 2028.
Will new demand response (DR) resources be included as options in the IRP model?	Contributions from existing and forecasted demand response resources are inputs to the IRP model rather than being selectable resource options.
What is the data source for the CT and CC capital costs?	CT and CC capital costs come from the Generic Unit Summary (GUS). Several sources are used to develop the prices in the GUS, including third party vendor forecasts, which are benchmarked against public sources and data from RFPs.
What is the source for CCS O&M assumptions?	CC w/ CCS O&M costs were provided by Burns and McDonnell as part of the Generic Unit Summary process.

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Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Info	Response/Update
In addition to the increased resource availability limits for Solar & Wind shared in Meeting 3, will Storage availability be increased in model?	There are no plans to increase the assumed energy storage availability at this time. Resource availability assumptions take into account interconnection, supply chain, and plan executability. Potential relief in any one of these areas alone may not justify increasing the assumed pace at which new storage resources could be added to system. As a reminder, energy storage, including SPS, is selectable in the following amounts: Reference case – • 2028-2029: 500 MW/yr • 2030+: 1,000 MW/yr Aggressive case – • 2028-2029: 500 MW/yr • 2030-2031: 1,700 MW/yr 4-hour and 100 MW/yr 10-hour • 2032+: 1,700 MW/yr 4-hour and 500 MW/yr combined total of 10-hour, 100-hour Also note that in modeling conducted to date, these assumptions do not constrain model selection of energy storage in any but a few years.
Model EV and data center load profiles explicitly in SERVM	It may be appropriate to consider this step in future IRPs as the temperature sensitivity of these loads becomes better understood, but the 2024 effort must remain focused on completion of the core analysis.
Will DEI provide estimated Scope 3 emissions for each case?	CO_2 emissions projections include estimated emissions associated with MISO energy market purchases.

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Q&A

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RFP Update

DEI 2023/2024 Request for Proposals (RFP) Status

All Source

- Two targeted RFPs issued concurrently: Intermittent (renewable) & Non-Intermittent (thermal and storage)
- RFP bid selection compared assets within categories based on both quantitative and qualitative criteria
- Capacity targets initially informed by IRP process and finalized based on recent IRP modeling
- Accepted Structures: Purchase Power Agreements (PPA), Build Transfer Agreements (BTA), Existing Asset Sale

Role of CRA as the Independent Third-Party Administrator

- Acted as RFP Manager facilitating the RFP process
- Reviewed proposals to ensure they conform with basic threshold requirements
- Independently evaluated bids according to pre-specified criteria
- Managed bidder communication and marketing
- Provided utility with a ranked list of projects by type to consider for advancement
- Duke Energy Indiana and CRA collaborate on additional due diligence for final selections and contracting

Schedule (Current)

- Advanced due diligence / Contract negotiations: July / August 2024
- Internal approvals for earliest projects / Definitive agreements signed: Q3 / Q4 2024
- First round of certificates of public convenience and necessity (CPCNs) filed: Late 2024 or first half 2025

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DEI 2023/2024 RFP – Product Definition

Intermittent Generation

- Stated Need: Up to 2,500 MW (ICAP) in-service by 12/31/2032
- New or existing resources using proven technologies with technology specific minimum capacities
- Resource type examples: Solar, wind, standalone storage, hybrid with storage

Non-Intermittent Generation

- Stated Need: Up to 2,500 MW (ICAP) in-service by 12/31/2032
- New or existing resources using proven technologies with no stated minimum capacity
- Resource type examples: Thermal (CT, CC, Industrial STG, no coal), standalone storage, system sales
- Firm fuel supply required

Definitions common to intermittent and non-intermittent generation

- Structures: Purchase Power Agreements (PPA), Build Transfer Agreements (BTA), Existing Asset Sale;
- PPA / useful life min length 3 to 5 years
- Strong preference for MISO Zone 6 NRIS Qualified (Firm) Capacity
  - Exceptions considered for wind resources or for PPA bids if there are limited in-zone options

STG: Steam Turbine Generator
NRIS: Network Resource Interconnection Service

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DEI's 2023/2024 RFP Evaluation Criteria

PRICE | NON-PRICE

Proposal Economics
(30% / 300 points)

300 points: The total points available under the evaluation category will be calculated using a **levelized cost of energy or levelized cost of capacity basis utilizing a 30-year period**

Other proposals will receive a percentage discount off points based on the proposal's cost premium versus the lowest cost proposal

Capital costs will include the asset purchase price, interconnection costs, and projected CAPEX requirements over asset

Operating costs will include annual fixed and variable O&M costs, fuel and emissions costs and all other costs including taxes, service agreements and fixed pipeline charges

The market value of facility output will be based on DEI's internal modeling and analysis of the Indiana and broader MISO region

If asset is not in service or under Duke Energy Indiana ("DEI") control at any point within the 30-year period, **the levelized cost will reflect market purchases of energy and capacity**

Reliability and Deliverability
(30% / 300 points)

300 points: All proposals will initially be allotted full points. Points will be subtracted based on an assessment of **environmental reliability**, **age and outage history**, and **fuel reliability**

(50) points: preference for advance class turbines

Facility Age and Demonstrated Reliability will be evaluated. Reliability will be based in observed vs projected UCAP and EFORd vs standards for the MISO asset classes

> **(10) points: Each year** in service beyond **technology specific benchmark**
>
> **(100), (50) and (25) point** deductions for High. Medium and Low-risk assets respectively based on outage history.

(100) point deduction based on an assessment of **of fuel security and reliability** at thermal assets. The evaluation metric will consider:

- An assessment of the "firm fuel" availability, facility infrastructure and fuel access
- An assessment of potential fuel price volatility.

Development
(20% / 200 points)

Four milestones have been selected and **15 Points** will be awarded for each:

1. MISO Queue number
2. Completed MISO System Impact Study
3. Completed MISO Facilities Study or using MISO generator interconnection agreement (GIA) Process
4. Completed a MISO GIA

All projects are required to have achieved site control and have a feasible plan for zoning

20 points: Completed all environmental studies / permits - impacted species, mitigation, conservation plans, etc.

20 points: EPC Contract awarded

100 points: Developers that have placed **1,000 MW ICAP or more of capacity** into service in MISO

> Other developers will receive points based on the following formula: **(MW in service/1,000) * 100 rounded to the nearest full point**

Asset Specific Benefits / Risks
(20% / 200 points)

100 points: Facilities with no material risks

100 points: Facilities will receive points for project specific benefits including but not limited to

- Black start capability
- Operating flexibility and optionality provide by storage assets
- Ability to integrate with DEI's corporate and operating frameworks

25 points: MBE diversity and community benefits each

- MBE (Minority Business Enterprise) or a WBE (Women's Business Enterprise) or a Veteran Owned Business
- Just Transition - Replacement generation in communities that have been impacted by other generation retirements
- Environmental Justice - New generation not impacting lower income communities disproportionally
- Positive Impact on local community DEI's serves (IN business / labor, environmental)

Red text indicates point reduction

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Attachment A-1
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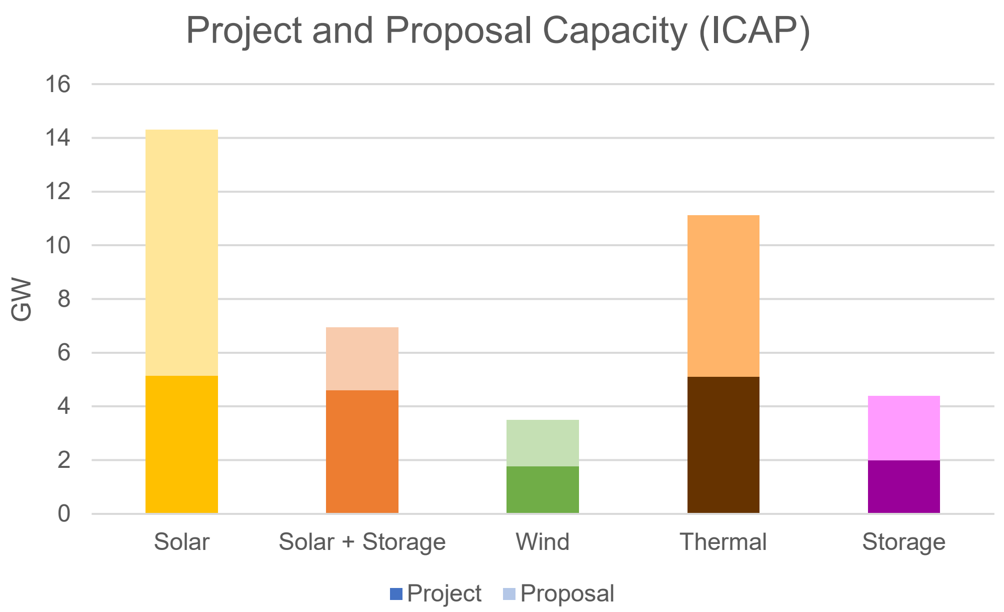
Cause No. 46193

DEI 2023/2024 RFP – Overview of Bids

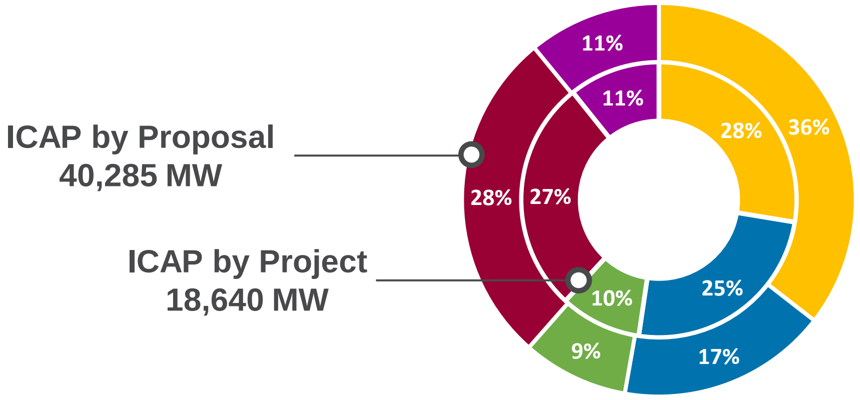
- 68 individual projects across six states with 18.6 GW (ICAP) represented
- 160+ different proposal structures between the 68 projects, totaling 40.3 GW (ICAP)



Note: Darker shade indicates Project GW, which are a are subset of Proposal GW

Allocation by Technology Type (ICAP)

	ICAP by Project		ICAP by Proposal	
	MW	%	MW	%
Solar	5,145	28%	14,308	36%
Solar + Storage	4,612	25%	6,954	17%
Wind	1,777	10%	3,507	9%
Thermal	5,105	27%	11,116	28%
Storage	2,001	11%	4,400	11%
Total (MW)	18,602	100%	40,254	100%



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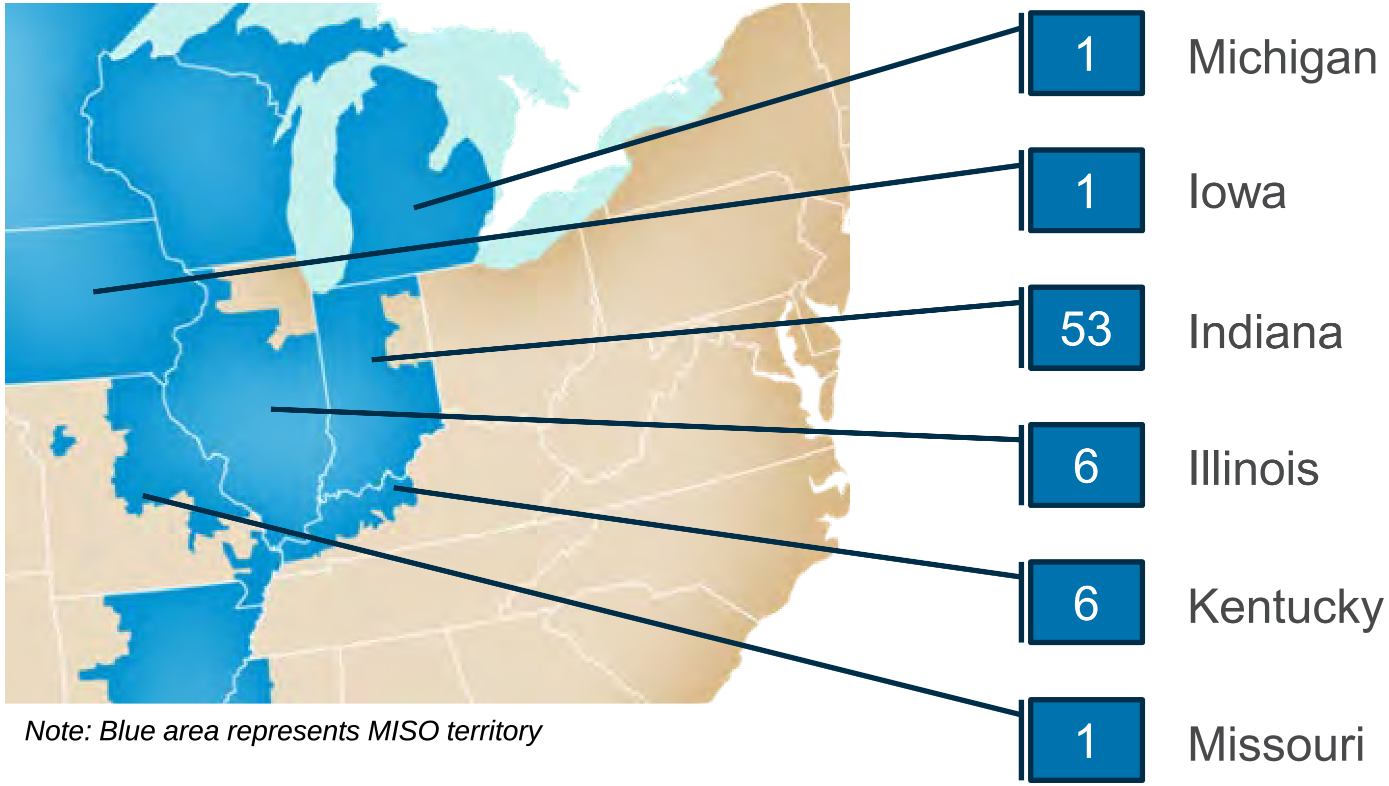
DEI 2023/2024 RFP – Distribution of Projects Received

- 68 individual projects across six states with 18.6 GW (ICAP) represented
- Sums below account for the largest MW proposal option of a given project

	Project MIN of ICAP and POI (MW)					
	Solar	**SPS**	**Wind**	**Thermal**	**Storage**	**Total**
IL	150	0	947	537	0	**1,634**
IN	4,695	4,462	110	3,332	1,601	**14,162**
IA	0	0	230	0	0	**230**
KY	300	150	200	0	400	**1,050**
MI	0	0	0	1,236	0	**1,236**
MO	0	0	290	0	0	**290**
Total	**5,145**	**4,612**	**1,777**	**5,067**	**2,001**	**18,602**



Note: Blue area represents MISO territory

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Attachment A-1
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DEI 2023/2024 RFP – Summary of Pricing

Average Weighted Pricing by Technology and Deal Structure

Technology	Asset Sale (BTA)		Power Purchase Agreement			
	$/kW	Count	$/MWh	$/kW-mo	$/kW-yr	Count
Solar	$ 2,099.79	10	$ 67.53			73
Solar + Storage	$ 3,360.14	8	$ 68.69			22
Wind			$ 66.09			15
Thermal	$ 1,665.42	8		$ 11.64		5
Storage	$ 1,931.26	7			$ 158.14	20

This table reflects proposals received (not projects). Some proposals are mutually exclusive or have been bid as both Asset Sale and PPA.

- Average bid prices shown for ‘Asset Sale’ represent capital costs and exclude on-going fuel and O&M
- Figures shown are for representation and do not purport competition between technologies; Separate short-listed assets are created for each RFP event
- All information is preliminary and subject to further review

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DEI 2023/2024 RFP – Considerations on Asset Selection

Resource Planning Optimization

Designed to optimize a portfolio composition and minimize rate-payer costs based on high-level market dynamics and market risk considerations

Captures portfolio-level considerations and trade offs between technology and market scenarios

Considers ONLY resource cost versus constraints; does not consider non-price considerations

Optimizes based on deterministic modeling inputs or project-level uncertainty

RFP Project Rankings

Designed to evaluate and rank order a large number of similar projects based on a mix of objectives and subjective criteria. Process is well-suited for screening options and identifying a short-list for advancement

Balances stated costs with uncertainties on interconnection cost, timing and performance risk

Considers a range of project and proposal attributes including cost, project risk and corporate social objectives

Considers ONLY project-level issues; not suited for portfolio considerations or issues

Final Due Diligence

Provides a final, formal review of each candidate project and counterparty based on a detailed assessment of site-level considerations, equipment manufacturers, counterparty level considerations and transfer agreement / PPA language

Allows Duke SME to review configuration and site-level considerations that may impact project cost and performance

Reviews site- and counterparty-specific considerations related to delivering an individual facility on time and within budget

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Preliminary Portfolio Modeling Update

Analytical Framework

Cause No. 46193

Generation Strategies

- Convert / Co-Fire Coal
- Retire Coal
- Convert Cayuga (Blend 1)
- Co-Fire Gibson (Blend 2)
- Incremental Generation (Blend 3)
- Exit Coal Earlier (Stakeholder)

Scenarios "Worldviews"

- Reference
- Aggressive Policy & Rapid Innovation
- Minimum Policy & Lagging Innovation

18
Scenario Portfolios

Strategy Variations

- 2x1 v. 1x1 replacement
- Full NG conversion v. co-firing
- No 111

> 3
Strategy Variation Portfolios

Portfolio Sensitivities

- Resource Capital Cost
- Load (high/low)
- SAC Accreditation (Select cases)

~ 20
Sensitivity Portfolios

Production Cost Sensitivities

- Fuel (high/low)
- Market exposure

Supplemental Stakeholder Portfolio

- DDRE (1 Supplemental Portfolio)

> 40
Total Resource Portfolios

+ *additional testing of preferred portfolio*

Generation Strategies Included in IRP Analysis

<table>
<tr><th></th><th colspan="6">CAA Section 111-Compliant Strategies</th><th>Non-Compliant</th></tr>
<tr><th>Unit</th><th>Convert / Co-Fire Coal</th><th>Retire Coal</th><th>Convert Cayuga (Blend 1)</th><th>Co-Fire Gibson (Blend 2)</th><th>Incremental Generation (Blend 3)*</th><th>Exit Coal Earlier (Stakeholder)</th><th>“No 111”</th></tr>
<tr><td>Cayuga 1</td><td rowspan="2">NG Conversion by 1/1/2030</td><td>Retire by 1/1/2030</td><td rowspan="2">NG Conversion by 1/1/2030</td><td>Retire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2029</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Cayuga 2</td><td>Retire by 1/1/2031</td><td>Retire by 1/1/2031</td></tr>
<tr><td>Gibson 1</td><td rowspan="2">Co-fire by 1/1/2030</td><td rowspan="4">Retire by 1/1/2032</td><td rowspan="4">Retire by 1/1/2032</td><td colspan="2" rowspan="2">Co-fire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">Retire by 1/1/2036</td></tr>
<tr><td>Gibson 2</td></tr>
<tr><td>Gibson 3</td><td rowspan="2">NG Conversion by 1/1/2030</td><td colspan="2" rowspan="2">Retire by 1/1/2032</td><td rowspan="2">Retire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Gibson 4</td></tr>
<tr><td>Gibson 5</td><td colspan="7">Retire by 1/1/2030</td></tr>
<tr><td>EDW</td><td colspan="6">NG Conversion by 1/1/2030</td><td>NG Conversion by 1/1/2035</td></tr>
</table>

*Economic growth-oriented strategy that includes an incremental 1x1 CC by 1/1/2030 in addition to prescribed 2x1 CCs to replace Cayuga 1&2 and Gibson 3&4 by 2032

Indicates strategies added since Meeting 3

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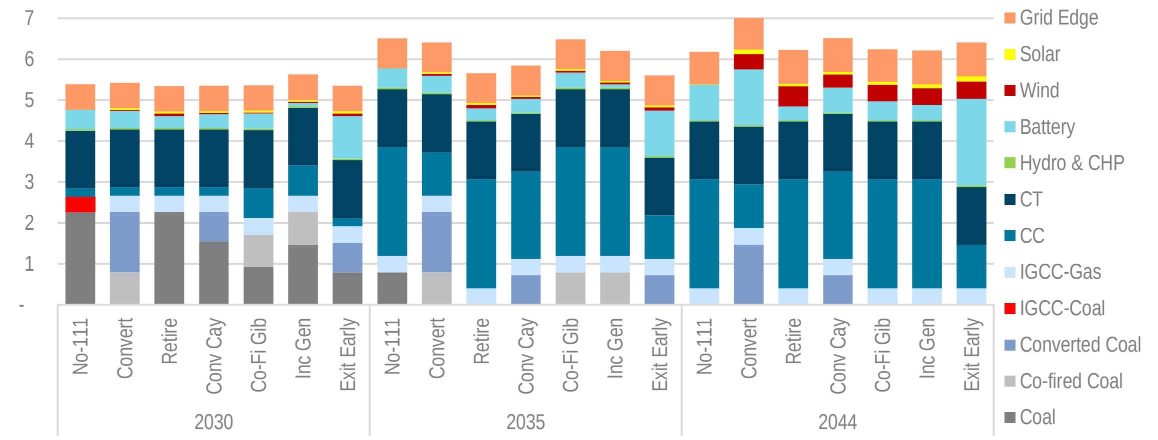
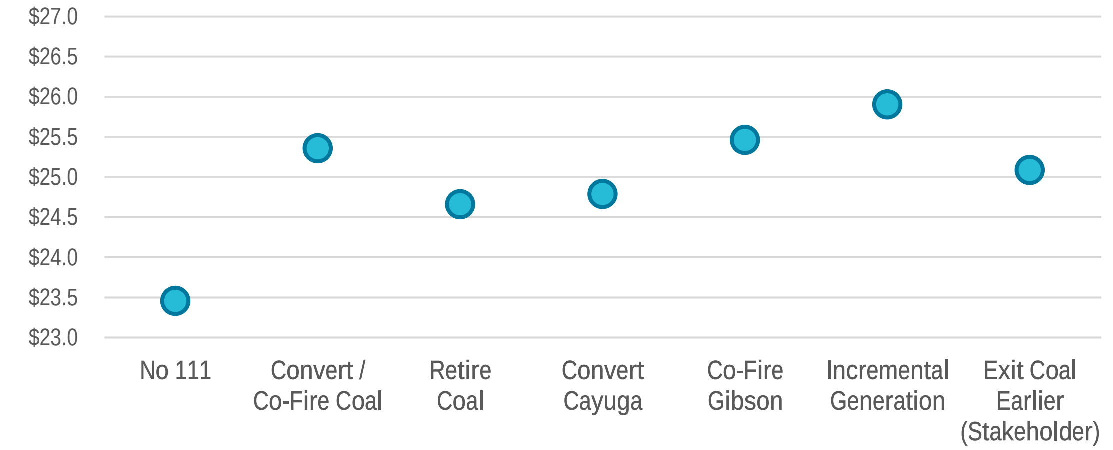
Preliminary Results Summary for All Strategies in Reference Scenario

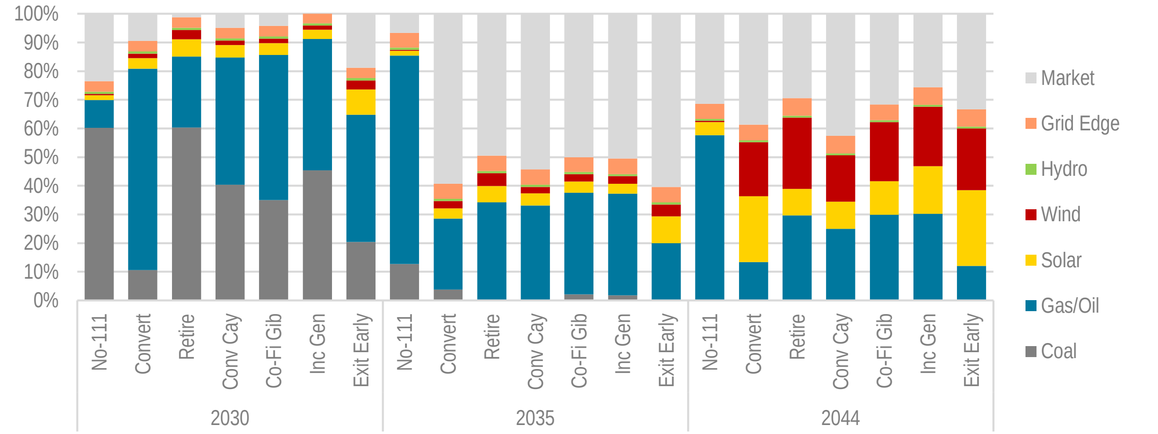
UCAP Capacity Mix Over Time (Winter GW)



Preliminary PVRRs ($B) through 2044



Energy Mix Over Time



Initial Observations

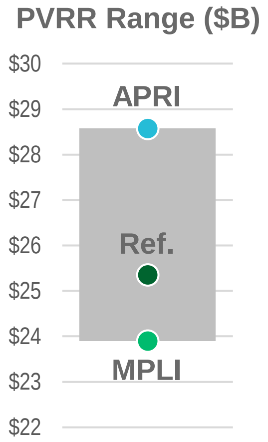
- Co-firing existing coal units or fully converting to natural gas provides capital cost savings but increases system operating costs, ultimately driving up PVRRs
- Dispatchable thermal generation contributes critical UCAP MW across all strategies into the late 2030s
- Contributions from wind and solar increase over time, providing a substantial portion of total energy by the end of the planning period for all 111-compliant strategies

Generation Strategy Results Summary: Convert / Co-Fire Coal

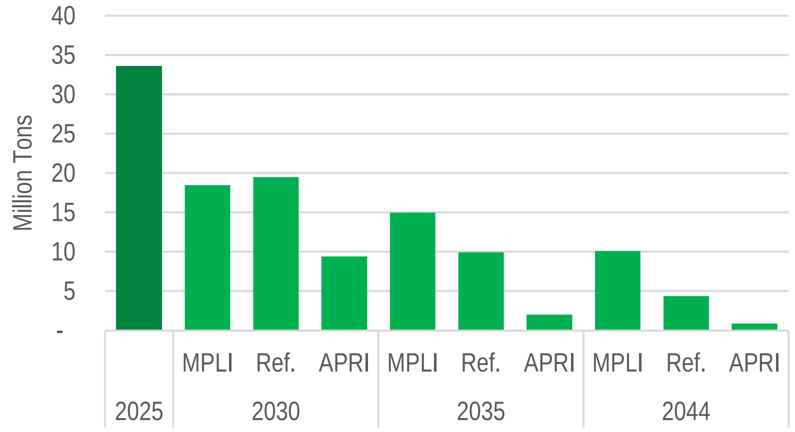
Cause No. 46193

Notes on Generation Strategy

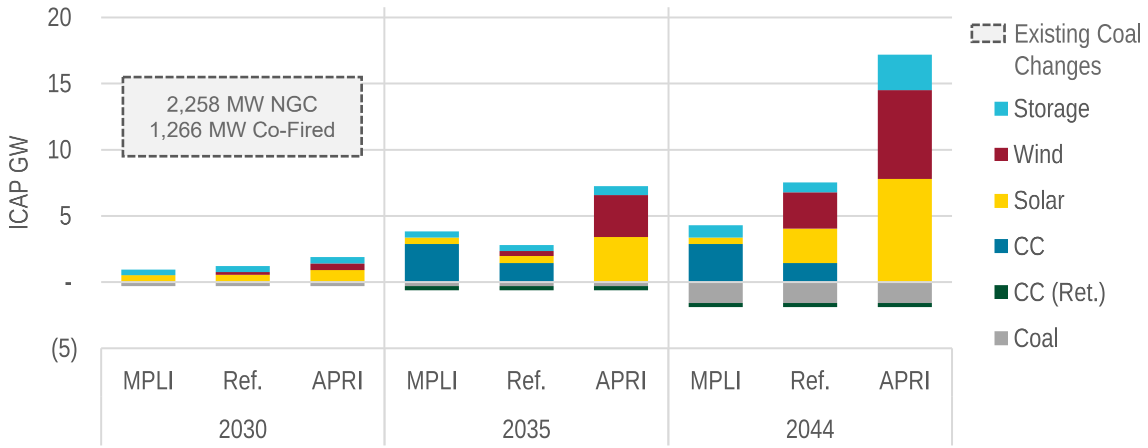
- Converting coal units to burn 100% natural gas or co-fire coal/gas, mitigates need for new capacity in near term, but does not provide additional capacity.
- Converted and co-fired coal units provide needed capacity but struggle to compete economically in the MISO energy market, with economic energy purchases supplying a substantial portion of total energy in the mid-2030s.
- Solar, wind, and battery additions supply needed incremental energy and capacity before 2030, with new CC capacity added in the early 2030s in the Minimum Policy & Lagging Innovation (MPLI) scenario, which envisions the rollback of GHG rules under CAA Section 111.
- Co-fired coal units (Gibson 1 & 2) must retire by 2039 under CAA Section 111, necessitating investment in replacement capacity in the mid/late 2030s.



CO_2 Emissions Over Time

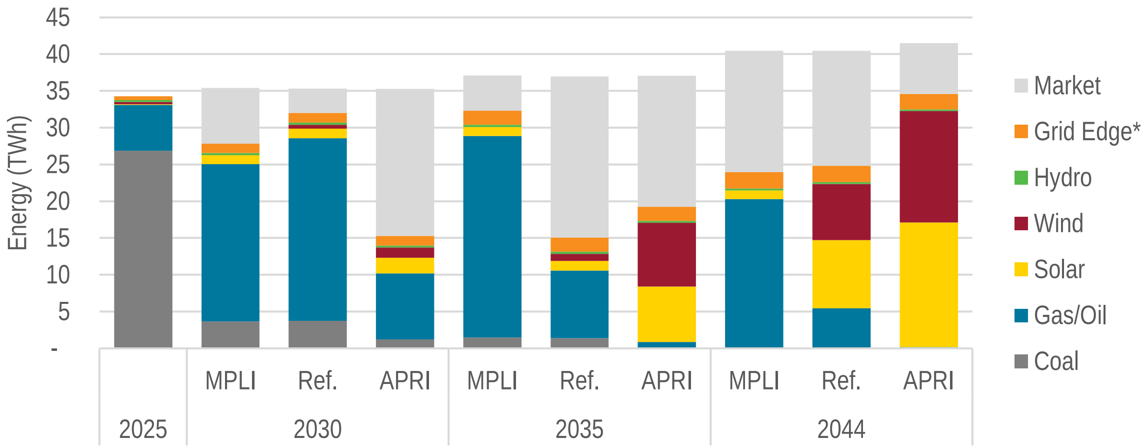


Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



*Grid Edge includes DSM (EE/DR) & IVVC

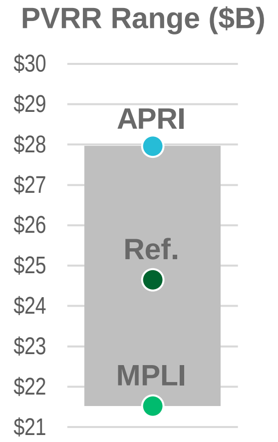
Preliminary modeling results subject to change

Cause No. 46193

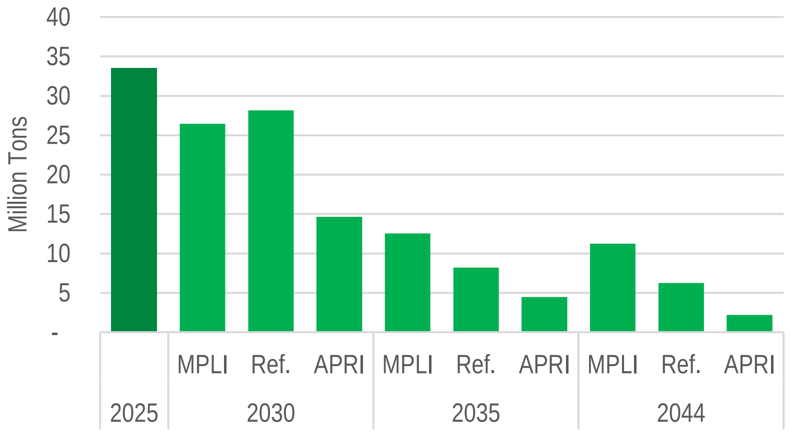
Generation Strategy Results Summary: Retire Coal

Notes on Generation Strategy

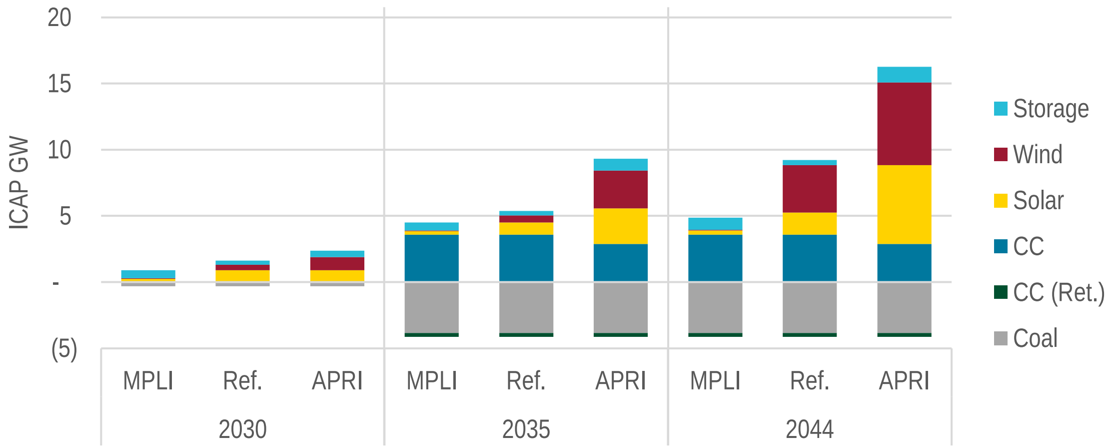
- Significant additions of dispatchable and variable energy resources are required by the early 2030s to meet incremental load growth and replace over 3.8 GW of retiring coal.
- New gas-fired combined-cycle generators provide improved resource accreditation over retiring units and operate competitively in the MISO market, dispatching up to the 40% capacity factor limit under CAA 111.
- Energy mix varies considerably across scenarios in the mid-2030s, with the repeal of the recently adopted GHG rule under CAA Section 111 allowing CCs to operate up to their economic limits in Minimum Policy & Lagging Innovation (MPLI), while additional policy constraints and falling costs drive greater adoption of renewables in Aggressive Policy & Rapid Innovation (APRI).



CO_2 Emissions Over Time

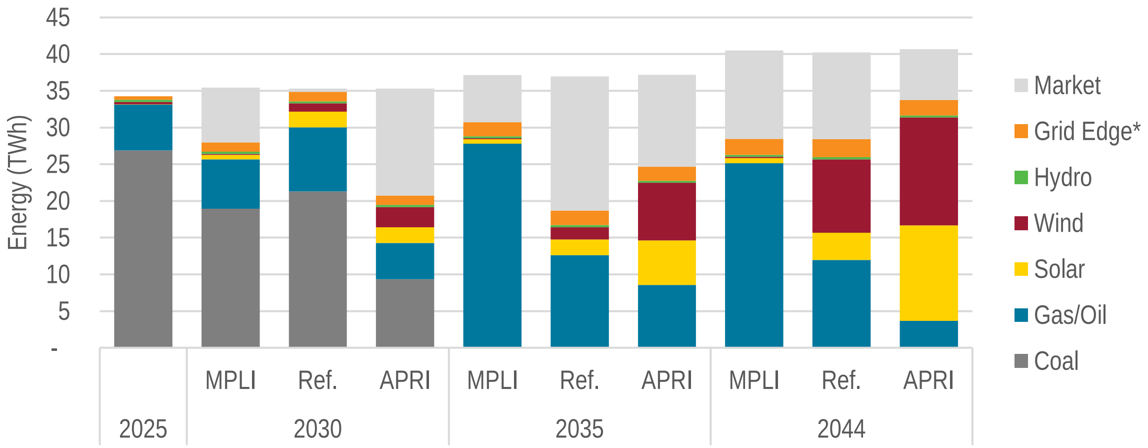


Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



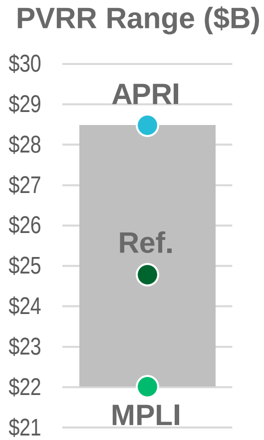
*Grid Edge includes DSM (EE/DR) & IVVC

Preliminary modeling results subject to change

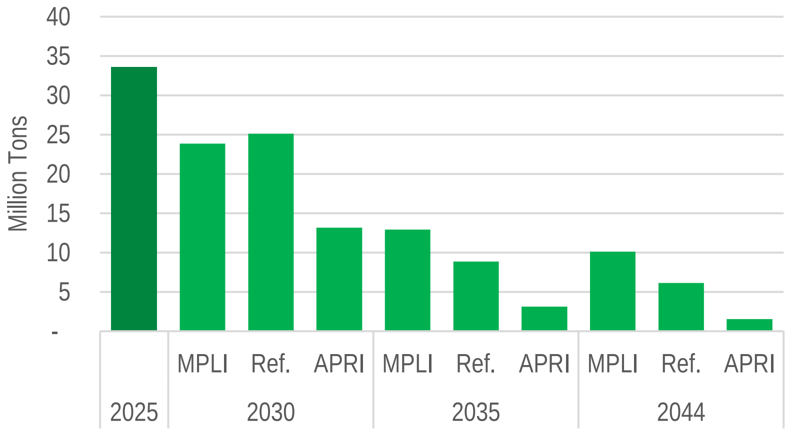
Generation Strategy Results Summary: Convert Cayuga (Blend 1)

Notes on Generation Strategy

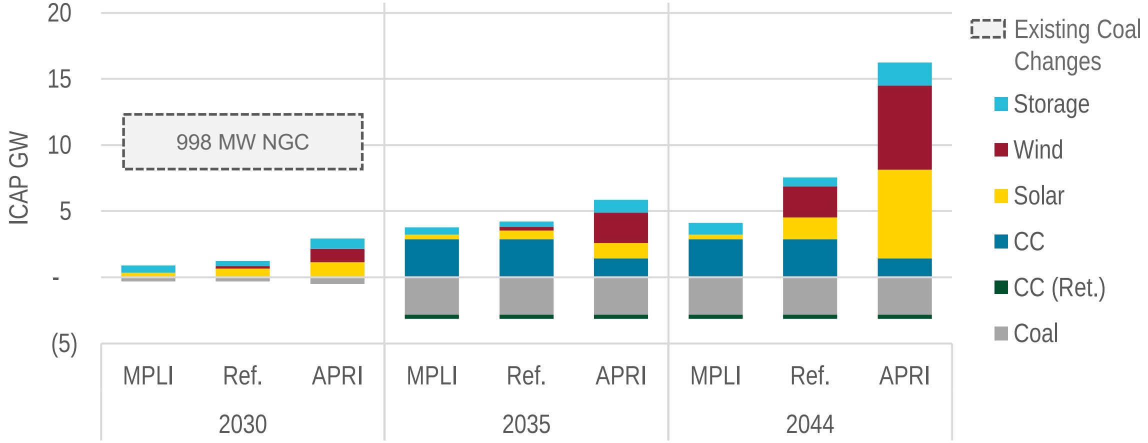
- Cayuga units 1 and 2 are repowered to burn 100% natural gas by 2030, while Gibson units 1 through 4 are retired and replaced with new combined-cycle generation by 2032.
- Renewables and storage are favored in the Aggressive Policy & Rapid Innovation (APRI) scenario, displacing a portion of the gas capacity added in other scenarios as coal units retire, while in the Minimum Policy & Lagging Innovation (MPLI) scenario, new CCs provide substantially more energy than in other cases.
- Full gas conversion at the Cayuga units allows them to operate through the end of the planning period, consistent with the GHG rule under CAA Section 111.



CO_2 Emissions Over Time

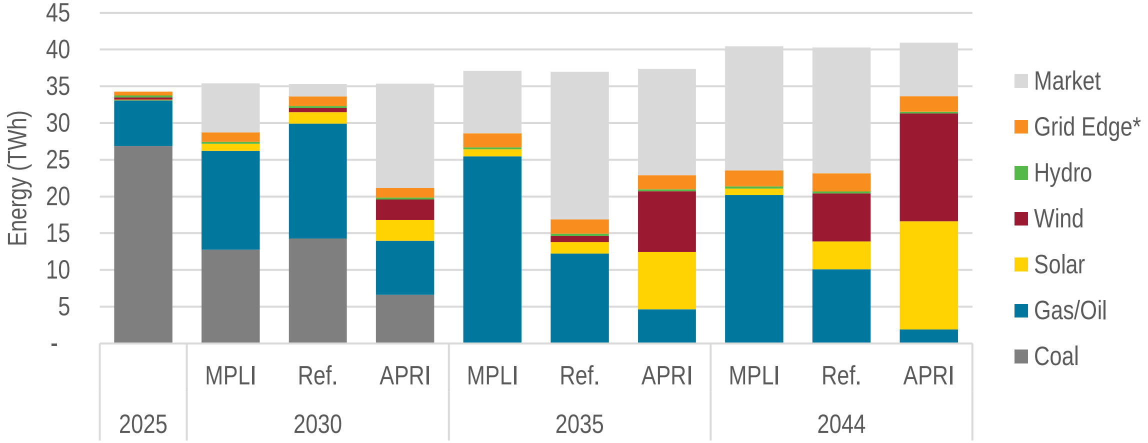


Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



*Grid Edge includes DSM (EE/DR) & IVVC

Preliminary modeling results subject to change

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Cause No. 46193 Attachment A-1
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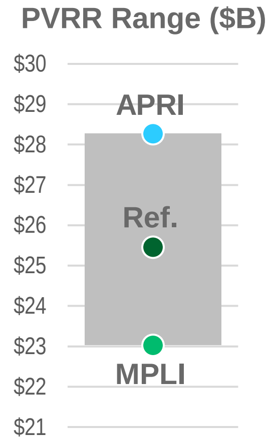
Generation Strategy Results Summary: Co-Fire Gibson (Blend 2)

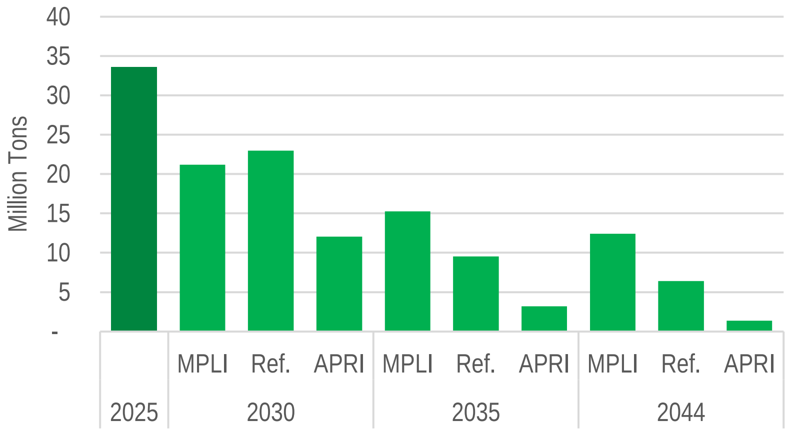
Cause No. 46193

Notes on Generation Strategy

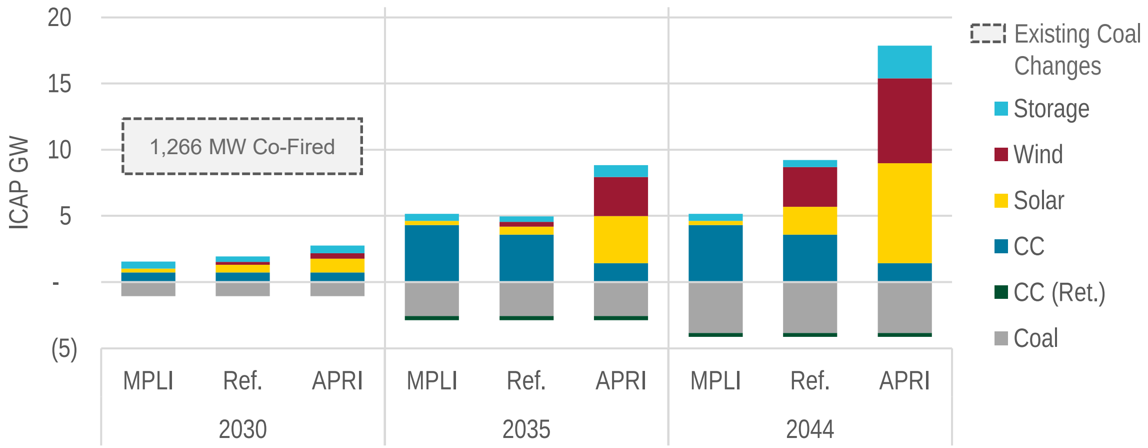
- Cayuga units 1 and 2 retire by 2030 and 2031. Two 1x1 CCs are added at the site, replacing the retiring coal and providing incremental MW to help serve growing load.
- Gibson 1 and 2 are converted to enable co-firing natural gas with coal, allowing them to continue to operate through 2038 under CAA Section 111, at which point additional capacity is needed.
- Renewables and storage are added in the late 2020s to meet near-term needs in all scenarios, with that trend accelerating in the Aggressive Policy & Rapid Innovation (APRI) scenario, and the balance shifting towards new gas in the Minimum Policy & Lagging Innovation (MPLI) scenario.
- Energy from new CCs displaces market purchases in the MPLI scenario.



CO_2 Emissions Over Time

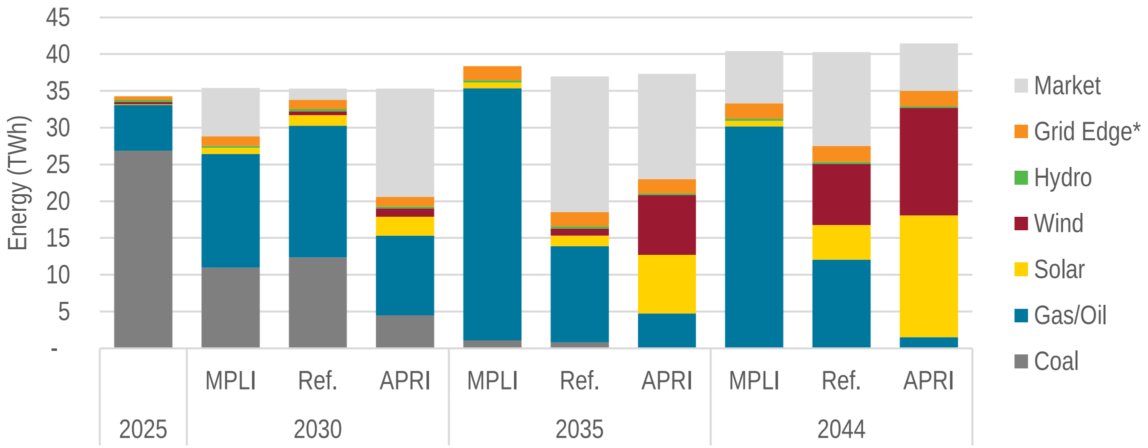


Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



*Grid Edge includes DSM (EE/DR) & IVVC

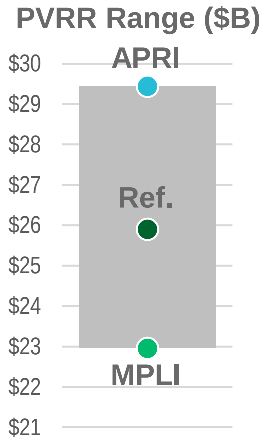
Preliminary modeling results subject to change

Generation Strategy Results Summary: Incremental Generation (Blend 3)

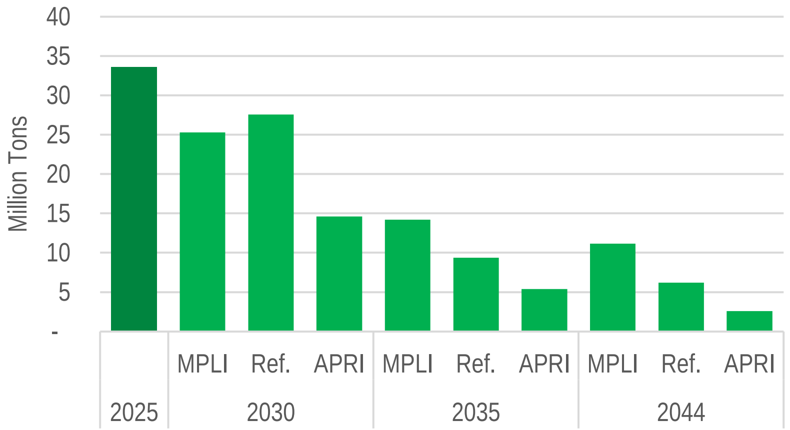
Cause No. 46193

Notes on Generation Strategy

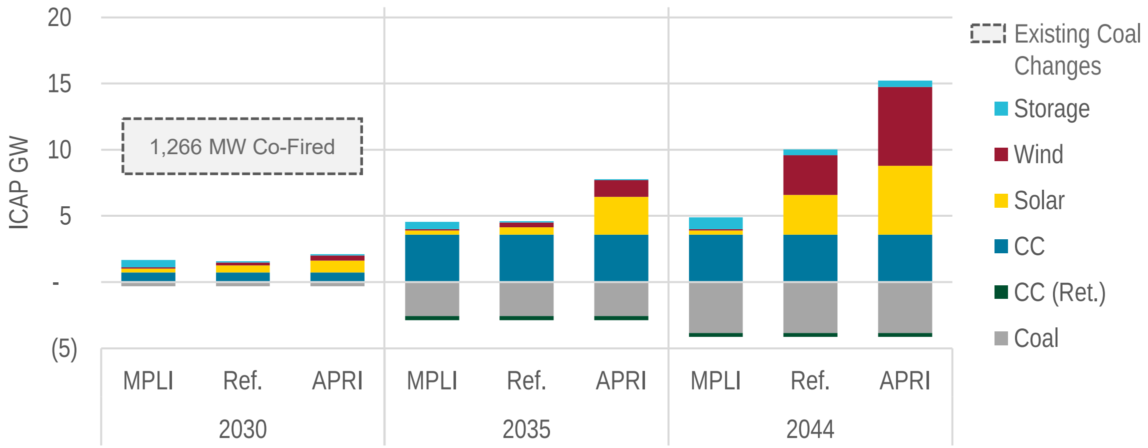
- The growth-oriented Incremental Generation (Blend 3) strategy builds on Co-Fire Gibson (Blend 2), seeking to support rapid economic development with the addition of a combined-cycle prior to the retirement of the Cayuga units.
- The inclusion of incremental capacity in the early 2030s mitigates the need for additional resources through the remainder of the decade.
- Solar, wind, and battery additions in the 2020s help meet near-term needs before incremental gas can be brought online, with further expansion of renewable capacity providing energy in the late 2030s, particularly in the Aggressive Policy & Rapid Innovation (APRI) scenario.



CO_2 Emissions Over Time

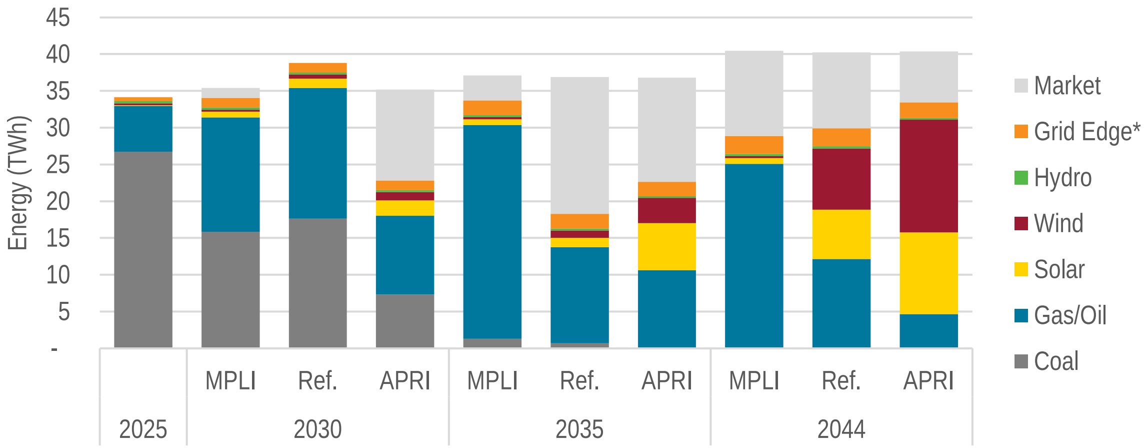


Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



*Grid Edge includes DSM (EE/DR) & IVVC

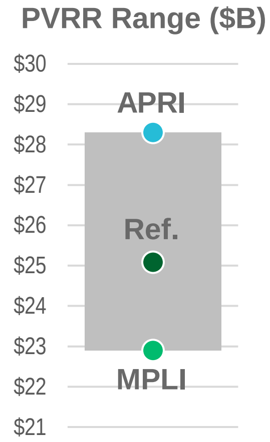
Preliminary modeling results subject to change

Generation Strategy Results Summary: Exit Coal Earlier (Stakeholder)

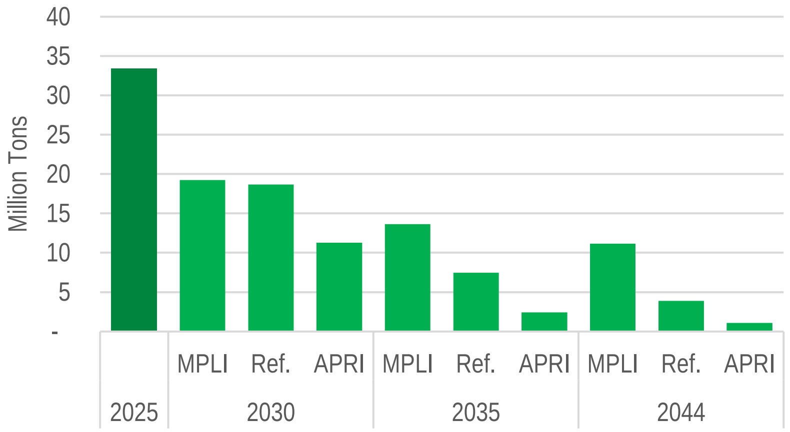
Cause No. 46193

Notes on Generation Strategy

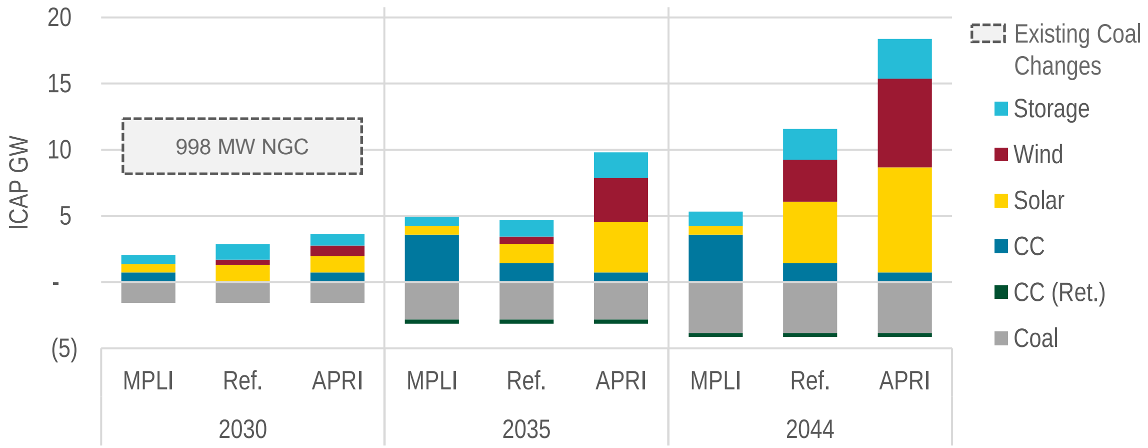
- Accelerating the retirement of Gibson 3 and 4 to 2030 necessitates the addition of higher volumes of renewables and storage by 2030 than in other strategies, while conversion of Cayuga to 100% natural gas maintains capacity at that site.
- New CC capacity is added to offset coal retirements in all scenarios, with a 2x1 replacing Gibson units 1 and 2 when they retire by 2032, consistent with the GHG rule under CAA Section 111.
- Additional gas capacity is selected in the Minimum Policy & Lagging Innovation (MPLI) scenario in which capacity factor limits under CAA Section 111 are assumed to be repealed, whereas in the Aggressive Policy & Rapid Innovation (APRI) scenario, renewables are favored.



CO_2 Emissions Over Time

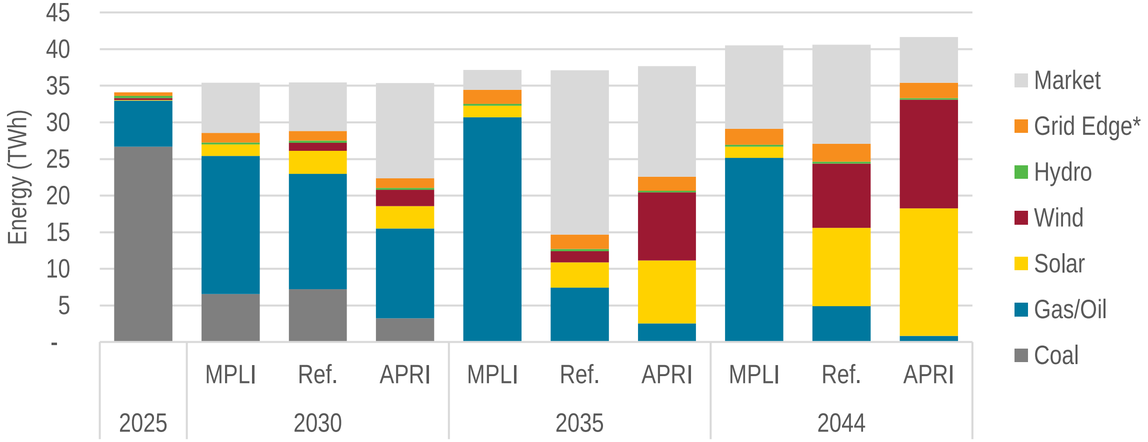


Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



*Grid Edge includes DSM (EE/DR) & IVVC

Preliminary modeling results subject to change

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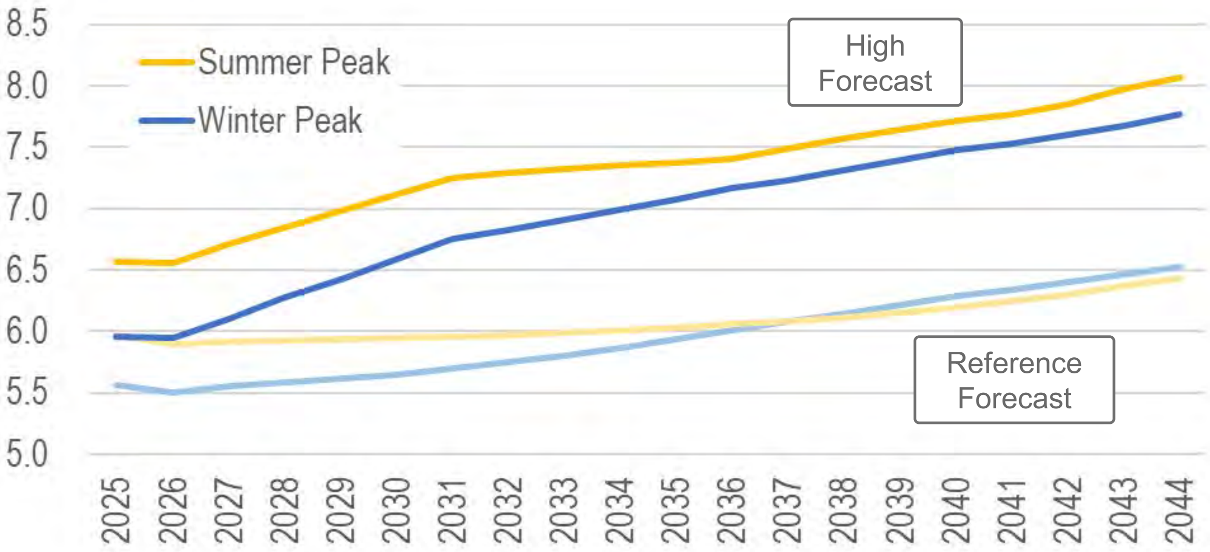
Preliminary Portfolio Modeling Update

High Load Sensitivity

Portfolio Sensitivity Analysis: High Load (Preliminary Results)

Cause No. 46193

Forecasted Peak Load (GW)



- The greatly increased load evaluated in the "high load" forecasts necessitates a substantial increase in resource additions of all types, relative to the Reference case analysis
- PVRRs across the "high load" cases are approximately 25% to 35% higher than in the Reference cases as a consequence of the additional capacity and energy needs

Impact of High Load on Resource Selection

Reference Case Resource Additions Through 2044 (GW)

Strategy	CC	Solar	Wind	Storage
Convert	1.4	2.6	2.8	0.8
Retire	3.6	1.6	3.6	0.4
Convert Cay.	2.9	1.6	2.4	0.7
Co-Fire Gib.	3.6	2.1	3.0	0.5
Incremental Gen.	3.6	3.0	3.0	0.4
Exit Coal Earlier	1.4	4.6	3.2	2.3

Results Changes in High Load Modeling (incremental GW)

Strategy	CC	Solar	Wind	Storage
Convert	+0.7	+4.4	+0.3	+1.3
Retire	--	+4.5	+0.9	+1.6
Convert Cay.	+0.7	+2.4	+1.6	+0.7
Co-Fire Gib.	+0.7	+3.5	+0.7	+0.9
Incremental Gen.	+1.2	+4.4	+0.8	+0.7
Exit Coal Earlier	+2.2	+0.8	+0.8	-0.3

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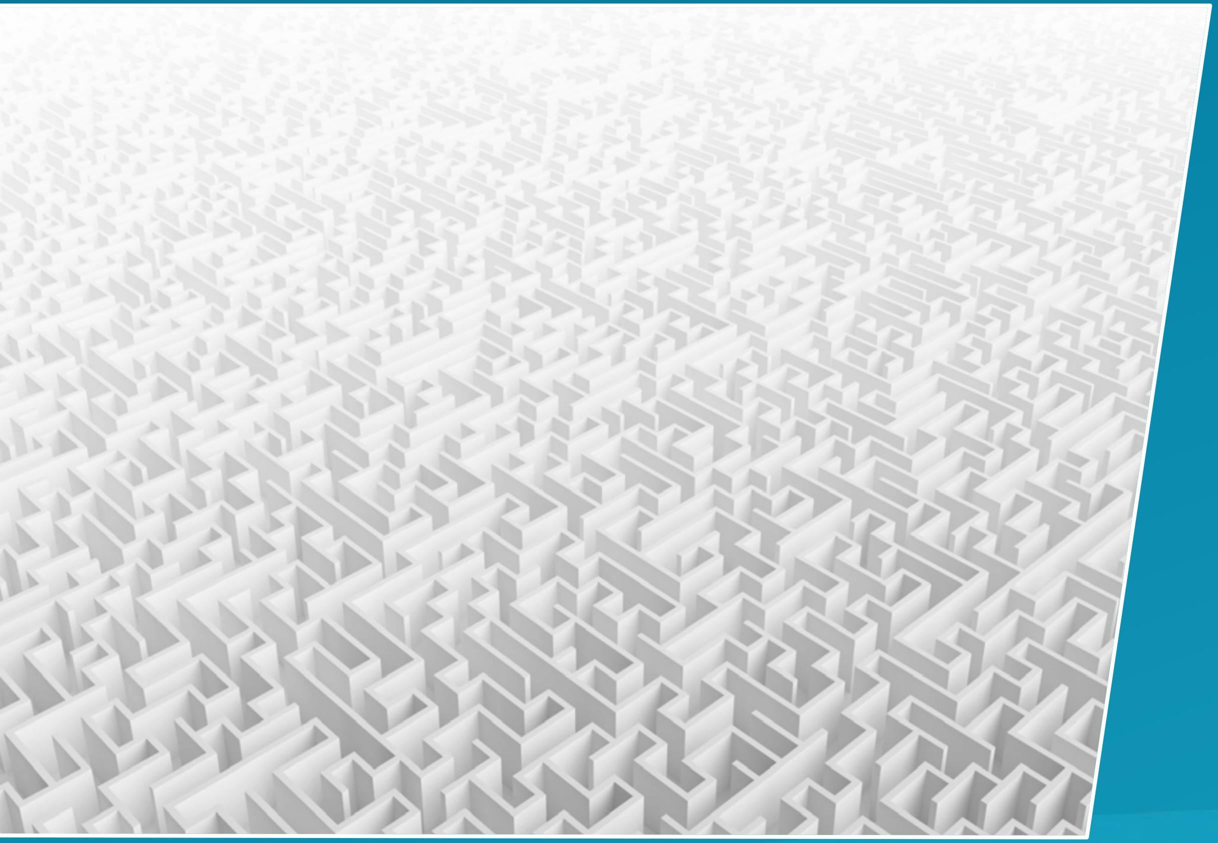

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Preliminary Portfolio Modeling Update

Considerations for Short-Term Action Plan

Reminder: Thinking About the IRP Planning Period

Iterative resource plan updates

2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044

Future IRP Filings

Immediate future

- Typically, less divergence across portfolios, relative to later years
- Limited capability to make resource changes due to project lead times
- Key consideration: Maintaining reliable service while supporting economic development

Early 2030s

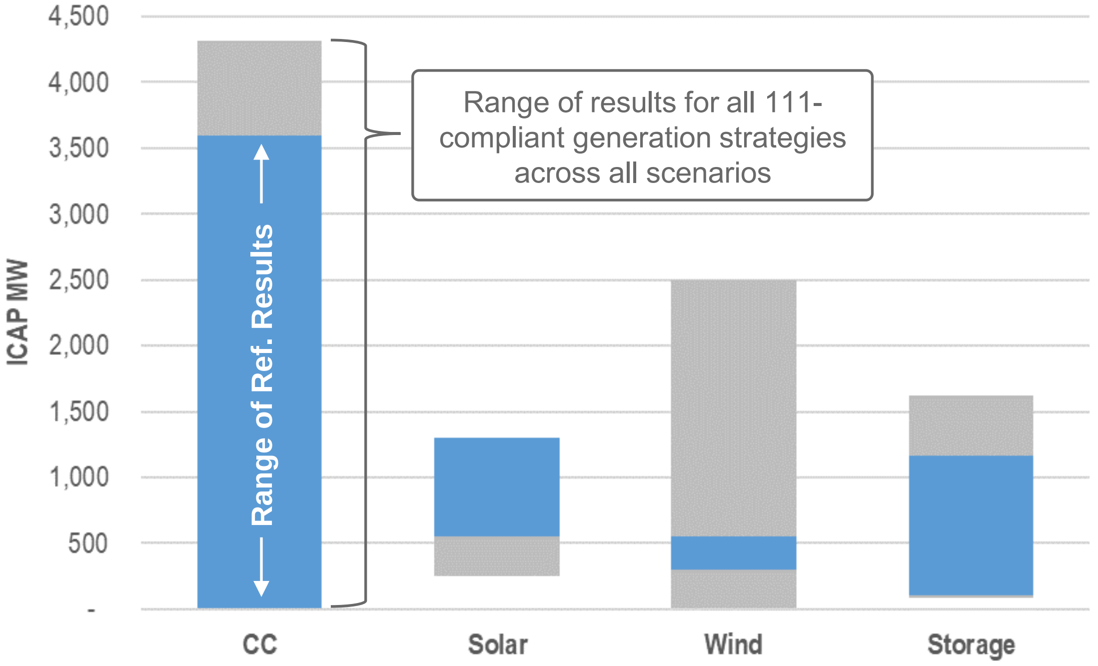
- Increased range of options further out in time
- Certain decisions fall into Short-Term Action Plan
- IRP cycles allow for checking and adjusting future resource decisions
- Key consideration: Strategy for transitioning coal units while meeting growing customer needs

Latter half of planning period

- More options, considerably more uncertainty around all planning factors
- Multiple opportunities to check and adjust plan
- Limited direct influence on Short-Term Action Plan

Using Model Results to Inform a Short-Term Action Plan

Range of Supply Side Resource Additions by 2032



In results to date, each portfolio also includes:

- 295 MW (1.5 TWh/yr) of new EE by 2032
- 548 MW of demand response by 2032, including existing programs

Significant Considerations for Developing a Short-Term Action Plan:

- Appropriate balance of retirement / gas conversion / co-firing across eight coal units totaling ~4.4 GW of dispatchable capacity
- Mix of new resources, both incremental and replacement, that appropriately balances the five pillars and supports economic development

Sources of Substantial Uncertainty:

- Regulatory – ultimate fate of EPA CAA Section 111 rule
- Demand – pace and scale of economic development in DEI service territory
- Market – resource adequacy and economic competitiveness dynamics by mid-2030s
- Supply chain – new resource availability and cost

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Preliminary Scorecard Results

Draft Scorecard

Cause No. 46193

Portfolio	Environmental Sustainability				Affordability			Reliability		Resiliency		Cost Risk			Market Exposure		Execution Risk			
	CO_2 Emissions Reduction		Cumulative CO_2 Reduction Over Planning Period (MM tons)	Non-CO_2 Emissions Ranking	PVRR ($B)	Customer Bill Impact (CAGR)		Availability of On-Demand Resources in High-Risk Hours	Fast Start & Spinning Reserve Capability	Resource Diversity	Performance in 95th Percentile Extreme Weather Event	Cost Variability ($B)	IRA Exposure		Fuel Market Exposure	Maximum Energy Market Exposure	Cumulative Resource Additions in MW		Cumulative Resource Additions as % of Current System ICAP	
	2035	2044	2044			2030	2035	2035	2035				2030	2035	2035	2035	2030	2035	2030	2035
Convert / Co-Fire Coal	-70%	-87%	355	3.8	$25.4			123%	124%	22%		$23.9 - $28.6	86%	44%	67%	68%	1,410	3,135	17%	39%
Retire Coal	-75%	-81%	344	3.8	$24.7			98%	98%	28%		$21.5 - $28.0	89%	32%	70%	50%	1,827	5,773	23%	71%
Convert Cayuga (Blend 1)	-74%	-82%	345	3.3	$24.8			103%	104%	23%		$22.0 – $28.5	86%	29%	75%	60%	1,427	4,554	18%	56%
Co-Fire Gibson (Blend 2)	-72%	-81%	342	3.3	$25.5			119%	120%	25%		$23.0 – $28.3	57%	26%	74%	53%	2,129	5,292	26%	65%
Incremental Generation (Blend 3)	-72%	-82%	333	5.5	$25.9			114%	115%	27%		$23.0 – $29.4	48%	20%	74%	52%	1,762	4,939	22%	61%
Exit Coal Earlier (Stakeholder)	-78%	-88%	380	1.5	$25.1			94%	95%	15%		$22.9 – $28.3	94%	64%	58%	61%	3,055	5,019	38%	62%

A description of each scorecard metric is included on the following slide

Analytics ongoing

Cause No. 46193

Scorecard Metrics

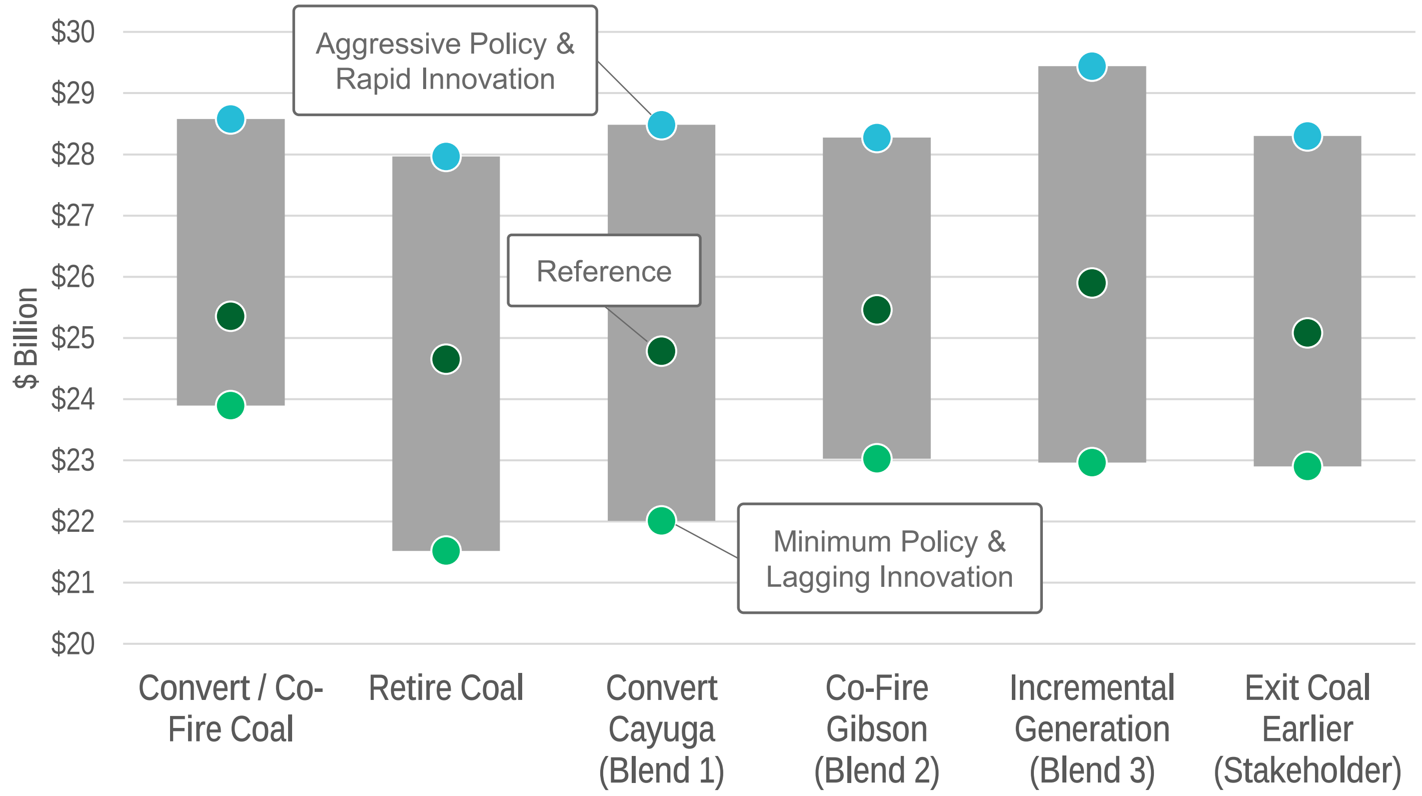
Metric	Description
CO_2 Emissions Reduction	Percent CO_2 reduction relative to 2025
Cumulative CO_2 Reduction	Cumulative volume of CO_2 reduction over the planning period (tons from 2025)
Non-CO_2 Emissions Ranking	Portfolio ranking based on cumulative volume of SO_2, NOx, Hg, and PM over planning period
Present Value of Revenue Requirement (PVRR)	Total revenue requirement associated with resource plan investments over the planning period, discounted to present; Provides estimate of total plan cost
Customer Bill Impact	Projected compound annual growth rate (CAGR) in customer bill associated with resource plan investments; Provides snapshot of portfolio cost impact at points in time
Availability of On-Demand Resources in High-Risk Hours	Thermal and Storage MW as percentage of peak load in June 2035
Fast Start & Spinning Reserve Capability	Fast start and spinning reserve capable installed resource capacity MW as percentage of peak load in 2035
Resource Diversity	The sum of squares of technology share on an installed MW capacity basis in 2035

Metric	Description
Performance in 95th Percentile Extreme Weather Event	Percent unserved energy during an extreme weather event in summer and winter based on most extreme weather events (95th percentile or greater) observed in Indiana with market purchases turned off
Cost Variability	Minimum and Maximum PVRR across worldview scenarios (MPLI, APRI, Reference)
IRA Exposure	Cumulative MW additions with exposure to IRA tax credits as a percentage of total MW additions
Fuel Market Exposure	Generation (MWh) with exposure to coal and gas market prices as a percent of total fleet generation averaged annually over the planning period
Maximum Energy Market Exposure	Maximum absolute value of net energy purchases/sales as a percentage of total energy demand through the study period
Cumulative Resource Additions in MW	Cumulative MW additions of capacity resources through 2030 and 2035
Cumulative Resource Additions as % of Total System ICAP	Cumulative MW additions of capacity resource technologies through 2030 and 2035 expressed as a percentage of total current system capacity

Affordability: PVRR

Cause No. 46193

Preliminary PVRR Results Across Scenarios through 2044



	Convert / Co-Fire Coal	Retire Coal	Convert Cayuga (Blend 1)	Co-Fire Gibson (Blend 2)	Incremental Generation (Blend 3)	Exit Coal Earlier (Stakeholder)
PVRR Range	$4.7B	$6.4B	$7.0B	$5.2B	$6.5B	$5.4B

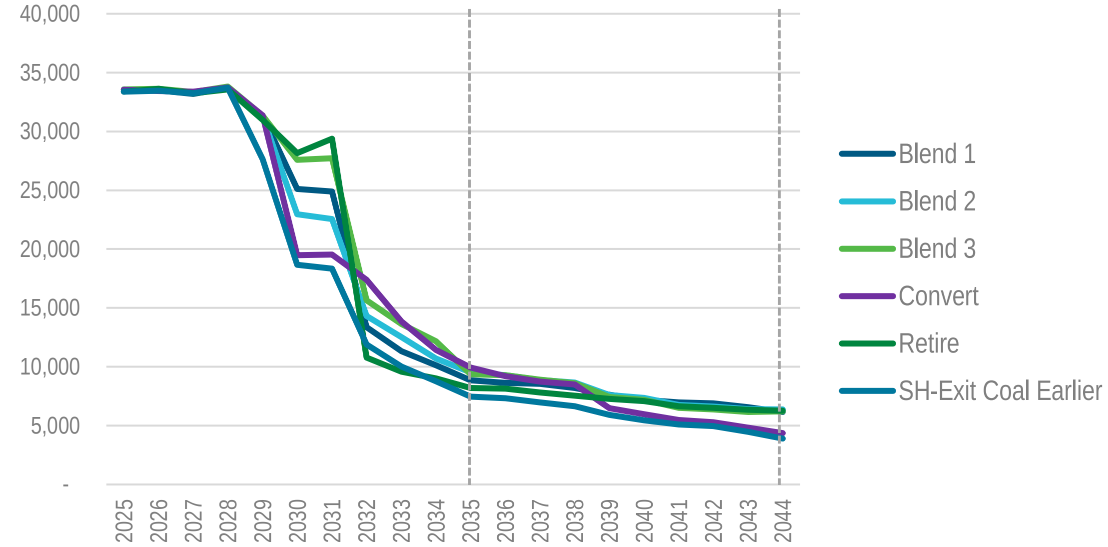
Initial Observations:

- In the Aggressive Policy & Rapid Innovation scenario, higher fuel costs, imposition of a CO2 tax, and capacity factor restrictions on existing gas assets outweigh savings from improved IRA benefits and accelerated cost declines for renewables and storage, resulting in higher PVRRs for all strategies.
- Cost savings from low fuel prices and the repeal of the GHG rule under CAA Section 111 offset the loss of IRA tax credits in Minimum Policy & Lagging Innovation, resulting in lower PVRRs for all strategies.
- Preliminary results for the Reference scenario suggest limited variability in total portfolio costs over the planning period in that case, as represented by PVRR.

CO_2 Emissions in Preliminary Results

Cause No. 46193

Annual CO_2 Emissions Over Time (000's Tons)



- Emissions include CO_2 associated with market purchases
- All 111-compliant portfolios achieve 70%-78% CO_2 reduction in the reference case over the first 10 years of the period (2035) and 81%-88% by 2044.
- Portfolios CO_2 emissions reductions are greater under the Aggressive Policy & Rapid Innovation Scenario.

2035 CO_2 Emissions Reduction (from 2025 levels)

Strategy	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation
Convert / Co-fire Coal	-70%	-94%	-61%
Retire Coal	-75%	-88%	-63%
Convert Cay. (Blend 1)	-74%	-90%	-61%
Co-Fire Gib. (Blend 2)	-72%	-90%	-61%
Incremental Gen. (B3)	-72%	-83%	-57%
Exit Coal Earlier (SH)	-78%	-94%	-65%

2044 CO_2 Emissions Reduction (from 2025 levels)

Portfolio	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation
Convert / Co-fire Coal	-87%	-97%	-73%
Retire Coal	-81%	-94%	-67%
Convert Cay. (Blend 1)	-82%	-95%	-66%
Co-Fire Gib. (Blend 2)	-81%	-96%	-63%
Incremental Gen. (B3)	-82%	-92%	-63%
Exit Coal Earlier (SH)	-88%	-97%	-67%

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Q&A

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Break

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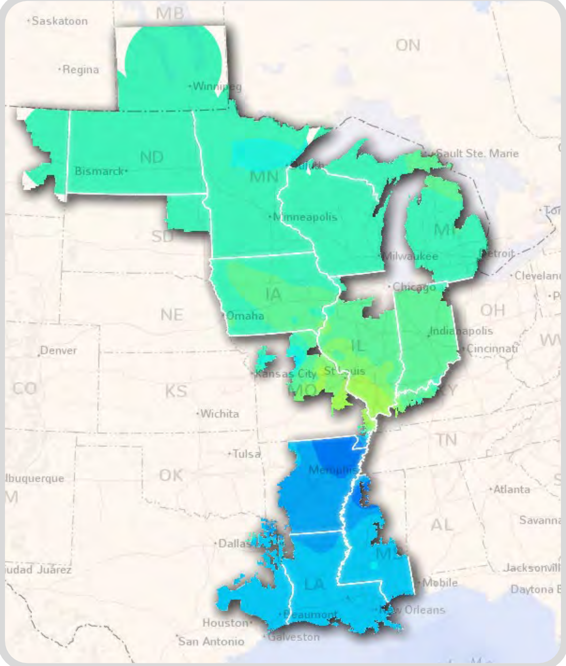
Energy Market Interaction & Modeling

MISO Energy Market Interaction

Duke Energy Indiana is a member of the Midcontinent Independent System Operator (MISO).



MISO dispatches the system by matching the amount of generation online in order to serve MISO's total load every hour of every day.

MISO Market Participants
(including Duke Energy Indiana)

Generation

Sell All Energy

All energy generated by DEI resources is sold into MISO.

MISO ENERGY MARKET

MISO Wide Energy

Generation = **Load**

Buy All Energy

DEI buys energy needed to serve load from the market.

MISO Market Participants
(including Duke Energy Indiana)

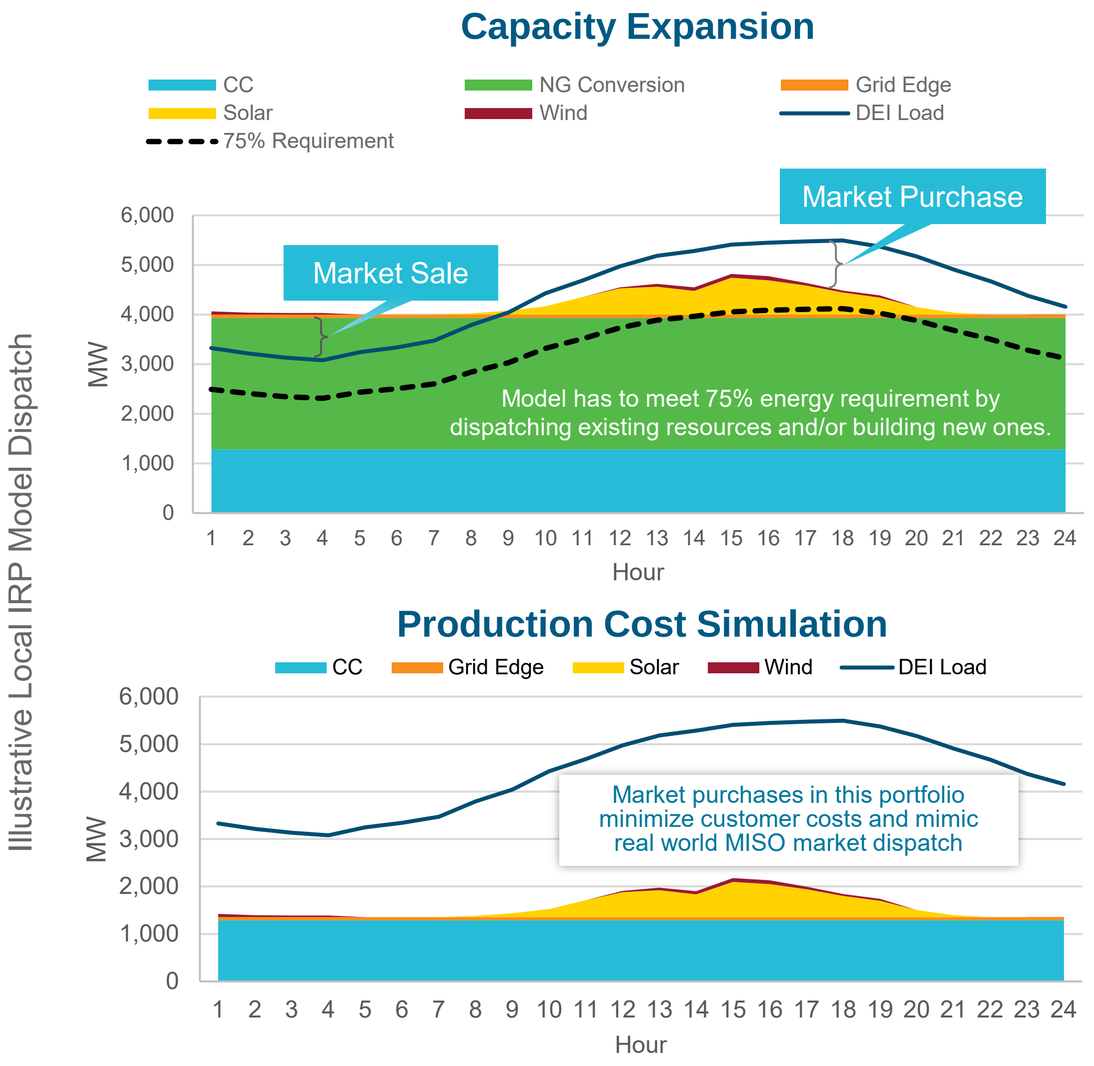
Load

Cause No. 46193

Market Purchases in the IRP Model

In the local IRP model, there are two parts to the simulation:

1. **Capacity expansion** – EnCompass builds new resources in order to meet capacity need. The objective of the model is to minimize portfolio costs.
   - During this step, the portfolio build is required to serve 75% of customers' energy needs with DEI generation.
2. **Production cost** – the portfolio developed in the capacity expansion is imported and simulated in a chronological 8760 simulation with more detailed settings.
   - DEI does not require the model to hit any customer energy need target, and generation is dispatched based on economics. This operation is more similar to the real-world MISO operations where DEI generation does not necessarily with DEI load.

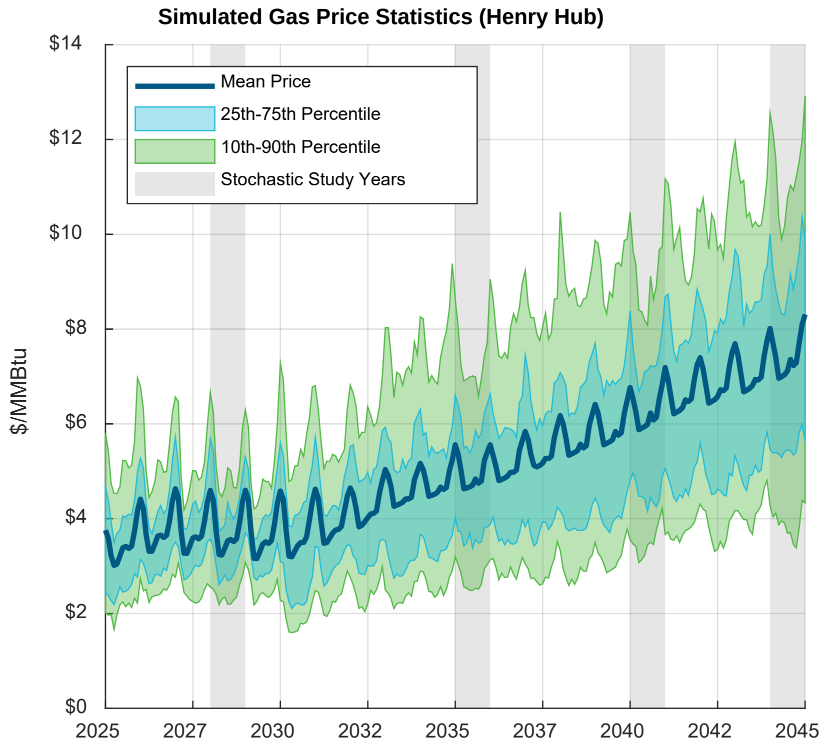


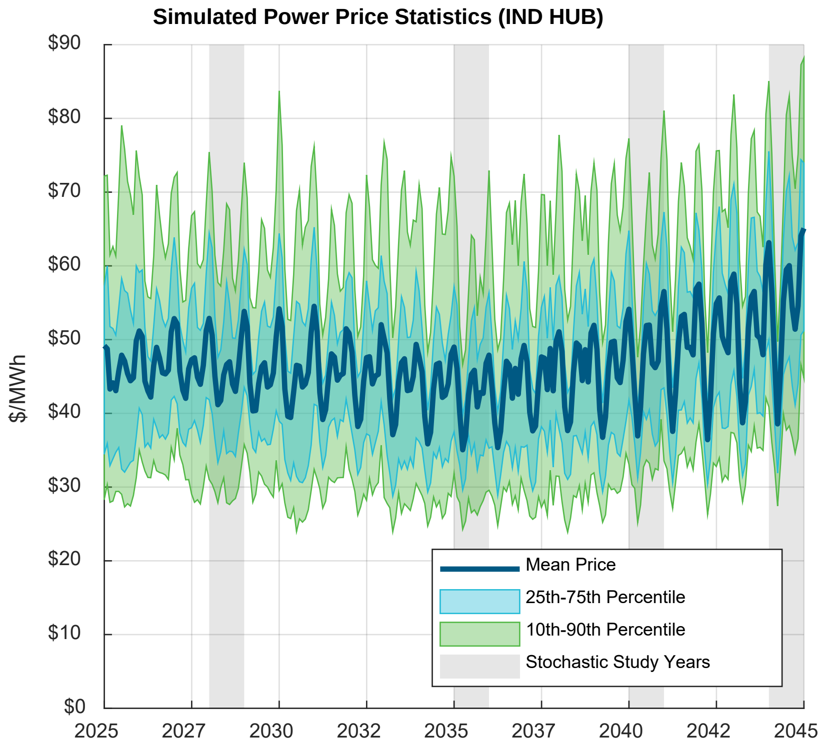
*Charts are illustrative-only and do not reflect any one modeled portfolio

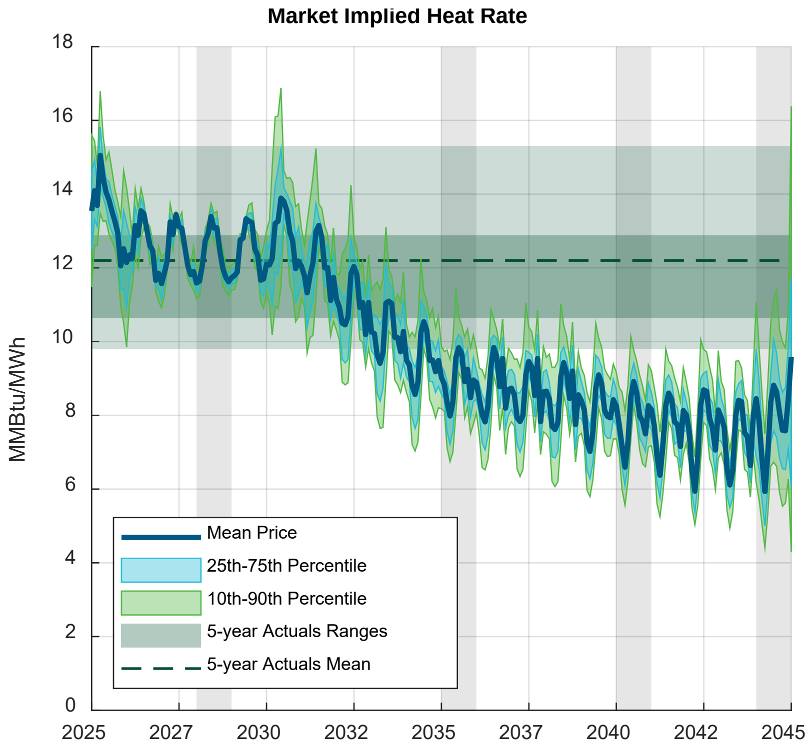
Cause No. 46193

Cause No. 46193

Stochastic Modeling of Energy Market Exposure







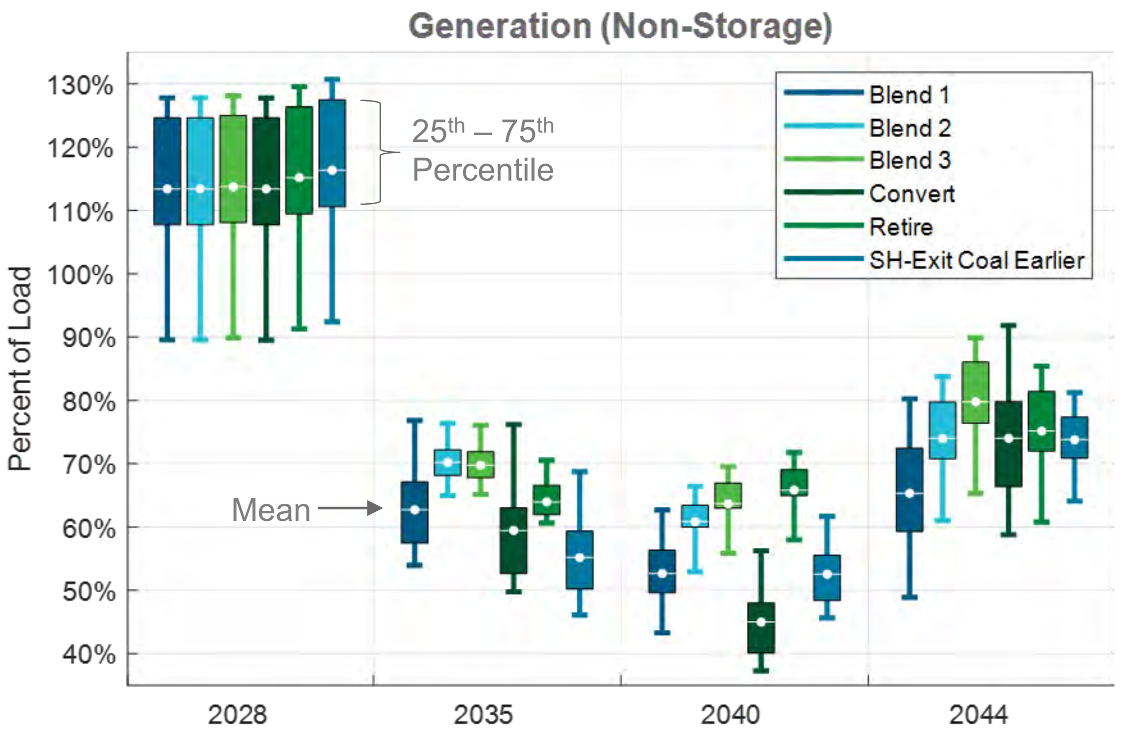
Methodology

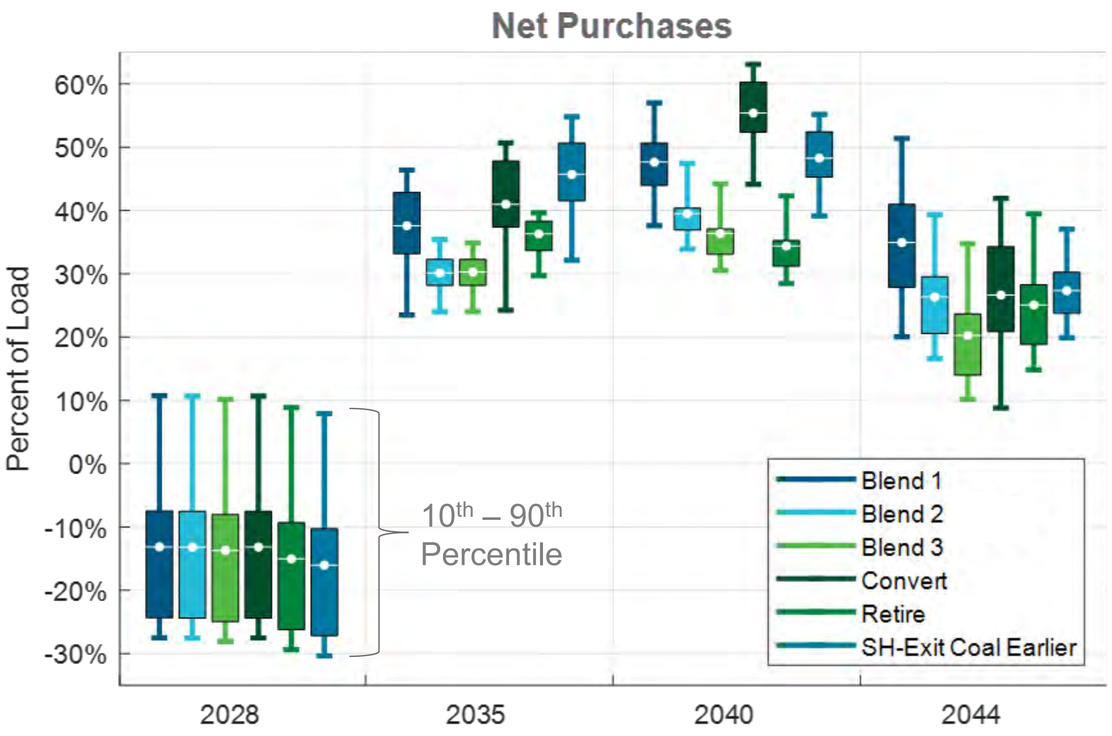
- Stochastic model produces simulations of correlated load, renewables, fuel prices and power prices using 43 years of weather history and market volatility
- Power price hourly shapes are driven by MISO net load projections. Monthly averages match Encompass 111 power prices

Observations

- Market implied heat rates (ratio of power to gas prices) drop as power price growth is not projected to keep pace with gas prices. In later study years, the rates are seen to be below historical ranges affecting profitability and the resulting capacity factors of the generation fleet.
- Preliminary, directional results shown, subject to revision.

Stochastic Modeling of Energy Market Exposure





- Stochastic model analyzes portfolios using 43 weather years, and simulations of load, fuel prices, power prices and outages
- Units dispatched based on profitability compared to simulated market prices, which are driven by MISO net load projections
- Produces ranges of energy and costs to estimate uncertainty in modeled projections
- Differences in portfolio generation and purchases driven by difference in cost competitiveness against common market prices
- Higher projected power prices & lower gas prices in 2028 drive higher generation and market sales compared to later years
- Preliminary, directional results shown, subject to revision. Model will be expanded to analyze portfolio costs and revenues

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Q&A

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Open Q&A

2024 DEI IRP Stakeholder Meetings

Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process

Meeting #1
February 22nd

- Review previous IRP
- IRP Enhancements
- Proposed timeline
- IRA / EPA 111
- Scenario development input
- Scorecard criteria discussion

Meeting #2
April 29th

- Generic Unit Summary
- Market Potential Study
- Fuels
- Accreditation / Reserve margin
- Load forecast
- Scenario review
- MISO modeling approach
- Final scorecard criteria review

Meeting #3
June 20th

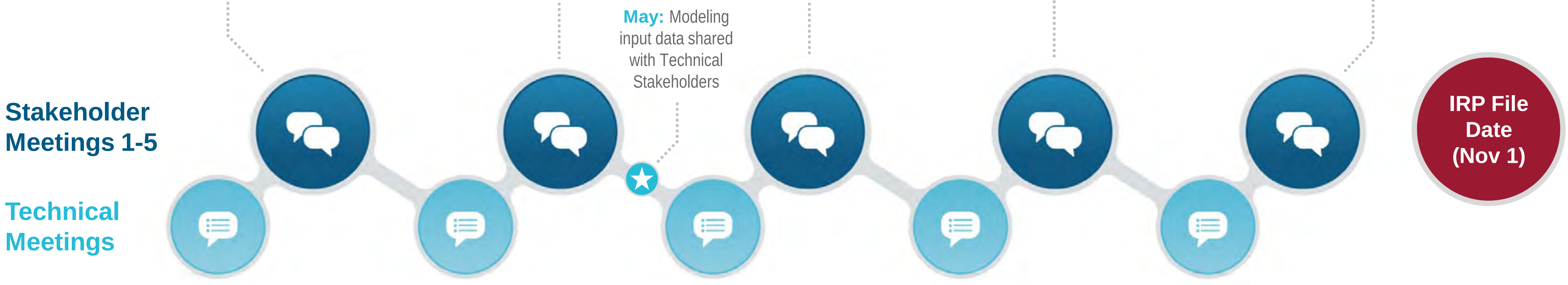
- Final inputs
- MISO modeling
- Power prices
- Initial preliminary portfolios
- Time for other items if delayed or requested

Meeting #4
1st half August

- Updated portfolios
- Initial results
- Initial scorecard

Meeting #5
Early October

- Present results
- Reliability study
- Final scorecard
- Preferred portfolio



Next Steps

Cause No. 46193

Modeling and analysis to be performed in coming weeks

Review Stakeholder Meeting Feedback
Perform Additional Sensitivity Modeling
Final Base Case and Scenario Simulations
Final Scorecard
Select Preferred Portfolio

Jul | **Aug** | **Sep** | **Oct**

Customer Programs Webinar
Aug. 6

Technical Stakeholder #4
Aug. 8
Public Stakeholder #4
Aug. 13

Public Stakeholder #5
Technical Stakeholder #5
Early Oct.

IRP File Date
Nov 1

Topics seeking input

- Scorecard calculations
- Analytical framework
- Meeting 5 format
- Data sharing

Next Steps

Cause No. 46193

Additional questions, comments, and feedback can be sent to

DEIndianaIRP@1898andco.com

Please provide any written feedback by August 20, 2024

The fifth technical and public stakeholders meeting will occur in early October.

Meeting registration will be sent out 4-6 weeks in advance.

Cause No. 46193

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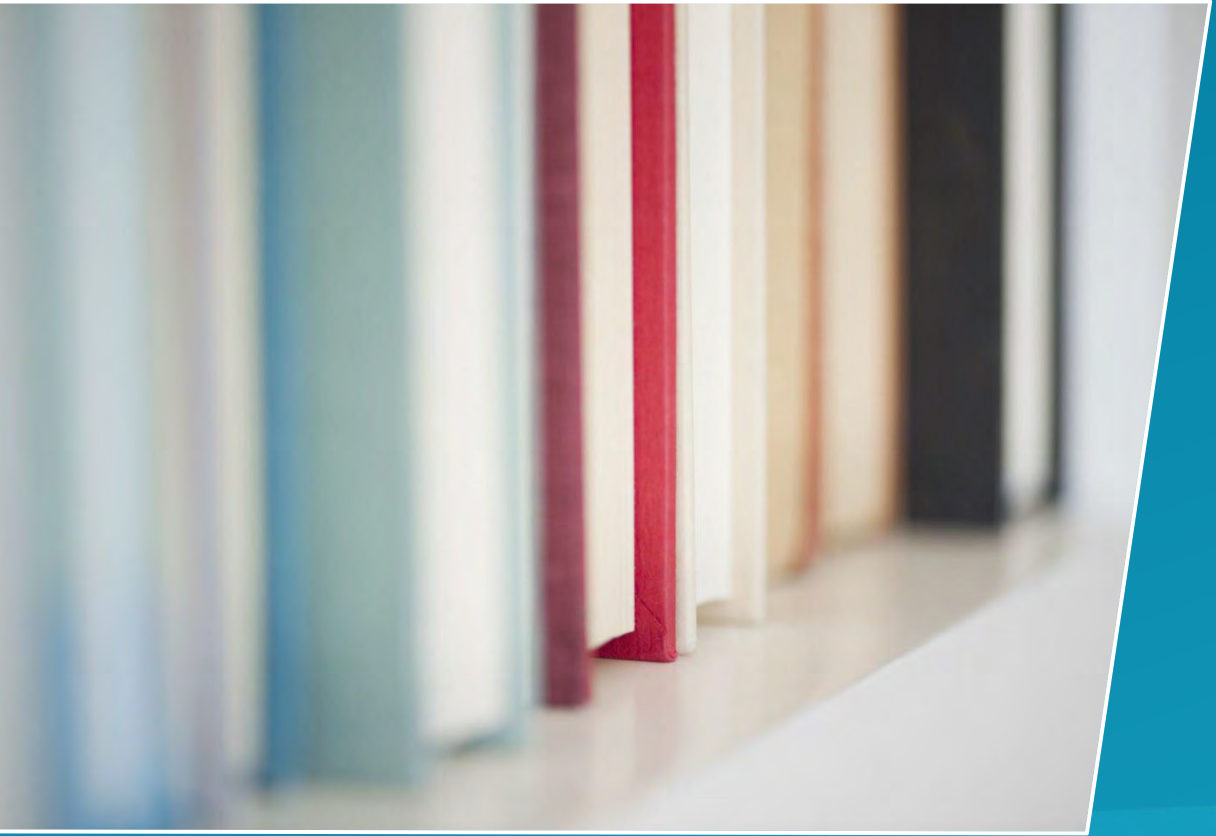
Thank you



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Appendix: Acronyms

Acronyms

Cause No. 46193

APRI	Aggressive Policy & Rapid Innovation
BOY	Beginning of Year
BTA	Build Transfer Agreements
CAA 111	Clean Air Act 111
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditures
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CPCN	Certificate of Public Conveniency and Necessity
CT	Combustion Turbine
DDRE	Deep Decarbonization and Rapid Electrification
DEI	Duke Energy Indiana
D-LOL	Direct Loss of Load
DPP	Definitive Planning Process
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EFORd	Equivalent Forced Outage Rate on Demand
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
FT	Firm Transport
GHG	Greenhouse Gas
GIA	Generator Interconnection Agreement
GUS	Generic Unit Summary

GW	Gigawatt
ICAP	Installed Capacity
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IVVC	Integrated Volt/VAR Control
kW	Kilowatt
MBE	Minority Business Enterprise
MISO	Midcontinent Independent System Operator
MPLI	Minimum Policy & Lagging Innovation
MW	Megawatt
MWh	Megawatt-hour
NG	Natural Gas
NGC	Natural Gas Conversion
NRIS	Network Resource Interconnection Service
O&M	Operations and Maintenance
PPA	Power Purchase Agreement
PVRR	Present Value of Revenue Requirement
RFP	Request for Proposal
SAC	Seasonal Accredited Capacity
SPS	Solar Plus Storage
STG	Steam Turbine Generator
TWh	Terawatt Hour
UCAP	Unforced Capacity
WBE	Women's Business Enterprise

Attachment A-1
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Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

OCTOBER 3, 2024, MEETING SUMMARY

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Meeting Information

On Thursday, October 3, 2024, Duke Energy Indiana convened the fifth stakeholder meeting to inform the development of the 2024 Duke Energy Indiana Integrated Resource Plan ("IRP"). The meeting was held virtually. Approximately 65 external individuals representing over 37 organizations participated in this session.

Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other**:
  Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve a better understanding and develop robust solutions.
- **Focus on today's topics**:
  Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**
  Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

Session Participation

This virtual event was facilitated by 1898 & Co., and the session included presentations and robust conversations on the following topics:

- Feedback from the Fourth Public Engagement Session
- Analytical Framework and Preferred Portfolio
- Scenario and Sensitivity Analysis
- Scorecard Results and Enhanced Reliability Evaluation
- Preferred Portfolio and Short-Term Action Plan Considerations

Virtual attendees used the "raise hand" feature in Teams to ask a question or make a comment aloud or submitted a question through the "Q&A" feature. Virtual attendees had access to the "chat" feature in Teams to share links to information and communicate with each other. Staff from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to DEIndianaIRP@1898andco.com.

Access to Meeting Materials

Meeting materials for the October 3, 2024 engagement session were posted to Duke Energy Indiana's IRP website at duke-energy.com/home/products/indiana-integrated-resource-plan on September 26, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders via email as the website is updated with materials.

Meeting Notes

This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed.

Safety

Karen Hall, Duke Energy Resource Planning Director

Ms. Hall provided a safety moment on fire prevention, covering cooking fire safety, tips for handling small fires, checking fire alarms, and the importance of all family members knowing what to do if there is a fire.

Welcome

Stan Pinegar, Duke Energy Indiana State President

Mr. Pinegar opened the meeting by welcoming attendees, thanking them for their participation, and encouraging active engagement in the fifth and final stakeholder meeting for the 2024 IRP.

Introductions

Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Mr. Burczyk introduced the Duke Energy teammates who are supporting the 2024 IRP.

Meeting Guidelines & Agenda

Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Mr. Burczyk discussed the ground rules for the virtual meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

Stakeholder Feedback and Incorporation

Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Mr. Burczyk provided an overview of stakeholder feedback that was received and incorporated into the agenda for the fifth Public Engagement Session and when this feedback would be discussed in the meeting. He then covered additional feedback and the responses from Duke Energy Indiana, which included topics such as heat rate inputs for the IRP modeling, data center load sensitivity clarifications, and other IRP modeling questions.

Analytical Framework & Preferred Portfolio

Nate Gagnon, Managing Director Midwest IRP

Mr. Gagnon provided an overview of the different generation strategies—Convert/Co-fire Coal, Retire Coal, Convert Cayuga, Co-fire/Retire Gibson, Co-fire/Convert Gibson, Exit Coal Earlier, and "No EPA 111"— and specifically addressed how they relate to the Cayuga, Gibson, and Edwardsport units in terms of retirement, co-firing, or natural gas conversion under each strategy. He explained that Blend 3, a strategy that included incremental generation, was replaced with Blend 4, which is a Co-fire/Convert Gibson generation strategy. Blend 4 includes the retirement of Cayuga 1 by 1/1/2030, the retirement of Cayuga 2 by 1/1/2031, and then to meet the requirements of CAA Section 111, Gibson 1 and Gibson 2 are converted co-fired units by 1/1/2030 while Gibson 3 and Gibson 4 are converted to natural gas units by 1/1/2030. Mr. Gagnon then reviewed the analytical framework for the IRP, which includes the generation strategies and worldviews (Reference, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation), resulting in 18 Scenario portfolios. He added that with additional strategy variations, portfolio sensitivities, production cost sensitivities, and a supplemental stakeholder portfolio, there is a total of 45 resource portfolios modeled.

Mr. Gagnon presented the Co-fire/Retire Gibson strategy (Blend 2) as the Preferred Portfolio, noting that it achieves an appropriate balance across the IRP planning objectives. He highlighted that Blend 2 balances cost and risk for customers, adds incremental capacity to serve economic development, and also preserves optionality to adapt to changing conditions. Mr. Gagnon also highlighted some of the short-term action plans that support Blend 2.

Q&A related to Analytical Framework & Preferred Portfolio

1. Question: Under the non-EPA 111-compliant pathway, why do Gibson 1 and 2 retire on 1/1/2036 but, under the EPA 111 compliant pathway, there are portfolios that convert existing coal units to be co-fired units that stay online through 2038?
    a. This is based on EPA 111 compliance deadlines. The EPA 111-compliant strategies have additional constraints for existing coal-fired units and new gas units which require many changes to be made by 2032, introducing additional challenges from an operational standpoint. In generation strategies that are EPA 111-compliant, Gibson 1 & 2 are co-fired by 1/1/2030, allowing them to run through 2038 in compliance with the rule. These co-fired units do not contribute

significantly to the total energy supply, but they provide vital capacity to maintain reliability for customers. Keeping this capacity online until the mandated retirement date under the rule defers the need for replacement resources and helps maintain affordability for customers. The “No 111” strategy variation benefits from a less restrictive regulatory environment, providing operational flexibility and allowing a more measured pace of transition out of coal through the early 2030s. In that case, all coal units retire by the end of 2035.

2. Question: What drives the differences between the retirement strategies in terms of the five Gibson units?
    a. The Duke Energy Indiana IRP team worked with plant engineers to determine the different strategies based on the operational considerations of the Gibson units (age of emissions controls, site layout, etc.). Moving forward, more refined engineering studies could confirm or lead to adjustments to which units are selected for co-firing, conversion, or retirement.
3. Question: What are the challenges related to existing unit retirement timing and what drives the new resource selection in the IRP model?
    a. There is a cost to retiring and replacing the existing capacity that is on the system. The IRP model is an economic optimization model that selects resources to meet energy and capacity needs, accounting for a variety of constraints. When resources are being selected over the planning period, the model is looking at the energy and capacity needs in the near and long term and the economics of these decisions drive the resource selection in order to meet the system’s needs.
4. Comment: It would be helpful to see the differences of non-CO_2 emissions metrics.
5. Question: Does the model assume a specific amount of coal or gas that must be used each year?
    a. The model utilizes an economic dispatch to determine which fuel to burn on an hourly basis. Generally, the converted and co-fired units are dispatched infrequently in the modeling and have low capacity factors. These units act primarily as capacity resources. With low capacity factors after converting to natural gas or co-fired units, the total emissions from these resources are also lower.
6. Question: How does the 2024 Preferred Portfolio compare with the Preferred Portfolio from the 2021 IRP in terms of clean energy and coal retirements?
    a. Significant changes have occurred in state and federal policies, regulatory environment and the marketplace since Duke Energy Indiana submitted its 2021 IRP that have impacted the resources this IRP. We are planning the 2024 IRP in a time of profound transformation, and many impactful changes have occurred since the 2021 IRP which are reflected in the 2024 IRP.
7. Question: Was an early switch to gas without any modifications of Edwardsport considered?
    a. No, Edwardsport is optimized to burn syngas, so its maximum unit output is lower when Edwardsport burns natural gas. With the projected load growth, derating Edwardsport in the near term increases the need for additional new capacity.

Attachment A-1
Page 460 of 534

8. Question: Are there potential technical or economic challenges associated with adding CCS at Edwardsport?
    a. Yes, but the ongoing Front-End Engineering Design (FEED) study with the DOE will help provide additional details and input on future plans at Edwardsport.
9. Question: What are the cost savings of timing the Edwardsport conversion with the next major maintenance outage?
    a. That is something that would be considered as part of the execution plan after the IRP analysis. Additional planning, studies, and engineering would play a role in the final conversion execution.
10. Question: When co-firing, can the unit run on 100% coal or 100% gas?
    a. In the model, co-fired units can run up to 50% of full load on gas. Operationally, it is possible for a co-fired unit to run on 100% coal; however, the emissions standards under the 111 rule effectively require co-fired units to burn at least 40% gas on an annual average basis.

Scenario & Sensitivity Analysis Summary

Nate Gagnon, Managing Director Midwest IRP
Matt Peterson, Lead Resource Planning Analyst

Mr. Peterson provided a summary of the individual generation strategies, focusing on how each strategy performed in the Reference, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation worldviews. He shared results related to cumulative supply-side changes, carbon emissions, Present Value of Revenue Requirement (PVRR), firm capacity mix, and energy mix over time and offered an overview of each strategy.

Mr. Gagnon reviewed the results of the portfolio sensitivity analysis, highlighting peak load forecasts for high/low cases, resource selection changes under high and low load cases, the impact of high CC costs, changes in the capacity accreditation methods, and fuel prices. He emphasized changes in solar, wind, and storage capacity by 2035 and 2044, the sensitivity of resource selection to accreditation methods, as well as the impact of installed costs, technology advancements, and renewable energy contributions on capacity planning decisions.

Q&A related to Scenario & Sensitivity Analysis Summary

1. Question: Several portfolios add additional solar and storage in the near term and then include significant wind, solar, and storage additions in the 2035-2044 time period. Why do we not see a steadier selection of resources in each year of the planning period?
    a. The timing of these resource additions is based on the selections made by the EnCompass model. The model is selecting resources that most economically meet Duke Energy Indiana's energy and capacity needs to maintain reliability. The model selects some solar and storage in the near term to fill in capacity needs prior to 2030. As coal units are retired around the early 2030s, the model generally selects combined cycles to replace the retiring coal capacity in order to maintain firm capacity needs. After 2035, incremental capacity and energy needs

in the model are fulfilled by renewables and storage resources. Forcing in additional resources before they are needed would increase portfolio costs.

2. Question: This IRP shows a reduction in renewables by 2035 when compared to the 2021 IRP. Can you explain how this is consistent with environmental sustainability?
    a. The Preferred Portfolio must balance all six planning objectives, of which environmental sustainability is one. There have been many changes since the development of the IRP that influence resource selection, including rapid increases in the cost of new resources, MISO capacity accreditation reform that emphasizes dispatchable resources, and industrial sector load growth that requires reliable, around-the-clock energy supply. All these significantly influence the timing and amount of resource additions and retirements.
3. Question: How are price changes, specifically for new generation, considered in the IRP. For example, if the Federal Reserve drops interest rates?
    a. Each IRP is essentially a snapshot in time. Cost forecasts, for both fuels and new resources, are based on the best information currently available, including prevailing interest rates and many other factors. The Preferred Portfolio allows flexibility to adapt to changing conditions, and the entire analysis is updated every three years with each new IRP.
4. Question: Do the CO_2 emissions graphs on slides 23-25 include emissions from market purchases?
    a. Yes, those graphs include emissions from market purchases.
5. Question: How does the firm capacity mix change between summer and winter?
    a. This depends on the MISO rules for capacity value of the various resource types. For instance, certain resources, like solar, receive a higher accreditation in the summer and lower in the winter. So, for solar, that leads to a larger percentage of the firm capacity mix in the summer and lower in the winter. We have shown the winter calculation on the slides because the winter reserve margin becomes more limiting over time than the summer for our system.
6. Question: Please explain why the Minimum Policy and Lagging Innovation Scenario wasn't selected as the Preferred Portfolio?
    a. Scenarios are not selectable generation strategies. Rather, they are intended to stress test the generation strategies under different conditions. The Reference Scenario has the assumptions that are believed to be most probable. Both the Minimum Policy and Lagging Innovation Scenario and the Aggressive Policy and Rapid Innovation Scenario consider potential futures that are less likely, but not implausible and are meant to explore the range of alternative future outcomes.
7. Question: Why are the winter peaks higher than the summer peaks starting in 2038?
    a. The load forecast indicates that Duke Energy Indiana's growth is driven significantly by industrial customers, which have around the clock energy needs and are less temperature sensitive than residential load, which flattens out the annual load profile and leads to the shift toward winter peaks.
8. Comment: Commenter is concerned that environmental sustainability is not viewed as a "must" for the IRP.
9. Question: Are renewable capital costs constant in the model?

   a. No, renewables include cost curve assumptions that change over the planning period. Additionally, the Aggressive Policy and Rapid Innovation Scenario assumes more rapid cost declines for renewables and storage.
10. Question: How does Duke Energy account for behind-the-meter generation for large customers, particularly those that can handle a substantial share of their own energy and capacity needs?
    a. The load forecast includes assumptions around customer behind-the-meter solar generation, with the effect of lowering the overall load over the forecast. A low, base, and high behind-the-meter generation forecast is included in the 2024 IRP modeling. Interruptible load, which is essentially equivalent to a demand response program is also modeled for large customers.
11. Question: Why do other investor-owned utilities in Indiana have more aggressive coal retirement and renewable generation additions than Duke Energy Indiana?
    a. It is important to remember that every system is different. While other utilities in Indiana are helpful context, they are not determinative of Duke Energy's analysis and the path forward for balancing objectives specific to Duke Energy's system. Duke Energy Indiana remains committed to maintaining reliability and affordability while transitioning to an increasingly diverse and environmentally sustainable mix of resources.

Scorecard Results & Enhanced Reliability Evaluation

Nate Gagnon, Managing Director Midwest IRP
Patrick O'Connor, Principal Quantitative Analyst
Ameya Deoras, Manager Quantitative Analytics

Mr. Gagnon reviewed the final scorecard metric updates, highlighting the incorporation of stakeholder feedback into the metrics. He discussed the separation of spinning reserve and fast start metrics, and the change in resource diversity to a firm capacity basis per stakeholder requests. He emphasized the PVRR results across Scenarios, noting that the Convert/Co-fire Coal strategy consistently yielded the highest PVRR, while the Retire strategy offered the lowest PVRR. He also highlighted the projected customer bill growth rates, with the Exit Coal Earlier strategy having a higher impact by 2030 and the Retire Coal strategy having higher rate impacts by 2035.

Mr. Gagnon then focused on environmental sustainability, detailing the CO_2 emissions trends across generation strategies. He noted that emissions drop steeply in 2030-2032 as coal is replaced by natural gas, renewables, and low-cost energy from the MISO market. He also discussed the CO_2 intensity of the Duke Energy Indiana portfolio, with the Retire Coal strategy having the lowest intensity in 2035 due to the significant contribution of advanced class CCs.

Mr. O'Connor reviewed the reliability and resiliency performance of the portfolios over a range of conditions in the stochastic analysis, including extreme cold weather scenarios. He highlighted the Expected Unserved Energy (EUE) metric, which represents periods of potential reliance on the MISO market to meet customer demand. The study year 2035 was used as a benchmark, showing differing levels of winter risk across generation strategies.

Mr. Deoras then discussed the stochastic modeling of energy market exposure, explaining that real data from 43 weather years was used to create 300 different iterations. He noted that the results for 2028 are similar across the scenarios but that the 2044 operating costs are reduced by higher PTC/ITC credits, with narrower ranges resulting from higher renewables not subject to dispatch based on market/fuel prices. This also leads to lower net purchases in 2044. He noted that CO_2 emissions reductions in later years are driven by portfolio composition changes and lower market power prices. He then reviewed results for maximum generation dispatch of the Preferred Portfolio.

Mr. Gagnon also presented the scorecard results, covering various metrics such as environmental sustainability, affordability, reliability, resiliency, cost risk, market exposure, and execution risk. He detailed the cumulative resource additions by 2035 and 2044, and the performance of the generation strategies across the scorecard metrics.

Q&A related to Scorecard Results & Enhanced Reliability Evaluation

1. Question: Can you provide data from the non-CO_2 emissions metric that was previously on the scorecard?
    a. Yes. This data will be included in the final IRP document.
2. Question: Please explain the 43-year weather factor used in the stochastic analysis?
    a. In place of the weather profile used in the capacity expansion model, the stochastic analysis utilizes weather data from 1980 to 2022 from Indiana weather stations to determine what load would look like in each of those weather years. That is then used to run outage simulations to get 300 different probabilistically generated scenarios.
3. Question: Is there a weighting applied to the 43 weather years?
    a. No, each of the weather years is viewed as being equally probable.
4. Comment: Commenter is concerned that the 43 years of historical weather data is not indicative of future weather patterns.
    a. Duke Energy is open to altering this methodology if there is another generally agreed upon method that can be applied to this analysis in the future.
5. Question: Did you use the same historical weather data in the 2021 IRP?
    a. The SERVM enhanced reliability analysis was not performed as part of the 2021 IRP. However, this is a similar process to what MISO and others follow. This analysis aims to get a wide range of outputs as opposed to the deterministic model, which uses a single weather profile.
6. Comment: Commenter recommends looking at IPCC for future weather trends.
7. Question: Has Duke Energy Indiana looked at how other utilities are modeling weather in their stochastic analyses?
    a. Using historical weather data is an industry standard practice as it pulls data that includes historical extreme weather years. There is no widely agreed-upon way to predict future weather patterns on an hourly basis.

8. Question: Are other Duke Energy subsidiaries using historical weather data that are relevant to their regions?
    a. Yes. Duke Energy subsidiaries are using similar weather data specific to their respective regions in other jurisdictions. From an input and software perspective, this analysis is also consistent with similar MISO and other peers' analysis.
9. Question: Does the idea that there is more decentralized and consumer access to rooftop solar and community solar factor into the resiliency and energy needs?
    a. The capacity expansion modeling includes a forecast for new rooftop solar, but it is not explicitly modeled in the stochastic analysis as this analysis is done to evaluate risk. The main risk factors are power prices, fuel prices, and outages.
10. Question: Are polar vortexes compelling evidence of climate change associated with overall global warming?
    a. Events like polar vortexes represent instances of past extreme weather and are an important component of the historical data used in the stochastic analysis to evaluate what Duke Energy's load might look like under extreme conditions in the future.
11. Question: How are you incorporating projected increases in temperature ranges due to climate change, particularly in the hotter summer months?
    a. No adjustments were made to any of the historical weather data, but the data does have extreme weather events, which helps to account for this.
12. Question: Why is the Exit Coal Earlier strategy weather risk higher?
    a. The Exit Coal Earlier strategy is more susceptible to reliability risk in the winter as it carries less thermal generation, relying more on more solar and storage. When the system is under stress, the storage cannot charge overnight.
13. Question: Can information for the cumulative CO_2 emissions by year and strategy be shared?
    a. Yes. The IRP will include the annual CO2 emissions by generation strategy.
14. Question: Work has been done with Purdue Climate Change Center to develop a load forecast that considers climate change as part of the previous IRP, is that not being used as part of this IRP?
    a. In the 2021 IRP, Duke Energy ran a sensitivity at request of stakeholders, working with Purdue data on climate change temperatures, which did not make a material difference to the load forecast. Since it did not have a significant impact, the sensitivity was not included in the 2024 IRP.
15. Question: What are some of the reasons for not transitioning away from thermal resources in the next few years?
    a. We must reliably serve our customers while maintaining affordability. Constraints such as project lead times, interconnection process delays, and permitting are all factors that are limiting the near-term speed of transition, and cost to customers is always an important consideration. The Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation scenarios, which are based on alternate assumptions and forecasts, explore potential futures in which the transition occurs more or less rapidly. As part of the IRP, it is important to identify a Preferred Portfolio which balances all of the planning objectives.

16. Question: Why does the scorecard make a comparison for CO_2 emissions reduction to 2025 instead of 2005 like the 2021 IRP?
    a. This baseline year was used at the request of stakeholders. 2025 is used to provide a baseline to compare what the emissions look like at the start and the end of the planning period. Additionally, we are factoring in the emissions from MISO market purchases in this IRP, which would not have been accounted for in the 2005 values. The change to use a more recent datapoint that was more representative of Duke Energy Indiana operations today was suggested by stakeholders and something that we highlighted as a change in the second public stakeholder meeting.
17. Question: In comparing the overall environmental impact, what data is included for quality impact such as particulate matter?
    a. Those impacts are correlated to CO_2 emissions, and are not explicitly outlined in the scorecard, but they will be included in the IRP document.
18. Question: Can you elaborate on the Energy Market Exposure metric?
    a. The Energy Market Exposure metric measures the maximum value of net energy purchases and sales from the MISO market as a percentage of total energy demand through the study period. The Preferred Portfolio does not need to purchase from the market to meet demand but does so when it is more economical.
19. Question: What is the confidence level on the CAGR metric?
    a. As with the IRP in general, the bill impact calculation is based on estimated and forecasted costs associated with each generation strategy over time and are therefore subject to fluctuations on how those factors materialize. Generally speaking, the more quickly a generation strategy transitions, the higher the CAGR will be in the early years of the planning horizon. Forecast error can be expected to affect the generation strategies in similar ways, which makes the relative bill impact results much more robust than the absolute numbers.
20. Question: Can the full cost breakdown and relationship between portfolio costs and the rate impact be shared?
    a. Bill impact analysis and calculations for each candidate portfolio have been provided to technical stakeholders who have signed an NDA.

Preferred Portfolio & Short-Term Action Plan Considerations

Nate Gagnon, Managing Director Midwest IRP

Mr. Gagnon provided model results for the Preferred Portfolio, highlighting cost metrics, capacity changes, and energy savings. He discussed the optionality provided by the Blend 2 portfolio for a future in which CAA Section 111 restrictions are relaxed. He highlighted the potential for tax credits associated with CCS at Edwardsport to lower the PVRR and the need to advance early studies to maintain small modular reactors (SMRs) as a viable future planning option.

Mr. Gagnon also reviewed the planning period, noting the limited capability to make resource changes in the immediate future due to project lead times, the increased range of options in the early 2030s, and the greater uncertainty in the latter half of the planning period. He emphasized

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the importance of maintaining reliable service while supporting economic development and transitioning coal units to meet growing customer needs.

Mr. Gagnon discussed the considerations for the short-term action plan, emphasizing the importance of maintaining flexibility to adapt to changing conditions. He highlighted the need to install two advanced class 1x1 combined cycle (CC) units at Cayuga Station by 2030 and 2031 to replace aging coal units and gain incremental capacity. He also stressed the importance of securing gas supply to Gibson Station to support co-firing, CC, and gas conversion options, and deploying approximately 500 MW of solar and 400 MW of battery energy storage by 2030 to meet near-term energy and capacity needs with the retirement of Gibson 5. Mr. Gagnon also presented potential plan adjustments if there is a delay of compliance deadlines under the 111 final rule, such as CCS evaluation at Edwardsport, and the preparation to develop a 2x1 CC to replace Gibson 3 and 4.

Q&A related to Preferred Portfolio & Short-Term Action plan Considerations

1. Question: Will you provide more information about the investigations, input data, and conclusions for SMRs?
    a. One of the appendices in the IRP document will be devoted to supply-side resources and contain more information on SMRs.
2. Question: How do you weigh the indirect environmental, health, and economic costs of emitting CO_2 when these costs exceed the direct costs of zero or low CO_2 approaches such as solar?
    a. The goal of the IRP is to select a portfolio that most appropriately balances many planning objectives, including environmental sustainability, which includes CO_2 emissions as one of the indicators. It is difficult to quantify indirect impacts of emissions from the Duke Energy Indiana portfolio so that is not within the scope of the IRP analysis.
3. Question: Are virtual power plants (via the aggregation of distributed energy resources) counted within demand response?
    a. A “virtual power plant” is another term used to describe the aggregation of demand response programs and an estimate is included in Duke Energy Indiana’s IRP as a resource. Over the summer, the Company held a webinar that highlighted many of the demand response programs available to our customers.
4. Question: Why is the demand response capacity flat?
    a. The demand response capacity is not flat, but with the scale it is difficult to see the increase. In addition, it is difficult to include new, innovative customer programs in the quantitative IRP analysis because there is not yet data on their potential effects.
5. Question: Can data on cost metrics, energy mix, CO_2 emissions, firm capacity, and installed capacity be shared for the other strategies like it is for the Preferred Portfolio?
    a. The appendix section of today’s meeting contains similar data for each of the generation strategies. Annual data will be included in the IRP document.
6. Question: Why are wind and solar investments not ramping up until 2035?
    a. Some solar and storage are selected in the near term before 2030. Wind and solar resources were available for selection over the entire planning period, but

the model did not select them in the earlier years. Forcing in these resources on top of what was economically selected by the model would increase costs to customers.

7. Question: Were wind + storage and solar + storage considered in the IRP analysis?
    a. Solar + storage is a selectable option in the model. With the granularity of how the model operates, it is better to determine whether energy storage should be co-located with renewables in the plan execution phase. Once energy storage is on the system, the analysis factors it in and utilizes storage resources to distribute renewable energy when needed. It is important to still consider that in some ways the MISO market and energy prices will also play a role in the storage resource dispatch.
8. Question: Does the Edwardsport conversion cost include the costs to optimize Edwardsport to run on natural gas?
    a. Yes, the conversion cost is included in the analysis.
9. Comment: Commenter believes there is a lack of diversity in the Preferred Portfolio.
10. Question: Can information on the size of rooftop solar and what Duke Energy might do to encourage more rooftop solar be provided?
    a. Rooftop (or “behind-the-meter") solar forecast and assumptions were presented in the second stakeholder meeting. Information on the capacity and adoption of behind-the-meter solar is included on slides 52-53 of the meeting two materials. Information about the Company’s behind-the-meter programs will be included in the IRP document. The aggregate capacity customer programs, including rooftop solar, that are included in IRP modeling can be found on slide 42 of the Meeting 5 material. Duke Energy Indiana continues to look for ways to educate and help make the process of considering and adopting renewable generation easier for customers. There are several resources available on the Company’s website. The “Generate Your Own” webpage provides an Interconnection Overview which includes generation options and details on how to get support. Customers can also get connected with trusted solar installers that have been vetted by the Company at Find It Duke.
11. Comment: Commenter believes there is more potential to increase sustainability and resiliency with behind the meter solar programs.
12. Question: What is Duke Energy proposing for the short-term action plan in regard to SMRs?
    a. Duke Energy Indiana and Purdue University published an interim study on the feasibility of SMR and advanced nuclear deployment. Duke Energy and Purdue continue to collaborate on these issues. Additionally, Duke Energy is performing a preliminary siting study in the Midwest. SMRs were not selected by the model in this analysis, but these studies are being done to keep SMRs as a potential option for the future to provide round-the-clock zero-carbon energy.
13. Question: Does the timeline for the Preferred Portfolio consider imminent climate tipping points?
    a. The timelines in the IRP analysis include compliance with required environmental rules and regulations, including those related to greenhouse gas emissions.

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14. Question: Should Duke receive credits from the federal government for CCS projects or any other federally incentivized projects, how will you ensure compliance with Justice 40 if applicable?
    a. The IRP aims to identify a resource plan that will reliably serve customers over the planning horizon, while siting and execution of resource additions occur after the IRP has identified resource needs for the overall system. The Company is committed to seeking feedback and input on its projects and adjusting and aligning efforts where possible to achieve the best outcomes for the communities it serves. Thoughtful consideration of how projects and resource decisions affect communities is a cornerstone of the Company's approach. Should Duke Energy Indiana receive federal funding for any such project, the Company would work with the appropriate agency on a detailed community benefits plan.
15. Question: How does Duke Energy Indiana's pace of conversion to low-CO_2, low-toxin emission sources compare to Duke Energy's other non-Indiana service territories?
    a. The right path forward for Duke Energy Indiana may not be the right path forward for another Indiana utility or another jurisdiction of Duke Energy. The goal of the IRP is to balance the portfolio across the Indiana objectives.
16. Question: Is the nearest term SMR in Indiana the Purdue reactor?
    a. Duke Energy and Purdue University worked together on an interim feasibility study for SMRs and advanced nuclear. The study examined the state of technology, the challenges such a deployment would pose, and proposed policy solutions. There has been no commitment from Purdue University or Duke Energy on siting or building an SMR. However, we continue to collaborate with Purdue University regarding SMR and advanced nuclear development.
17. Question: When will Duke Energy release an RFP regarding solar and storage needs to meet their near-term action plan?
    a. The Duke Energy team is working with bidders on an RFP currently to secure that capacity. More information surrounding this RFP can be found in the Meeting 4 materials.
18. Question: In 10 years, what would change regarding wind and solar that would change the model and its demand?
    a. 10 years out is unpredictable, but a future IRP evaluation will be performed in 2027 with updated inputs that have the possibility to contribute to different resources being selected.
19. Question: In comparing Blend 4 to Blend 2, Blend 4 achieves lower emissions over time with minimal customer impact. Why was Blend 2 selected as the Preferred Portfolio over Blend 4?
    a. The key difference between these portfolios is retiring Gibson 3 and 4 or converting the units to natural gas. This will continue to be evaluated, but ultimately the decision came down to transitioning away from legacy steam units toward a more efficient, flexible, resilient resource mix faster, which adds incremental generation.
20. Question: Do any of the evaluated strategies lock in fossil fuel use beyond 2050?

   a. Nothing is locked in place. With the uncertainty of long-term planning, it is difficult to predict what the energy mix will look like that far out.
21. Question: Will more information on the FEED study at Edwardsport for carbon capture be available?
   a. This is a DOE study, so results will be public once the study is completed.
22. Question: Where can information on the modeled portfolios and how much of each resource was considered be found?
   a. Information on what the model selected for each portfolio can be found in the appendix of the meeting slides. The IRP document will contain more details on what was considered and selected in the model.
23. Question: Will the appendix of the IRP include modeling assumptions?
   a. Chapter 3 – Key Assumptions will outline the modeling assumptions used in the IRP analysis.
24. Question: Did the IRP include any results from Duke Energy's recent clean energy RFP?
   a. Indirectly, yes. Cost forecasts used in the analysis were benchmarked against RFP bids to ensure cost projections are in line with what is currently in the market. The RFP also helped to inform how much new capacity would be available in the late 20s and early 30s.

2024 Duke Energy Indiana Integrated Resource Plan

Stakeholder Meeting 5

October 3, 2024

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Safety

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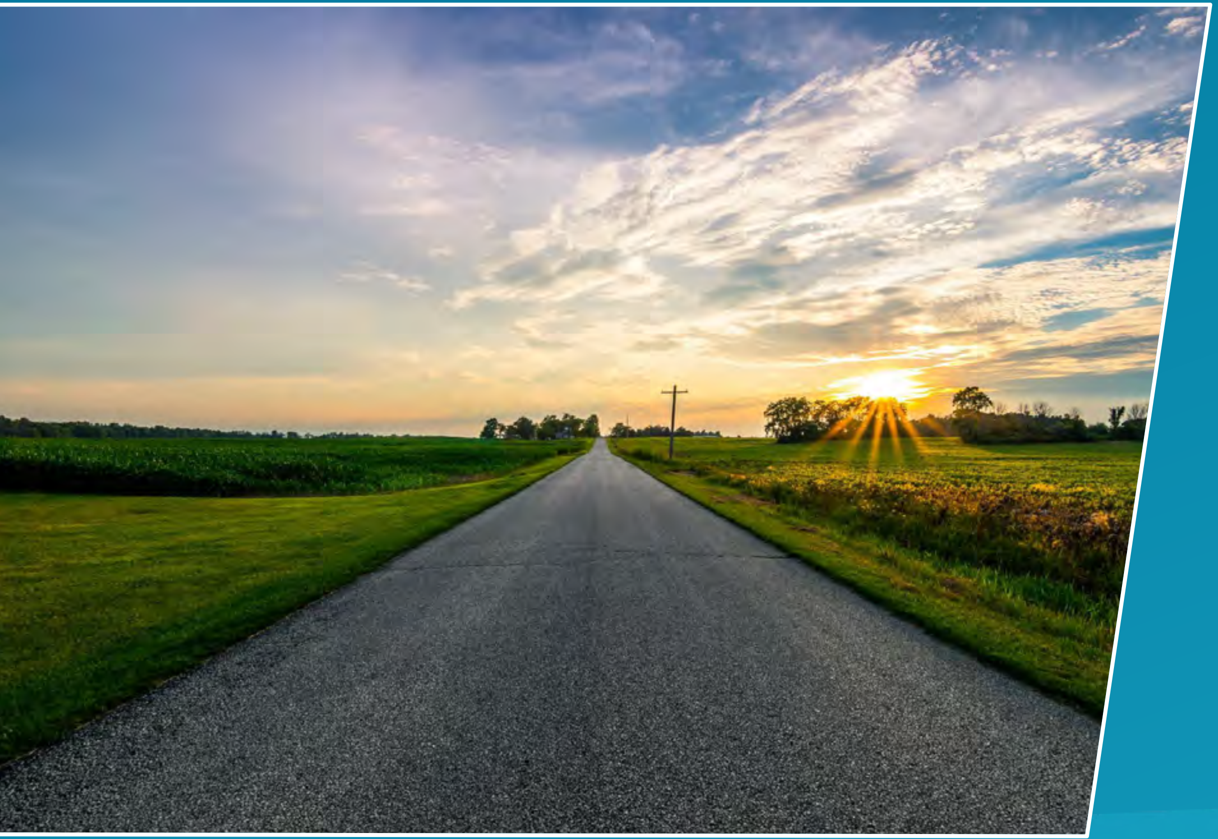
October is Fire Prevention Month

1. **Cooking fires are the leading cause of home fires and home fire injuries**
   - Stay in the kitchen – Unattended cooking is the leading cause of cooking fires and deaths
   - Keep anything that can catch fire — oven mitts, wooden utensils, food packaging, towels or curtains — away from your stovetop
   - Have a “kid-free zone” of at least 3 ft around the stove and areas where hot food or drink is prepared or carried
2. **If you have a small (grease) cooking fire and decide to fight the fire...**
   - On the stovetop, smother the flames by sliding a lid over the pan and turning off the burner - Leave the pan covered until it is completely cooled
   - For an oven fire, turn off the heat and keep the door closed
3. **If you have any doubt about fighting a small fire…**
   - Just get out! Close the door behind you to help contain the fire
   - Call 9-1-1 from outside the home
4. **Check Alarms**
   - Twice a year check batteries and replace equipment that’s more than 10 years old
5. **Know what to do if there is a fire and conduct a fire drill, including a meet-up location**

Cause No. 46193



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Welcome

Stan Pinegar

State President, Duke Energy Indiana

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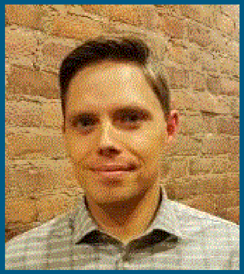
Introductions

Duke Energy Team

Integrated Resource Planning Team

Matt Kalemba
Vice President, Integrated Resource Planning



Nate Gagnon
Managing Director, Midwest Integrated Resource Planning

Matt Peterson
Resource Planning Manager

Emma Goodnow
Market Strategy & Intelligence Director

Karen Hall
Resource Planning Director

Chris Hixson
Principal Engineer, Resource Modeling

Josh Paragas
Engineer, Resource Modeling

Tyler Cook
Engineer, Resource Modeling

Indiana Regulatory and Legal Team

Kelley Karn
Vice President, Indiana Regulatory Affairs and Policy

Beth Heneghan
Deputy General Counsel

Liane Steffes
Associate General Counsel

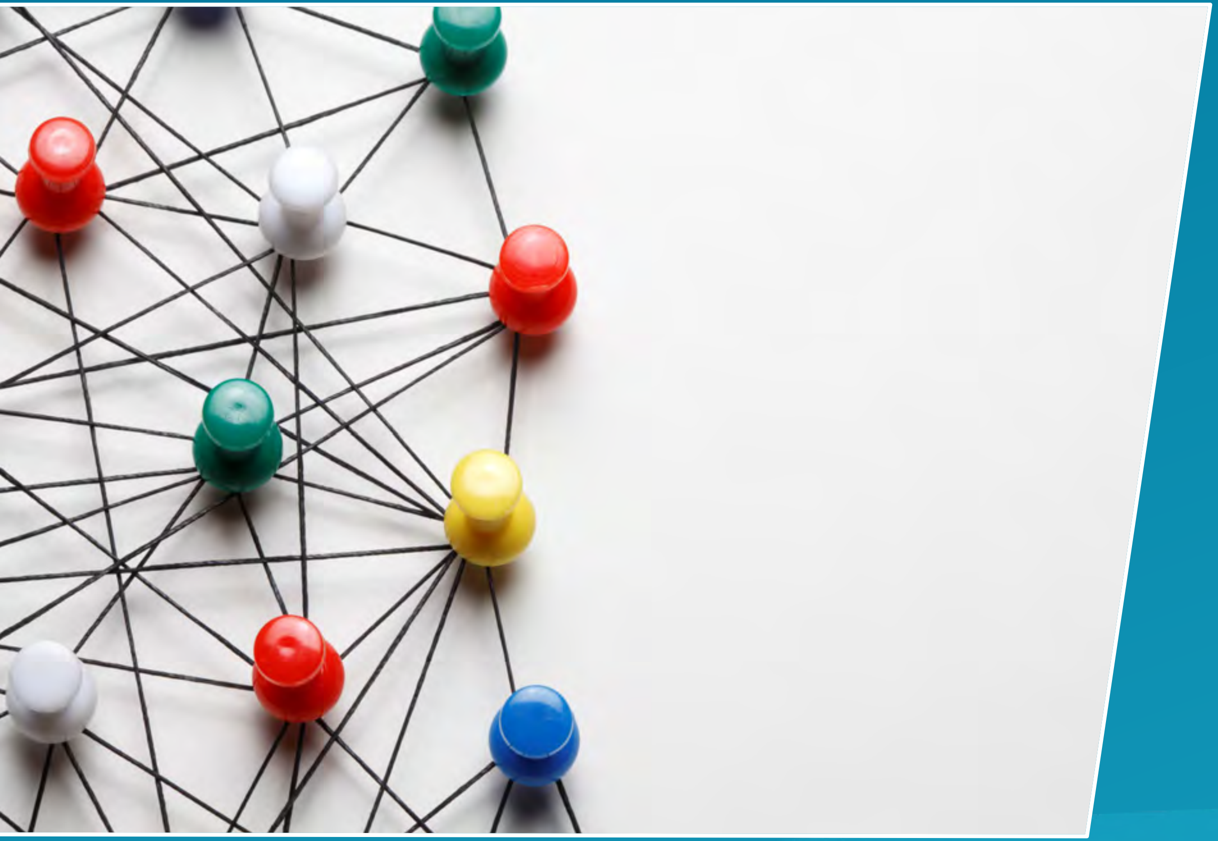
Reliability Analytics

Ameya Deoras
Manager, Quantitative Analytics

Patrick O'Connor
Principal Quantitative Analyst

1898 & Co.

Drew Burczyk
Consultant, Resource Planning & Market Assessments



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Agenda

Public Stakeholder Meeting #5 Agenda

Time	Duration	Present | Q&A	Topic	Presenter
9:30	5	5 | 0	Welcome & Safety	**Stan Pinegar,** Duke Energy Indiana State President **Karen Hall,** Duke Energy Resource Planning Director
9:35	5	5 | 0	Meeting Guidelines & Agenda	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:40	10	5 | 5	Stakeholder Feedback & Incorporation	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:50	25	15 | 10	Analytical Framework & Preferred Portfolio	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP
10:15	45	25 | 20	Scenario & Sensitivity Analysis Summary	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP **Matt Peterson,** Duke Energy Lead Resource Planning Analyst
11:00	10	-	BREAK	
11:10	60	30 | 30	Scorecard Results & Enhanced Reliability Evaluation	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP **Patrick O'Connor**, Duke Energy Principal Quantitative Analyst **Ameya Deoras,** Duke Energy Manager Quantitative Analytics
12:10	40	-	BREAK	
12:50	30	15 | 15	Preferred Portfolio & Short-Term Action Plan Considerations	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP
1:20	40	0 | 40	Open Q&A	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
2:00	5	5 | 0	Next Steps & Closing Remarks	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co. **Nate Gagnon,** Duke Energy Managing Director Midwest IRP
2:05	-	-	Adjourn	

Technical Stakeholder Meeting #5 Agenda

Cause No. 46193

Time	Duration	Present | Q&A	Topic	Presenter
9:00	5	5 | 0	**Welcome & Safety**	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co
9:05	20	10 | 10	**Analytical Framework & Preferred Portfolio**	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP
9:25	45	25 | 20	**Scenario & Sensitivity Analysis Summary**	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP **Matt Peterson,** Duke Energy Lead Resource Planning Analyst
10:10	10	-	**BREAK**	
10:20	65	35 | 30	**Scorecard Results & Enhanced Reliability Evaluation**	**Nate Gagnon,** Duke Energy Managing Director Midwest IRP **Patrick O'Connor**, Duke Energy Principal Quantitative Analyst **Ameya Deoras,** Duke Energy Manager Quantitative Analytics
11:25	15	-	**BREAK**	
11:40	30	0 | 30	**Open Q&A**	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co.
12:10	5	5 | 0	**Next Steps & Closing Remarks**	**Drew Burczyk,** Consultant, Resource Planning & Market Assessments, 1898 & Co. **Nate Gagnon,** Duke Energy Managing Director Midwest IRP
12:15	-	-	**Adjourn**	

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Meeting Guidelines

Meeting Ground Rules

Respect each other:

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

Focus on today's topics:

Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.

Chatham House Rule:

Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

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Participation

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There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

- **Q&A:** Please use the "Q&A" feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the "raise hand" feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.

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Stakeholder Feedback and Incorporation

Cause No. 46193

Stakeholder Feedback Received & Incorporated into Meeting #5 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
Scorecard Metric Feedback	Final Scorecard Metric Updates
How are risks of data center load captured in the IRP analysis?	Scenario and Sensitivity Analysis Summary

Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
What is the basis of the heat rate inputs for the existing coal units? And why might these be higher or lower than the operational heat rate of these units in recent years?	We just recently completed an evaluation of the heat rate coefficients for our Indiana coal fleet. The updated coefficients have been included in the final IRP analytics. The changes are not dramatic and reflect both increases and decreases depending on the unit, the season, and the loading level. There can be some differences between model inputs/outputs when compared to historical heat rate data, one main driver can be due to unit loading levels when comparing operational data over the past few years against the EnCompass production cost model, which optimizes unit dispatch with perfect foresight. Since heat rates describe a curve, with units generally operating less efficiently near min load than they do closer to max.
How many MW of Data Center load is included in the high load sensitivity?	The high load sensitivity includes 500 MW of new data center load by 2031.
Please provide additional detail on the input assumptions and the results of the National Database Simulations used to determine the market energy price assumptions.	Model inputs and results summaries from the National Database were re-posted to Datasite for technical stakeholders to review.

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Q&A

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Analytical Framework and Preferred Portfolio

Generation Strategies Included in IRP Analysis

<table>
<tr><th colspan="7">CAA Section 111-Compliant Strategies</th><th>Non-Compliant</th></tr>
<tr><th>Unit</th><th>Convert / Co-Fire Coal</th><th>Retire Coal</th><th>Convert Cayuga (Blend 1)</th><th>Co-fire/Retire Gibson (Blend 2)</th><th>Co-fire/Convert Gibson (Blend 4)</th><th>Exit Coal Earlier (Stakeholder)</th><th>“No 111”</th></tr>
<tr><td>Cayuga 1</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="6">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td colspan="2">Retire by 1/1/2030</td><td rowspan="2">NG Conversion by 1/1/2029</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Cayuga 2</td><td colspan="2">Retire by 1/1/2031</td></tr>
<tr><td>Gibson 1</td><td rowspan="2">Co-fire by 1/1/2030</td><td rowspan="4">Retire by 1/1/2032</td><td colspan="2" rowspan="2">Co-fire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">Retire by 1/1/2036</td></tr>
<tr><td>Gibson 2</td></tr>
<tr><td>Gibson 3</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Gibson 4</td></tr>
<tr><td>Gibson 5</td><td colspan="7">Retire by 1/1/2030</td></tr>
<tr><td>EDW</td><td colspan="6">NG Conversion by 1/1/2030</td><td>NG Conversion by 1/1/2035</td></tr>
</table>

Indicates strategies added since Meeting 4

Analytical Framework

Generation Strategies

- Convert / Co-Fire Coal
- Retire Coal
- Convert Cayuga (Blend 1)
- Co-fire / Retire Gibson (Blend 2)
- Co-fire / Convert Gibson (Blend 4)
- Exit Coal Earlier (Stakeholder)

Scenarios "Worldviews"

Reference

Aggressive Policy & Rapid Innovation

Minimum Policy & Lagging Innovation

18
Scenario Portfolios

Strategy Variations

- 2x1 v. 1x1 replacement
- Full NG conversion v. co-firing
- No 111
- Add SMRs
- Edwardsport CCS
- Edwardsport conversion by 2028

6
Strategy Variation Portfolios

Portfolio Sensitivities

- Resource Capital Cost
- Load (high/low)
- SAC Accreditation (select cases)

20
Sensitivity Portfolios

Production Cost Sensitivities

- Fuel (high/low)
- Market Exposure

Supplemental Stakeholder Portfolio

- DDRE (1 Supplemental Portfolio)

45
Total Resource Portfolios

2024 Preferred Portfolio: Blend 2

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Preferred portfolio based on IRP criteria:

Co-fire/Retire Gibson (Blend 2)

✓ **BALANCES COST & RISK FOR CUSTOMERS**

✓ **ADDS INCREMENTAL CAPACITY TO SUPPORT ECONOMIC DEVELOPMENT**

✓ **PRESERVES OPTIONALITY TO ADAPT TO CHANGING CONDITIONS**

Short-term actions supporting

Blend 2

- Advance development of 1x1 CCs to replace retiring Cayuga coal units, add ~440 MW of incremental capacity by 2031
- Prepare to co-fire units Gibson 1&2 on 50% coal, 50% natural gas in compliance with the EPA CAA Section 111 Final Rule
- Commence development of 2x1 CC to replace retiring Gibson units 3&4, add ~177 MW of incremental capacity by 2032
- Prepare to retire Gibson unit 5, add ~499 MW of solar, ~400 MW of battery energy storage by 2030
- Prepare to convert Edwardsport to operate on 100% natural gas fuel by 2030 in compliance with EPA 111 Rule, while completing CCS FEED study to inform final decision
- Continue to monitor environmental regulations and market conditions, and evaluate opportunities to adjust course offered by the Blend 2 strategy

Resource Planning Objectives

Reliability | Resiliency | Stability | Environmental Sustainability | Affordability | Risk & Uncertaintly

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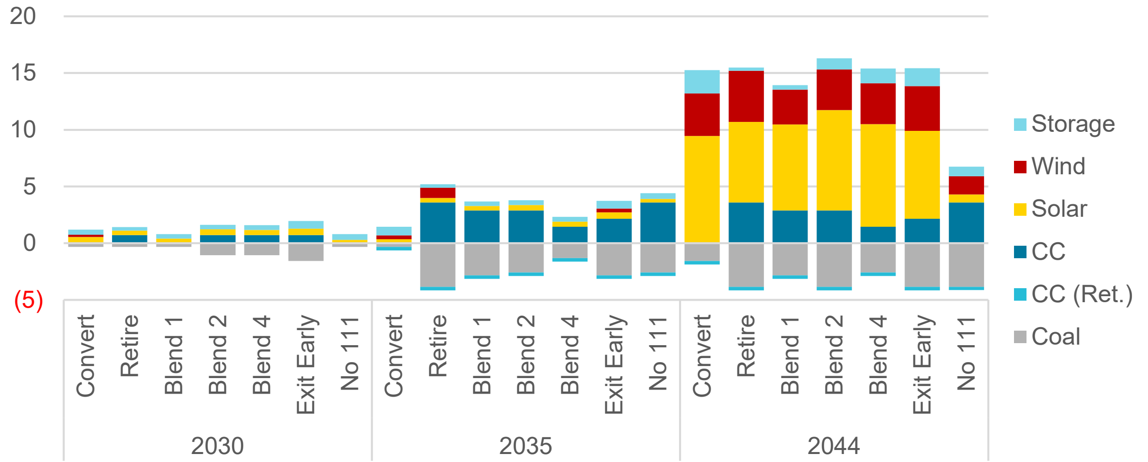
Scenario and Sensitivity Analysis Summary

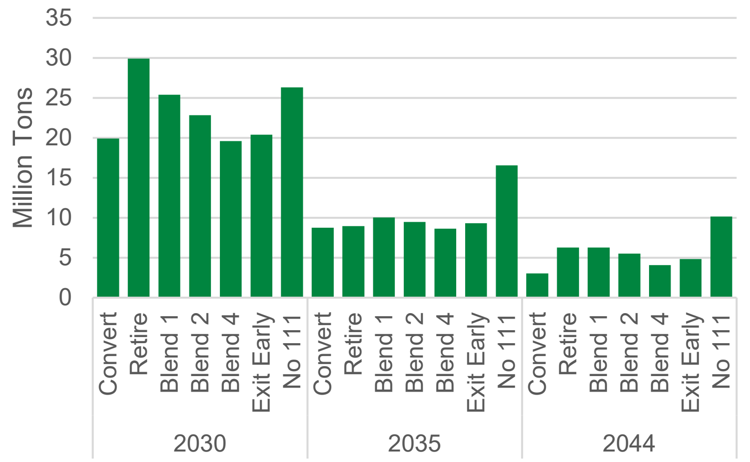
Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.

Results Summary for All Strategies in Reference Scenario

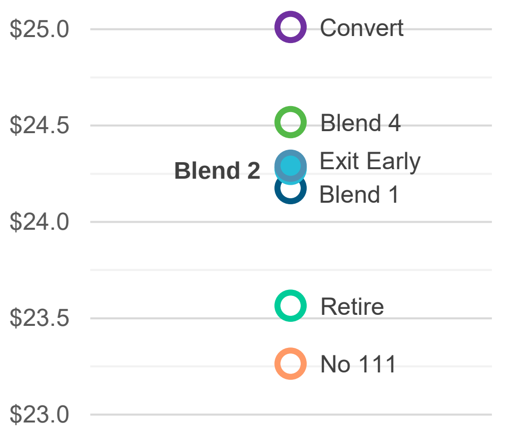
Cumulative Supply-Side Changes (Installed GW, BOY)



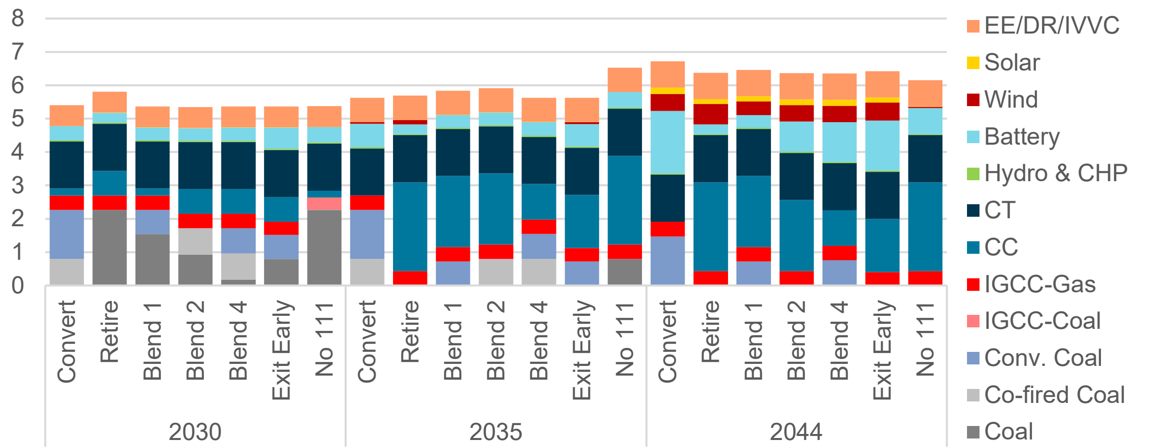
CO_2 Emissions (Mt)



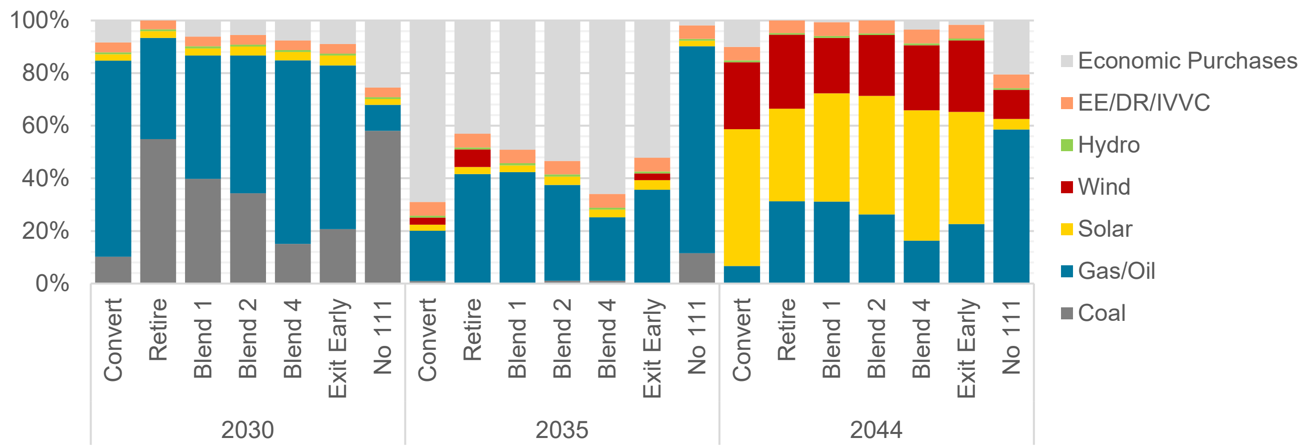
PVRR ($B)



Firm Capacity Mix (Winter GW, BOY)

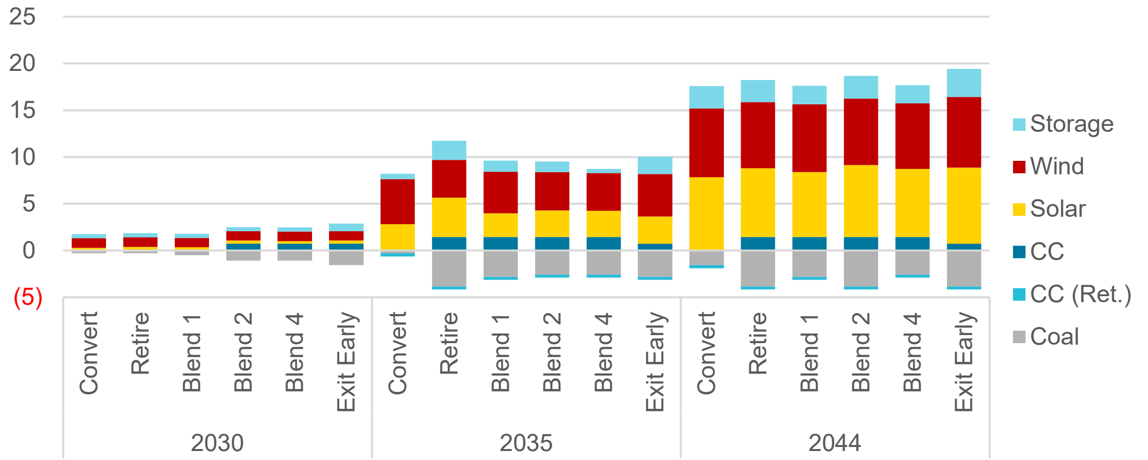


Energy Mix

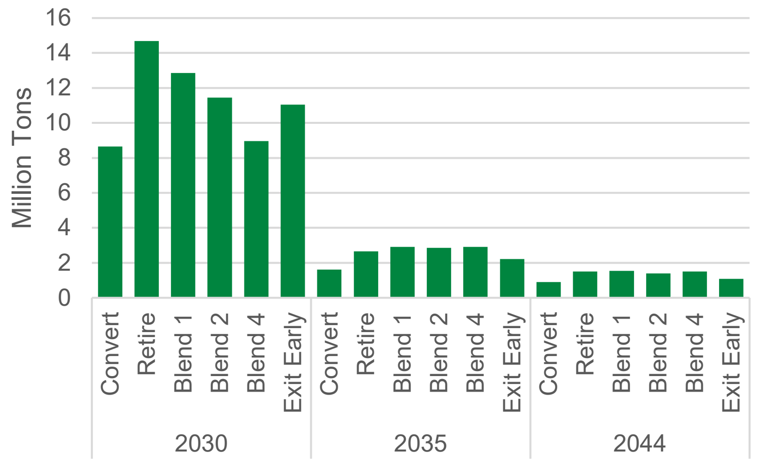


Results Summary in Aggressive Policy & Rapid Innovation Scenario

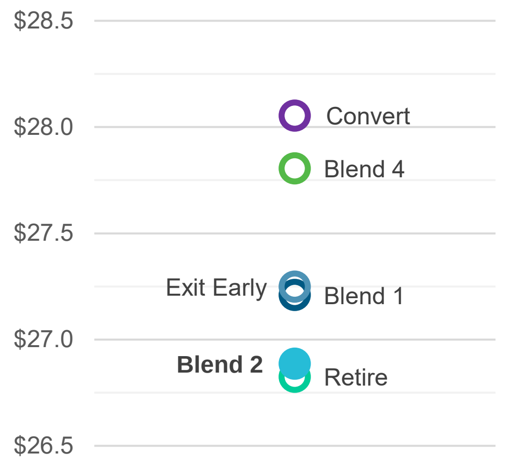
Cumulative Supply-Side Changes (Installed GW, BOY)



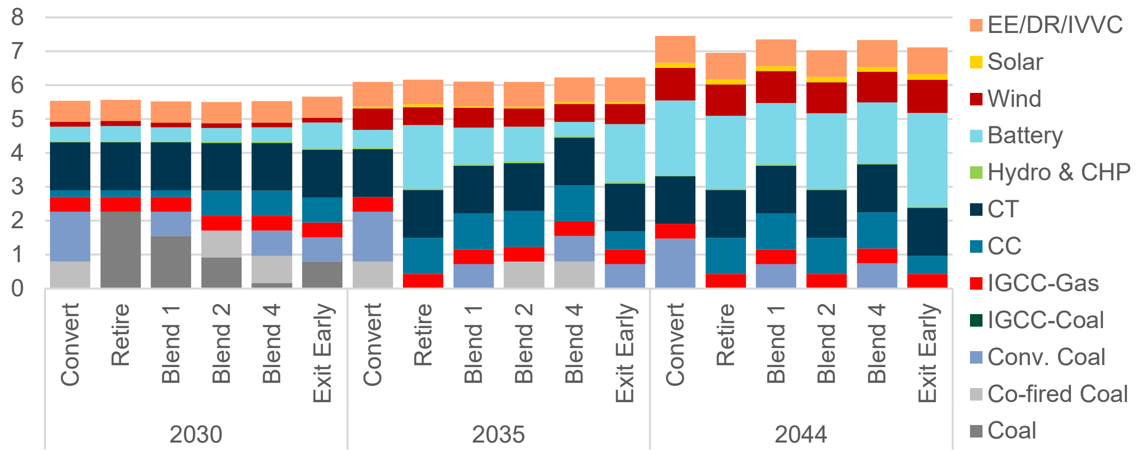
CO_2 Emissions (Mt)



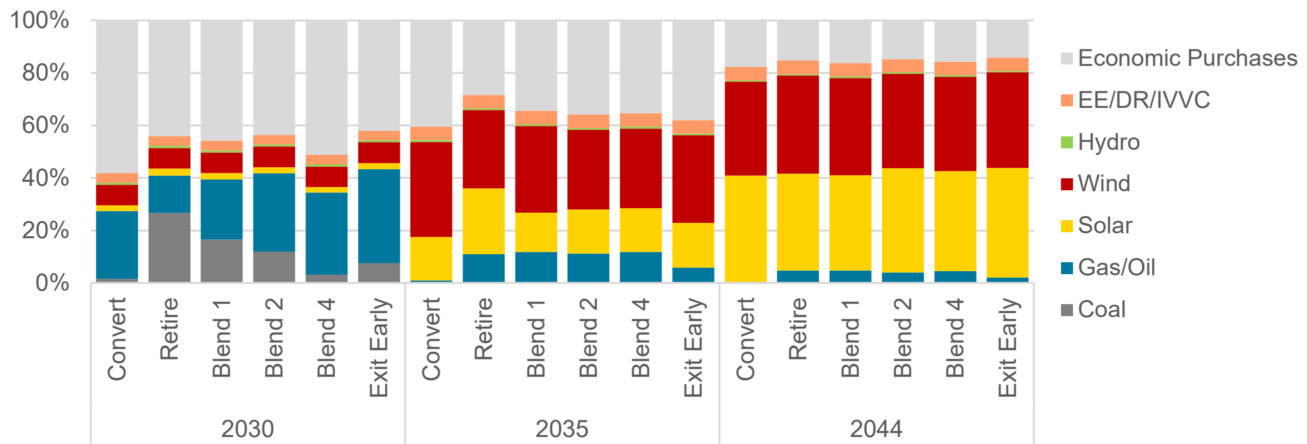
PVRR ($B)



Firm Capacity Mix (Winter GW, BOY)



Energy Mix



Note: The "No 111" generation strategy is modeled in the Reference scenario only

Results Summary in Minimum Policy & Lagging Innovation Scenario

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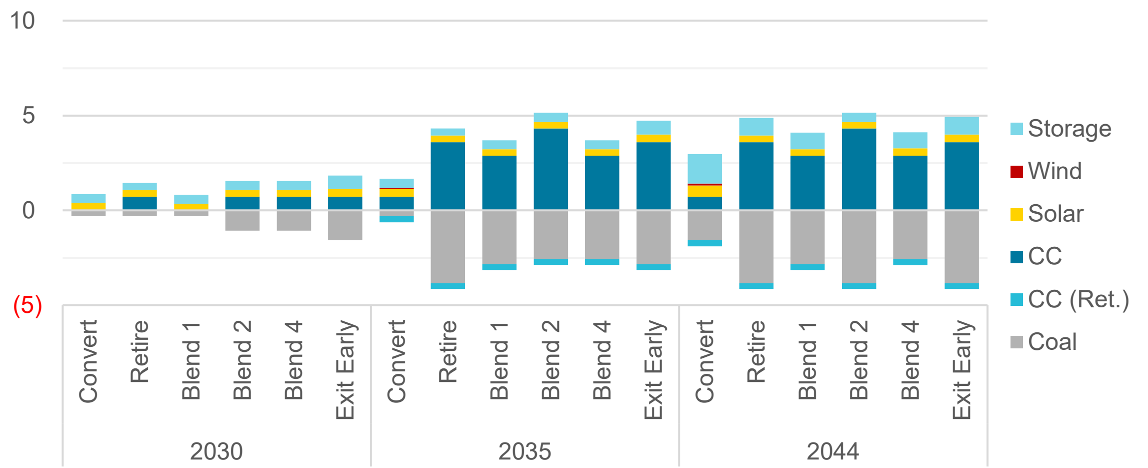
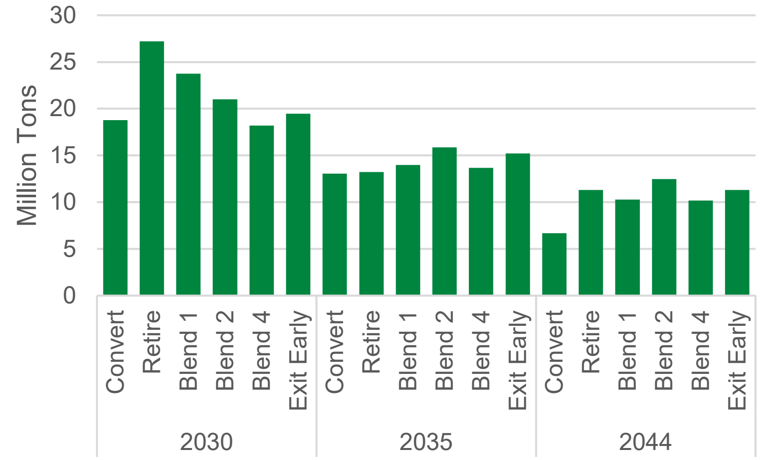
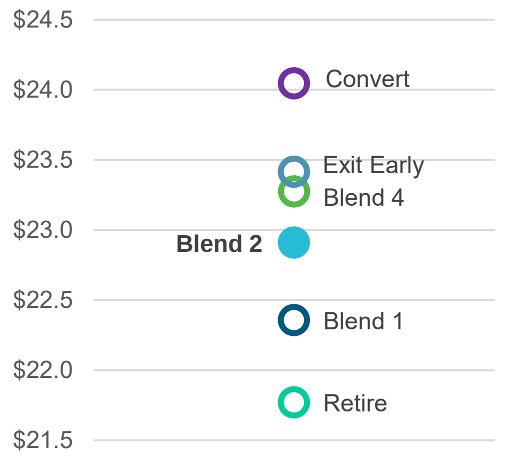
Cumulative Supply-Side Changes (Installed GW, BOY)



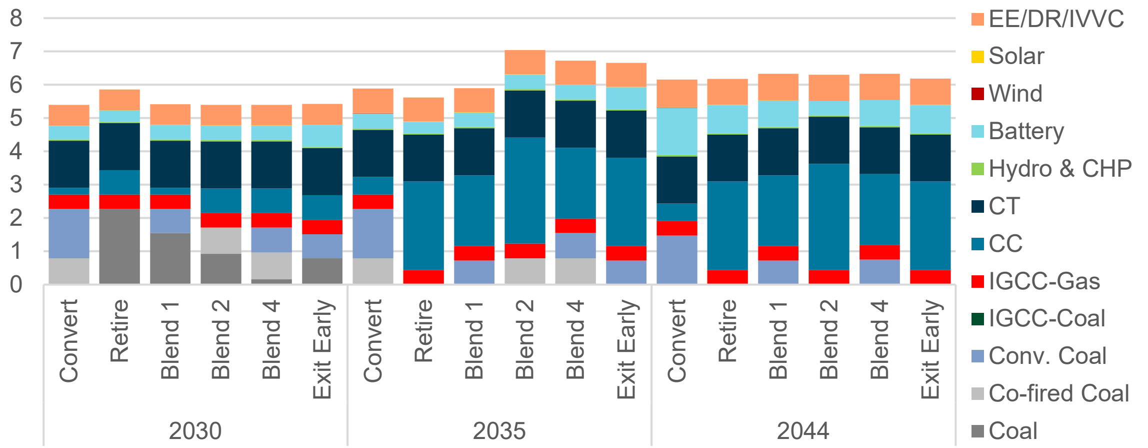
CO_2 Emissions (Mt)



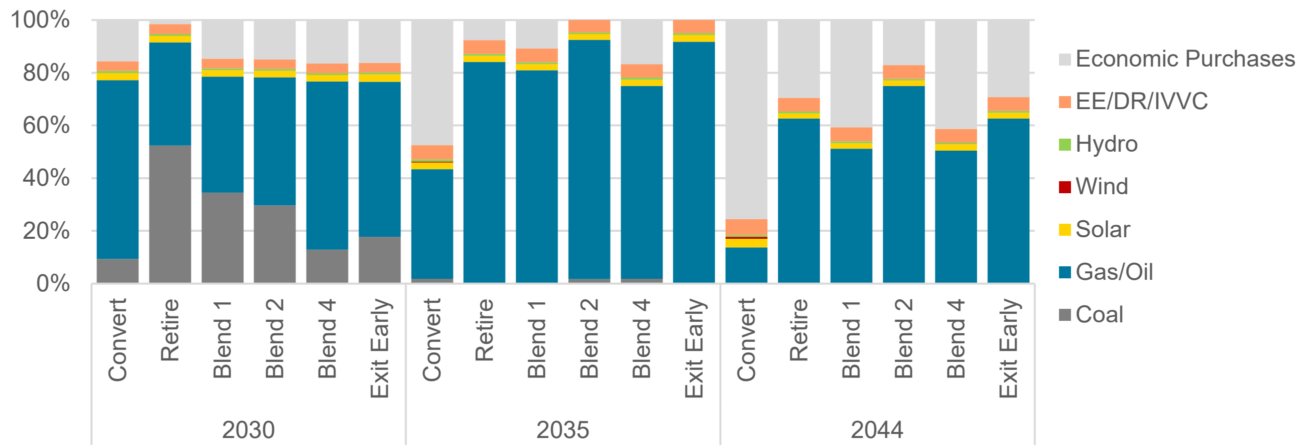
PVRR ($B)



Firm Capacity Mix (Winter GW, BOY)



Energy Mix

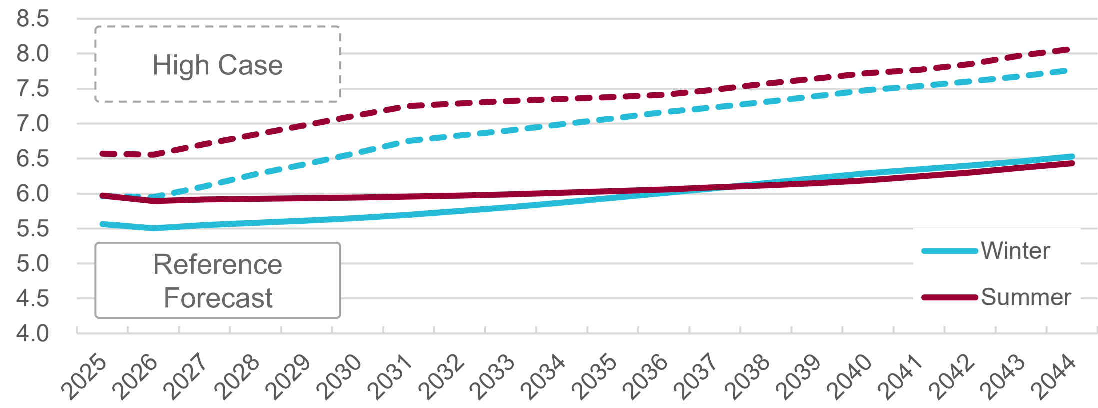


Note: The “No 111” generation strategy is modeled in the Reference scenario only

Portfolio Sensitivity Analysis: Load Forecast

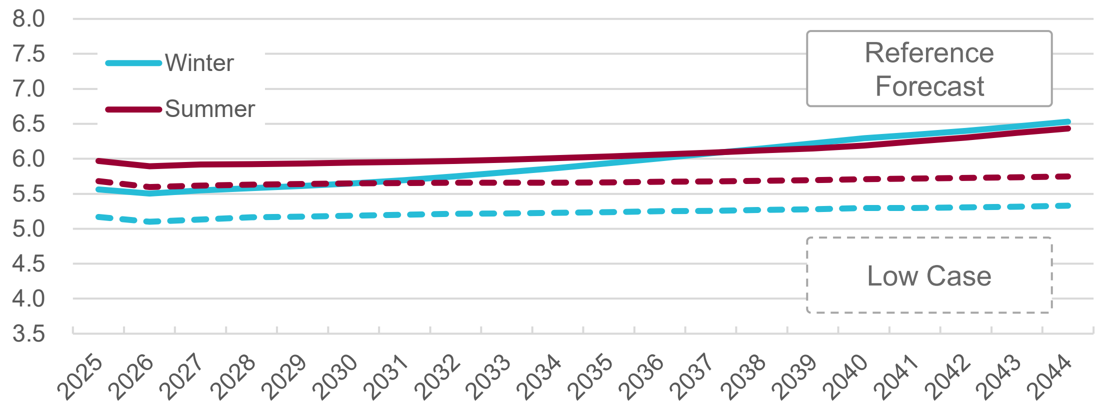
Cause No. 46193

Peak Load Forecast: Reference and High Cases (GW)



Note: High load forecast includes 500 MW of data center load in addition to assumption that 75% of economic development pipeline projects come to fruition

Peak Load Forecast: Reference and Low Cases (GW)



Resource Selection Changes in High Load Case (Installed MW change from Reference Case by 2035)

Generation Strategy	CC	Solar	Wind	Storage
Convert / Co-fire Coal	+719	+1,200	+400	+900
Retire Coal	+719	+1,950	+1,450	+725
Blend 1	+719	+1,000	+1,200	+650
Blend 2	+1,438	+1,000	+300	+900
Blend 4	+1,438	+1,100	+550	+875
Exit Coal Earlier (SH)	+1,438	+1,000	+1,200	+900

Resource Selection Changes in Low Load Case (Installed MW change from Reference Case by 2035)

Generation Strategy	CC	Solar	Wind	Storage
Convert / Co-fire Coal	--	(150)	+50	(400)
Retire Coal	(719)	+500	--	--
Blend 1	+719	(150)	+650	(175)
Blend 2	--	(200)	--	(200)
Blend 4	--	--	--	(250)
Exit Coal Earlier (SH)	--	--	(250)	(500)

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Portfolio Sensitivity Analysis: CC Cost, Capacity Accreditation

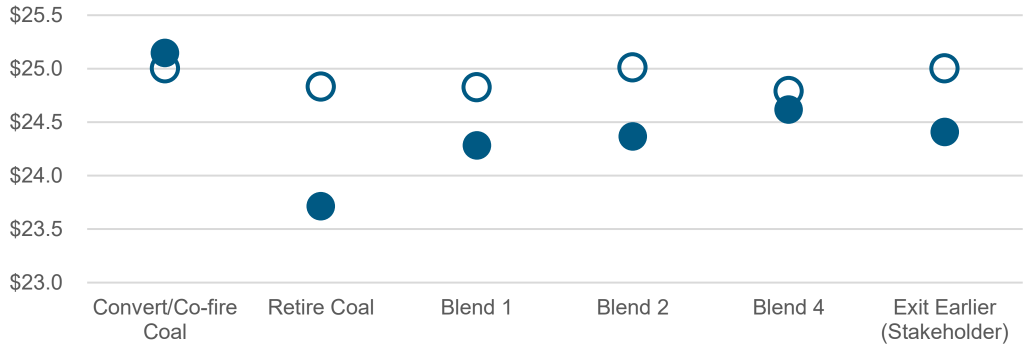
Impact of High (1.6x) CC Costs on Resource Selection & PVRR

- In a high CC cost future, at least 1,438 MW of new CC capacity is selected for most generation strategies (equivalent of two 1x1 CCs or one 2x1 CC)
- A high CC cost environment tightens the already narrow range of PVRR results across generation strategies, increasing total cost in proportion to CC MW in the Reference Case

CC Capacity Additions by 2035 (MW)

Strategy	Reference Case	High CC Cost	*Change from Ref*
Convert/Co-fire Coal	--	--	--
Retire Coal	3,595	2,876	*(719)*
Blend 1	2,876	1,438	*(1,438)*
Blend 2	2,876	1,438	*(1,438)*
Blend 4	1,438	--	*(1,438)*
Exit Earlier	2,157	1,438	*(719)*

PVRR in Ref. (solid circle) vs. High CC Cost (open circle) Cases ($B)



Impact of Accreditation Method on Resource Selection

- Results show some sensitivity to capacity accreditation method, with additional selection of renewables in the bookend strategies evaluated (Convert, Retire) using Seasonal Accredited Capacity (SAC) throughout the study period in comparison to the adoption of Direct Loss of Load (D-LOL) methodology starting in 2028

Capacity Accreditation for D-LOL & SAC Methods (Summer | Winter)

Accreditation Method	CC	Solar	Wind	Storage
D-LOL (used in IRP 2028+)	90% | 74%	36% | 2%	11% | 16%	94% | 91%
SAC (used in IRP through 2027)	91% | 90%	45% | 6%	18% | 40%	95% | 95%

Reference Worldview Resource Additions by 2035 (Nameplate MW)

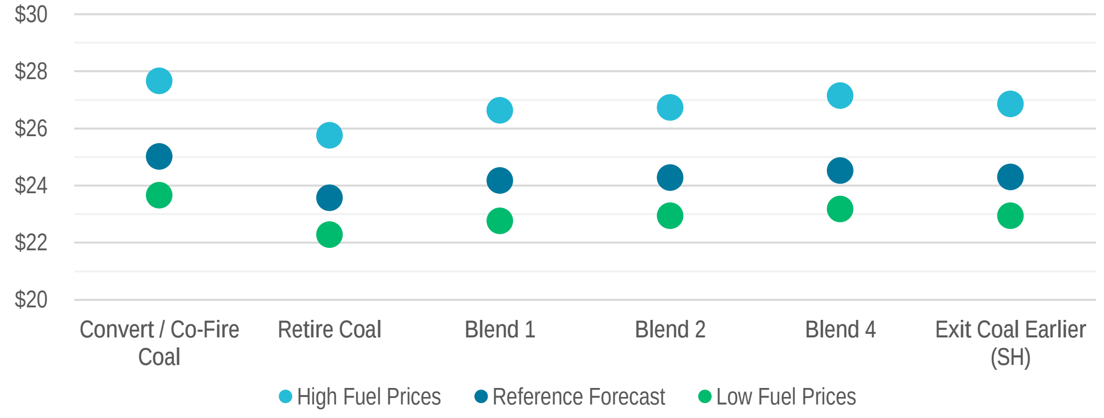
Strategy	CC	Solar	Wind	Storage
Convert/Co-fire Coal in Ref.	--	349	350	750
► *Change w/ SAC throughout*	*+719*	*+700*	*+500*	*+75*
Retire Coal Reference	3,595	399	900	300
► *Change w/ SAC throughout*	*(719)*	*+600*	*+900*	*+550*

Reference Worldview Resource Additions by 2044 (Nameplate MW)

Strategy	CC	Solar	Wind	Storage
Convert/Co-fire Coal in Ref.	--	9,449	3,750	2,050
► *Change w/ SAC throughout*	*+719*	*+200*	*+700*	*(750)*
Retire Coal Reference	3,595	7,099	4,500	300
► *Change w/ SAC throughout*	*(719)*	*+50*	*+900*	*+550*

Production Cost Sensitivity Analysis: Fuel Price Forecasts

PVRR Results for Alternate Fuel Price Forecasts ($B)

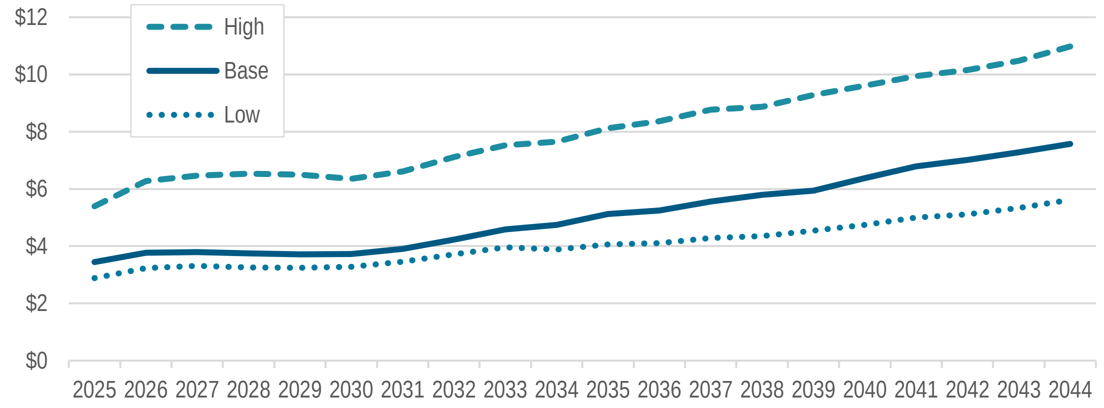


Note: Fuel price sensitivity modeled for each generation strategy in the Reference case

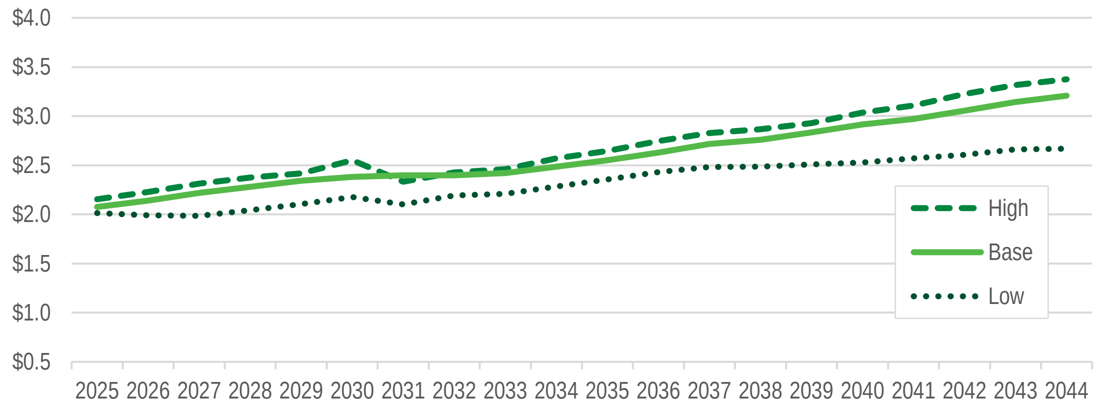
Evaluation of Sensitivity to Fuel Price Variability

- Analysis of relative changes in portfolio operating costs under alternate fuel price forecasts, without altering the composition of the candidate portfolios
- Changes in fuel costs affect the cost of energy purchased from the MISO market as well as operating cost for the Duke Energy Indiana portfolio.
- Alternate fuel price forecasts do not capture supply shocks, the risk of which can reasonably be expected to increase over time for coal as the domestic utility industry shifts to other resources.
- PVRR changes are very similar across generation strategies, with little impact to relative ranking among the candidate portfolios.

Natural Gas Price Forecasts (Henry Hub, $/MMBtu)



Coal Price Forecasts (Illinois Basin, $/MMBtu)



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Scorecard Results

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Final Scorecard Metric Updates

In **meeting 4** we discussed several potential changes to the final scorecard metrics and requested feedback on those updates. Following the meeting, we received feedback from several stakeholders. These are the updates made to the final scorecard.

Metric	Change	Summary
Non-CO_2 Emission Ranking	Removed	The non-CO_2 emissions ranking did not provide insight into portfolio emissions differently than the CO_2 metrics that were already included. Also, the magnitude and scale of differences between portfolios were not clear. There will still be commentary on non-CO_2 emissions in the IRP report.
CO_2 Intensity	Added	We have included the CO_2 intensity metric in the scorecard today. The CO_2 emissions reduction and cumulative CO_2 emissions both capture estimated CO_2 emissions associated with market purchases. The CO_2 intensity metric shows the emissions of DEI-specific unit generation across the different strategies.
Spinning Reserve and Fast Start	Split into 2 metrics	The spinning reserve and fast start metrics have been broken out separately in the final scorecard. This will provide more granular insights on the two metrics in isolation.
Resource Diversity from Firm Capacity	Changed	We have updated resource diversity to be shown on a firm capacity basis in the final scorecard.

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Affordability: PVRR & Customer Bill Impacts

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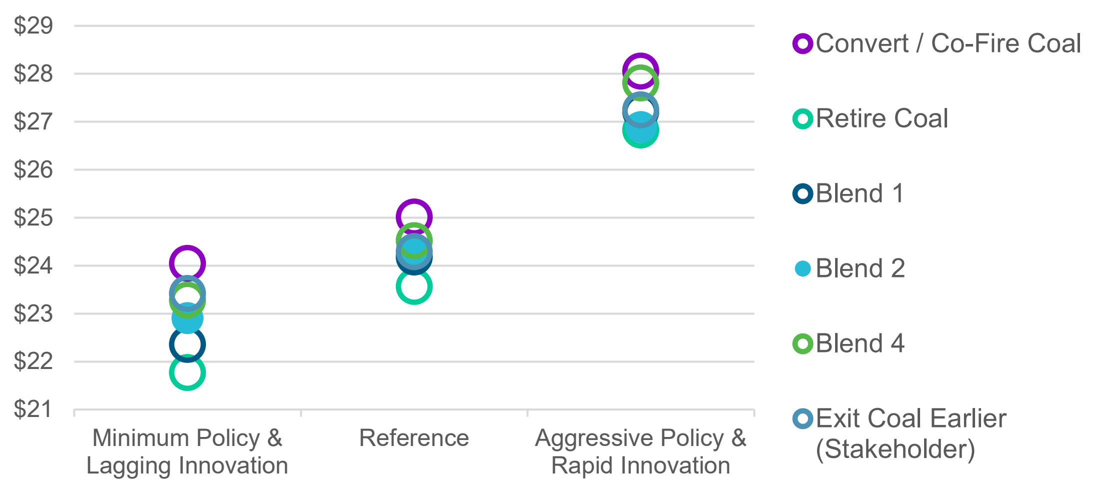
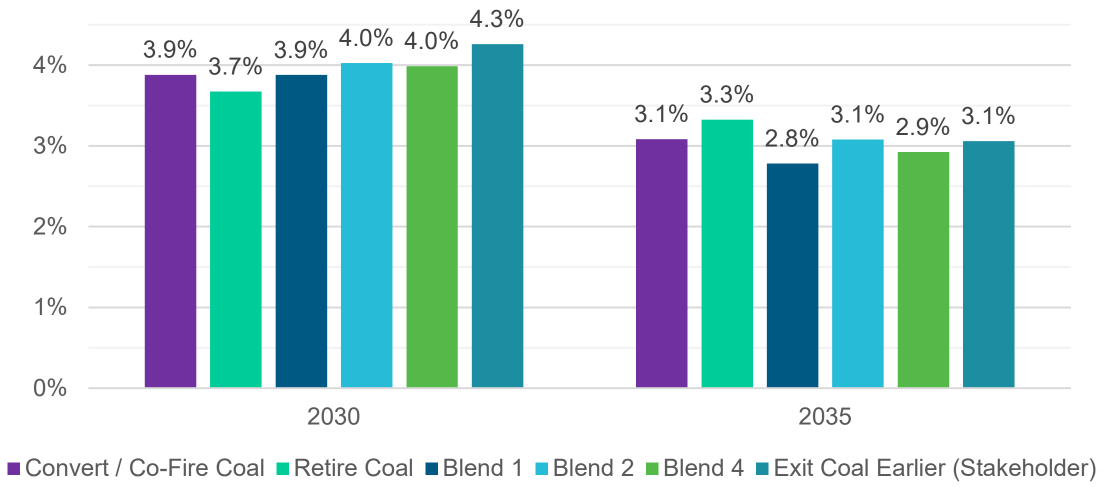
PVRR Results Across Scenarios



- PVRRs are tightly grouped in the Reference and Aggressive scenarios and exhibit more divergence in the Minimum scenario where strategies with more flexibility to maximize the value of new CC resources provide opportunities to lower total cost.
- Convert/Co-fire Coal strategy consistently yields the highest PVRR, while the Retire strategy that replaces aging coal units with highly efficient advanced class CCs offers the lowest PVRR over the planning period.

Note: IRP PVRR calculations do not consider depreciation of existing assets, other non-avoidable costs, costs not related to resource planning (e.g., distribution), and are useful for comparison only.

Customer Bill Compound Annual Growth Rates (Reference)

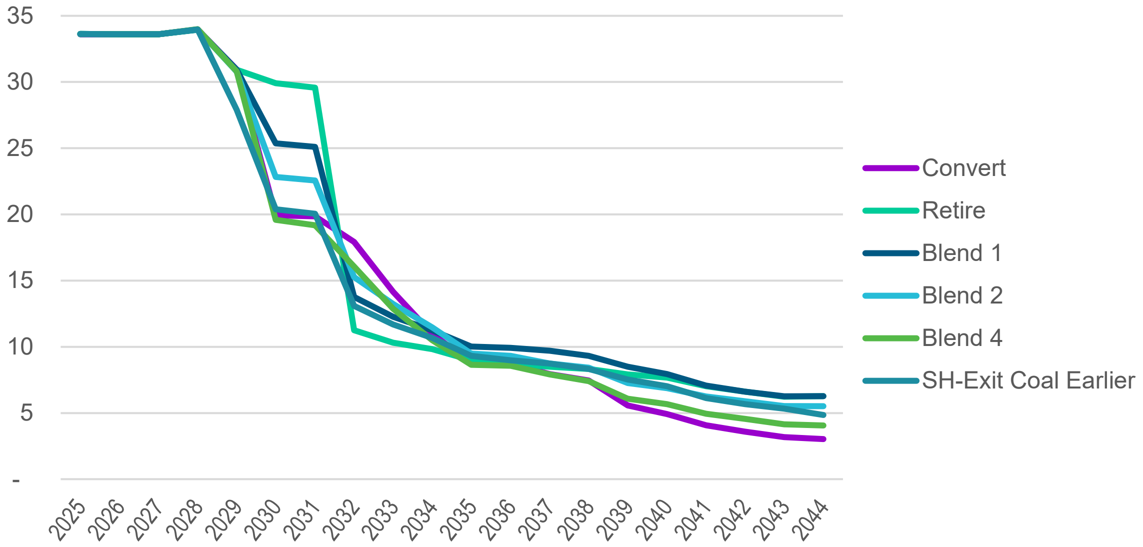


- Projected customer bill growth rates (nominal) provide an estimate of IRP-related cost to customers at a specified snapshot in time.
- The Exit Coal Earlier strategy, which calls for aggressive deployment of new resources in the 2020s, carries a relatively higher customer bill impact by 2030. Similarly, the Retire Coal strategy, which requires significant investment to replace all steam units by 2032, yields a relatively higher bill impact by 2035.

Note: IRP bill impacts for typical residential household using 1,000 kWh/month exclude depreciation of existing assets, other non-avoidable costs, costs not related to resource planning (e.g., distribution). IRP bill impact projections are useful only for relative comparison of portfolios.

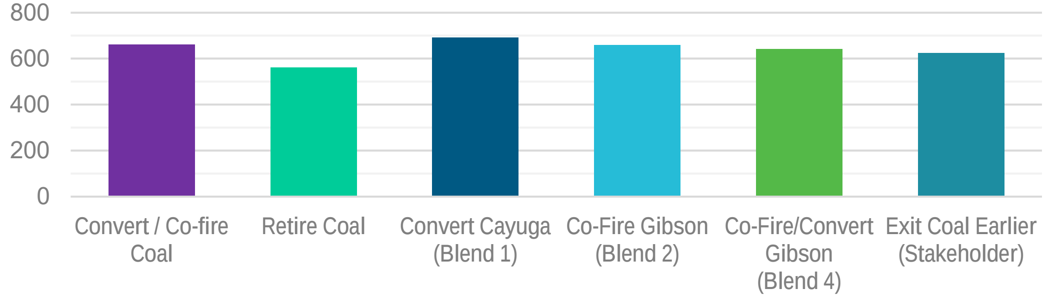
Environmental Sustainability: CO_2 Emissions & Intensity

Annual CO_2 Emissions in Reference Scenario (Mt)*



Includes estimated CO_2 emissions associated with market purchases

2035 CO_2 Intensity of Duke Energy Indiana Portfolio (lbs./MWh)



- CO_2 emissions trends are very similar across generations strategies, with emissions dropping off steeply in 2030-2032 as coal gives way to gas, renewables, and low-cost energy from the MISO market in the energy mix.
- Emissions decline steadily through the second half of the planning period, as renewables are added to the portfolio, displacing purchased energy.
- CO_2 intensity of the Duke Energy Indiana portfolio varies only slightly across generation strategies. In 2035, a year in which economic energy purchases account for 50% or more of the total mix for several strategies, the Retire Coal strategy, in which advanced class CCs account for most of the Company-generated energy, has the lowest CO_2 intensity.

2044 CO_2 Emissions Reduction (from 2025 levels)*

Portfolio	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation
Convert / Co-fire Coal	-91%	-97%	-80%
Retire Coal	-81%	-95%	-66%
Convert Cay. (Blend 1)	-81%	-95%	-69%
Co-Fire Gib. (Blend 2)	-84%	-96%	-63%
Conv. Gib. (Blend 4)	-88%	-95%	-70%
Exit Coal Earlier (SH)	-86%	-97%	-66%

Includes estimated CO_2 emissions associated with market purchases

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Reliability & Resiliency: Performance Over a Range of Conditions

- **Purpose:** evaluate portfolio reliability and resiliency across a wide range of conditions.
- **Approach:** simulate an islanded system across thousands of scenarios with varying weather, unit outages, and economic conditions.
- **Metric:** Expected Unserved Energy ("EUE") represents periods of potential reliance upon the broader MISO market to meet customer demand. EUE is shown as a percentage of 2035 load, and also indexed to 2028 results to show change over time.
- **Study year:** 2035 is a benchmark year for this IRP near the middle of the planning period, far enough into the future that portfolios diverge substantially but not so far that increasing uncertainty limits the usefulness of the results

2035 EUE Relative to 2028 Baseline

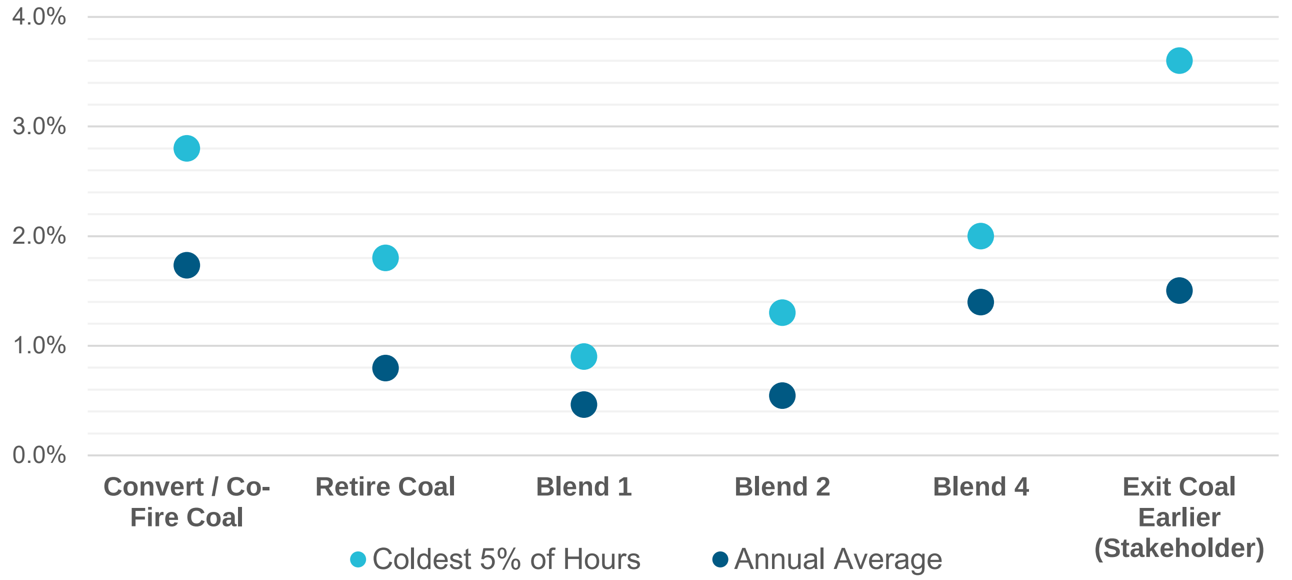
Normalized EUE	2035
Convert	3.6
Retire	1.6
Blend 1	1.0
Blend 2	1.1
Blend 4	2.9
SH – Exit Coal Earlier	3.1

- **Extreme cold:** To explore cold weather risk in more detail, simulations were run for 95th percentile or colder winter hours only. Results are presented here along with results for the full year, showing differing levels of winter risk across generation strategies.

Cold-Weather (95th Percentile) Simulated EUE as a % of Load in 2035

Portfolio	Convert	Retire	Blend 1	Blend 2	Blend 4	SH – Exit Earlier
Mean EUE	2.8%	1.8%	0.9%	1.3%	2.0%	3.6%

2035 Average Annual and Cold-Weather Simulated EUE as a % of Load



Stochastic Modeling of Energy Market Exposure

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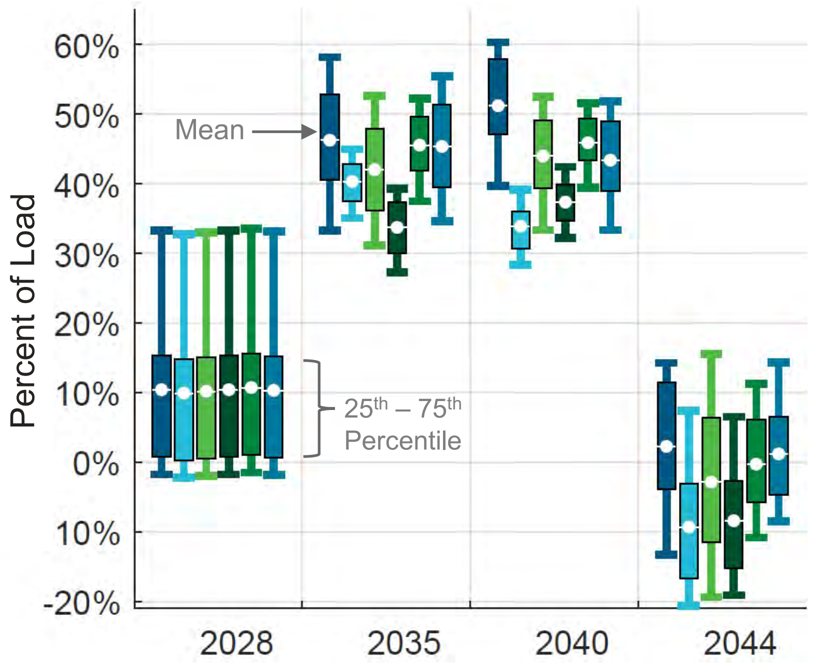
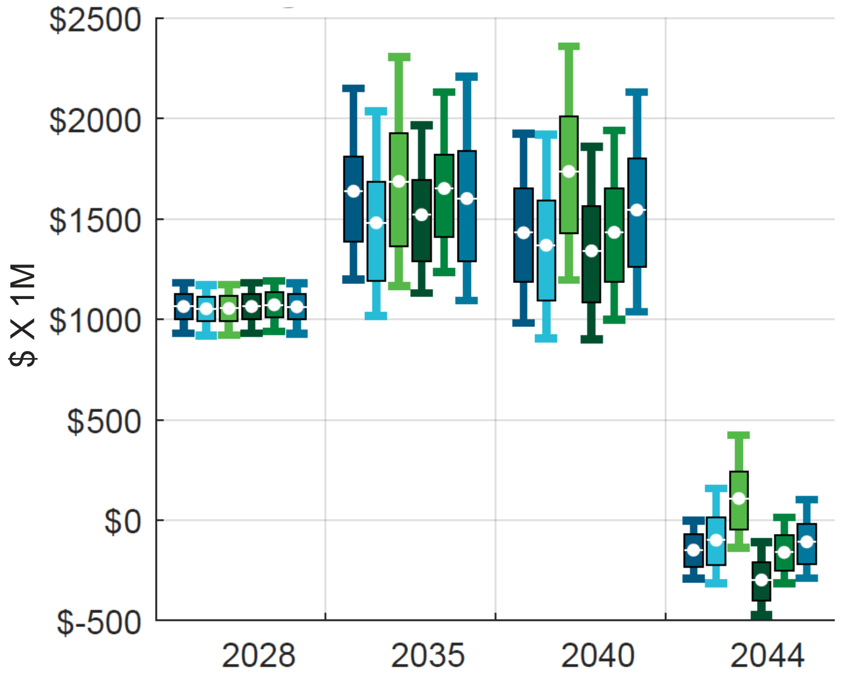
Net Purchases with Economic Dispatch



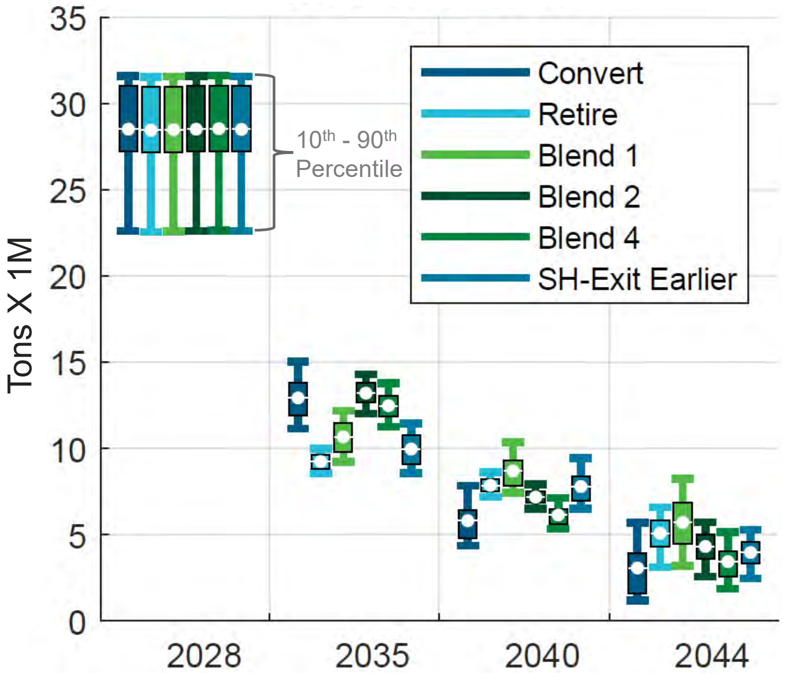
- Net purchases represent opportunities to reduce costs by transacting with the market when economic.
- 2028 lower net purchases driven by projections of higher power prices & lower gas prices.
- 2044 lower net purchases mainly due to increase in renewables.

Operating Cost Net of Purchases/Sales



- Operating costs net of purchases and sales include fixed and variable operating costs.
- 2044 operating costs reduced by higher PTC/ITC credits. Narrower ranges in 2044 result from higher renewables that are not subject to dispatch based on market/fuel prices.

CO_2 Emissions



- CO_2 emissions reductions in later years driven by portfolio composition changes as well as lower market power prices.
- Preliminary directional results shown are subject to revision

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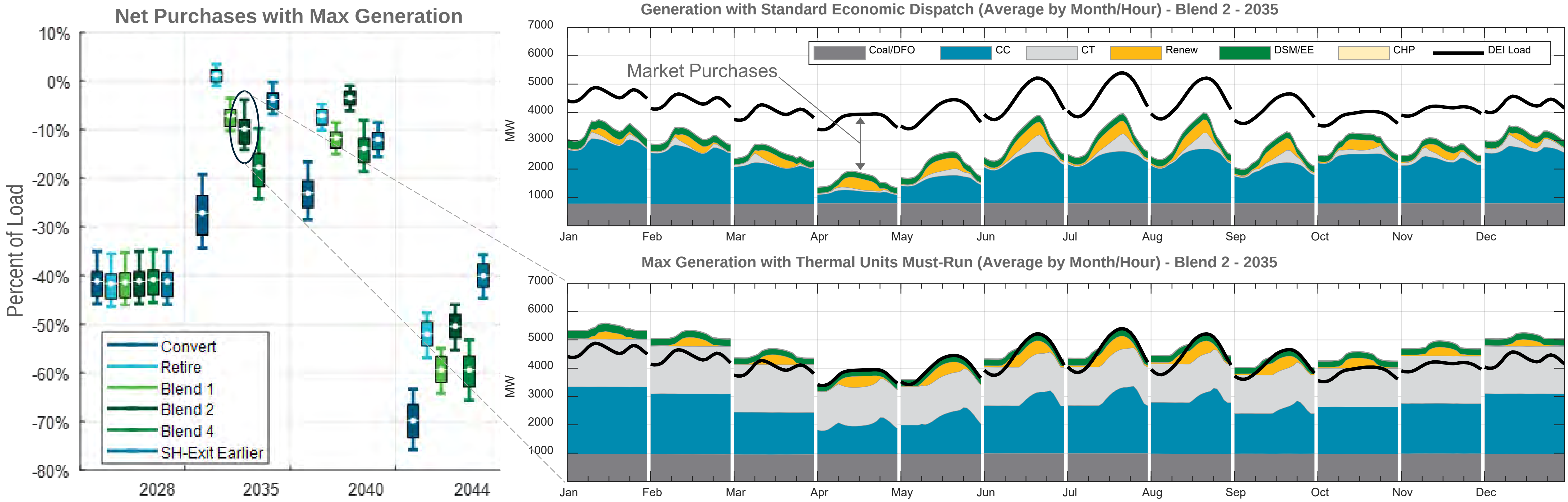
Stochastic Modeling of Energy Market Reliance



- Max Generation dispatch runs thermal units at max capacity subject to outages & annual EPA 111 rules.
- Annual average purchases net of sales shown. Almost all portfolios are net sellers of energy (negative purchases) under max generation dispatch.
- Average 12x24 month/hour profiles show representative (expected) asset generation mix for a single portfolio in a given dispatch year.
- Difference between total generation and load is treated as purchase or sale. MWh of excess sales net against MWh of purchases are used to produce annual averages shown in chart to left.
- Economic dispatch optimizes purchases to reduce total cost to serve load for customers thereby reducing capacity factors.
- Difference between standard (economic) dispatch and max generation dispatch demonstrates portfolio capacity available to reduce market reliance.

Scorecard Results

	Environmental Sustainability				Affordability			Reliability		Resiliency		Cost Risk			Market Exposure		Execution Risk			
Portfolio	CO_2 Emissions Reduction Over Planning Period		Cumulative CO_2 Reduction Over Planning Period (MM tons)	CO_2 Intensity of Duke Energy Indiana Portfolio (lbs./MWh)	PVRR ($B)	Customer Bill Impact (CAGR)		Fast Start Capability (as % of Coincident Peak)	Spinning Reserve Capability (as % of Coincident Peak)	Resource Diversity (Firm Capacity)	Simulated EUE in 95%+ Cold Weather (Islanded System)	Cost Variability Across Scenarios ($B)	IRA Exposure		Fuel Market Exposure	Maximum Energy Market Exposure	Cumulative Resource Additions in MW		Cumulative Resource Additions as % of Current System Installed Capacity	
	2035	2044	2044	2035	2044	2030	2035	2035	2035	2035	2035	2044	2030	2035	Avg.	Max Year	2030	2035	2030	2035
Convert / Co-fire Coal	74%	91%	367	661	$25.0	3.9%	3.1%	39%	93%	1766	2.8%	$24.0 – $28.1	81%	81%	61%	69%	992	1,779	12%	22%
Retire Coal	73%	81%	340	562	$23.6	3.7%	3.3%	31%	93%	3853	1.8%	$21.8 - $26.8	43%	29%	72%	43%	1,611	5,542	20%	68%
Blend 1	70%	81%	337	691	$24.2	3.9%	2.8%	33%	98%	2802	0.9%	$22.4 - $27.2	81%	20%	76%	51%	992	4,005	12%	49%
Blend 2	72%	84%	348	660	$24.3	4.0%	3.1%	33%	102%	2739	1.3%	$22.9 - $26.9	50%	22%	72%	53%	1,811	4,105	22%	51%
Blend 4	74%	88%	367	641	$24.5	4.0%	2.9%	33%	100%	1758	2.0%	$23.3 - $27.8	49%	33%	66%	66%	1,786	2,642	22%	33%
Exit Coal Earlier (Stakeholder)	72%	86%	362	624	$24.3	4.3%	3.1%	38%	87%	2291	3.6%	$23.4 - $27.2	57%	39%	70%	52%	2,136	4,061	26%	50%

A description of each scorecard metric is included on the following slide. Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.

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Scorecard Metrics

Metric	Description
CO_2 Emissions Reduction	Percent CO_2 reduction relative to 2025
Cumulative CO_2 Reduction	Cumulative volume of CO_2 reduction over the planning period (tons from 2025)
CO_2 Intensity	CO_2 emissions from Duke Energy Indiana's generation divided by DEI resource generation
Present Value of Revenue Requirement (PVRR)	Total revenue requirement associated with resource plan investments over the planning period, discounted to present; Provides estimate of total plan cost
Customer Bill Impact	Projected compound annual growth rate (CAGR) in customer bill associated with resource plan investments; Provides snapshot of portfolio cost impact at points in time
Fast Start Capability	Fast start capable capacity (CT and battery MW) as percentage of peak load in 2035
Spinning Reserve Capability	Spinning reserve capable capacity (steam, CC, CT, CHP and hydro MW) as percentage of peak load in 2035
Resource Diversity	The sum of squares of technology share in 2035 on a firm capacity basis

Metric	Description
Simulated EUE of Islanded System in 95th Percentile Cold Weather	Percent unserved energy during coldest weather (95th percentile or greater) observed in Indiana with market purchases turned off
Cost Variability	Minimum and Maximum PVRR across worldview scenarios
IRA Exposure	Cumulative MW additions with exposure to IRA tax credits as a percentage of total MW additions
Fuel Market Exposure	Generation (MWh) with exposure to coal and gas market prices as a percent of total fleet generation averaged annually over the planning period
Maximum Energy Market Exposure	Maximum absolute value of net energy purchases/sales as a percentage of total energy demand through the study period
Cumulative Resource Additions in MW	Cumulative MW additions of capacity resources through 2030 and 2035
Cumulative Resource Additions as % of Total System Installed Capacity	Cumulative MW additions of capacity resource technologies through 2030 and 2035 expressed as a percentage of total current system capacity

Cause No. 46193

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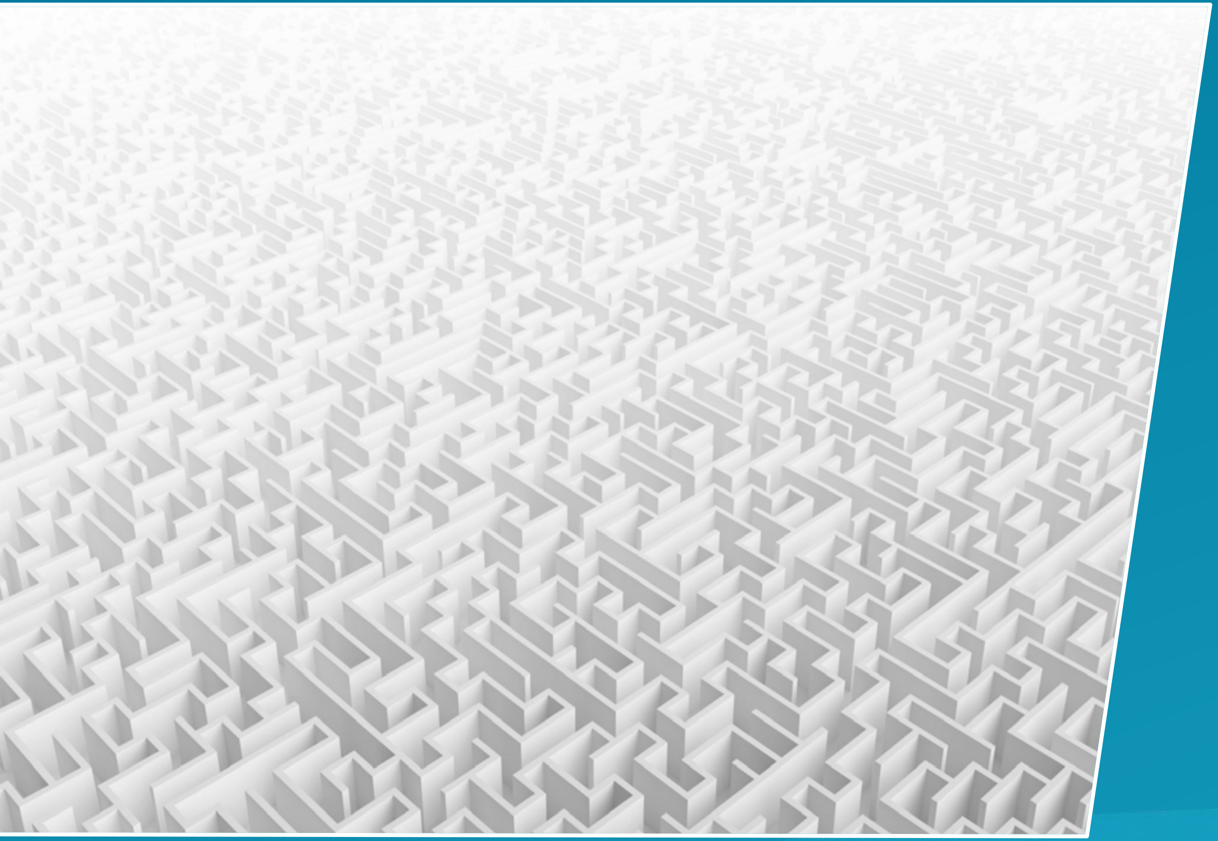

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Preferred Portfolio

Considerations for Short-Term Action Plan

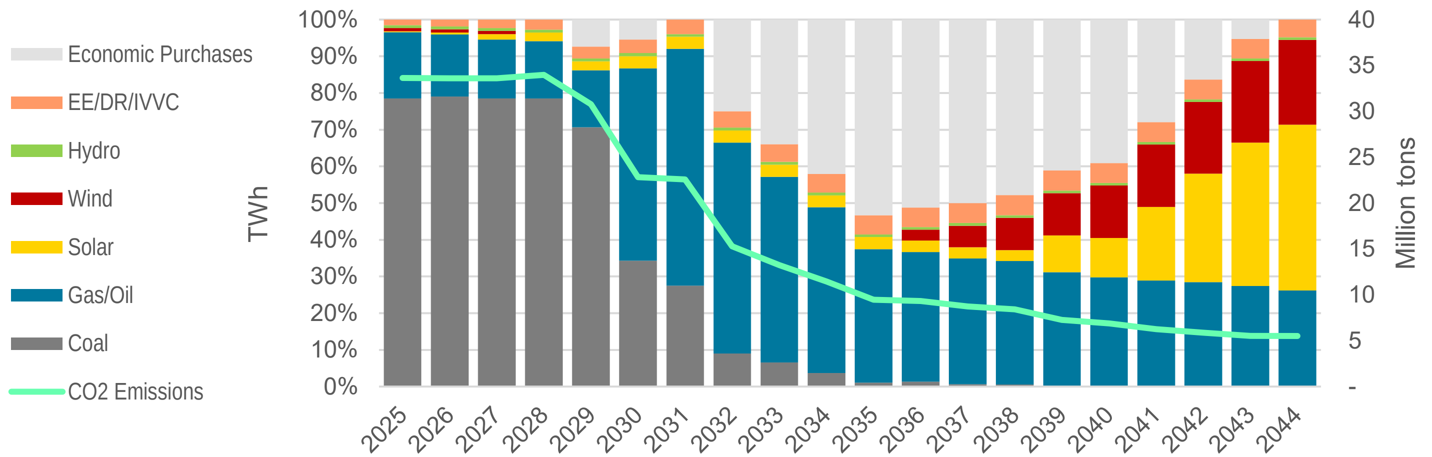
Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.

Co-Fire / Retire Gibson (Blend 2) | Reference Scenario

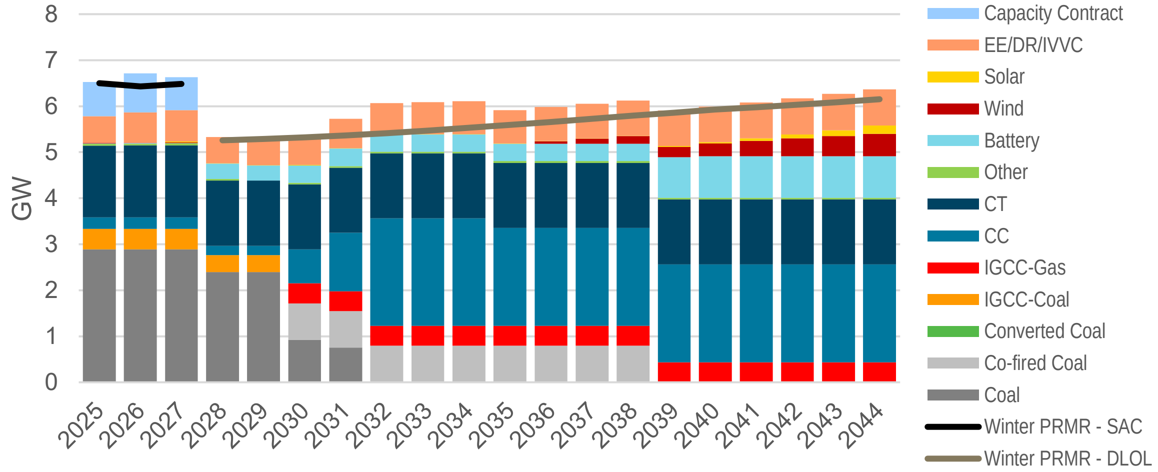
Cost Metrics

PVRR ($B)	$24.3
Bill Impact (CAGR) 2030	4.0%
Bill Impact (CAGR) 2035	3.1%

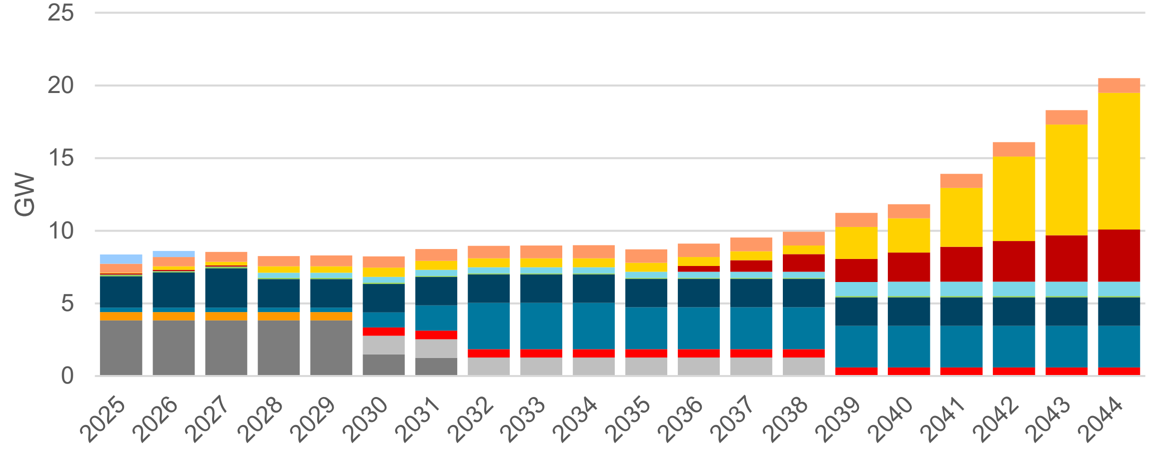
Energy Mix and CO_2 Emissions



Firm Capacity Mix and PRMR[1] (Winter GW, BOY)



Total Installed Capacity (GW, BOY)

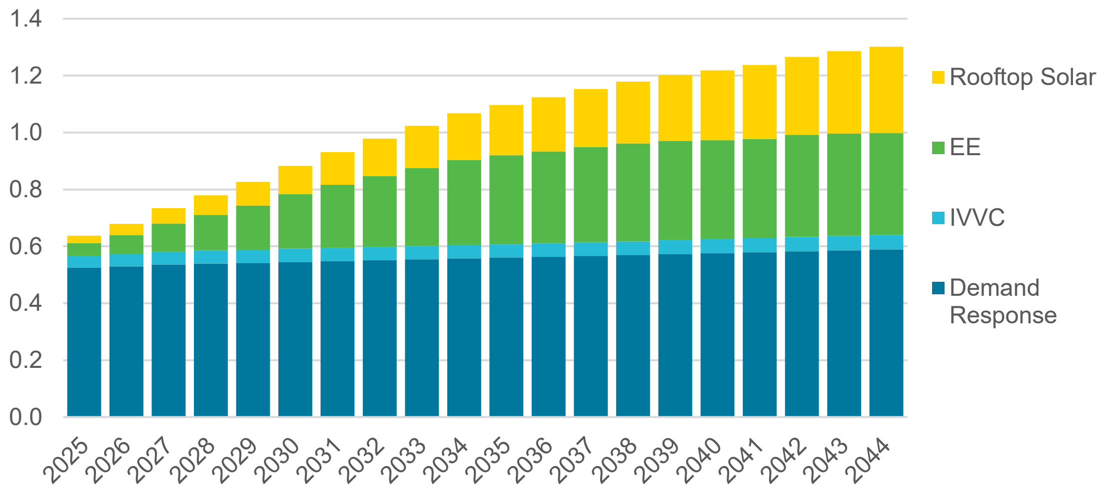


[1]Planning Reserve Margin Requirement (PRMR): Assumes MISO SAC 2025-2027, converts to DLOL beginning 2028

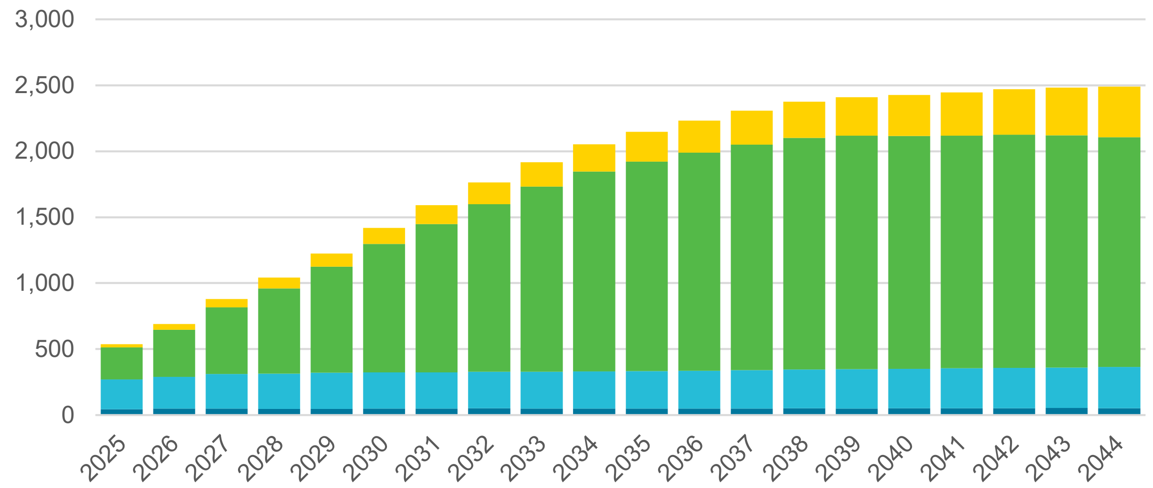
Cause No. 46193

Demand-Side Resources in the Preferred Portfolio

Max Capacity (GW, Beginning of Year)



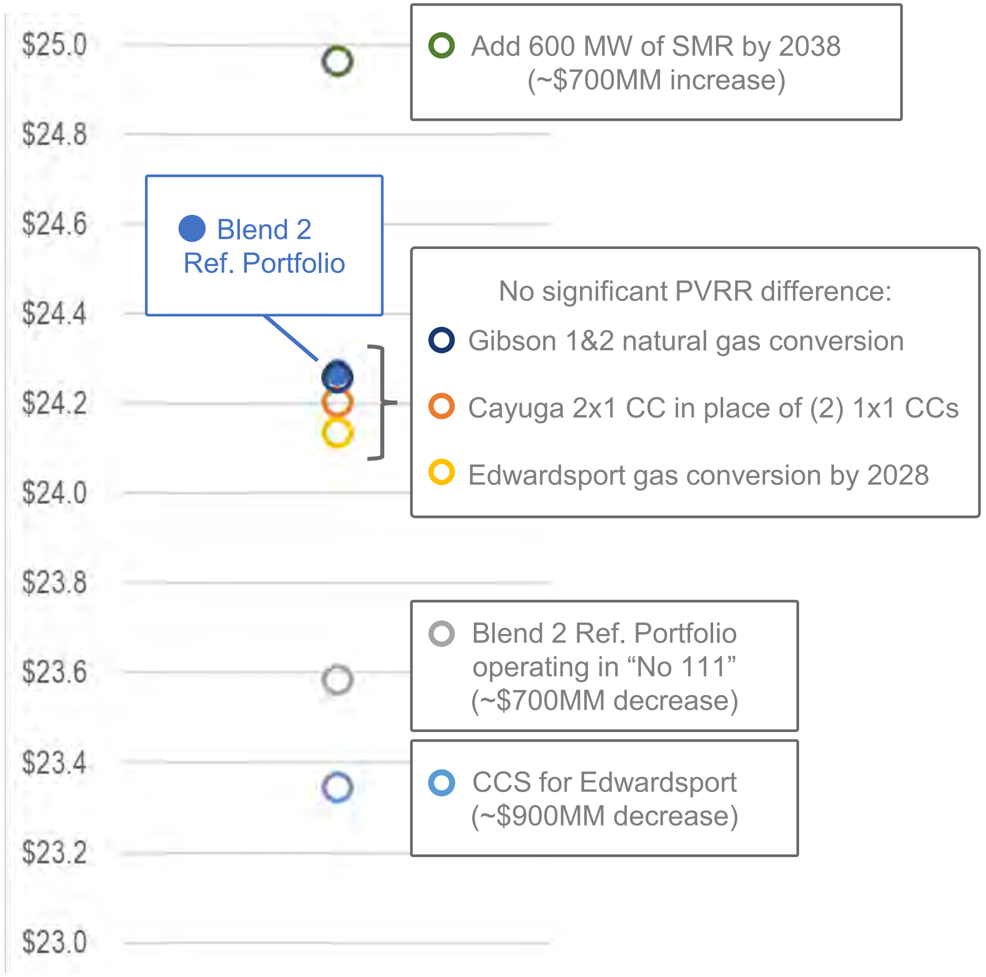
Energy Contribution (GWh)



Bundles Available for Selection				Energy Savings (GWh)																			
Bundle	Type	Year Avail.	Levelized Cost ($/MWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
EE Bundle 1	Base	2025	$28.86	242	357	346	346	345	345	344	340	332	311	277	238	207	183	135	71	24	9	8	7
EE Bundle 2	Base	2027	$32.46	0	0	159	300	459	458	447	428	405	386	370	356	333	305	276	255	241	205	149	88
EE Bundle 7	High	2027	$51.22	0	0	176	348	538	552	540	518	492	469	450	434	409	377	344	319	304	260	191	117
EE Bundle 3	Base	2030	$33.28	0	0	0	0	0	171	331	502	667	654	632	602	571	543	521	494	457	422	387	360
EE Bundle 8	High	2030	$52.72	0	0	0	0	0	190	384	589	788	789	763	729	693	661	635	604	562	523	482	451
EE Bundle 4	Base	2034	$27.59	0	0	0	0	0	0	0	0	0	166	310	457	597	724	839	944	1,042	977	936	885
EE Bundle 9	High	2034	$43.34	0	0	0	0	0	0	0	0	0	187	371	557	734	896	1,044	1,180	1,307	1,252	1,206	1,147
EE Bundle 5	Base	2042	$27.59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	156	279	403
EE Bundle 10	High	2042	$42.68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	175	331	488

PVRR Changes in Response to Blend 2 Strategy Variations

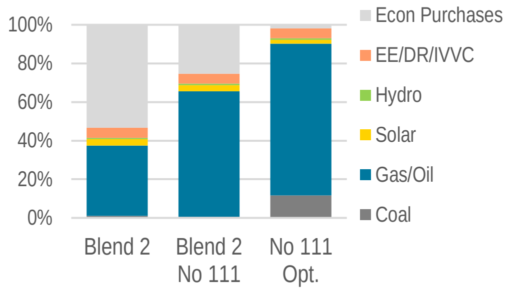
PVRR Results Across Blend 2 Variations



Key Insights

- Several variations on Blend 2 result in no significant changes to PVRR
  - Full gas conversion of Gibson units 1 & 2 (rather than co-firing)
  - Replacing Cayuga with a 2x1 CC (rather than two 1x1 CCs)
  - Retiring the Edwardsport gasifiers by 2028 (rather than 2030)
- Small modular reactors (SMR) were not economically selected as a resource in the preferred portfolio for the 2024 IRP. However, the considerable cost uncertainty for SMRs and the potential future value of reliable, around-the-clock, carbon-free generation make it prudent for Duke Energy Indiana to continue to advance early studies to maintain advanced nuclear as a viable option in future resource planning.
- The potential for tax credits associated with CCS at Edwardsport to lower PVRR makes it prudent to complete the ongoing FEED study. At this point, however, risk and uncertainty regarding cost, timely project execution, and long-term reliable operation of a CCS system preclude it from being part of the preferred portfolio.
- The Blend 2 portfolio is well-positioned for a future in which CAA Section 111 restrictions are relaxed, with an estimated PVRR only slightly greater than the $23.3 billion PVRR of the optimized "No 111" portfolio and the ability to operate competitively in the MISO energy market, limiting future purchases.

2035 Energy Mix Across Cases



Reminder: Thinking About the IRP Planning Period

Iterative resource plan updates

2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044

Future IRPs

Immediate future

- Typically, less divergence across portfolios, relative to later years
- Limited capability to make resource changes due to project lead times
- Key consideration: Maintaining reliable service while supporting economic development

Early 2030s

- Increased range of options further out in time
- Certain decisions fall into Short-Term Action Plan
- IRP cycles allow for checking and adjusting future resource decisions
- Key consideration: Strategy for transitioning coal units while meeting growing customer needs

Latter half of planning period

- More options, considerably more uncertainty around all planning factors
- Multiple opportunities to check and adjust plan
- Limited direct influence on Short-Term Action Plan

Blend 2 Provides Optionality for "No 111" World, Other Circumstances

Short-Term Actions Prudent Across a Range of Future Conditions

- Install two highly-efficient advanced-class 1x1 CCs at Cayuga Station by 2030, 2031 to gain incremental capacity and replace aging coal units
- Secure gas supply to Gibson Station to support co-firing, CC, and gas conversion options
- Deploy ~500 MW of solar and ~400 MW of battery energy storage by 2030 to meet near-term energy and capacity needs, retire Gibson 5
- Advance early studies to maintain SMRs as a viable future planning option
- Pursue additional cost-effective contributions from EE and DR resources

Opportunities to Adjust Course in Response to Changing Market Conditions, Maintaining 111 Compliance

Gibson Units 3&4
Base plan is to retire and replace with 2x1 CC by 2032
→ **Market Signposts**
- Cost of CC
- Load forecast

→ Proceed with CC
OR
Natural Gas Conversion

Edwardsport IGCC
Base plan is to convert to natural gas by 2030
→ **Complete CCS FEED Study**
→ Proceed with Gas Conversion
OR
Pursue CCS

Opportunities to Adjust Course in Response to Potential Delay of Compliance Deadlines Under EPA CAA Section 111 Final Rule

Plan for 111 Compliance	Adjustment for Delay
Edwardsport IGCC	
• Prepare to convert to 100% natural gas fuel by 2030	• Continue coal gasification and monitor regulatory developments
• Complete FEED study to inform ultimate decision on CCS	• Complete CCS FEED study and update evaluations of gas conversion and CCS options as appropriate
Gibson Station	
• Co-fire units 1 & 2 with natural gas (up to 50%) by 2030	• Delay action on units 1 & 2 and monitor regulatory developments
• Prepare to develop 2x1 CC to replace units 3 & 4, while monitoring market conditions to inform potential pivot to gas conversion	• Prepare to develop 2x1 CC to replace units 3 & 4, while monitoring market conditions to inform potential delay

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Open Q&A

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Thank you

2024 DEI IRP Stakeholder Engagement

Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process

Meeting #1
February 22nd
- Review previous IRP
- IRP Enhancements
- Proposed timeline
- IRA / EPA 111
- Scenario development input
- Scorecard criteria discussion

Meeting #2
April 29th
- Generic Unit Summary
- Market Potential Study
- Fuels
- Accreditation / Reserve margin
- Load forecast
- Scenario review
- MISO modeling approach
- Final scorecard criteria review

Meeting #3
June 20th
- Final inputs
- MISO modeling
- Power prices
- Initial preliminary portfolios

Meeting #4
August 13th
- Updated portfolios
- Initial results
- Initial scorecard

Meeting #5
October 3rd
- Present results
- Reliability study
- Final scorecard
- Preferred portfolio

Stakeholder Meetings 1-5

Technical Meetings

Next Steps

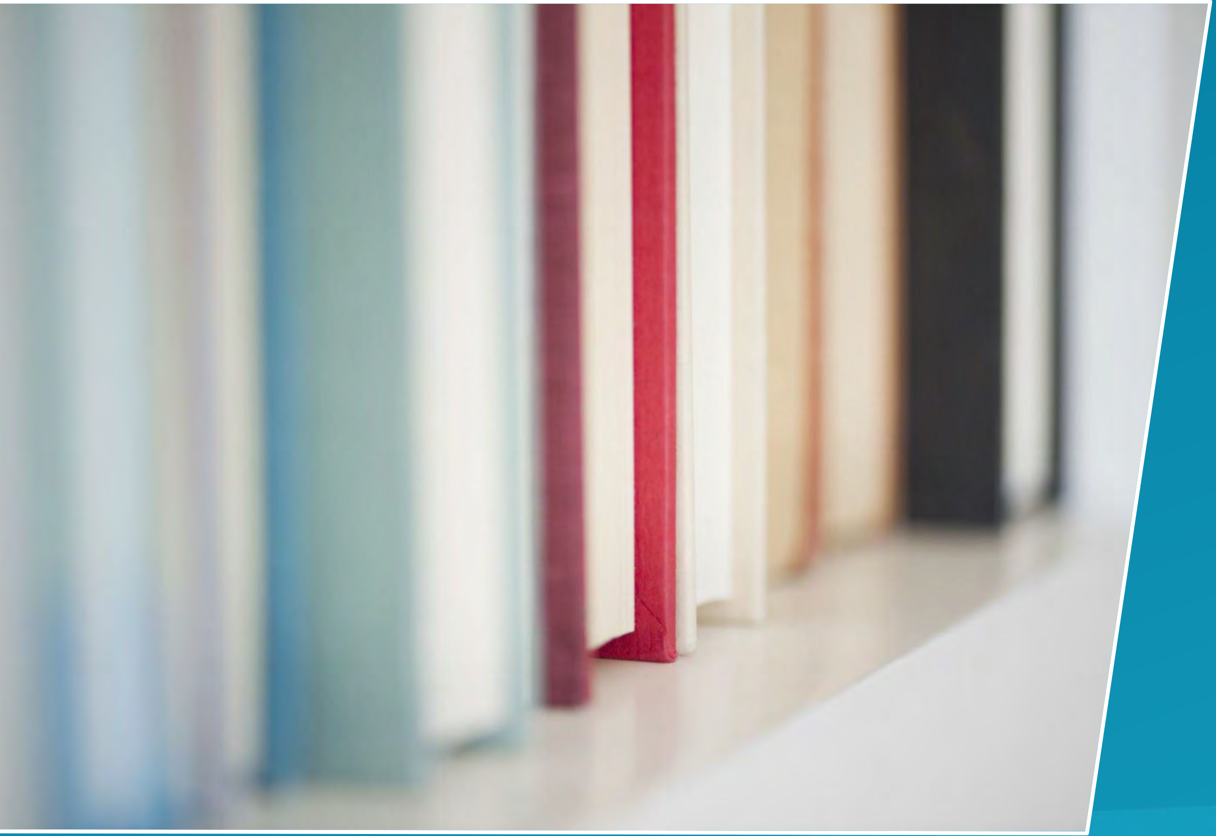
Cause No. 46193

Additional questions, comments, and feedback can be sent to

DEIndianaIRP@1898andco.com

The IRP submittal date is November 1.

After the IRP is submitted, the email address above will no longer be active. A Duke Energy IRP email address will be communicated to stakeholders and updated on the IRP webpage at that time.



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Appendix: Generation Strategy Results

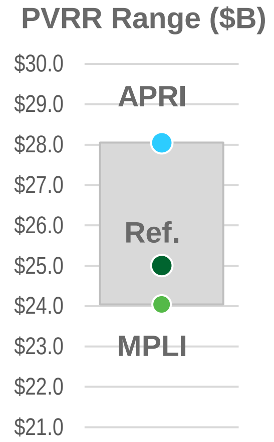
Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.

Cause No. 46193

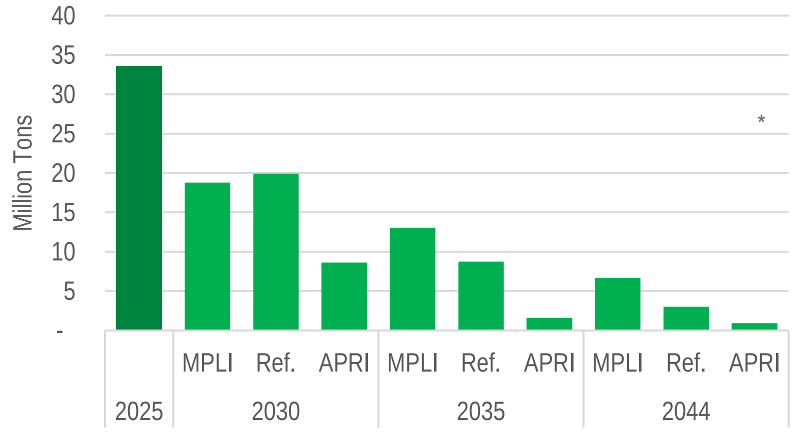
Generation Strategy Results Summary: Convert / Co-Fire Coal

Notes on Generation Strategy

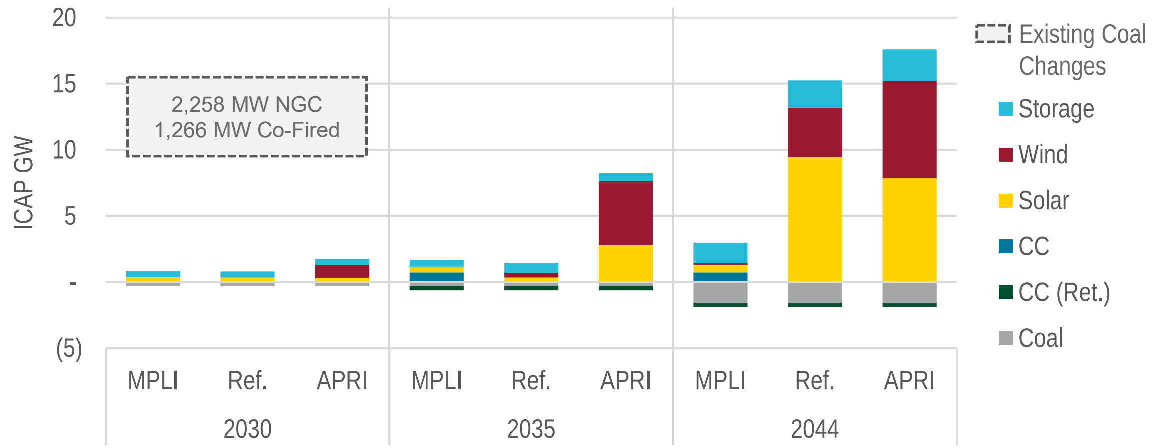
- Converting coal units to burn 100% natural gas or co-fire coal/gas, mitigates need for new capacity in near term, but does not provide additional capacity.
- Converted and co-fired coal units provide needed capacity but struggle to compete economically in the MISO energy market, with economic energy purchases supplying a substantial portion of total energy in the mid-2030s.
- Solar, wind, and battery additions supply needed incremental energy and capacity before 2030, with new CC capacity added in the early 2030s in the Minimum Policy & Lagging Innovation (MPLI) scenario, which envisions the rollback of GHG rules under CAA Section 111.
- Co-fired coal units (Gibson 1 & 2) must retire by 2039 under CAA Section 111, necessitating investment in replacement capacity in the mid/late 2030s.



CO_2 Emissions Over Time

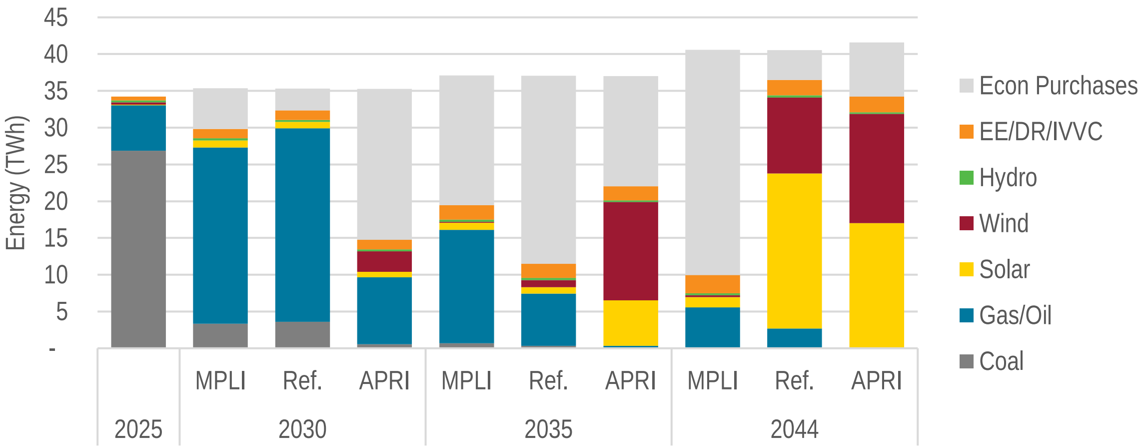


Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



Cause No. 46193

Convert / Co-Fire Coal : Annual Resource Additions & Retirements (Beginning-of- Year)

Existing Resources

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						Conv.														
Cayuga 2						Conv.														
Gibson 1						Cofire									(632)					
Gibson 2						Cofire									(633)					
Gibson 3						Conv.														
Gibson 4						Conv.														
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions

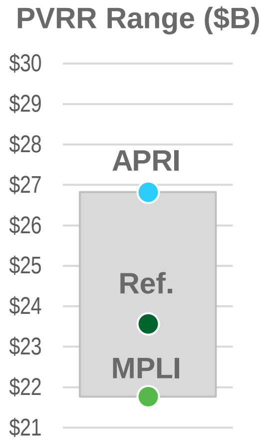
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC																				
2x1 CC																				
Solar[1]		199		150											1,800	200	1,750	1,800	1,750	1,800
Wind										250	100	200	400	400	400	400	400	400	400	400
Battery[1]				350		100					300				50	50				350
EE/DR[2]	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

[1]*Includes paired*
[2]*EE/DR additions, net of annual program roll off*

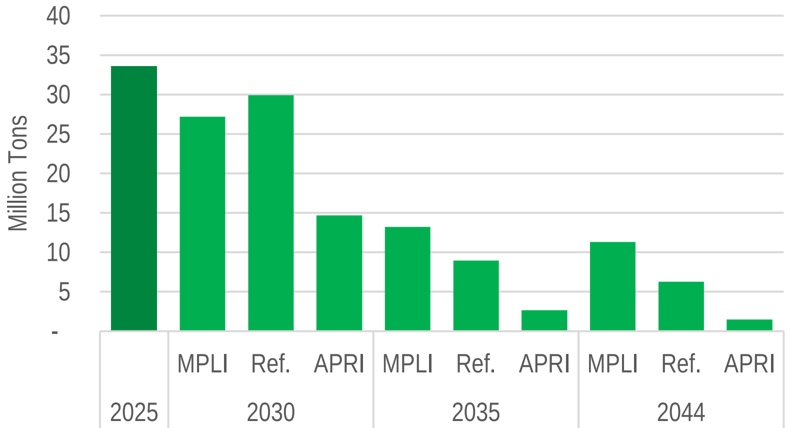
Generation Strategy Results Summary: Retire Coal

Notes on Generation Strategy

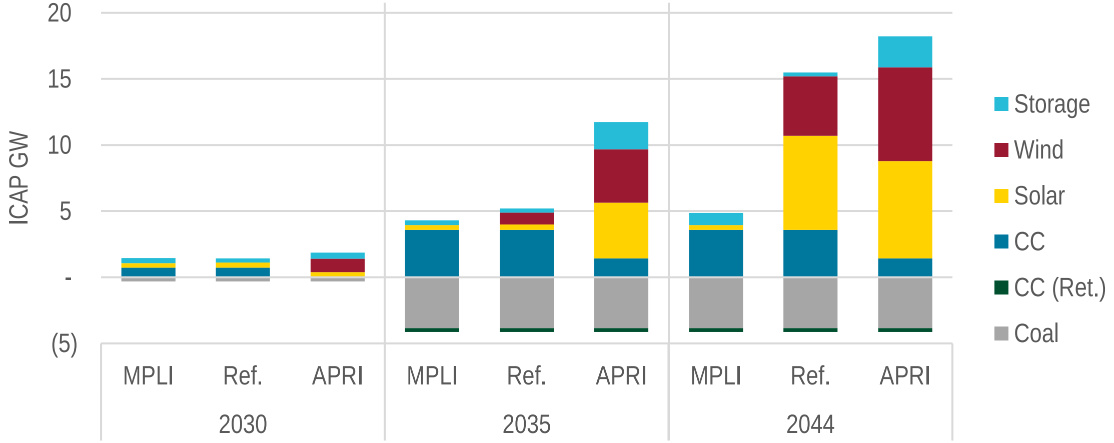
- Significant additions of dispatchable and variable energy resources are required by the early 2030s to meet incremental load growth and replace over 3.8 GW of retiring coal.
- New gas-fired combined-cycle generators provide improved resource accreditation over retiring units and operate competitively in the MISO market, dispatching up to the 40% capacity factor limit under CAA 111.
- Energy mix varies considerably across scenarios in the mid-2030s, with the repeal of the recently adopted GHG rule under CAA Section 111 allowing CCs to operate up to their economic limits in Minimum Policy & Lagging Innovation (MPLI), while additional policy constraints and falling costs drive greater adoption of renewables in Aggressive Policy & Rapid Innovation (APRI).



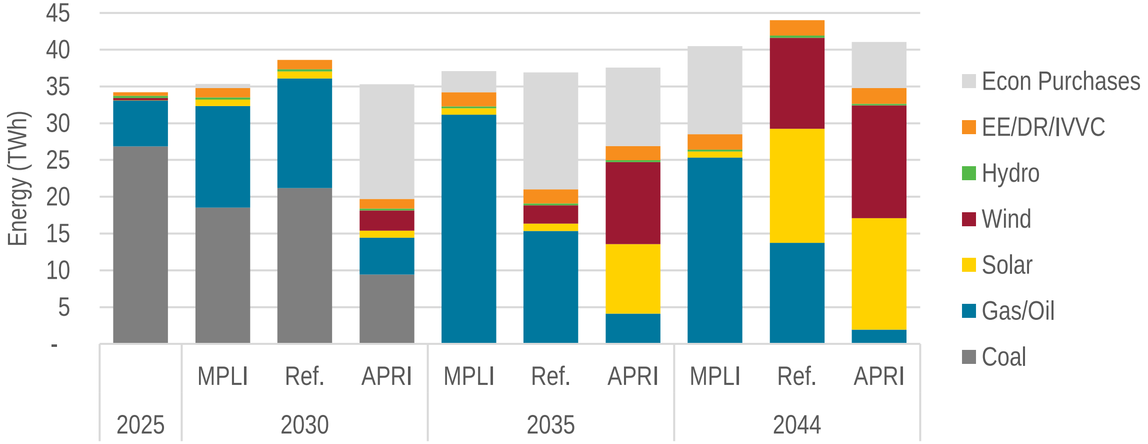
CO_2 Emissions Over Time



Cumulative Supply-Side Changes (Installed GW, BOY)



Energy Mix Over Time



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Retire Coal: Resource Additions & Retirements (Beginning-of-Year Basis)

Cause No. 46193

Existing Resources

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1								(502)												
Cayuga 2								(496)												
Gibson 1								(632)												
Gibson 2								(633)												
Gibson 3								(635)												
Gibson 4								(626)												
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions

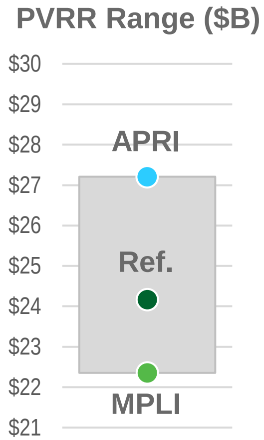
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719														
2x1 CC								2,876												
Solar[1]		199		200													1,500	1,600	1,800	1,800
Wind									250	250	400	400	400	400	400	400	400	400	400	400
Battery[1]				300																
EE/DR[2]	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

[1]*Includes paired*
[2]*EE/DR additions, net of annual program roll off*

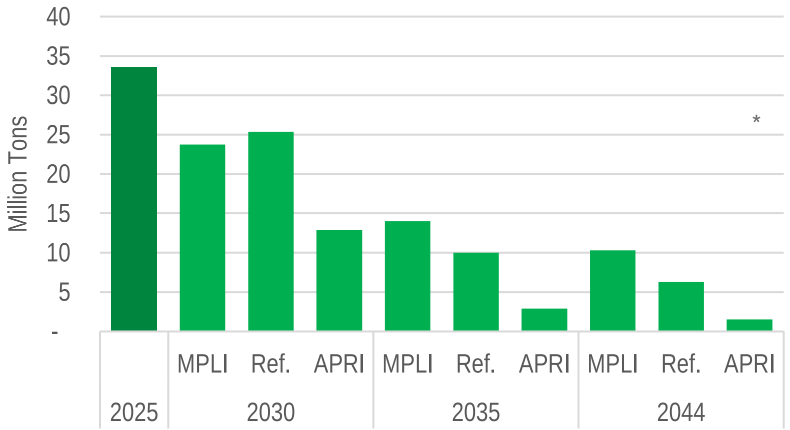
Generation Strategy Results Summary: Convert Cayuga (Blend 1)

Notes on Generation Strategy

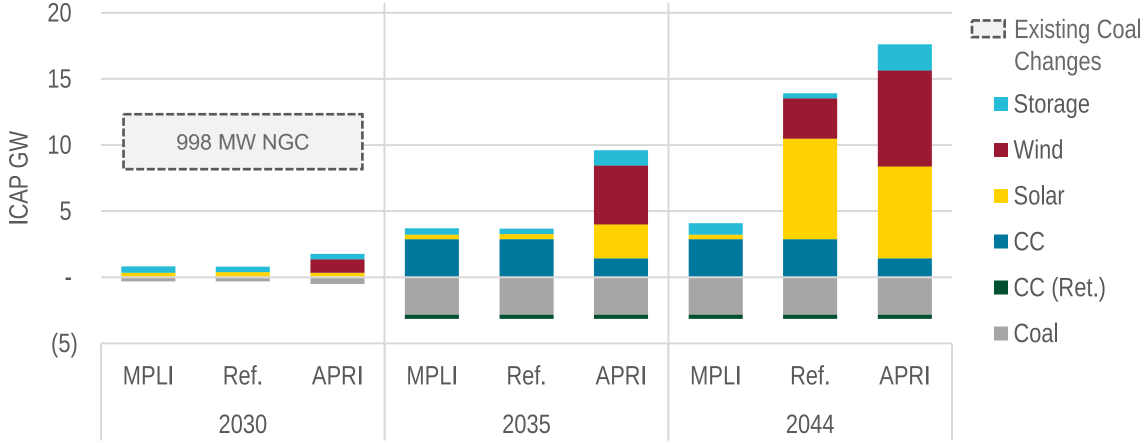
- Cayuga units 1 and 2 are repowered to burn 100% natural gas by 2030, while Gibson units 1 through 4 are retired and replaced with new combined-cycle generation by 2032.
- Renewables and storage are favored in the Aggressive Policy & Rapid Innovation (APRI) scenario, displacing a portion of the gas capacity added in other scenarios as coal units retire, while in the Minimum Policy & Lagging Innovation (MPLI) scenario, new CCs provide substantially more energy than in other cases.
- Full gas conversion at the Cayuga units allows them to operate through the end of the planning period, consistent with the GHG rule under CAA Section 111.



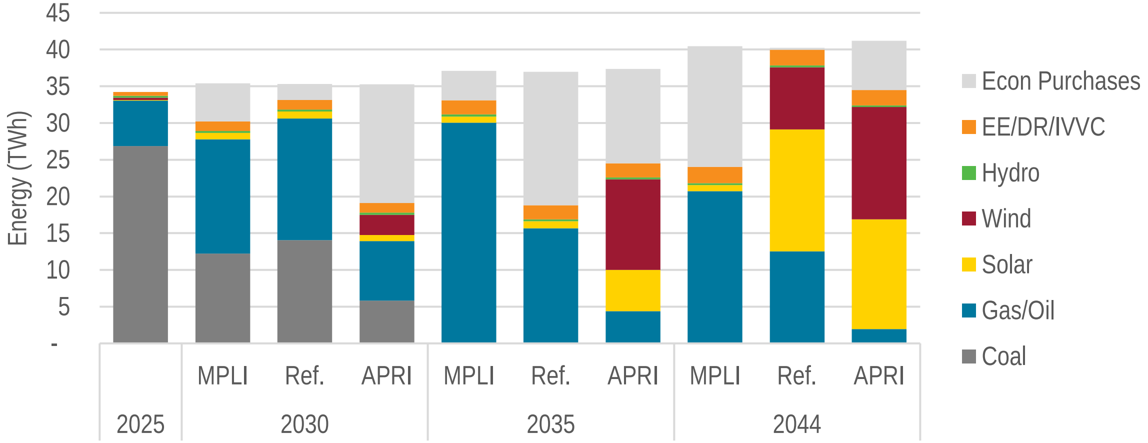
CO_2 Emissions Over Time



Cumulative Supply-Side Changes (Installed GW, BOY)



Energy Mix Over Time



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Blend 1: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						Conv.														
Cayuga 2						Conv.														
Gibson 1								(632)												
Gibson 2								(633)												
Gibson 3								(635)												
Gibson 4								(626)												
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC																				
2x1 CC								2,876												
Solar[1]		199		200													1,800	1,800	1,800	1,800
Wind													250	400	400	400	400	400	400	400
Battery[1]				300		100														
EE/DR[2]	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

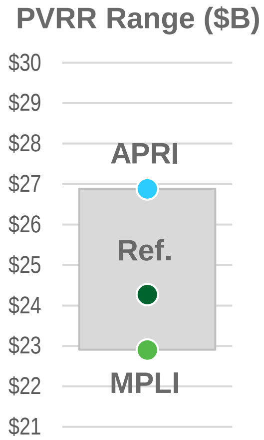
[1]*Includes paired*
[2]*EE/DR additions, net of annual program roll off*

Preferred Portfolio: Co-Fire Gibson (Blend 2)

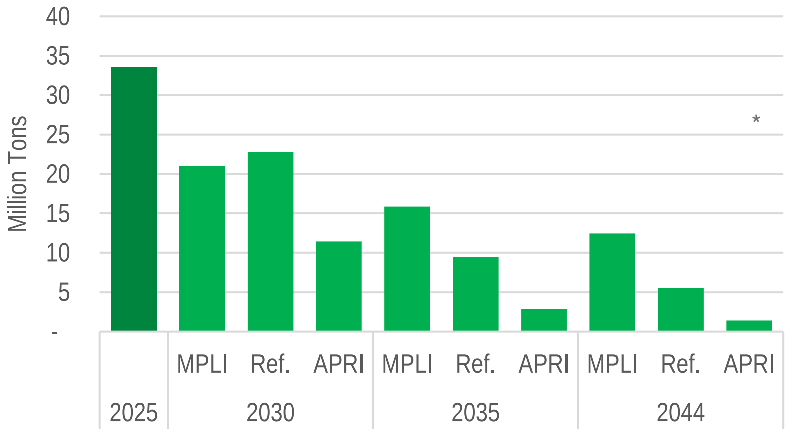
Cause No. 46193

Notes on Generation Strategy

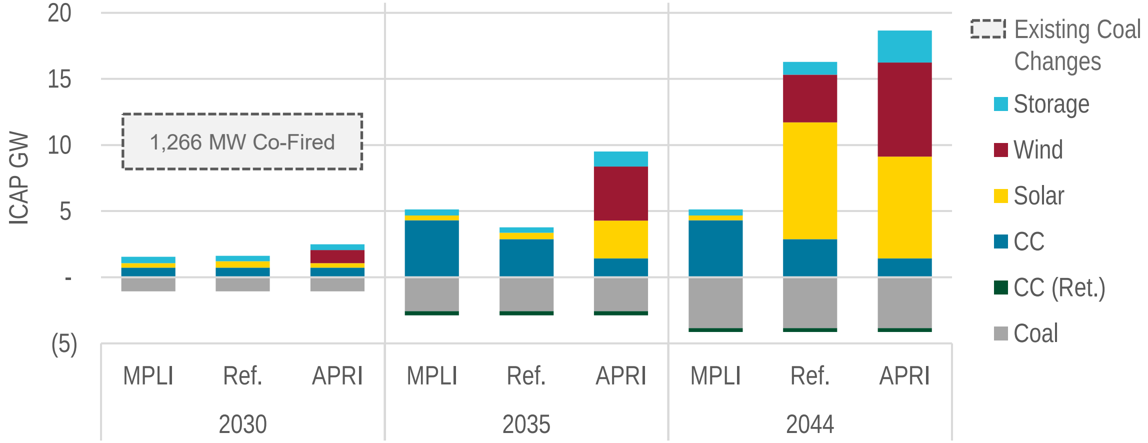
- Cayuga units 1 and 2 retire by 2030 and 2031. Two 1x1 CCs are added at the site, replacing the retiring coal and providing incremental MW to help serve growing load. Similarly, Gibson 3 and 4 are replaced with a 2x1 CC by 2032.
- Gibson 1 and 2 are converted to enable co-firing natural gas with coal, allowing them to continue to operate through 2038 under CAA Section 111, at which point additional capacity is needed.
- Renewables and storage are added in the late 2020s to meet near-term needs in all scenarios, with that trend accelerating in the Aggressive Policy & Rapid Innovation (APRI) scenario, and the balance shifting towards new gas in the Minimum Policy & Lagging Innovation (MPLI) scenario.
- Energy from new CCs displaces market purchases in the MPLI scenario.



CO_2 Emissions Over Time

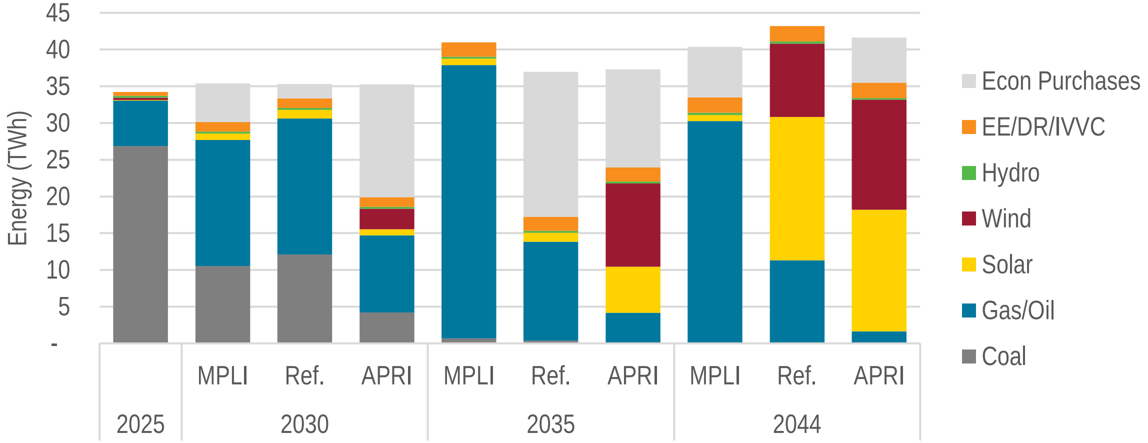


Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



Blend 2: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						(502)														
Cayuga 2						(256)	(240)													
Gibson 1						Cofire									(632)					
Gibson 2						Cofire									(633)					
Gibson 3								(635)												
Gibson 4								(626)												
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions

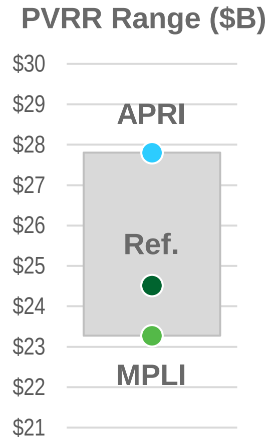
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719	719													
2x1 CC								1,438												
Solar[1]		199		150		150									1,150	150	1,700	1,750	1,800	1,800
Wind												400	400	400	400	400	400	400	400	400
Battery[1]				350		50									550	25				
EE/DR[2]	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

[1] *Includes paired*
[2] *EE/DR additions, net of annual program roll off*

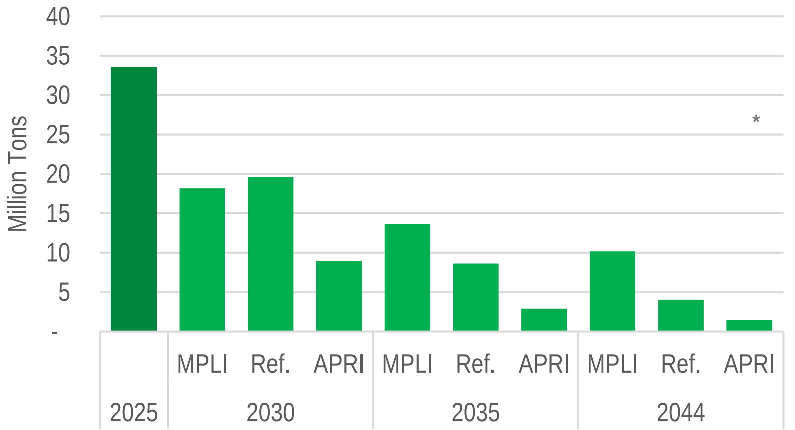
Generation Strategy Results Summary: Co-fire/Convert Gibson (Blend 4)

Notes on Generation Strategy

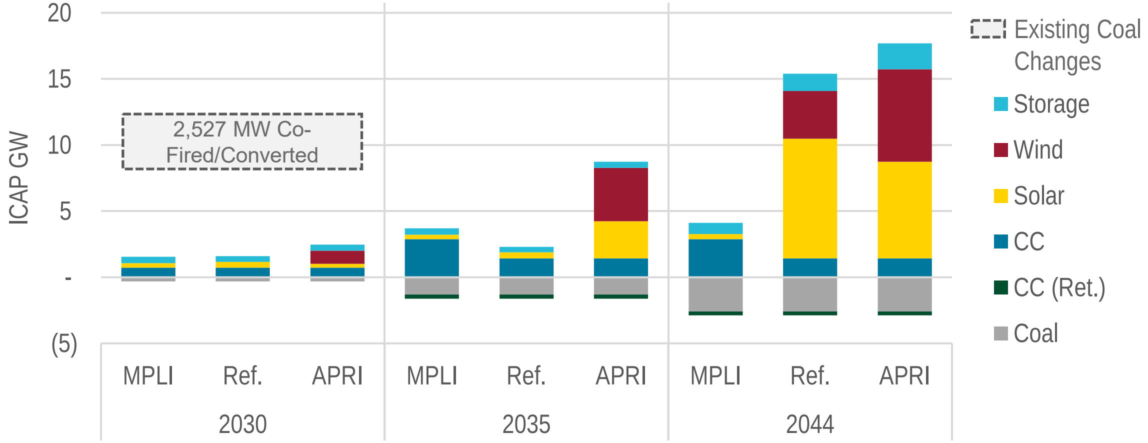
- Cayuga units 1 and 2 retire by 2030 and 2031. Two 1x1 CCs are added at the site, replacing the retiring coal and providing incremental MW to help serve growing load.
- Gibson 1 and 2 are converted to enable co-firing natural gas with coal, allowing them to continue to operate through 2038 under CAA Section 111, at which point additional capacity is needed. Gibson 3 and 4 are converted to natural gas and operate throughout the study period.
- Renewables and storage are added in the late 2020s to meet near-term needs in all scenarios, with that trend accelerating in the Aggressive Policy & Rapid Innovation (APRI) scenario, and the balance shifting towards new gas in the Minimum Policy & Lagging Innovation (MPLI) scenario.



CO_2 Emissions Over Time

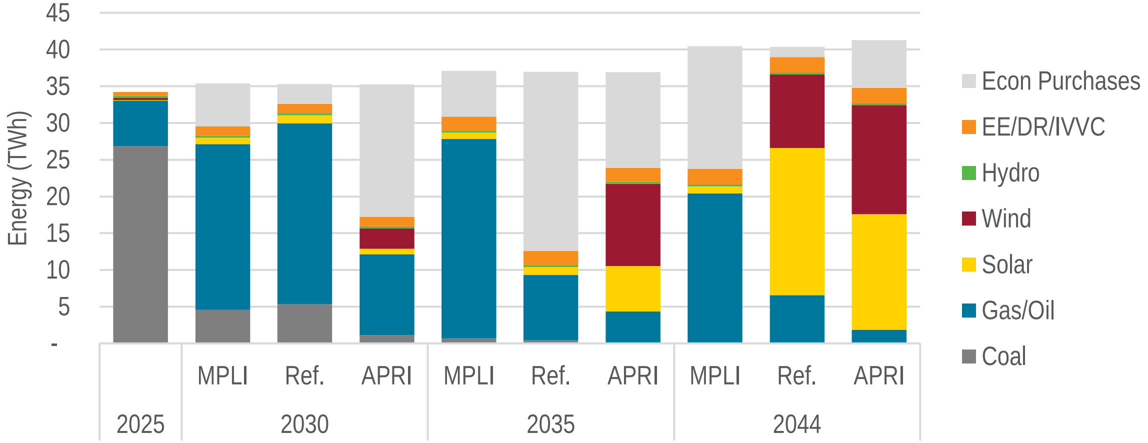


Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



Blend 4: Resource Additions & Retirements (Beginning-of-Year Basis)

Cause No. 46193

Existing Resources

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						(502)														
Cayuga 2						(256)	(240)													
Gibson 1						Cofire									(632)					
Gibson 2						Cofire									(633)					
Gibson 3						Conv.														
Gibson 4						Conv.														
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719	719													
2x1 CC																				
Solar[1]		199		100		150									1,700	50	1,800	1,500	1,750	1,800
Wind												400	400	400	400	400	400	400	400	400
Battery[1]				350		75									850	25				
EE/DR[2]	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

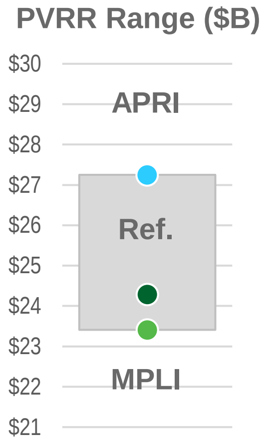
[1]*Includes paired*
[2]*EE/DR additions, net of annual program roll off*

Generation Strategy Results Summary: Exit Coal Earlier (Stakeholder)

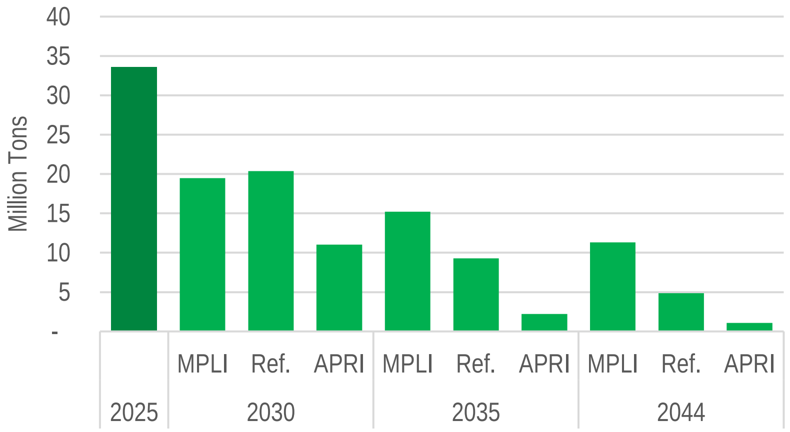
Cause No. 46193

Notes on Generation Strategy

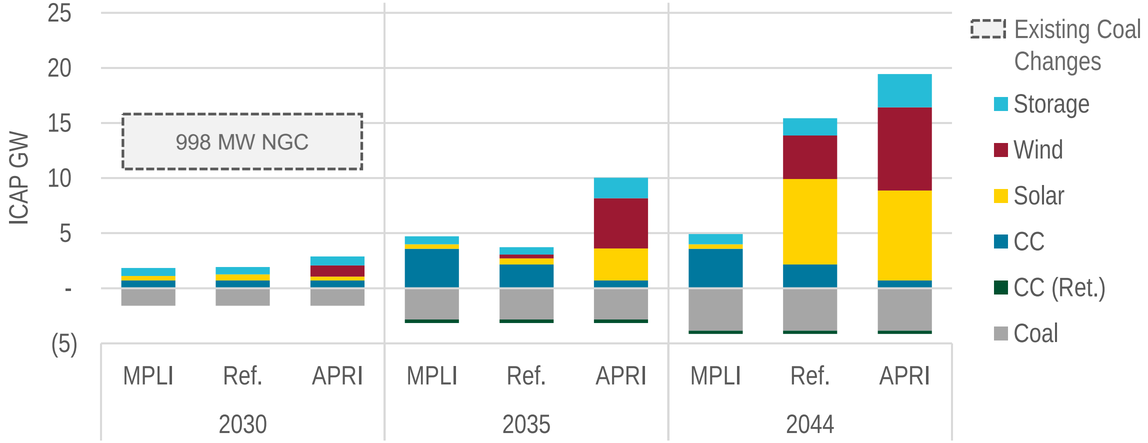
- Accelerating the retirement of Gibson 3 and 4 to 2030 necessitates the addition of higher volumes of renewables and storage by 2030 than in other strategies, while conversion of Cayuga to 100% natural gas maintains capacity at that site.
- New CC capacity is added to offset coal retirements in all scenarios, with a 2x1 replacing Gibson units 1 and 2 when they retire by 2032, consistent with the GHG rule under CAA Section 111.
- Additional gas capacity is selected in the Minimum Policy & Lagging Innovation (MPLI) scenario in which capacity factor limits under CAA Section 111 are assumed to be repealed, whereas in the Aggressive Policy & Rapid Innovation (APRI) scenario, renewables are favored.



CO_2 Emissions Over Time

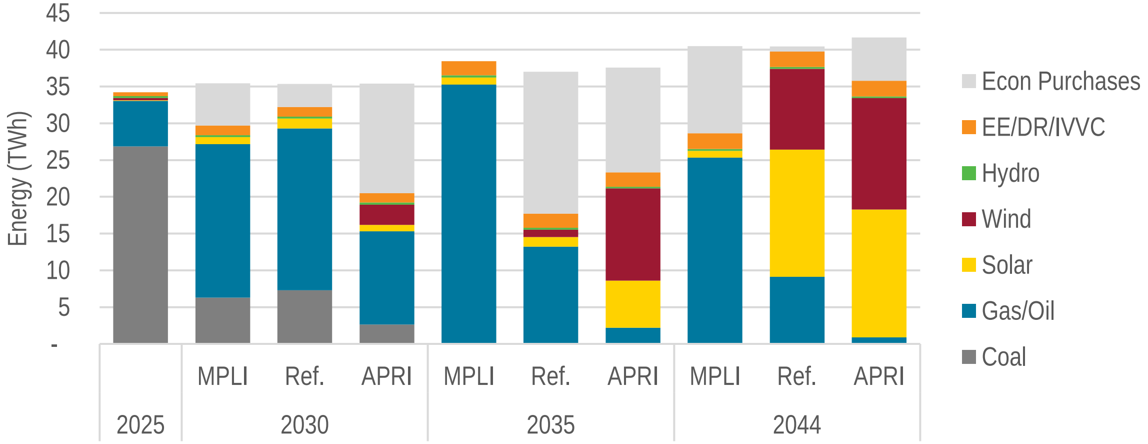


Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

Energy Mix Over Time



Exit Coal Earlier: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1					Conv.															(502)
Cayuga 2					Conv.															(496)
Gibson 1								(632)												
Gibson 2								(633)												
Gibson 3						(635)														
Gibson 4						(626)														
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719														
2x1 CC								1,438												
Solar[1]		199		150		200											1,800	1,800	1,800	1,800
Wind											350	400	400	400	400	400	400	400	400	400
Battery[1]				325		350														900
EE/DR[2]	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

[1]*Includes paired*
[2]*EE/DR additions, net of annual program roll off*

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Appendix: Acronyms

Cause No. 46193
Attachment A-1
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Acronyms

APRI	Aggressive Policy & Rapid Innovation
BOY	Beginning of Year
CAA 111	Clean Air Act 111
CAGR	Compound Annual Growth Rate
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
DDRE	Deep Decarbonization and Rapid Electrification
DEI	Duke Energy Indiana
D-LOL	Direct Loss of Load
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EPA	Environmental Protection Agency
EUE	Expected Unserved Energy
FEED	Front-End Engineering Design
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hour
ICAP	Installed Capacity
IGCC	Integrated Gasification Combined Cycle
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan

ITC	Investment Tax Credit
IVVC	Integrated Volt/VAR Control
kWh	Kilowatt-hour
MISO	Midcontinent Independent System Operator
MM	Million
MMBtu	Million British Thermal Units
MPLI	Minimum Policy & Lagging Innovation
Mt	Million Tons
MW	Megawatt
MWh	Megawatt-hour
NG	Natural Gas
NGC	Natural Gas Conversion
PPA	Power Purchase Agreement
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PVRR	Present Value of Revenue Requirement
RFP	Request for Proposal
SAC	Seasonal Accredited Capacity
SMR	Small Modular Reactor
TWh	Terawatt Hour

Cause No. 46193

Attachment A-2

Datasite Uploads

INDIANA

2024 | INTEGRATED RESOURCE PLAN

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Date Posted	Date Removed	File Name
4/12/2024	6/11/2024	Confidential Projected Inflation-Adjusted PTC Rates Under Sections 45 and 45Y_03.04.24_Preliminary.xlsx
4/12/2024	6/11/2024	DEI Base Load Forecast and Comparison Over Time for Spring 2024 IRP 4_11_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI Demand Response Forecast for IRP - Preliminary Draft.xlsx
4/12/2024	6/11/2024	DEI ELCC Curves_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI Fuel Curves_04_11_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI Reserve Margin Conversion from MISO_4_3_2024_Preliminary_Confidential.xlsx
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5/31/2024	6/11/2024	23F Renewable ITC_PTC Input Cleared.xlsx
5/31/2024	6/11/2024	23F Schedule 53 Class Average.xlsx
5/31/2024	6/11/2024	23F Wind OS ISONE-Maine PTC.xlsx
5/31/2024	6/11/2024	23S No Zone 6 Renewables.xlsx
5/31/2024	6/11/2024	24S 111 Gas CF.xlsx
5/31/2024	6/11/2024	24S 111 ST CF.xlsx
5/31/2024	6/11/2024	24S 50% Coal DFO.xlsx
5/31/2024	6/11/2024	24S Base.xlsx
5/31/2024	6/11/2024	24S CCS Projects.xlsx
5/31/2024	6/11/2024	24S CSAPR Update.xlsx
5/31/2024	6/11/2024	24S DLOL PRM & ELCC.xlsx
5/31/2024	6/11/2024	24S Duke Adders 111.xlsx
5/31/2024	6/11/2024	24S Duke Capital Costs.xlsx
5/31/2024	6/11/2024	24S Duke Fuel Costs.xlsx
5/31/2024	6/11/2024	24S MISO SAC ELCC.xlsx
5/31/2024	6/11/2024	24S Updates.xlsx
5/31/2024	6/11/2024	24S Z6R Duke Adders 111.xlsx
5/31/2024	6/11/2024	Dataset_for_Viewing.xlsx
5/31/2024	6/11/2024	No Coal Must Run.xlsx
5/31/2024	6/11/2024	Object Creation.xlsx
5/31/2024	6/11/2024	Reduce Zone 6 CC.xlsx
5/31/2024	6/11/2024	_DEI IRP NDB 111 Reference Runs.xlsx
6/11/2024	7/23/2024	Preliminary - No-111 portfolio
6/11/2024	7/23/2024	_DEI IRP Local Runs 2024.06.10.xlsx

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6/11/2024	7/23/2024	24S 111 MISO Market.xlsx
6/11/2024	7/23/2024	24S 111 Z6R MISO Market.xlsx
6/11/2024	7/23/2024	24S REF MISO Market.xlsx
6/11/2024	7/23/2024	24S REF Z6R MISO Market.xlsx
6/11/2024	7/23/2024	DEIN 23F New CC.xlsx
6/11/2024	7/23/2024	DEIN 23S CPCN Solar.xlsx
6/11/2024	7/23/2024	DEIN 23S EE Projects.zip
6/11/2024	7/23/2024	DEIN 23S No Market Limit.xlsx
6/11/2024	7/23/2024	DEIN 23S No Market Limit.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP Coal Retirements.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP REF Optimized Retirement FOM.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP Thermal Tranches.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP Tranches.xlsx
6/11/2024	7/23/2024	DEIN 24S Base.xlsx
6/11/2024	7/23/2024	DEIN 24S Capital.xlsx
6/11/2024	7/23/2024	DEIN 24S Cay CC Cost Inc.xlsx
6/11/2024	7/23/2024	DEIN 24S Cayuga NGC.xlsx
6/11/2024	7/23/2024	DEIN 24S Cayuga Retire by '31.xlsx
6/11/2024	7/23/2024	DEIN 24S CC4 CT2 Avail.xlsx
6/11/2024	7/23/2024	DEIN 24S Coal to Gas Options.xlsx
6/11/2024	7/23/2024	DEIN 24S DLOL.xlsx
6/11/2024	7/23/2024	DEIN 24S Edwardsport Gas 2030.xlsx
6/11/2024	7/23/2024	DEIN 24S Edwardsport Gas 2035.xlsx
6/11/2024	7/23/2024	DEIN 24S EE Firm Capacity.xlsx
6/11/2024	7/23/2024	DEIN 24S ELCC Curves 111.xlsx
6/11/2024	7/23/2024	DEIN 24S ELCC Curves REF.xlsx
6/11/2024	7/23/2024	DEIN 24S Emissions on Fuel.xlsx
6/11/2024	7/23/2024	DEIN 24S Existing CT Limit.xlsx
6/11/2024	7/23/2024	DEIN 24S Fuel Prices.xlsx
6/11/2024	7/23/2024	DEIN 24S Gib 1-2 NGC.xlsx
6/11/2024	7/23/2024	DEIN 24S Gib 3-4 DFO.xlsx
6/11/2024	7/23/2024	DEIN 24S Gibson Gas Cost.xlsx
6/11/2024	7/23/2024	DEIN 24S Gibson Retire by '32.xlsx
6/11/2024	7/23/2024	DEIN 24S Hourly Profiles.zip
6/11/2024	7/23/2024	DEIN 24S IRA Extended.xlsx
6/11/2024	7/23/2024	DEIN 24S IRA.xlsx
6/11/2024	7/23/2024	DEIN 24S IRP Project Limits.xlsx
6/11/2024	7/23/2024	DEIN 24S Load.xlsx
6/11/2024	7/23/2024	DEIN 24S Market Limit - 25percent.xlsx
6/11/2024	7/23/2024	DEIN 24S New Gas CF Limit.xlsx
6/11/2024	7/23/2024	DEIN 24S New Gas Update.xlsx
6/11/2024	7/23/2024	DEIN 24S Nuclear ITC.xlsx
6/11/2024	7/23/2024	DEIN 24S Outage Schedule.xlsx
6/11/2024	7/23/2024	DEIN 24S Split Cay Retire.xlsx
6/11/2024	7/23/2024	DEIN 24S Transmission Adder.xlsx
6/11/2024	7/23/2024	DEIN Remove FOM - PC.xlsx
6/11/2024	7/23/2024	Duke Midwest Base.zip
7/9/2024	7/23/2024	CONFIDENTIAL_DEI Inflated Installed Calculation Example_June 2024.xlsx
7/9/2024	7/23/2024	CONFIDENTIAL_Generic Cost vs RFP Bids.xlsx
7/9/2024	7/23/2024	CONFIDENTIAL_IRP Generic Unit Summary Midwest.xlsx
7/23/2024	8/26/2024	_111 Generation Strategies.xlsx
7/23/2024	8/26/2024	24S 111 MISO Market.xlsx
7/23/2024	8/26/2024	24S 111 Z6R MISO Market.xlsx
7/23/2024	8/26/2024	DEIN 23F New CC.xlsx
7/23/2024	8/26/2024	DEIN 23S CPCN Solar.xlsx
7/23/2024	8/26/2024	DEIN 23S EE Projects.xlsx
7/23/2024	8/26/2024	DEIN 23S No Market Limit.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP Blend 3 Forced Units.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP Consolidate 2x1s.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP Thermal Tranches.xlsx

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7/23/2024	8/26/2024	DEIN 24S Cay CC Cost Inc.xlsx
7/23/2024	8/26/2024	DEIN 24S Cayuga NGC 2029.xlsx
7/23/2024	8/26/2024	DEIN 24S Cayuga NGC.xlsx
7/23/2024	8/26/2024	DEIN 24S Cayuga Retire by '32.xlsx
7/23/2024	8/26/2024	DEIN 24S CC4 1x1 Avail.xlsx
7/23/2024	8/26/2024	DEIN 24S CCU Gib Fix Cost Adj.xlsx
7/23/2024	8/26/2024	DEIN 24S Coal to Gas Options.xlsx
7/23/2024	8/26/2024	DEIN 24S DLOL.xlsx
7/23/2024	8/26/2024	DEIN 24S Edwardsport Gas 2030.xlsx
7/23/2024	8/26/2024	DEIN 24S EE Projects.xlsx
7/23/2024	8/26/2024	DEIN 24S ELCC Curves 111.xlsx
7/23/2024	8/26/2024	DEIN 24S Emissions on Fuel.xlsx
7/23/2024	8/26/2024	DEIN 24S Existing CT Limit.xlsx
7/23/2024	8/26/2024	DEIN 24S Force CAY 1x1s.xlsx
7/23/2024	8/26/2024	DEIN 24S Fuel Prices.xlsx
7/23/2024	8/26/2024	DEIN 24S Gib 1-2 DFO.xlsx
7/23/2024	8/26/2024	DEIN 24S Gib 3-4 NGC.xlsx
7/23/2024	8/26/2024	DEIN 24S Gib 3-4 Retire.xlsx
7/23/2024	8/26/2024	DEIN 24S Gibson Gas Cost.xlsx
7/23/2024	8/26/2024	DEIN 24S Gibson Retire by '32.xlsx
7/23/2024	8/26/2024	DEIN 24S Gibson Retire Stakeholder 1.xlsx
7/23/2024	8/26/2024	DEIN 24S Hourly Profiles.xlsx
7/23/2024	8/26/2024	DEIN 24S IRA Extended.xlsx
7/23/2024	8/26/2024	DEIN 24S IRA.xlsx
7/23/2024	8/26/2024	DEIN 24S IRP Project Limits.xlsx
7/23/2024	8/26/2024	DEIN 24S Load.xlsx
7/23/2024	8/26/2024	DEIN 24S Market Limit - 25.xlsx
7/23/2024	8/26/2024	DEIN 24S New Gas CF Limit.xlsx
7/23/2024	8/26/2024	DEIN 24S New Gas Update.xlsx
7/23/2024	8/26/2024	DEIN 24S Nuclear ITC.xlsx
7/23/2024	8/26/2024	DEIN 24S Outage Schedule.xlsx
7/23/2024	8/26/2024	DEIN 24S Split Cay Retire.xlsx
7/23/2024	8/26/2024	DEIN 24S Transmission Adder.xlsx
7/23/2024	8/26/2024	Duke Midwest Base.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 Blend 1 PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 Blend 3 PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 CCU PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 RCU PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 SH 1 PC.xlsx
7/23/2024	8/26/2024	DEI 2024 IRP Modeling_Change Log_07.22.2024
7/25/2024	8/26/2024	_111 Generation Strategies.xlsx
7/25/2024	8/26/2024	24S No 111 MISO Market.xlsx
7/25/2024	8/26/2024	24S No 111 Z6R MISO Market.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP Coal Retirements.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP No 111 Opt Ret FOM.xlsx
7/25/2024	8/26/2024	DEIN 24S Edwardsport Gas 2035.xlsx
7/25/2024	8/26/2024	DEIN 24S ELCC Curves No 111.xlsx
7/25/2024	8/26/2024	DEIN 24S Force Gib 1x1.xlsx
7/25/2024	8/26/2024	DEIN 24S Market Limit - 25percent.xlsx
7/25/2024	8/26/2024	DEIN Remove FOM - PC.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP 111 Blend 2 - CAY 1x1s Gib 1x1 PC.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/3/2024	9/20/2024	_DEIN 24 IRP Local Input Share 08.29.2024.xlsx
9/3/2024	9/20/2024	24S 111 MISO Market.xlsx
9/3/2024	9/20/2024	24S 111 Z6R MISO Market.xlsx
9/3/2024	9/20/2024	24S APRI MISO Market.xlsx
9/3/2024	9/20/2024	24S APRI Z6R MISO Market.xlsx
9/3/2024	9/20/2024	24S MPLI MISO Market.xlsx

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9/3/2024	9/20/2024	DEIN 23S CPCN Solar.xlsx
9/3/2024	9/20/2024	DEIN 23S EE Projects.xlsx
9/3/2024	9/20/2024	DEIN 23S No Market Limit.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Blend 4 Adjustments.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP CCU Gib Fix Cost Adj.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP CCU Project Limits.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Coal Retirements.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Consolidate CCs.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP High Load CT PPA.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP No 111 Opt Ret FOM.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP SH 1 Relax Battery Limit.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Thermal Tranches.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Tranches.xlsx
9/3/2024	9/20/2024	DEIN 24S APRI Capital and FOM Costs.xlsx
9/3/2024	9/20/2024	DEIN 24S APRI Market Sale Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S APRI Project Limits.xlsx
9/3/2024	9/20/2024	DEIN 24S Base.xlsx
9/3/2024	9/20/2024	DEIN 24S Capital.xlsx
9/3/2024	9/20/2024	DEIN 24S Cay CC Cost Inc.xlsx
9/3/2024	9/20/2024	DEIN 24S Cayuga NGC 2029.xlsx
9/3/2024	9/20/2024	DEIN 24S Cayuga NGC.xlsx
9/3/2024	9/20/2024	DEIN 24S Cayuga Retire by '32.xlsx
9/3/2024	9/20/2024	DEIN 24S CC Min Up April 2035.xlsx
9/3/2024	9/20/2024	DEIN 24S CC Min Up April 2046.xlsx
9/3/2024	9/20/2024	DEIN 24S CO2 Tax.xlsx
9/3/2024	9/20/2024	DEIN 24S Coal to Gas Options.xlsx
9/3/2024	9/20/2024	DEIN 24S DLOL.xlsx
9/3/2024	9/20/2024	DEIN 24S Edwardsport Gas 2030.xlsx
9/3/2024	9/20/2024	DEIN 24S Edwardsport Gas 2035.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Firm Cap High Load.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Firm Cap High PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Firm Cap Low PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Projects.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves 111.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves APRI.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves MPLI.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves No 111.xlsx
9/3/2024	9/20/2024	DEIN 24S Emissions on Fuel.xlsx
9/3/2024	9/20/2024	DEIN 24S Existing CT Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S Existing Gas CF Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S Force CAY 1x1s.xlsx
9/3/2024	9/20/2024	DEIN 24S Fuel Prices.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 1-2 DFO FT.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 1-2 DFO.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 3-4 NGC.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 3-4 Retire.xlsx
9/3/2024	9/20/2024	DEIN 24S Gibson Gas Cost.xlsx
9/3/2024	9/20/2024	DEIN 24S Gibson Retire by '32.xlsx
9/3/2024	9/20/2024	DEIN 24S Gibson Retire Stakeholder 1.xlsx
9/3/2024	9/20/2024	DEIN 24S High Fuels Prices.xlsx
9/3/2024	9/20/2024	DEIN 24S High Load.xlsx
9/3/2024	9/20/2024	DEIN 24S High PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S Hourly Profiles.xlsx
9/3/2024	9/20/2024	DEIN 24S IRA 100 percent Domestic Content.xlsx
9/3/2024	9/20/2024	DEIN 24S IRA Extended.xlsx
9/3/2024	9/20/2024	DEIN 24S IRA.xlsx
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9/3/2024	9/20/2024	DEIN 24S Limit 1x1 CC.xlsx
9/3/2024	9/20/2024	DEIN 24S Load.xlsx
9/3/2024	9/20/2024	DEIN 24S Low Fuels Price.xlsx
9/3/2024	9/20/2024	DEIN 24S Low PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S Market Limit - 25 percent.xlsx
9/3/2024	9/20/2024	DEIN 24S New Gas CF Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S New Gas Update.xlsx
9/3/2024	9/20/2024	DEIN 24S No IRA.xlsx
9/3/2024	9/20/2024	DEIN 24S No Nuc.xlsx
9/3/2024	9/20/2024	DEIN 24S Nuclear ITC.xlsx
9/3/2024	9/20/2024	DEIN 24S Outage Schedule.xlsx
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9/3/2024	9/20/2024	DEIN Remove FOM - PC.xlsx
9/3/2024	9/20/2024	Duke Midwest Base.xlsx
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9/3/2024	9/20/2024	101. NDB_Topology_11-01-2023.xlsx
9/3/2024	9/20/2024	102. NDB_Demand_RPS_11-01-2023.xlsx
9/3/2024	9/20/2024	103. NDB_Fuel_Emission_11-01-2023.xlsx
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9/3/2024	9/20/2024	104. NDB_Nuclear_11-01-2023.xlsx
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9/3/2024	9/20/2024	112. NDB_Hydro_11-01-2023.xlsx
9/3/2024	9/20/2024	112a. NDB_New_Hydro_11-01-2023.xlsx
9/3/2024	9/20/2024	113. NDB_PS_11-01-2023.xlsx
9/3/2024	9/20/2024	114. NDB_Biomass_11-01-2023.xlsx
9/3/2024	9/20/2024	114a. NDB_New_Biomass_11-01-2023.xlsx
9/3/2024	9/20/2024	115. NDB_FuelCell_11-01-2023.xlsx
9/3/2024	9/20/2024	116. NDB_Geothermal_11-01-2023.xlsx
9/3/2024	9/20/2024	116a. NDB_New_Geothermal_11-01-2023.xlsx
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9/3/2024	9/20/2024	117a. NDB_New_Landfill_11-01-2023.xlsx
9/3/2024	9/20/2024	118. NDB_Other_11-01-2023.xlsx
9/3/2024	9/20/2024	119. NDB_OnShore_Wind_11-01-2023.xlsx
9/3/2024	9/20/2024	120. NDB_OffShore_Wind_11-01-2023.xlsx
9/3/2024	9/20/2024	121. NDB_Solar_PV_11-01-2023.xlsx
9/3/2024	9/20/2024	122. NDB_Solar_Steam_11-01-2023.xlsx
9/3/2024	9/20/2024	123. NDB_Expansion_11-01-2023.xlsx
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9/3/2024	9/20/2024	125. NDB_DER_Solar_11-01-2023.xlsx
9/3/2024	9/20/2024	126. NDB_DER_Battery_11-01-2023.xlsx
9/3/2024	9/20/2024	126a. NDB_Battery_11-01-2023.xlsx
9/3/2024	9/20/2024	126b. NDB_Battery_Target_11-01-2023.xlsx
9/3/2024	9/20/2024	127. Market_Rules_11-01-2023.xlsx
9/3/2024	9/20/2024	22F H2 CT.xlsx
9/3/2024	9/20/2024	23F 111 Gas CF Limits.xlsx
9/3/2024	9/20/2024	23F CCS Projects.xlsx
9/3/2024	9/20/2024	23F EIA High Fuels.xlsx
9/3/2024	9/20/2024	23F EIA Low Fuels.xlsx
9/3/2024	9/20/2024	23F Future 2A Siting.xlsx
9/3/2024	9/20/2024	23F MISO Z6 KY NUC PTC.xlsx
9/3/2024	9/20/2024	23F PJM RTEP.xlsx
9/3/2024	9/20/2024	23F PTC Swap.xlsx

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9/3/2024	9/20/2024	23F Renewable ITC_PTC Input Cleared.xlsx
9/3/2024	9/20/2024	23F Schedule 53 Class Average.xlsx
9/3/2024	9/20/2024	23F Wind OS ISONE-Maine PTC.xlsx
9/3/2024	9/20/2024	23S No Zone 6 Renewables.xlsx
9/3/2024	9/20/2024	24S 111 Gas CF.xlsx
9/3/2024	9/20/2024	24S 111 Proposed Existing Gas CF.xlsx
9/3/2024	9/20/2024	24S 111 ST CF.xlsx
9/3/2024	9/20/2024	24S 50 percent Coal DFO.xlsx
9/3/2024	9/20/2024	24S AGRI Project Limits.xlsx
9/3/2024	9/20/2024	24S Base.xlsx
9/3/2024	9/20/2024	24S CCS Projects.xlsx
9/3/2024	9/20/2024	24S CO2 Tax.xlsx
9/3/2024	9/20/2024	24S CSAPR Update.xlsx
9/3/2024	9/20/2024	24S DLOL PRM & ELCC.xlsx
9/3/2024	9/20/2024	24S Duke Adders 111.xlsx
9/3/2024	9/20/2024	24S Duke Adders.xlsx
9/3/2024	9/20/2024	24S Duke AGRI Capital and FOM Costs.xlsx
9/3/2024	9/20/2024	24S Duke Capital Costs.xlsx
9/3/2024	9/20/2024	24S Duke Fuel Costs.xlsx
9/3/2024	9/20/2024	24S IRA Repealed.xlsx
9/3/2024	9/20/2024	24S LDES.xlsx
9/3/2024	9/20/2024	24S MISO SAC ELCC.xlsx
9/3/2024	9/20/2024	24S No Nuclear.xlsx
9/3/2024	9/20/2024	24S PTC with 100 percent Domestic Content.xlsx
9/3/2024	9/20/2024	24S Updates.xlsx
9/3/2024	9/20/2024	24S Z6R Duke Adders 111.xlsx
9/3/2024	9/20/2024	24S Z6R Duke Adders.xlsx
9/3/2024	9/20/2024	Dataset_for_Viewing.xlsx
9/3/2024	9/20/2024	No Coal Must Run.xlsx
9/3/2024	9/20/2024	Object Creation.xlsx
9/3/2024	9/20/2024	Reduce Zone 6 CC.xlsx
9/3/2024	9/20/2024 A	DEIN 24 IRP APRI Blend 1 PC.xlsx
9/3/2024	9/20/2024 A	DEIN 24 IRP APRI Blend 2 - CAY 1x1s PC.xlsx
9/3/2024	9/20/2024 A	DEIN 24 IRP APRI Blend 4 PC.xlsx
9/3/2024	9/20/2024 A	DEIN 24 IRP APRI CCU PC.xlsx
9/3/2024	9/20/2024 A	DEIN 24 IRP APRI RCU PC.xlsx
9/3/2024	9/20/2024 A	DEIN 24 IRP APRI SH 1 PC.xlsx
9/3/2024	9/20/2024 M	DEIN 24 IRP MPLI Blend 1 PC.xlsx
9/3/2024	9/20/2024 M	DEIN 24 IRP MPLI Blend 2 - CAY 1x1s PC.xlsx
9/3/2024	9/20/2024 M	DEIN 24 IRP MPLI Blend 4 PC.xlsx
9/3/2024	9/20/2024 M	DEIN 24 IRP MPLI CCU PC.xlsx
9/3/2024	9/20/2024 M	DEIN 24 IRP MPLI RCU PC.xlsx
9/3/2024	9/20/2024 M	DEIN 24 IRP MPLI SH 1 PC.xlsx
9/3/2024	9/20/2024 R	DEIN 24 IRP 111 Blend 1 PC.xlsx
9/3/2024	9/20/2024 R	DEIN 24 IRP 111 Blend 2 - CAY 1x1s PC.xlsx
9/3/2024	9/20/2024 R	DEIN 24 IRP 111 Blend 4 PC.xlsx
9/3/2024	9/20/2024 R	DEIN 24 IRP 111 CCU PC.xlsx
9/3/2024	9/20/2024 R	DEIN 24 IRP 111 RCU PC.xlsx
9/3/2024	9/20/2024 R	DEIN 24 IRP 111 SH 1 PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 Blend 1 High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 Blend 4 High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 CCU High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 RCU High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 SH 1 High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/3/2024	9/20/2024	24S AGRI PC.xlsx
9/3/2024	9/20/2024	24S AGRI Z6R PC.xlsx
9/3/2024	9/20/2024	24S EPA 111 PC Adders.xlsx

Date Posted	Date Removed	File Name
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9/3/2024	9/20/2024	24S MPLI PC.xlsx
9/3/2024	9/20/2024	24S MPLI Z6R PC.xlsx
9/3/2024	9/20/2024	24S Ref PC Adders.xlsx
9/3/2024	9/20/2024	24S Ref Z6R PC Adrs.xlsx
9/3/2024	9/20/2024	READ ME.txt
9/20/2024	10/4/2024	_DEIN 24 IRP Local Input Share 09.19.2024.xlsx
9/20/2024	10/4/2024	24S 111 High Fuel MISO Market.xlsx
9/20/2024	10/4/2024	24S 111 Low Fuel MISO Market.xlsx
9/20/2024	10/4/2024	24S 111 MISO Market.xlsx
9/20/2024	10/4/2024	24S 111 Z6R MISO Market.xlsx
9/20/2024	10/4/2024	24S APRI MISO Market.xlsx
9/20/2024	10/4/2024	24S APRI Z6R MISO Market.xlsx
9/20/2024	10/4/2024	24S MPLI MISO Market.xlsx
9/20/2024	10/4/2024	24S MPLI Z6R MISO Market.xlsx
9/20/2024	10/4/2024	24S No 111 MISO Market.xlsx
9/20/2024	10/4/2024	24S No 111 Z6R MISO Market.xlsx
9/20/2024	10/4/2024	DEIN 23F New CC.xlsx
9/20/2024	10/4/2024	DEIN 23S CPCN Solar.xlsx
9/20/2024	10/4/2024	DEIN 23S Edwardsport CCS Boiler.xlsx
9/20/2024	10/4/2024	DEIN 23S EE Projects.xlsx
9/20/2024	10/4/2024	DEIN 23S No Market Limit.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Blend 4 Adjustments.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP CCU Gib Fix Cost Adj.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP CCU Project Limits.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Coal Retirements.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Consolidate CCs.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Force Nuc.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP High CC CT Cost.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP High Load CT PPA.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP No 111 Opt Ret FOM.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP SH 1 Relax Battery Limit.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Thermal Tranches.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Tranches.xlsx
9/20/2024	10/4/2024	DEIN 24S 2032 2x1.xlsx
9/20/2024	10/4/2024	DEIN 24S APRI Capital and FOM Costs.xlsx
9/20/2024	10/4/2024	DEIN 24S APRI Market Sale Limit.xlsx
9/20/2024	10/4/2024	DEIN 24S APRI Project Limits.xlsx
9/20/2024	10/4/2024	DEIN 24S Base.xlsx
9/20/2024	10/4/2024	DEIN 24S Blend 2 Gib Fixed Cost Adj.xlsx
9/20/2024	10/4/2024	DEIN 24S Capital.xlsx
9/20/2024	10/4/2024	DEIN 24S Cay CC Cost Inc.xlsx
9/20/2024	10/4/2024	DEIN 24S Cayuga NGC 2029.xlsx
9/20/2024	10/4/2024	DEIN 24S Cayuga NGC.xlsx
9/20/2024	10/4/2024	DEIN 24S Cayuga Retire by '32.xlsx
9/20/2024	10/4/2024	DEIN 24S CO2 Tax.xlsx
9/20/2024	10/4/2024	DEIN 24S Coal to Gas Options.xlsx
9/20/2024	10/4/2024	DEIN 24S DLOL.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport CCS 2032.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport Gas 2028.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport Gas 2030.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport Gas 2035.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap High Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap High PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap Low Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap Low PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Projects.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves 111.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves APRI.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves MPLI.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves No 111.xlsx

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9/20/2024	10/4/2024	DEIN 24S Existing Gas CF Limit.xlsx
9/20/2024	10/4/2024	DEIN 24S Extend MISO SAC.xlsx
9/20/2024	10/4/2024	DEIN 24S Force CAY 1x1s.xlsx
9/20/2024	10/4/2024	DEIN 24S Force CAY 2x1.xlsx
9/20/2024	10/4/2024	DEIN 24S Fuel Prices.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 1-2 DFO FT.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 1-2 DFO.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 1-2 NGC.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 3-4 NGC.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 3-4 Retire.xlsx
9/20/2024	10/4/2024	DEIN 24S Gibson Gas Cost.xlsx
9/20/2024	10/4/2024	DEIN 24S Gibson Retire by '32.xlsx
9/20/2024	10/4/2024	DEIN 24S Gibson Retire Stakeholder 1.xlsx
9/20/2024	10/4/2024	DEIN 24S High Fuels Prices.xlsx
9/20/2024	10/4/2024	DEIN 24S High Load.xlsx
9/20/2024	10/4/2024	DEIN 24S High PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S Hourly Profiles.xlsx
9/20/2024	10/4/2024	DEIN 24S IRA 100percent Domestic Content.xlsx
9/20/2024	10/4/2024	DEIN 24S IRA Extended.xlsx
9/20/2024	10/4/2024	DEIN 24S IRA.xlsx
9/20/2024	10/4/2024	DEIN 24S IRP LDES Set Up.xlsx
9/20/2024	10/4/2024	DEIN 24S IRP No Renewable Tranches.xlsx
9/20/2024	10/4/2024	DEIN 24S IRP Project Limits.xlsx
9/20/2024	10/4/2024	DEIN 24S Limit 1x1 CC.xlsx
9/20/2024	10/4/2024	DEIN 24S Load.xlsx
9/20/2024	10/4/2024	DEIN 24S Low Fuels Price.xlsx
9/20/2024	10/4/2024	DEIN 24S Low Load.xlsx
9/20/2024	10/4/2024	DEIN 24S Low PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S Market Limit - 25 percent.xlsx
9/20/2024	10/4/2024	DEIN 24S New Gas CF Limit.xlsx
9/20/2024	10/4/2024	DEIN 24S New Gas Update.xlsx
9/20/2024	10/4/2024	DEIN 24S No 111 Gas Limits.xlsx
9/20/2024	10/4/2024	DEIN 24S No IRA.xlsx
9/20/2024	10/4/2024	DEIN 24S No Nuc.xlsx
9/20/2024	10/4/2024	DEIN 24S Nuclear ITC.xlsx
9/20/2024	10/4/2024	DEIN 24S Outage Schedule.xlsx
9/20/2024	10/4/2024	DEIN 24S Split Cay Retire.xlsx
9/20/2024	10/4/2024	DEIN 24S Transmission Adder.xlsx
9/20/2024	10/4/2024	DEIN Remove FOM - PC.xlsx
9/20/2024	10/4/2024	Duke Midwest Base.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 1 High CC CT Cost PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 1 High Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 1 Low Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 1 PC High Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 1 PC Low Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 - CAY 1x1s PC High Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 - CAY 1x1s PC Low Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 - CAY 1x1s PC No 111 Sens.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 - CAY 1x1s PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 - CAY 2x1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s EDW 2028 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s EDW CCS PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s Force Nuc PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s Gib NGC PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s High CC CT Cost PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s High Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s Low Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 4 High CC CT Cost PC.xlsx

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9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 4 PC High Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 4 PC Low Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 Blend 4 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU Extend SAC PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU High CC CT Cost PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU High Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU Low Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU PC High Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU PC Low Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 CCU PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU Extend SAC PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU High CC CT Cost PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU High Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU Low Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU PC High Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU PC Low Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 RCU PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 SH 1 High CC CT Cost PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 SH 1 High Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 SH 1 Low Load PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 SH 1 PC High Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 SH 1 PC Low Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP 111 SH 1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP APRI Blend 1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP APRI Blend 2 - CAY 1x1s PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP APRI Blend 4 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP APRI CCU PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP APRI RCU PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP APRI SH 1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP MPLI Blend 1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP MPLI Blend 2 - CAY 1x1s PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP MPLI Blend 4 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP MPLI CCU PC.xlsx
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9/20/2024	10/4/2024	DEIN 24 IRP MPLI SH 1 PC.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/27/2024	10/11/2024	HistSimDates_WxYrs_I1075_H80-22_S24-45.xlsx
9/27/2024	10/11/2024	LoadSim_DEI.csv
9/27/2024	10/11/2024	LoadSim_MISO.csv
9/27/2024	10/11/2024	Readme.txt
9/27/2024	10/11/2024	SimHenryHubGas.csv
9/27/2024	10/11/2024	SimHenryHubGas_Daily.csv
9/27/2024	10/11/2024	SimHenryHubGas_Monthly.csv
9/27/2024	10/11/2024	SimPowerPrice.csv
9/27/2024	10/11/2024	LoadSim_MISO.xlsx
9/27/2024	10/11/2024	SimPowerPrice.xlsx
9/30/2024	10/15/2024	Confidential - 111 Generation Strategies and No 111 - Ongoing CAPEX & FOM.xlsx
10/4/2024	10/21/2024	BillImpactTemplate_Blend1_091824_CONFIDENTIAL1.xlsx
10/4/2024	10/21/2024	BillImpactTemplate_Blend2_091824_CONFIDENTIAL1.xlsx
10/4/2024	10/21/2024	BillImpactTemplate_Blend4_091824_CONFIDENTIAL1.xlsx
10/4/2024	10/21/2024	BillImpactTemplate_Convert_CCU_091824_CONFIDENTIAL1.xlsx
10/4/2024	10/21/2024	BillImpactTemplate_ExitEarlySH_091824_CONFIDENTIAL1.xlsx
10/4/2024	10/21/2024	BillImpactTemplate_Retire_RCU_091824_CONFIDENTIAL1.xlsx
10/22/2024	11/1/2024	Confidential - Blend 2 What If Scenarios - Ongoing CAPEX & FOM

Attachment C-1

EnCompass Modeling Inputs & Outputs

Confidential - Provided Electronically

INDIANA

2024 | **INTEGRATED**
DUKE ENERGY | **RESOURCE PLAN**

DUKE ENERGY.

BUILDING A SMARTER ENERGY FUTURE ®

Attachment C-2

Ongoing Capital & FOM Costs

Confidential - Provided Electronically

INDIANA

2024 DUKE ENERGY | INTEGRATED RESOURCE PLAN

DUKE ENERGY

BUILDING A SMARTER ENERGY FUTURE ®

Attachment C-3

Projected Bill Impact Calculations

Confidential - Provided Electronically

INDIANA

2024 DUKE ENERGY | INTEGRATED RESOURCE PLAN

DUKE ENERGY

*BUILDING A **SMARTER** ENERGY FUTURE ®*

Attachment D-1

Additional
Load Shapes

INDIANA

2024 | INTEGRATED
DUKE ENERGY | RESOURCE PLAN

DUKE ENERGY®

BUILDING A **SMARTER** ENERGY FUTURE ®

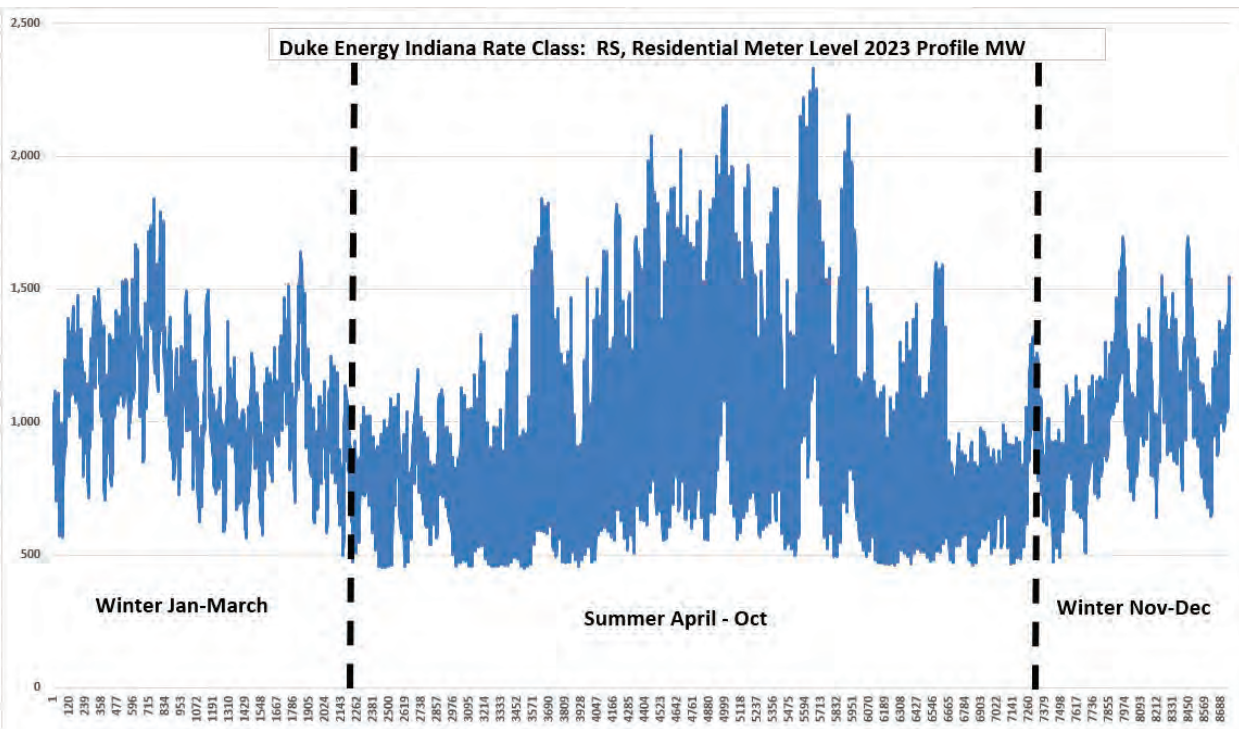
Cause No. 46193

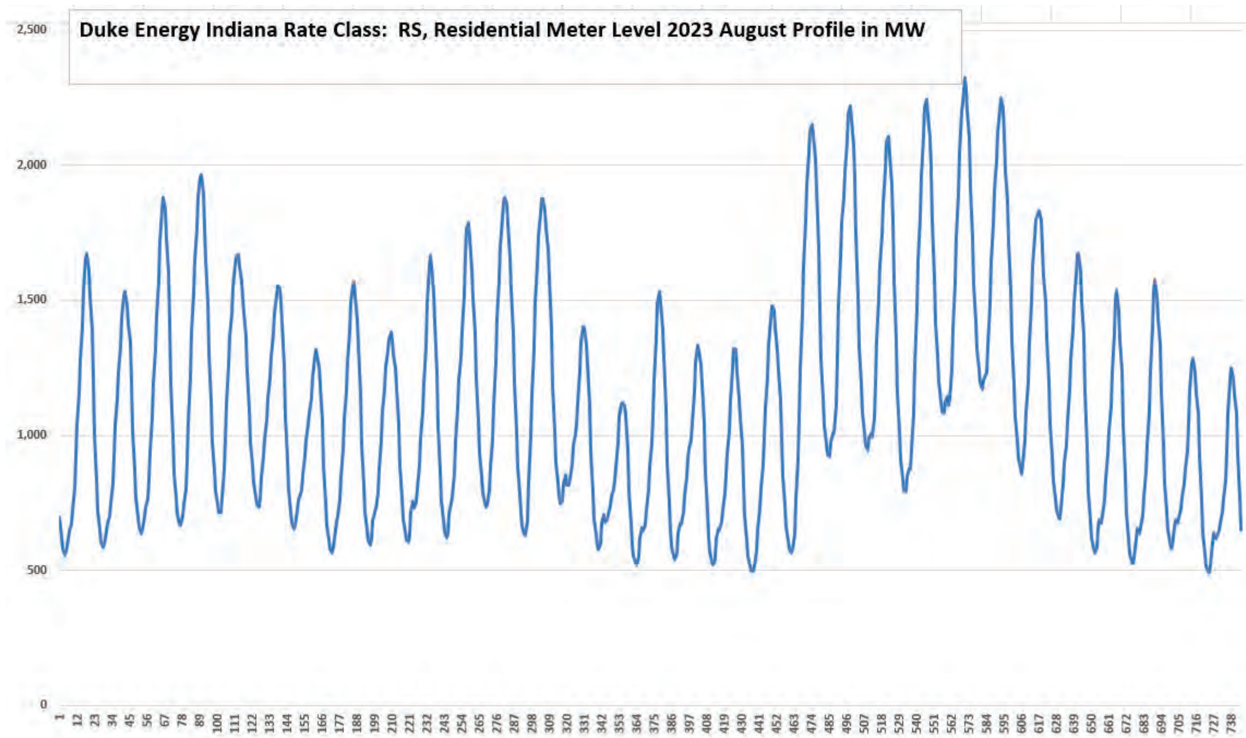
D-1

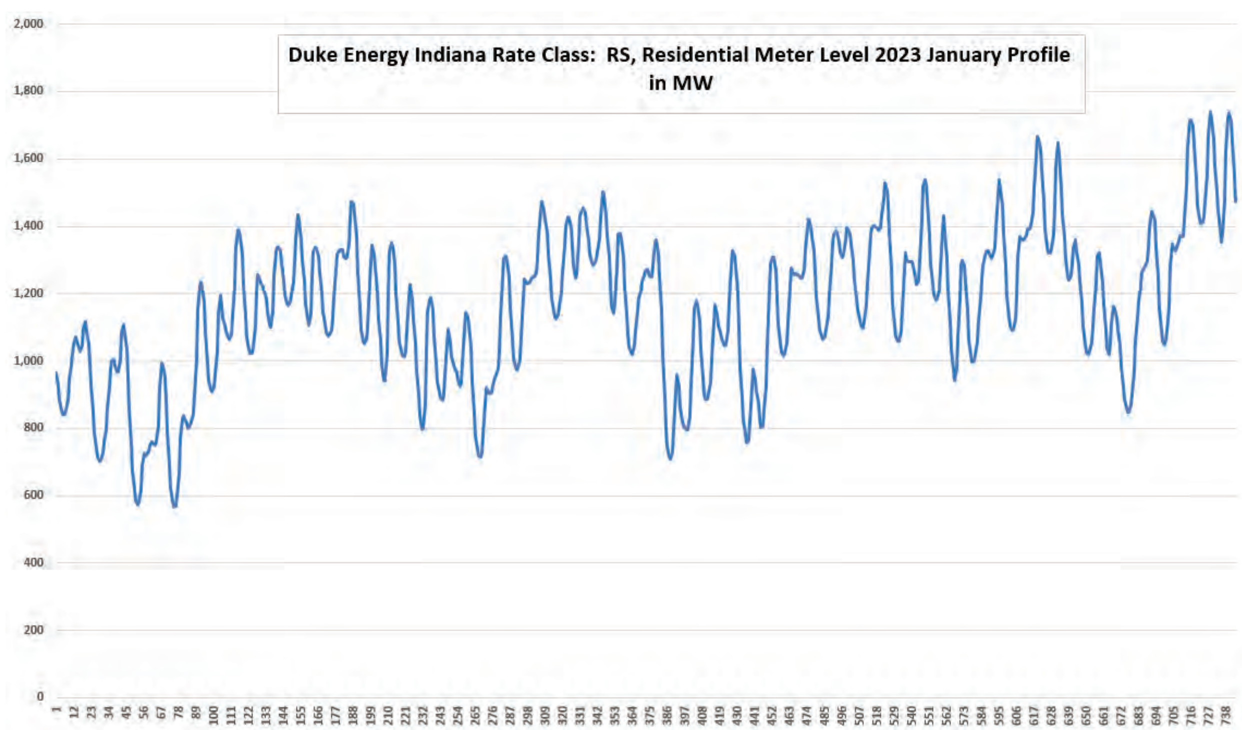
Load Shapes

Historical Metered Hourly Load Shapes by Rate Class & Load Factor

The following charts are metered hourly load shapes by rate class for 2023 using actual weather. Metered hourly load shapes from history support the hourly load shape model, Itron LT, which supports the Duke Energy Indiana hourly load forecast. Weather adjustments are applied to the hourly load shape and the historic monthly sales history for reference and for calibration of the model to generate the forecast under normal weather conditions for the 2024 IRP. Actual weather load shapes are provided to reflect history without model imputation.




Duke Energy Indiana Rate Class: RS, Residential Meter Level 2023 August Profile in MW
2,500
2,000
1,500
1,000
500
0


Duke Energy Indiana Rate Class: RS, Residential Meter Level 2023 January Profile in MW
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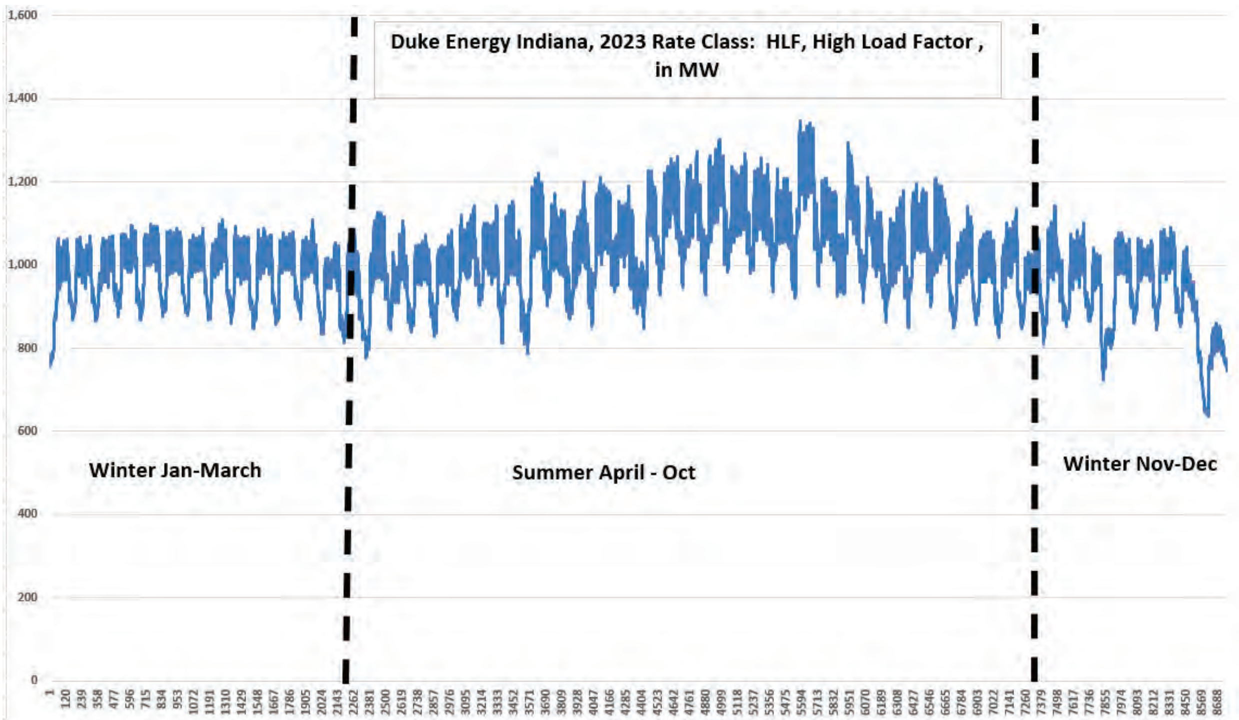
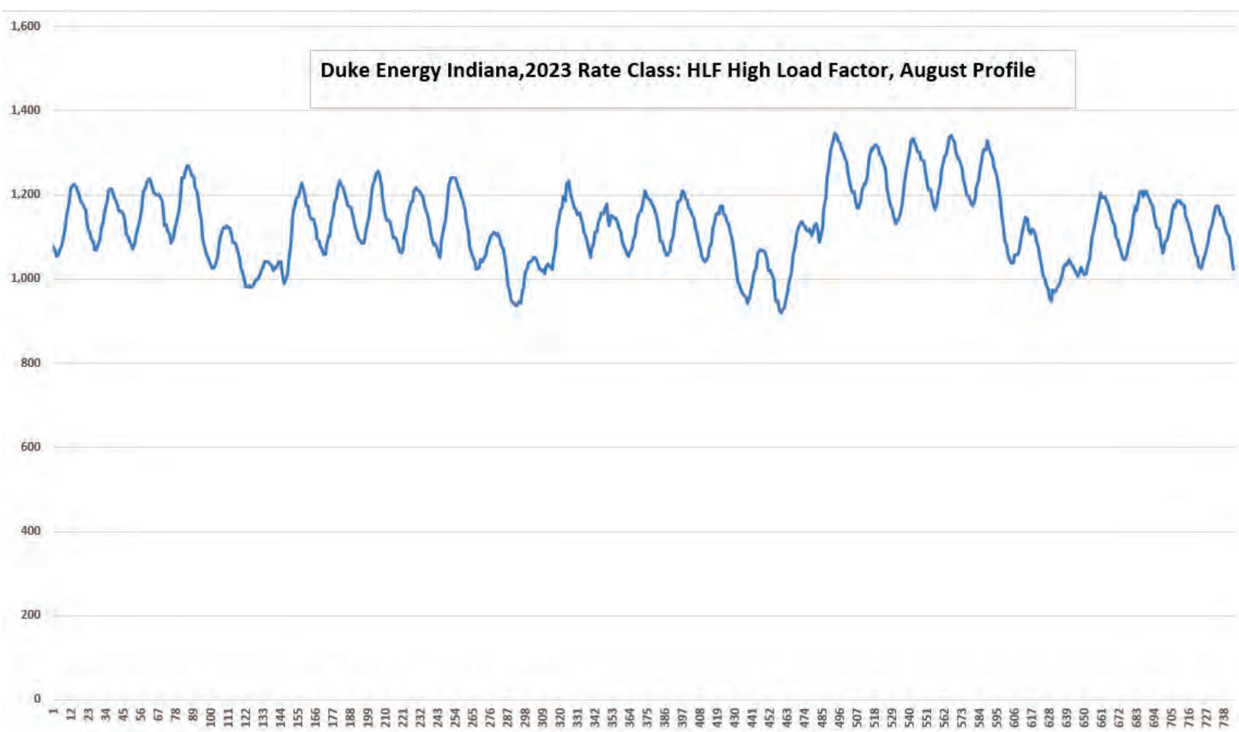
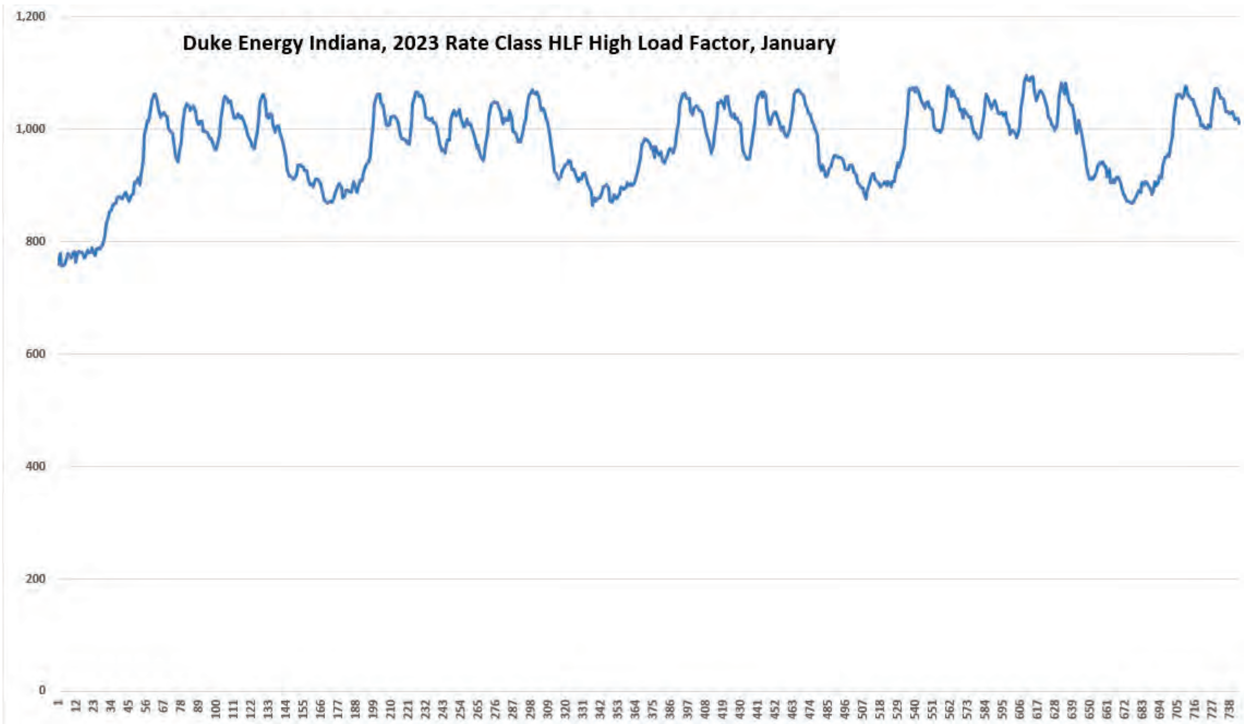
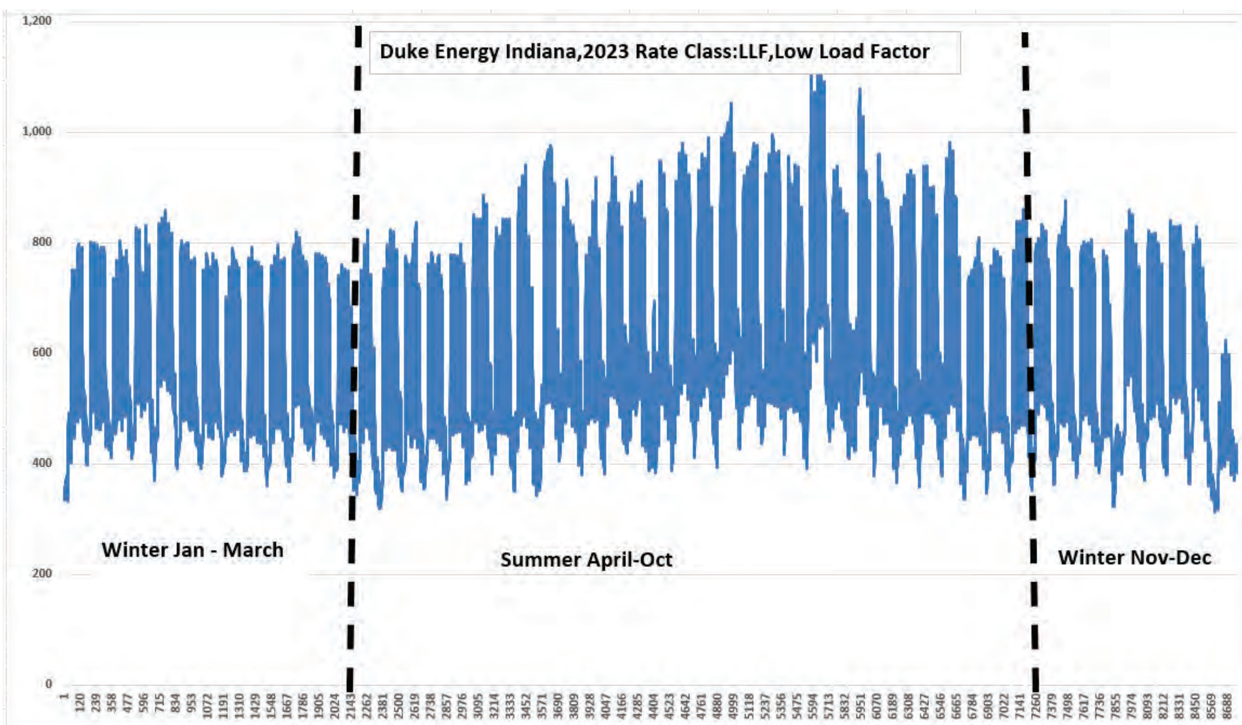
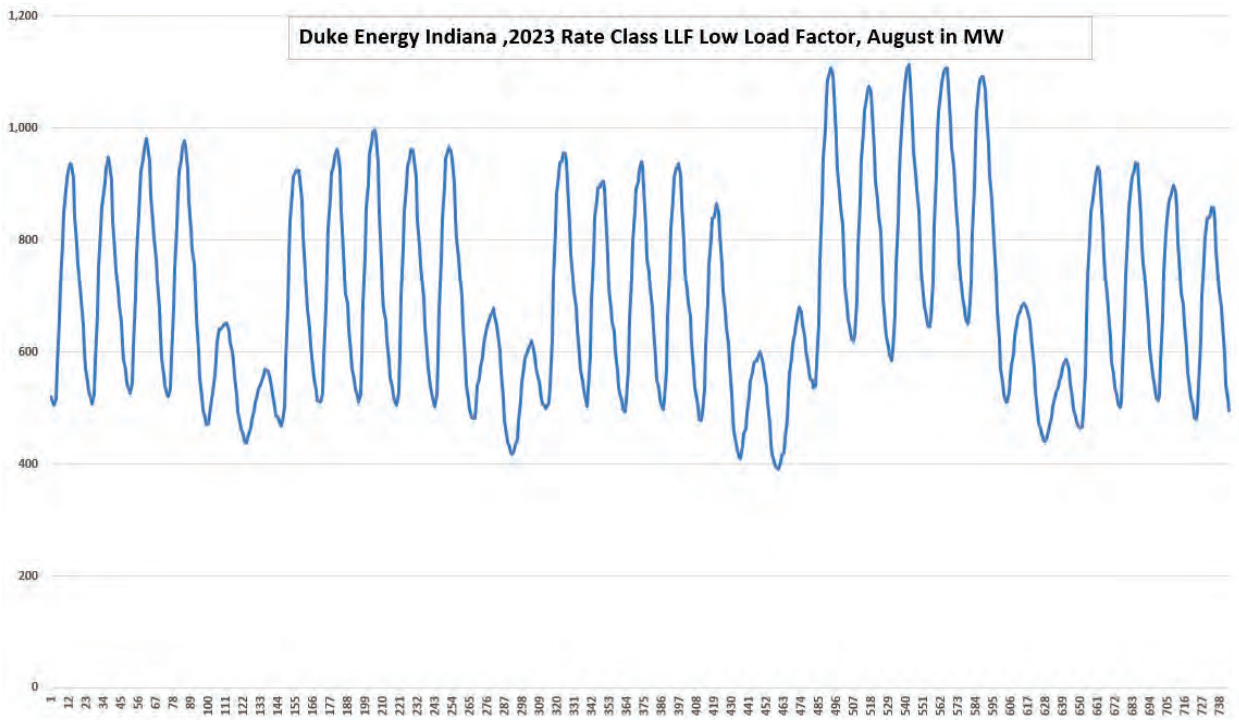
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0

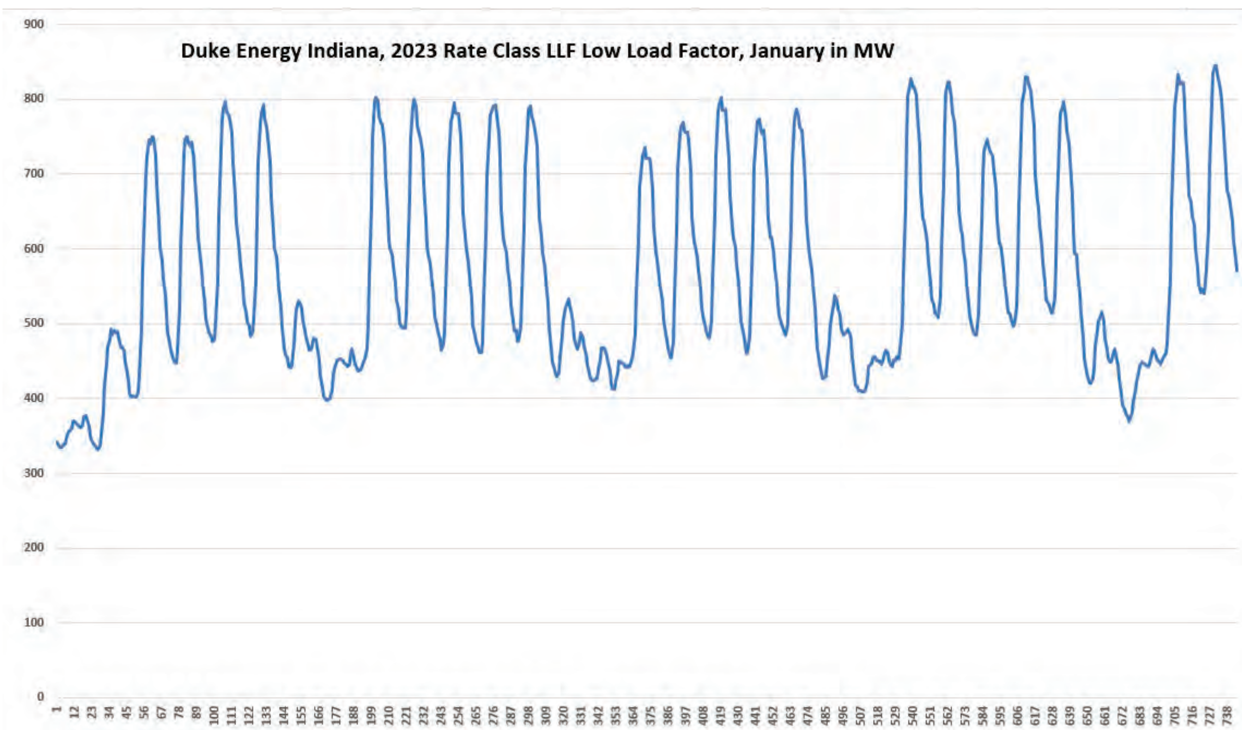

Duke Energy Indiana, 2023 Rate Class: HLF, High Load Factor , in MW
Winter Jan-March
Summer April - Oct
Winter Nov-Dec


Duke Energy Indiana,2023 Rate Class: HLF High Load Factor, August Profile

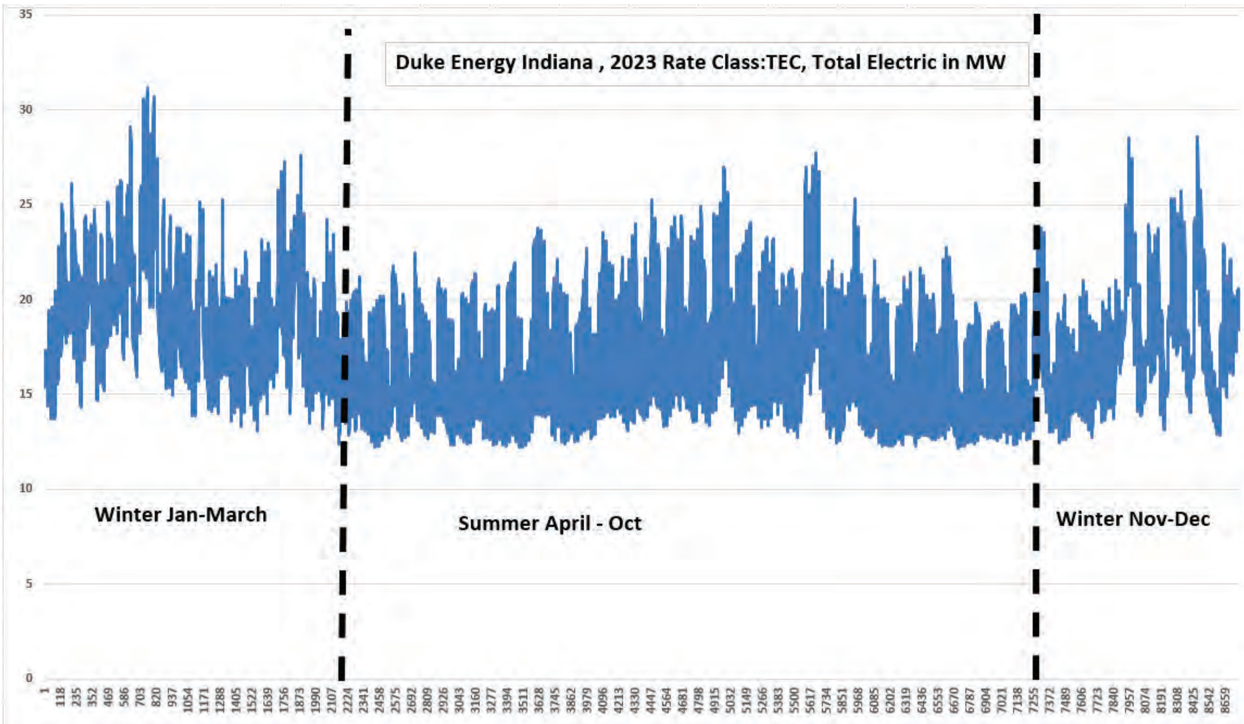

Duke Energy Indiana, 2023 Rate Class HLF High Load Factor, January

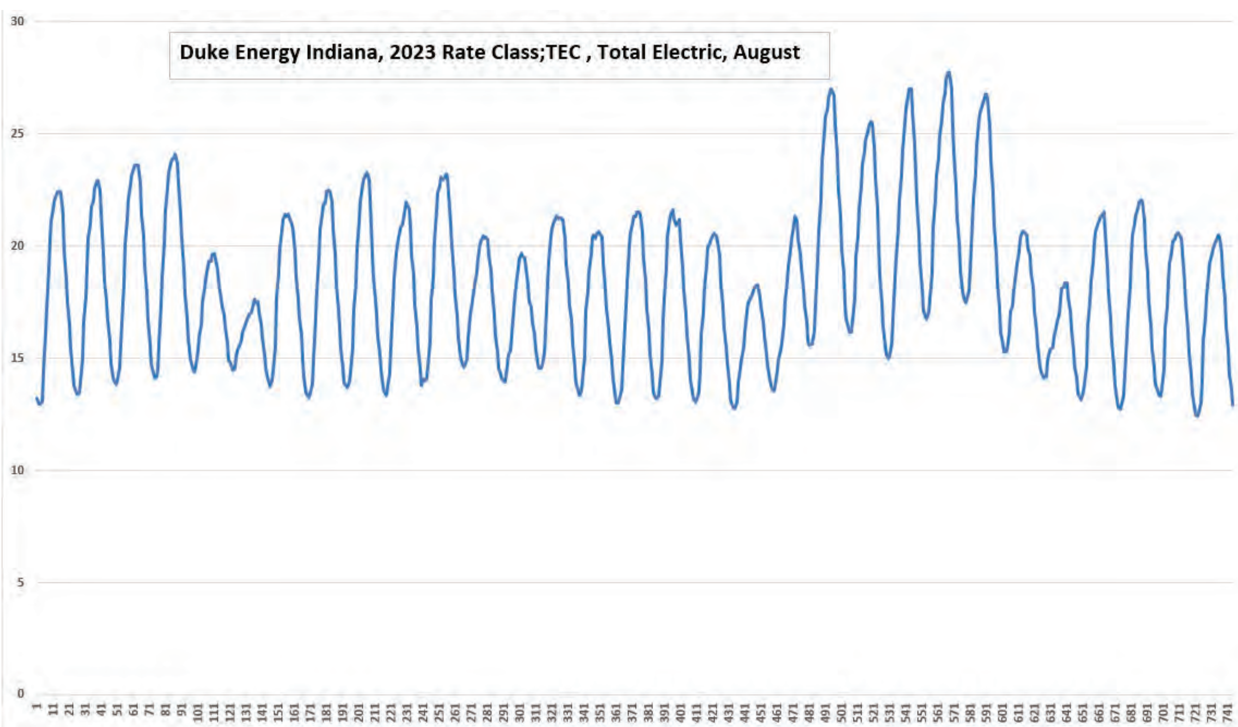

Duke Energy Indiana,2023 Rate Class:LLF,Low Load Factor
Winter Jan - March
Summer April-Oct
Winter Nov-Dec

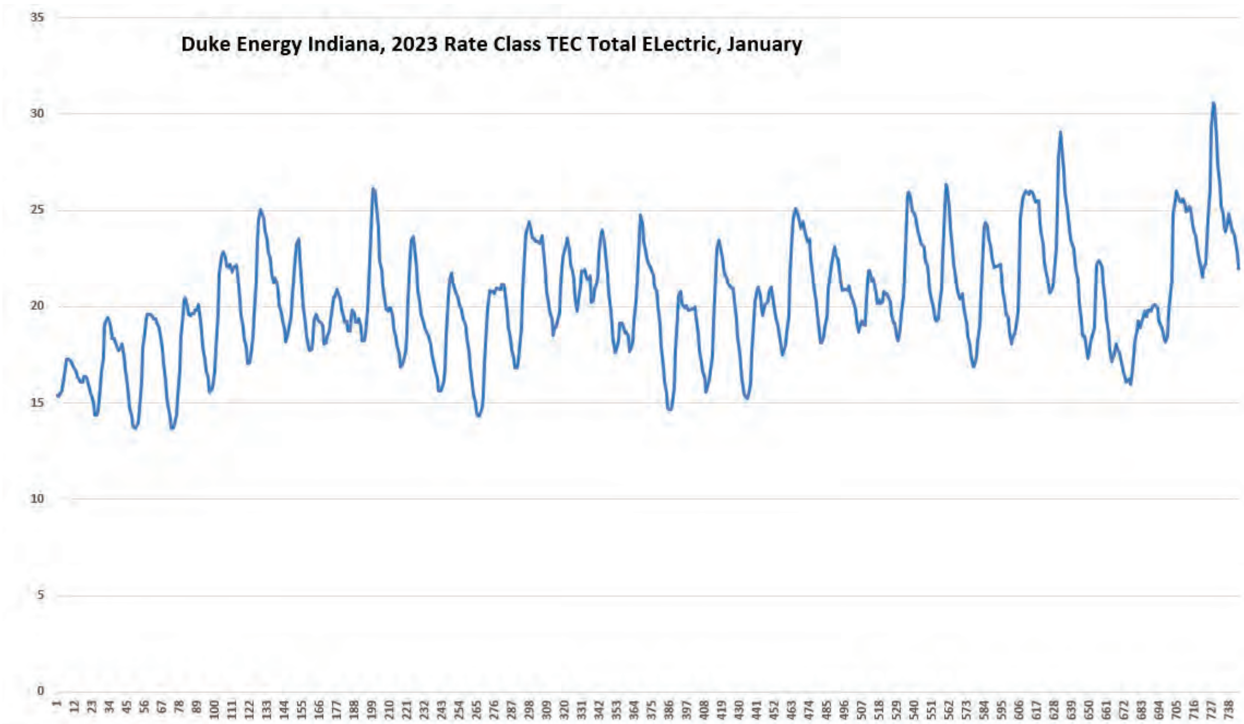

Duke Energy Indiana ,2023 Rate Class LLF Low Load Factor, August in MW
1,200
1,000
800
600
400
200
0

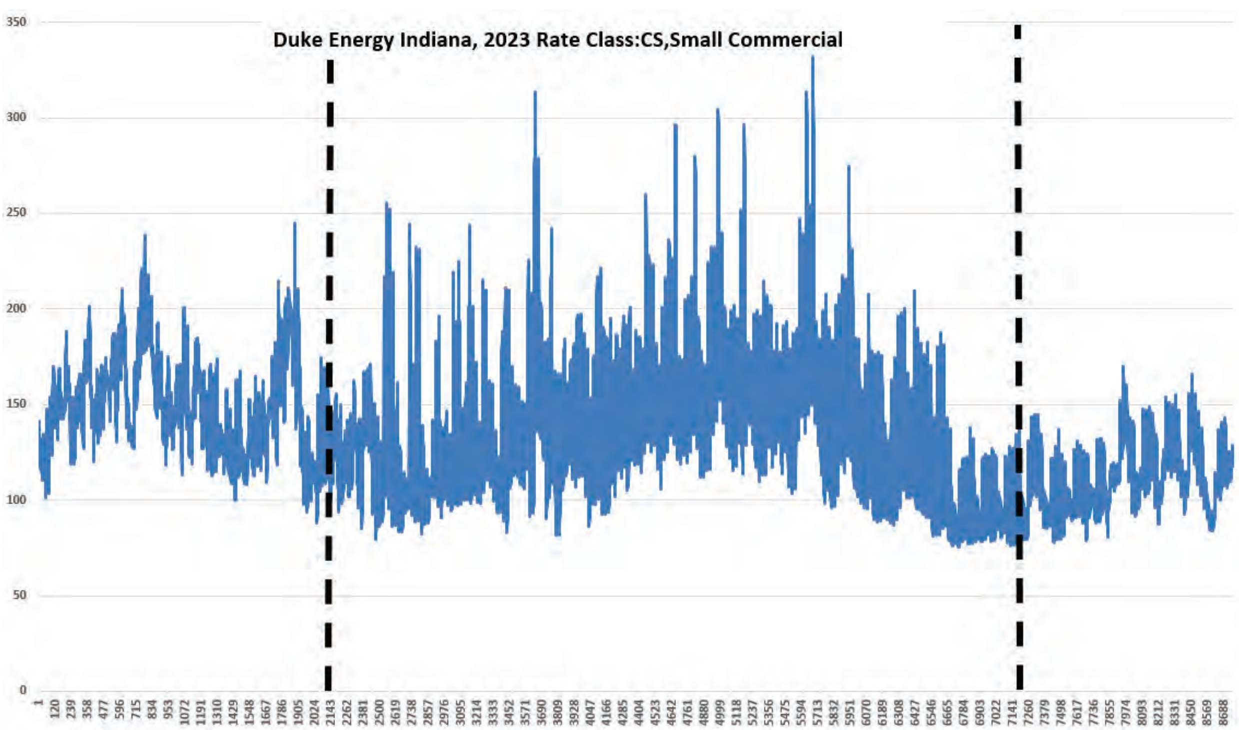

Duke Energy Indiana, 2023 Rate Class LLF Low Load Factor, January in MW
900
800
700
600
500
400
300
200
100
0

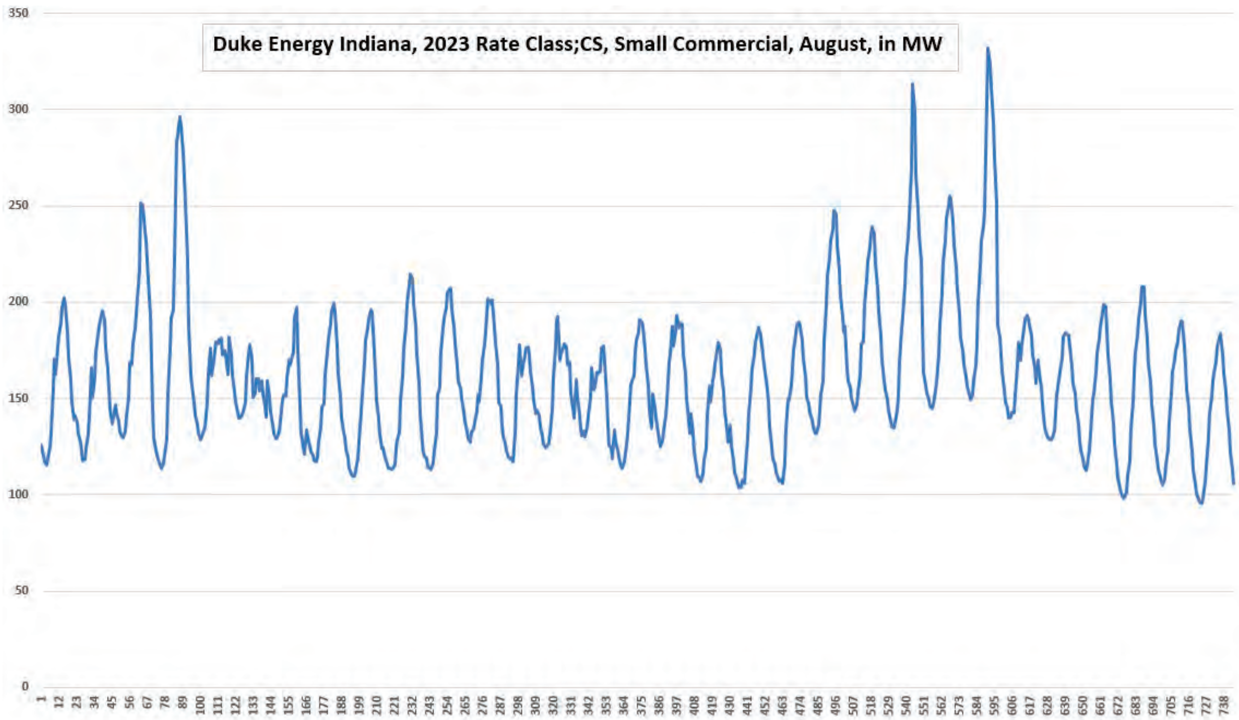
Total Electric Class ("TEC")

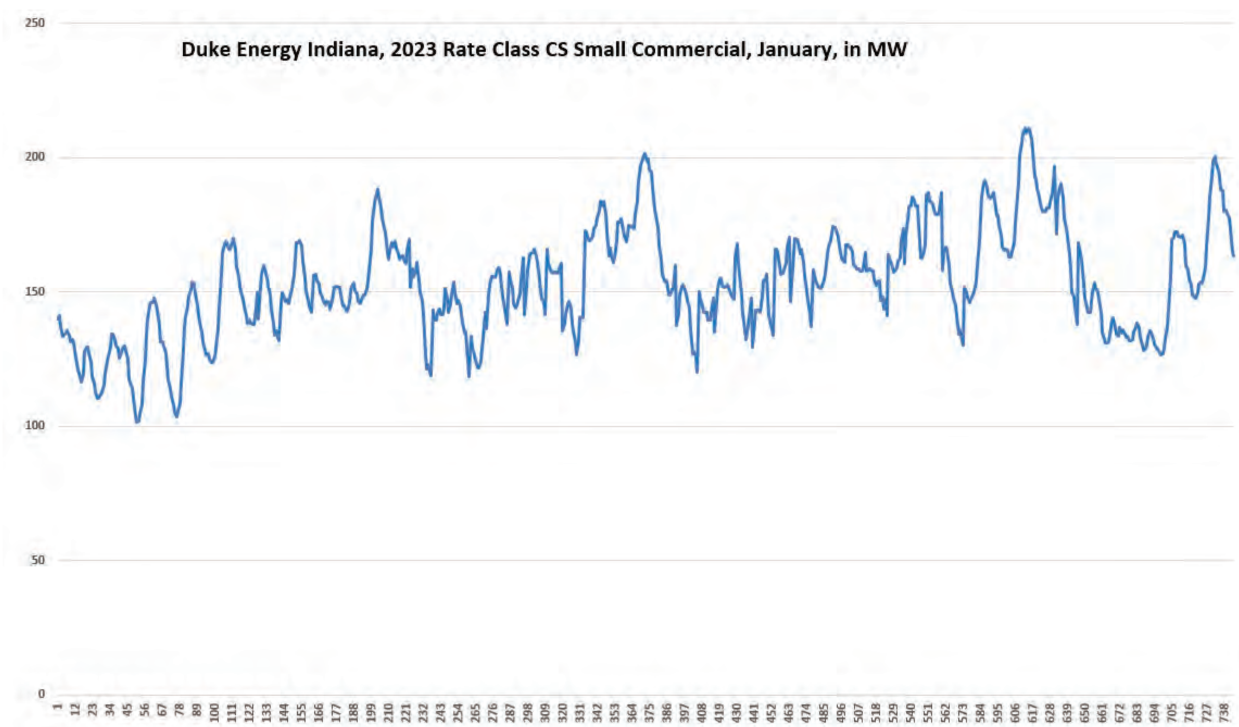





Duke Energy Indiana, 2023 Rate Class TEC Total ELectric, January


Duke Energy Indiana, 2023 Rate Class:CS,Small Commercial


Duke Energy Indiana, 2023 Rate Class;CS, Small Commercial, August, in MW


Duke Energy Indiana, 2023 Rate Class CS Small Commercial, January, in MW

Attachment D-2

Load Forecast Files

Confidential - Provided Electronically

INDIANA

2024 DUKE ENERGY | INTEGRATED RESOURCE PLAN

DUKE ENERGY

BUILDING A SMARTER ENERGY FUTURE ®

Attachment H-1

Market Potential Study

INDIANA

2024 DUKE ENERGY | INTEGRATED RESOURCE PLAN

DUKE ENERGY

BUILDING A SMARTER ENERGY FUTURE ®

Cause No. 46193

resource innovations

Duke Energy Indiana Energy Efficiency and Demand Response Market Potential Report

Date: August 2024

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1. Executive Summary

In fall of 2023, Duke Energy retained Resource Innovations, formerly Nexant Inc., to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand response (DR) programs in the Duke Energy Indiana (DEI) service territory. This report describes the potential for EE and DR savings in the service territory in Indiana. The main objectives of the study include:

- Estimating EE and DR potential over the short term (five years), medium term (ten years), and long term (twenty-five years) planning horizons
- Exploring the sensitivity of savings estimates to changes in incentive rates and avoided energy costs
- Developing customer participation estimates that are independent of historical Duke Energy program trends
- Assessing the potential impact of the 2022 Inflation Reduction Act on EE/DR savings potential
- Engaging the Indiana OSB members and offering opportunities for feedback and contribution to the market potential study (MPS)
- Providing data to Duke Energy for integrated resource planning

Technical potential indicates the theoretical upper limit on savings from EE. We estimate cumulative technical potential as a share of projected 2025 electricity sales to be 22% in DEI (regardless of customer EE/DR opt-out status). Technical potential ignores measure costs to focus on energy savings wherever technically feasible. Cumulative economic potential is 20% of all sales, regardless of EE/DR program eligibility. This estimate is based on using the utility cost test (UCT) to determine if a measure is cost-effective. The test compares the costs and benefits of offering a measure to customers through a utility-sponsored EE or DR program.

The UCT costs are for utility incentives and program administration, and UCT benefits stem from avoiding the energy, capacity, transmission, and distribution (T&D) costs of the electricity saved by the program measure. Economic potential with a UCT screening criterion does not examine customer benefits and costs; rather, it simply assumes all customers adopt a measure that is cost-effective under the UCT screening directive. As constructed, this economic potential estimate using a UCT screening indicates how utility program costs and benefits affect measures' potential savings if all customers are assumed to adopt measures that are cost-effective for the utility to offer.

For customers eligible to participate in EE/DR programs, achievable market potential (AMP) represents expected customer adoption for each AMP scenario. Using the set of cost-effective measures from the UCT Economic Potential, Resource Innovations applied customer payback acceptance curves to calculate a measure's long-run market share relative to competing EE measures, including baseline technologies (e.g., current codes and standards). With the data available for this MPS, payback acceptance is the most feasible approach for estimating customers' willingness to invest in EE/DR equipment and retrofit measures. As the payback acceptance approach considers only simple payback and the presence of utility incentives from the economic potential scenario, the achievable potential scenario implicitly assumes programs continually identify and successfully reduce barriers to customer participation. Duke Energy has a demonstrated history of applying best practices and concepts from the EE and DR program lifecycle to accomplish this end by continually engaging in the cycle of program planning, implementation, evaluation, and adaptation.

We present results for three primary scenarios:

- **Base** – reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program; includes estimated impacts from the 2022 Inflation Reduction Act (IRA)
- **High Incentive** – doubles current incentive rates with a cap at 75% of the measure incremental cost; applies utility avoided cost benefits from the base scenario.
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates

1.1.1. Energy Efficiency Potential

The estimated technical and economic potential scenarios for DEI are summarized in Table 1-1, which lists cumulative energy and demand savings for each type of potential[1]. Savings percentages are presented as a share of end year sales over 25 years. Technical and economic potential includes savings estimates for all DEI customers, regardless of program eligibility. Technical and economic potential also do not include impacts from the IRA since the IRA funding is irrelevant to technical potential and economic potential is based on the utility cost test.

Table 1-1: DEI Cumulative Energy Efficiency Technical and Economic Potential (2025 – 2049)

Scenario	Energy (GWh)	% of 2025 Sales	Demand (MW)			
			Spring	Summer	Fall	Winter
Technical Potential	5,878	22%	1,456	1,478	1,350	876
Economic Potential	5,255	20%	1,345	1,367	1,247	752

Table 1-2 and Table 1-3 summarize the short-term (5-year), medium term (10-year) and long-term (25-year) DEI portfolio EE achievable market potential for the base, high incentive, and high avoided cost scenarios. AMP estimates adjust the customer base to remove customers that have opted-out of EE

[1] "Cumulative" potential includes savings "roll off" for non-equipment measures or EE retrofits. Retrofit opportunities can typically only be addressed once before the associated equipment is replaced or energy savings from the retrofit decays. Cumulative potential represents impacts to the baseline utility forecast and should not be equated with the concept of "total energy saved." The sum of annual incremental EE savings represents total energy saved.

and DR and include estimate impacts from the IRA funding; these impacts are presented over each stated time horizon (5 years, 10 years, or 25 years).

Table 1-2: DEI Energy Efficiency Achievable Market Potential - Energy Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	244,600	214,301	200,437
High Incentive	Annual Incremental Energy (MWh)	277,521	251,706	231,005
High Avoided Cost	Annual Incremental Energy (MWh)	254,363	216,096	200,812
Base	Cumulative Energy (MWh)	820,509	1,577,248	1,703,116
High Incentive	Cumulative Energy (MWh)	963,366	1,874,902	2,188,708
High Avoided Cost	Cumulative Energy (MWh)	858,177	1,653,518	1,742,073

Table 1-3: DEI Energy Efficiency Achievable Market Potential - Demand Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	48	42	42
High Incentive	Annual Incremental Spring Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	49	42	42
Base	Annual Incremental Summer Peak Demand (MW)	47	41	42
High Incentive	Annual Incremental Summer Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	49	42	42
Base	Annual Incremental Fall Peak Demand (MW)	44	38	38
High Incentive	Annual Incremental Fall Peak Demand (MW)	53	46	45
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	45	39	39
Base	Annual Incremental Winter Peak Demand (MW)	55	44	39
High Incentive	Annual Incremental Winter Peak Demand (MW)	58	51	43
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	57	44	39
Base	Cumulative Spring Peak Demand (MW)	156	307	347
High Incentive	Cumulative Spring Peak Demand (MW)	201	401	476
High Avoided Cost	Cumulative Spring Peak Demand (MW)	162	319	353
Base	Cumulative Summer Peak Demand (MW)	155	304	344
High Incentive	Cumulative Summer Peak Demand (MW)	201	402	475
High Avoided Cost	Cumulative Summer Peak Demand (MW)	159	314	349
Base	Cumulative Fall Peak Demand (MW)	144	283	322
High Incentive	Cumulative Fall Peak Demand (MW)	185	369	440
High Avoided Cost	Cumulative Fall Peak Demand (MW)	149	293	327
Base	Cumulative Winter Peak Demand (MW)	176	335	326
High Incentive	Cumulative Winter Peak Demand (MW)	190	367	401
High Avoided Cost	Cumulative Winter Peak Demand (MW)	183	350	335

1.1.2. Demand Response Potential

DR opportunities were analyzed for Indiana service territories to determine the amount of seasonal peak capacity that could be reduced through DR initiatives from a technical, economic, and achievable potential perspective. While technical and economic potential are theoretical upper limits, participation rates applied to achievable potential are calculated as a function of the incentives offered to each customer group for utility-enabled DR. For a given incentive level and participation rate, the cost-effectiveness of each DR measure is evaluated to determine whether the aggregate DR potential from that measure should be included in the achievable potential.

Base and Enhanced scenarios were constructed for the DR potential analysis. Base and Enhanced scenarios assume different levels of customer incentive and marketing efforts/costs. The Base Scenario aligns with current Duke Energy offerings for measures covered by existing programs, and assumes conservative incentive and marketing for new measures, while the Enhanced Scenario assumes more aggressive expansion. Figure 1-1 and Figure 1-2 summarizes the achievable seasonal peak DR potential estimated for DEI for the base and enhanced scenarios respectively. These results represent incremental DR potential beyond current Duke Energy program enrollments.

Figure 1-1 DEI DR Peak Capacity Achievable Potential – Base Case

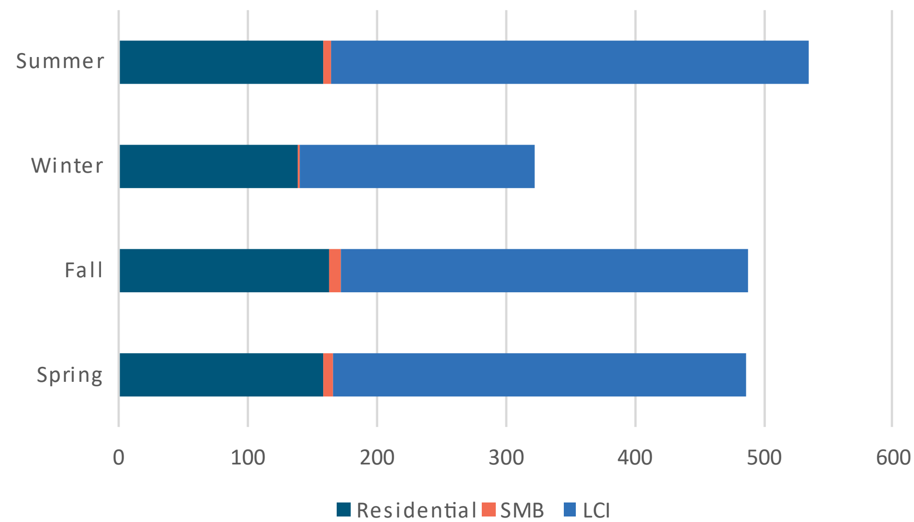
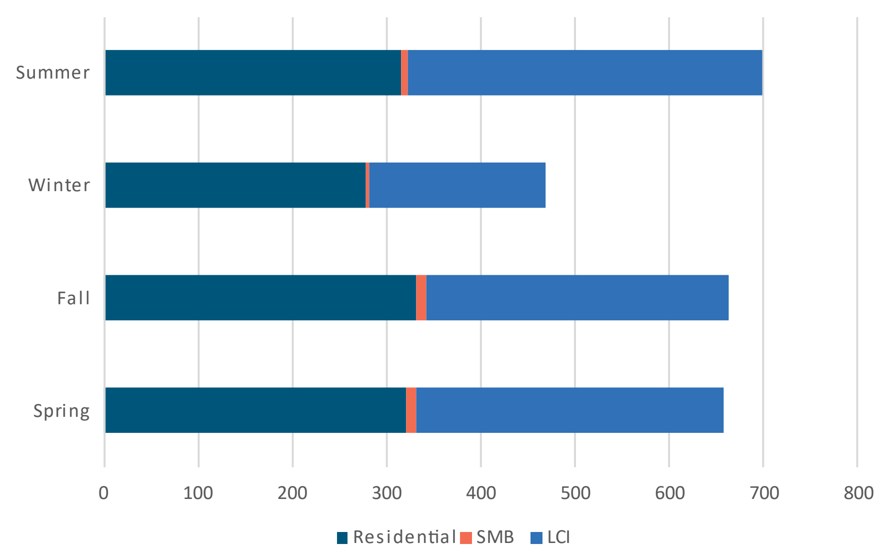


Figure 1-2: DEI DR Peak Capacity Achievable Potential – Enhanced Case

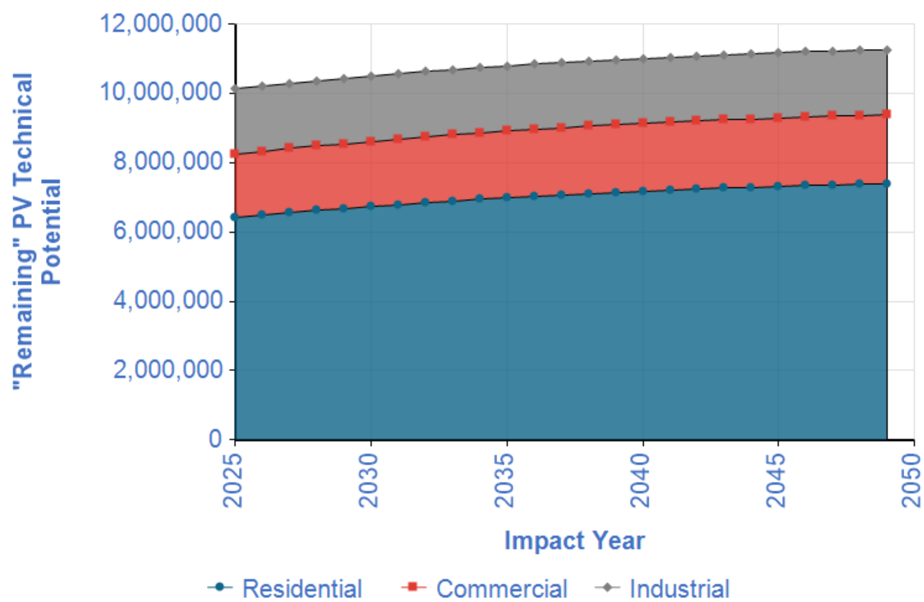


1.1.3. Distributed Energy Resources Potential

The Distributed Energy Resources (DERs) technologies included in this study are rooftop solar photovoltaic (PV) systems, and battery storage systems charged from customers' PV systems. The study leveraged the customer segmentation and load disaggregation data assembled for the EE and DR analyses, and applied our DER model, SPIDER™ (Spatial Penetration and Integration of Distributed Energy Resources), to analyze system economics and adoption trends for solar and battery storage. This model dynamically responds to rapidly changing technologies and accounts for all key time-varying elements such as technology costs, incentives, tax credits, and electric rates.

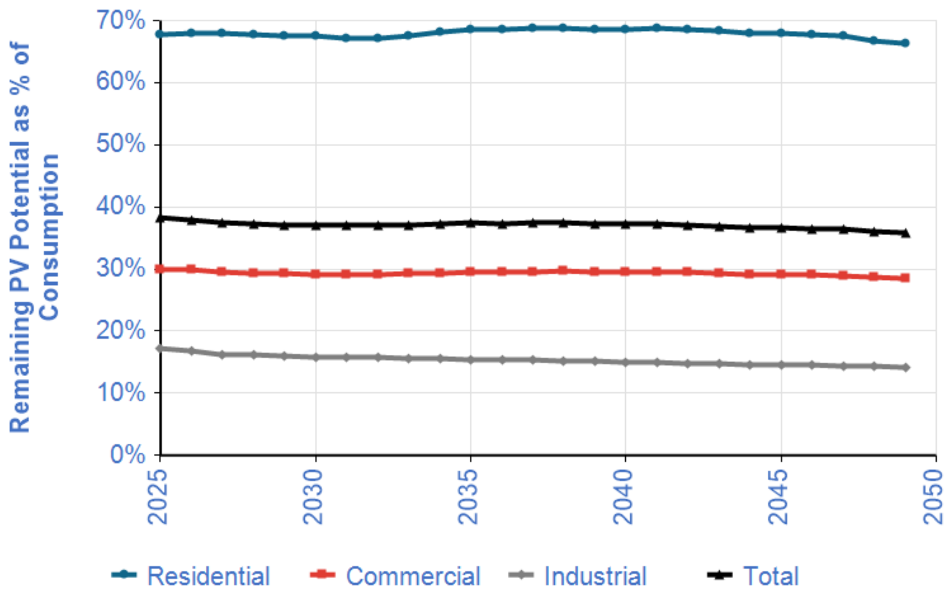
DER technical potential estimates quantify all technically feasible distributed generation opportunities from PV systems and battery storage systems charged from PV. The estimated PV technical potential results are summarized in Figure 1-3.

Figure 1-3: PV Technical Potential Remaining (MWh)



Remaining PV can also be expressed as a share of the DEI baseline energy sale forecast, as below in Figure 1-4.

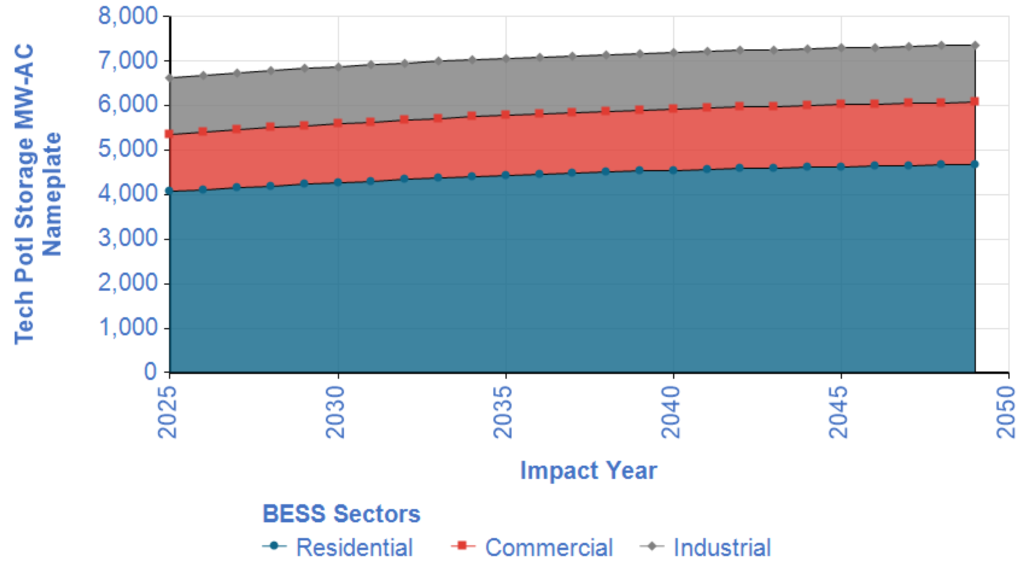
Figure 1-4: Remaining PV as a Share of the DEI Sales Forecast



RI analyzed two technical potential results for storage: one based on the nameplate rating of the storage system, and the other based on the expected grid impact of customer-sited storage dispatch under existing rates structures.

Nameplate technical potential assumes all PV calculated technical potential is paired with storage, and storage systems are sized according to maximum solar PV output. Under this assumption, nameplate MW-AC of paired storage technical potential is equivalent to nameplate MW-AC of solar PV assuming storage system sized equal to max PV capacity, and the result is presented in Figure 1-5.

Figure 1-5: Nameplate Technical Potential in MW-AC of PV and Paired Storage



The technical potential of expected grid impacts is much different than physical nameplate capacity under the current DEI rate structures. The technical potential of the expected grid impact describes the system impact when an impaired storage system is dispatched optimally to maximize customer benefit, using the current (most cost-effective) electric rate for that installed system. Expected paired storage grid impact is examined in all four seasons (due to transition to MISO seasonal resources accreditation) and is mostly negative (e.g. an expected increase in load during the system peak hour), for several reasons:

- Small energy rate spread between peak and off peak.
- Solar generation peaks are coincident with system peaks, leading to customer battery charging during peak periods.
- Non-residential customers are expected to dispatch to reduce their own facility/account peaks as opposed to system peaks.

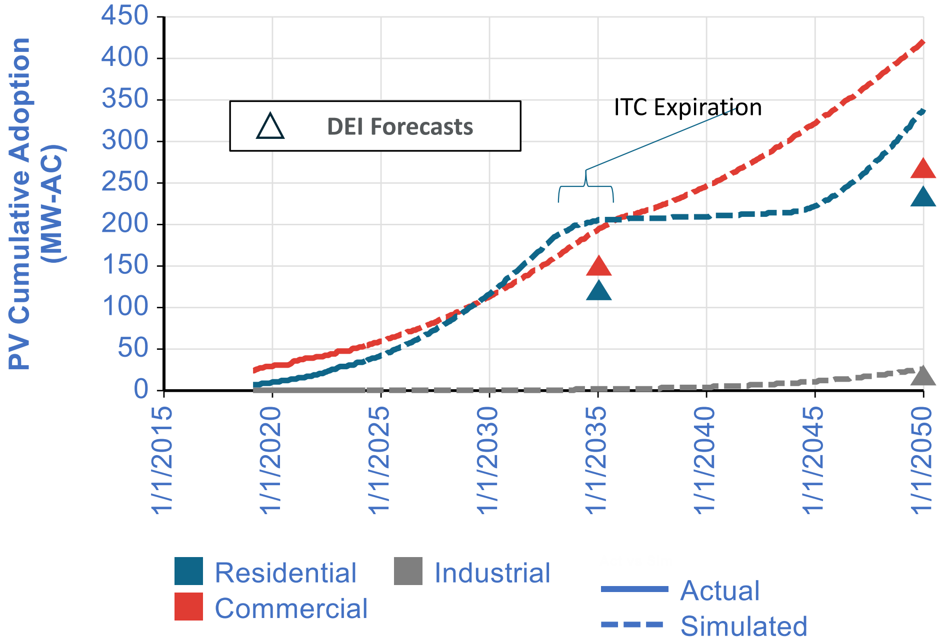
Different rate structures, or a DR program, would change the expected grid impacts. The expected seasonal grid impacts for PV and paired storage technical potential are presented in Figure 1-6.

Figure 1-6: Expected Grid Impacts of PV and Paired Storage

Year	Residential				Commercial				Industrial			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2025	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.68	1.11	-23.85
2026	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.74	1.11	-23.93
2027	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.77	1.11	-23.98
2028	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.78	1.11	-23.99
2029	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.79	1.11	-24.01
2030	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2031	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2032	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2033	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2034	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2035	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2036	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2037	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2038	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2039	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2040	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2041	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2042	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2043	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2044	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2045	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2046	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2047	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2048	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2049	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02

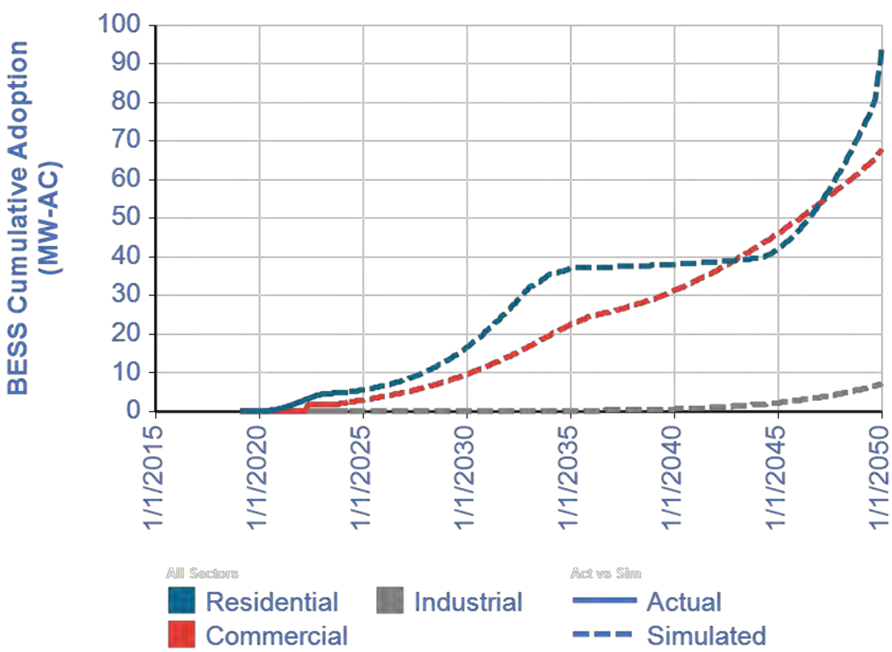
Technical potential indicates the theoretical upper limit on DER opportunities, as it ignores measure costs to focus on opportunities wherever technically feasible. Economic and achievable potential use the utility cost test (UCT) that compares the costs and benefits of offering the DER systems to customers through a utility-sponsored program. We model technology diffusion over time, with time-varying factors such as expect system costs and complex market dynamics; the resulting solar PV forecast is presented below in Figure 1-7.

Figure 1-7: Baseline Solar PV Adoption Forecast, MW-AC



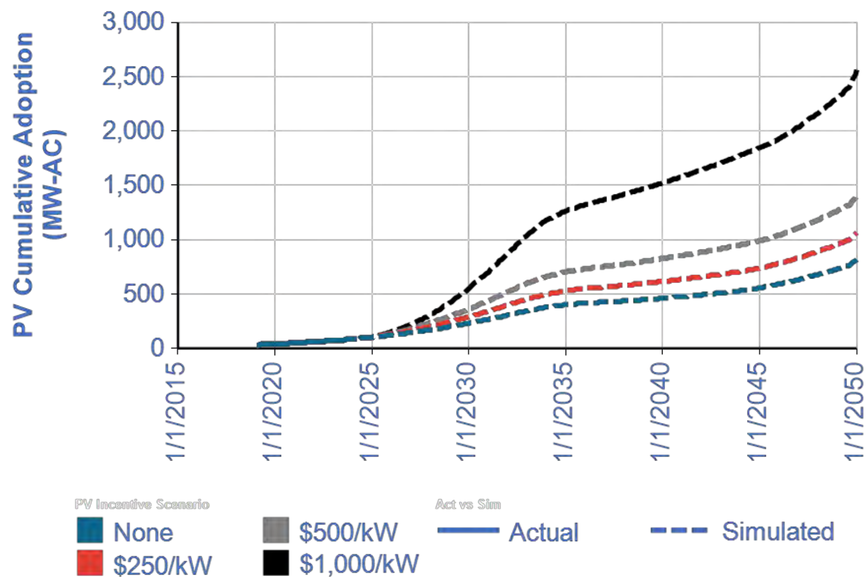
The forecast for Paired Battery Storage is presented below in Figure 1-8.

Figure 1-8: Paired Battery Storage Forecast



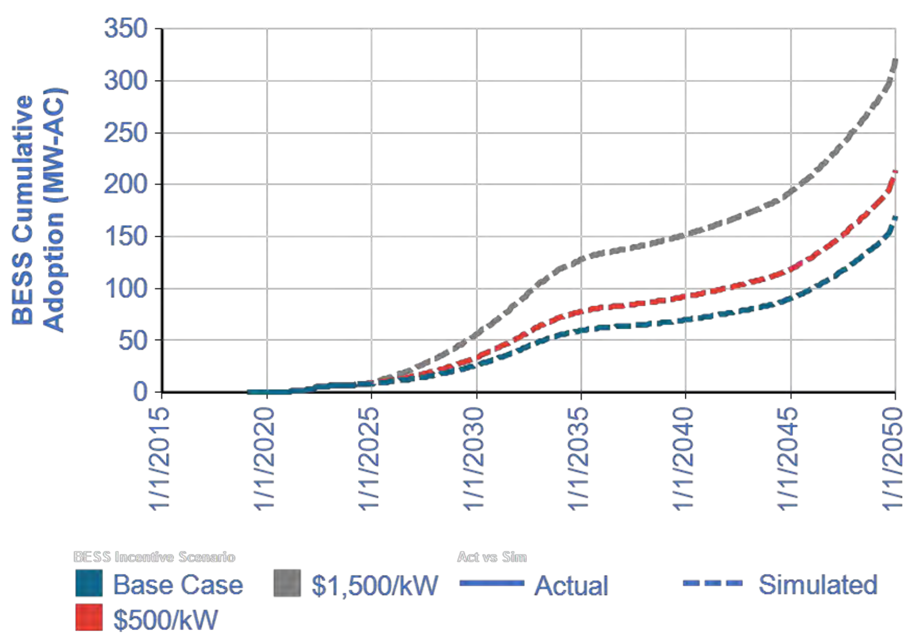
These forecasts can be influenced by utility incentives for equipment and installation. RI developed forecasts for several different incentive scenarios. The results are presented below in Figure 1-9 and Figure 1-10.

Figure 1-9 Solar PV Forecast with Incentive Offers



The battery storage forecast is similarly influences, as below in Figure 1-10.

Figure 1-10 Paired Battery Storage Forecast with Incentive Offers



2. Introduction

In fall of 2023, Duke Energy retained Resource Innovations to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand response (DR) programs in the Duke Energy Indiana (DEI) service territory. This report describes the potential for EE and DR savings in the service territory in Indiana.

2.1. Objectives and Deliverables

The main objectives of the study include:

- Estimating EE and DR potential over the short term (five years), medium term (ten years), and long term (twenty-five years) planning horizons
- Exploring the sensitivity of savings estimates to changes in incentive rates and avoided energy costs
- Developing customer participation estimates that are independent of historical Duke Energy program trends
- Assessing the potential impact of the 2022 Inflation Reduction Act on EE/DR savings potential
- Engaging the Indiana Energy Efficiency Oversight Board (OSB) and offering opportunities for feedback and contribution to the market potential study (MPS)
- Providing data to Duke Energy for integrated resource planning

RI developed the following deliverables for the MPS:

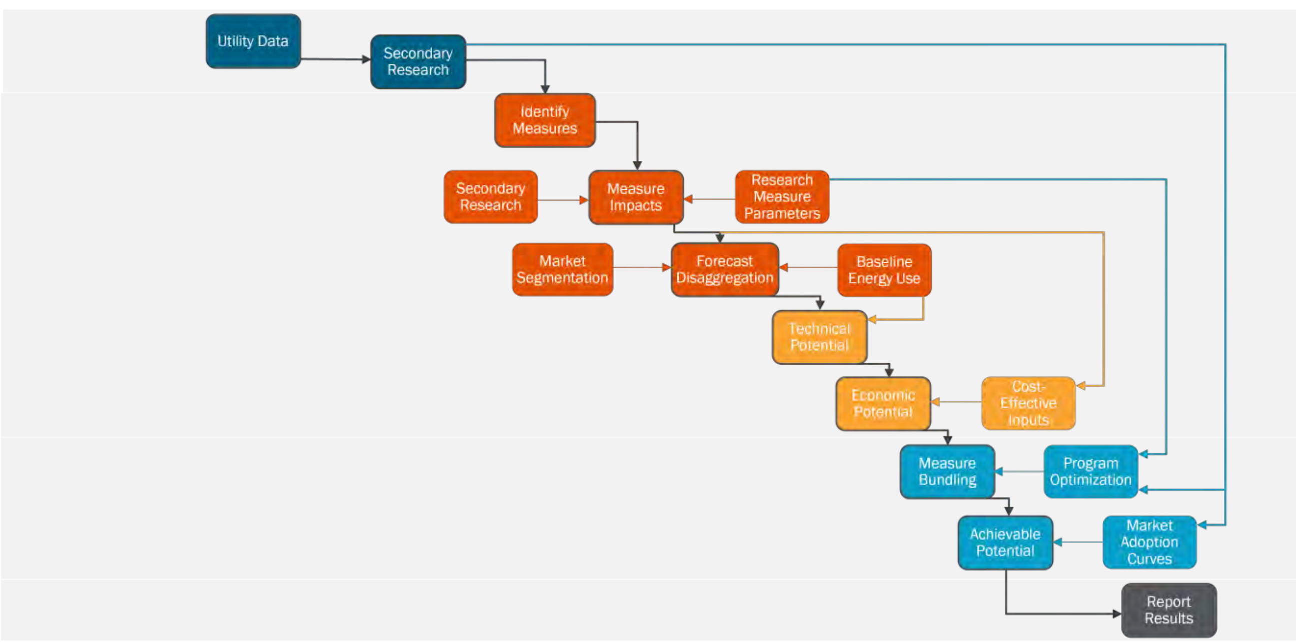
- Measure list and supporting memorandum describing the measure research process
- An MPS work plan
- Periodic presentations to Duke Energy and the Indiana OSB
- Responses to Indiana OSB members' feedback on interim study components
- Interim, draft results of technical and economic potential
- Presentations to Duke Energy and the OSB to solicit feedback on estimating the impacts of the 2022 Inflation Reduction Act
- Achievable potential estimates describing three APS scenarios: base, high incentive, and high avoided costs
- This report and summary of all project activities

2.2. Study Approach

Market potential studies describe each type of energy efficiency potential: technical, economic, and achievable. These assessments should incorporate current market conditions and trends, as observed with available primary and secondary data. All components of the study, such as baseline energy consumption, expected utility sales forecasts, and available EE and DR measures, among others, are determined based on available data. A market potential study is therefore a discrete estimate of EE and DR potential based on current market conditions and savings opportunities. This study considers existing technology and market trends as observed with currently available data and does not speculate on the potential impact of unknown, emerging technologies that are not yet commercially available.

Resource Innovations developed estimates with models, tools, and techniques developed over dozens of client engagements for EE and DR resource planning over the past two decades. We examined multiple scenarios by changing inputs related to program incentives, utility avoided cost benefits, and eligible customers. Resource Innovations used primary data provided by Duke Energy and secondary data sources to decompose DEI sales forecasts into customer-class and end use components. Resource Innovations characterized measures for all electric end uses, accounting for end use saturation, fuel shares, technical feasibility, current efficiency levels, and costs. As illustrated in Figure 2-1, we used these results to assess the savings that could be captured by Duke Energy customers with the full range of commercially available energy efficiency measures and practices. We estimated EE and DR savings for each customer class, market segment, and electric end use by applying measure impacts to the service territory over time.

Figure 2-1: Market Potential Study Flow Chart



We aggregated measure impacts for the technical, economic, and achievable scenarios by sorting and ranking measures according to scenario criteria and modeled the application of measures to replace equipment failures or to retrofit existing buildings. Following regulatory and stakeholder direction, we estimated economic potential by applying the utility cost test (UCT) to weigh EE and DR costs against their estimated benefits, the latter provided to us by Duke Energy.

The savings potential for EE and DR in Duke Energy's Indiana territory is characterized by levels of opportunity. The ceiling or theoretical maximum savings is based on commercialized technologies and behavioral measures, whereas the realistic savings that may be achieved through DR programs reflect real world market constraints such as utility budgets, customer perspectives and energy efficiency policy. This analysis defines these levels of energy efficiency potential according to the

Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE) as illustrated in Figure 2-2.

Figure 2-2: Energy Efficiency Potential

EPA – National Guide for Resource Planning

Technical potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Economic potential is the amount of energy and capacity saved by applying efficiency measures that pass a cost-effectiveness test. The utility cost test (UCT) is used in this study, in keeping with jurisdictional practice. Achievable market potential is the energy and capacity savings that can be achieved in a market with cost-effective, utility-sponsored programs; achievable market potential is primarily driven by the influence of incentive levels on customer adoption rates and addresses market barriers associated with customer preferences and opportunity costs. Our analysis assumed Duke Energy will continue to adaptively manage programs, following the EE/DR program life cycle: market assessment, program design, implementation, evaluation, and adaptation.

RI explored technical, economic, and achievable market program potential over a 25-year period from January 2025 to December 2049. The quantification of these three levels of energy efficiency potential reflects assumptions developed from feedback by the EE and DR Collaborative, Duke Energy, and regulators. Savings opportunity follows the path from a theoretical maximum to realistic savings potential in a market with utility-sponsored programs.

Achievable potential is based on customer payback acceptance curves; this approach describes customers' adoption decisions relative to the length of time required to recoup their investment in energy efficiency. Payback acceptance is calculated for all measures that pass the UCT cost screening.

Owing to these MPS parameters and focus, we describe our estimates as expected EE and DR potential in a market featuring utility-sponsored programs and incentives. The estimates assume adaptive program management is applied to successfully lower market and non-market barriers to customer adoption over time; the customer payback acceptance approach addresses only the barriers of investment costs and opportunity costs.

Naturally occurring conservation and efficiency is captured in this analysis by the Duke Energy electricity sales and load forecasts. We addressed changing energy codes and equipment standards by incorporating changes to codes and standards in the development of the base-case forecasts or with adjustment to measure savings that reflect changing baselines. The Duke Energy forecasts account for known or planned future federal code changes and existing market trends towards more efficient equipment. RI estimated savings potential based on a combination of market research, analysis, and a review of Duke Energy's existing programs, all in consideration of feedback from Duke Energy and the OSB. The programs that RI examined included both energy efficiency (EE) and demand response (DR) programs; therefore, this report is organized to offer detail on both types of programs.

The remainder of the report provides describes each step in the potential analysis process, according to the following sections:

- Market Characterization
- Measure List
- Technical Potential
- Economic Potential
- Achievable Market Potential

3. Market Characteristics

Market potential studies estimate savings potential relative to existing market conditions. This study used base year energy use and sales forecasts provided to us by Duke Energy. We used customer segmentation and secondary data to decompose the sales forecast into its end use components and to describe customer segments in the DEI service territory. This section presents baseline market conditions, while the subsequent sections address measure opportunities and market potential scenarios.

3.1. Customer Segments

As electricity consumption patterns vary by customer type, RI segmented customers to better describe opportunities for energy efficiency or customers' ability to provide DR grid services. Customer segmentation provides higher resolution estimates of cost-effective EE and DR programs. Significant cost efficiency can be achieved through strategic EE and DR program designs that recognize and address the similarities of EE and DR potential that exists within each customer group.

RI segmented DEI customers by economic sector to describe how much of the Duke Energy sales and peak load forecasts are attributable to the residential, commercial, and industrial sectors. Customer segments within each economic sector are used to estimate how much electricity each customer type consumes annually and during system peaking conditions. End use disaggregation looks within a typical home or business in each segment to describe the typical equipment using electricity during periods of peak demand and to estimate annual consumption within each end use for current consumption trends.

The Technical and Economic potential estimates include all customers, but for Achievable, RI used Duke Energy customer data to identify and remove customers that have opted out of DR programs or are not eligible to participate in Duke Energy programs. Table 3-1 lists study segments for each economic sector. We also segmented customers according to space heating fuel (electric vs. gas) and by annual consumption tertiles (that is, three groups of equal customer size). Segmentation allows for more accurate estimates of which customers exhibit consumption patterns that make them cost effective to recruit for EE and DR programs.

Table 3-1: MPS Customer Segments by Economic Sector

Residential	Commercial		Industrial	
Single Family	Assembly	Lodging/ Hospitality	Chemicals and plastics	Primary resource industries
Multifamily	College and University	Miscellaneous	Construction	Stone, clay, glass, and concrete
Mobile Home	Data Center	Offices	Electrical and electronic equipment	Textiles and leather
	Grocery	Restaurant	Lumber, furniture, pulp, and paper	Transportation equipment
	Healthcare	Retail	Metal products and machinery	Water and wastewater
	Hospitals	Schools K-12	Miscellaneous manufacturing	
	Institutional	Warehouse		

From an equipment and energy use perspective, each segment has variation within each building type or sub-sector. For example, the energy consuming equipment in a convenience store will vary significantly from the equipment found in a supermarket. To account for the resolution of available baseline consumption data, the selected end uses describe energy savings potential that are consistent with those typically studied in national or regional surveys. These end uses are listed in Table 3-2.

Table 3-2: Electricity End Uses by Economic Sector

Residential End Uses	Commercial End Uses	Industrial End Uses
Space heating	Space heating	Process heating
Space cooling	Space cooling	Process cooling
Domestic hot water	Domestic hot water	Compressed air
Ventilation and circulation	Ventilation and circulation	Motors, pumps
Lighting	Interior lighting	Motors, fans, blowers
Cooking	Exterior lighting	Process-specific
Refrigerators	Cooking	Lighting
Freezers	Refrigeration	HVAC
Clothes washers	Office equipment	Other
Clothes dryers	Miscellaneous	
Dishwashers		
Plug load		
Miscellaneous		

For demand response potential, customers were classified into sectors based on rate class and further segmented using premise-level characteristics. A summary is presented below in Figure 3-1. Residential customers were segmented using premise type; SMB customers were segmented using annual kWh consumption bins; large C&I customers were segmented using maximum hourly load.

Figure 3-1: Demand Response Customer Segmentation

Sector	Residential	SMB	Large C&I
Rates Included	RS	C110 (CS) OCS	LLF HLF
Segments	Single Family Multi-family Mobile Home	0-15,000 kWh 15,001-30,000 kWh 30,001-50,000 kWh 50,001+ kWh	0-50 kW 51-300 kW 301-500 kW 501+ kW

We targeted end uses with controllable load for residential customers and small/medium business (SMB) customers. Table 3-3 summarizes the control strategies analyzed for each sector. For large commercial and industrial (large C&I) customers who would potentially reduce large amounts of electricity consumption for a limited time, all load during peak hours was included. For residential and SMB customers, AC/heating loads, pool pumps and electric water heaters, as well as some DERs, were studied. For large C&I customers the analysis included automated and contractual demand response, as well as EV charging and battery storage measures.

Table 3-3: Demand Response Measures

Residential	SMB	LCI
• HVAC, Utility Direct Load Control • Smart Thermostats • Temporary Price Responsiveness • Water Heater, Utility Direct Load Control • Pool Pump, Utility Direct Load Control • EV Charging, Utility Direct Load Control • Rooftop Solar • Battery Storage	• HVAC, Utility Direct Load Control • Smart Thermostats • Water Heater, Utility Direct Load Control • Pool Pump, Utility Direct Load Control • Temporary Price Responsiveness • EV Charging, Utility Direct Load Control • Battery Storage	• Contractual Load Curtailment • Auto DR • EV Load Shed • Battery Storage

3.2. Forecast Disaggregation

We worked with Duke Energy to establish a common understanding of the assumptions and granularity in the baseline load and sales forecasts. We reviewed the following:

- How are Duke Energy's current program offerings reflected in the energy and demand forecast?
- What are the assumed weather conditions and hour(s) of the day when the system is projected to peak?
- How much of the sales forecast is attributable to accounts that are not eligible for EE and DR programs or have opted-out of the EE and DR riders?
- How are projections of population increase, changes in appliance efficiency, and evolving distribution of end use load shares accounted for in the twenty-five-year peak sales and demand forecasts?

RI segmented the DEI electricity consumption forecasts by customer class and end use. The resulting baseline represents the Indiana electricity market by describing how electricity is consumed within the service territory. RI developed these forecasts for the years 2025–2049 and based them on data provided by Duke Energy and supporting, secondary sources. The data addressed current baseline consumption, system load, and sales forecasts.

The baseline for DR potential describes loads in the absence of existing, dispatchable DR. This baseline was necessary to assess how DR can assist in meeting specific planning and operational requirements. RI used Duke Energy's seasonal demand forecast, which was developed for system planning purposes.

RI developed a list of electricity end uses by sector (Table 3-2) and examined EE and DR measures that could potentially reduce baseline consumption for each end use. RI began with Duke Energy's estimates of average end use consumption for residential customers and shares of Duke Energy sales to non-residential customer segments. We combined these data with Duke Energy's 2022 residential appliance saturation surveys, data products from the Energy Information Agency (EIA) and estimates of manufacturing end use consumption from the Department of Energy (DOE).

3.3. Market Description

Customer segmentation addresses the diverse energy savings opportunities for Duke Energy's customer base. Duke Energy provided RI with data describing premises type and load characteristics for all customers. RI's approach to segmentation varied slightly for commercial and residential accounts, but the overall logic was consistent with the concept of expressing the accounts in terms that are relevant to EE and DR opportunities. The following sections describe the segmentation analysis and results for commercial and industrial C&I accounts (Section 3.3.1) and residential accounts (Section 3.3.2).

3.3.1. Commercial and Industrial Accounts

RI segmented C&I accounts according to two approaches: annual energy consumption and peak energy demand.

Duke Energy provided RI with customer data containing rate codes for individual accounts. RI classified the customers in this group as *either* small and medium businesses (SMB) or large commercial & industrial (LCI)using rate class and peak demand characteristics. SMB customers were segmented based on annual energy consumption, while large LCI customers were segmented using maximum demand.

RI segmented both the SMB and Large C&I customer segments using monthly billing records and hourly AMI data, which was provided by Duke Energy as part of the customer data request. RI aggregated the SMB segments using data available, and the resulting customer counts are shown in Table 3-4 for SMB customers.

Table 3-4: Summary of SMB Segment

Segment	DEI Number of Accounts
0-15,000 kWh	52,858
15,001-25,000 kWh	11,595
25,001-50,000 kWh	6,298
50,000 kWh+	7,256
Total	**78,007**

Large C&I customers were defined for the DR potential analysis based on account size (demand). Duke Energy provided a census of AMI data to RI for estimating the DR potential capacity available from these large accounts. Table 3-5 presents the resulting customer counts by customer segment.

Table 3-5: Summary of Large C&I Segment

Segment	DEI Number of Accounts
<100 kW	4,808
100-300 kW	2,838
300-500 kW	667
>500 kW	688
Total	**9,001**

3.3.2. Residential Accounts

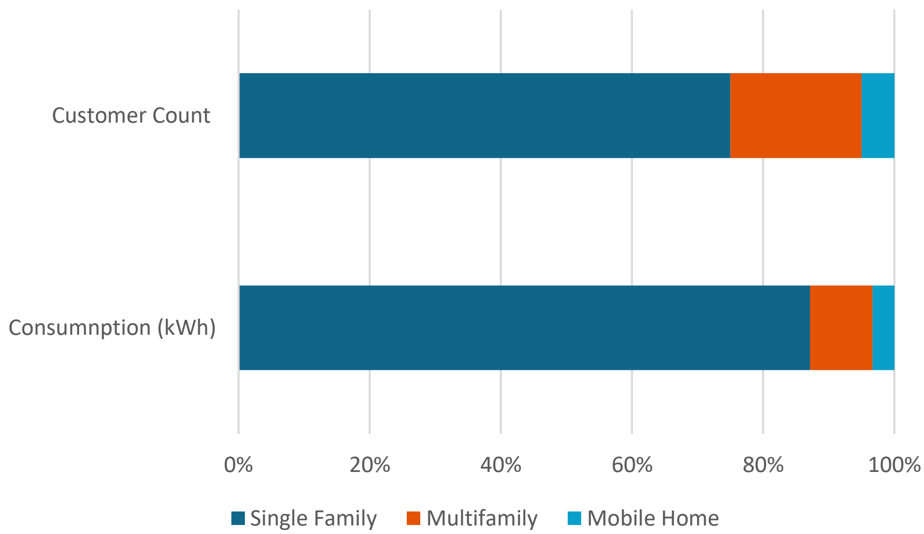
RI segmented residential accounts to align DR opportunities with appropriate DR measures. Residential segments are based on customer dwelling type (single family or multifamily). The resulting distribution of customers and total electricity consumption by each segment is presented below in Table 3-6.

Table 3-6: DEI Residential Market Characteristics by Type of Dwelling Unit

Attribute	Single Family	Multi-Family	Mobile Home
Customer Count	599,719	159,925	39,981
Total kWh Consumption	8,261,990,781	904,383,546	315,680,288

Figure 3-2 presents a visual representation of this information. The DEI territory in Indiana consists primarily of single-family dwellings, which have the greater share of both accounts and consumption.

Figure 3-2: DEI Residential Market Characteristics by Type of Dwelling Unit



The DR assessment required the use of interval data to estimate the loads associated with space cooling and space heating. For this study, interval data were available from all DEI customers.

The residential sector was segmented into three different groups based on premise type (i.e., single-family, multi-family, other). Within each of these customer groups, heating and cooling load profiles were estimated using observed AMI consumption data and weather data.

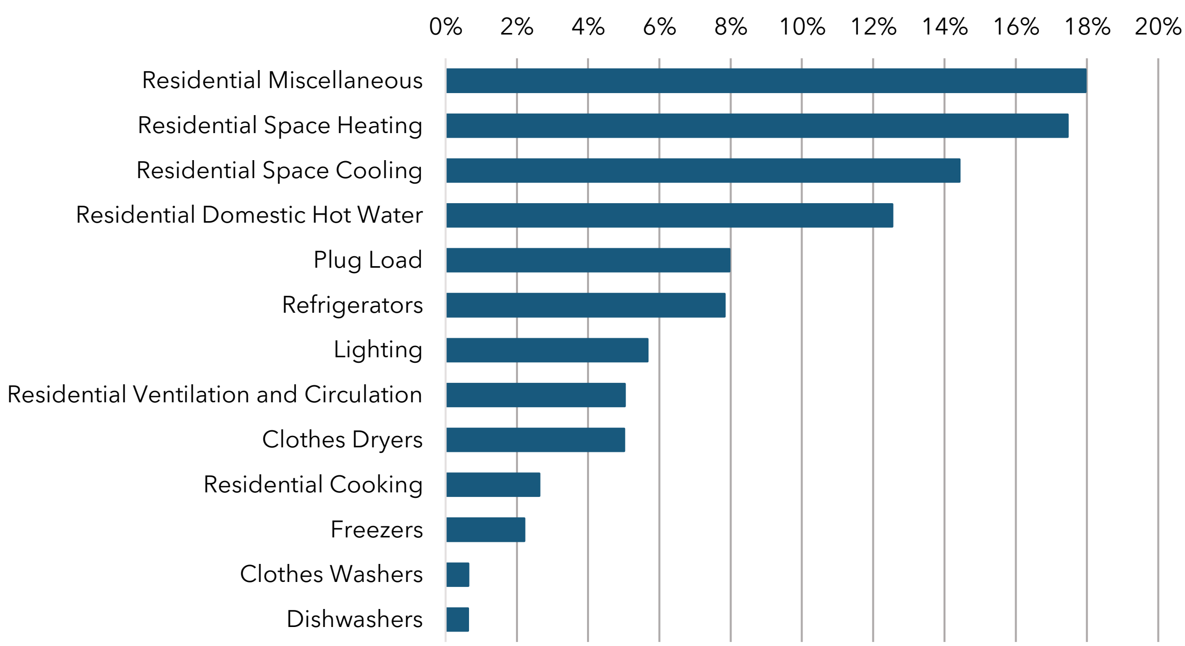
3.4. Start Year 2025 Disaggregated Sales

Duke Energy provided Resource Innovations with an end use forecast for residential customers and a forecast of sales by customer segment for non-residential customers. These forecasts are based in part on the Energy Information Administration (EIA) research activities in the residential, commercial, and manufacturing sectors. As of the time of this study the data provided by these products represented the best available secondary data sources for end use consumption within each economic sector. The following secondary data sources were used by RI to disaggregate each sector's loads:

- Residential load disaggregation is based on Duke Energy's estimates of residential end use load shares; this information in turn is derived from the EIA Residential End Use Consumption Survey (RECS), vintage 2020.
- Commercial load disaggregation is based on the Commercial Building Energy Consumption Survey (CBECS) and Duke Energy estimates of sales by commercial segment, vintage 2018.
- Industrial load disaggregation is based on Manufacturers' Energy Consumption Survey (MECS), vintage 2018.

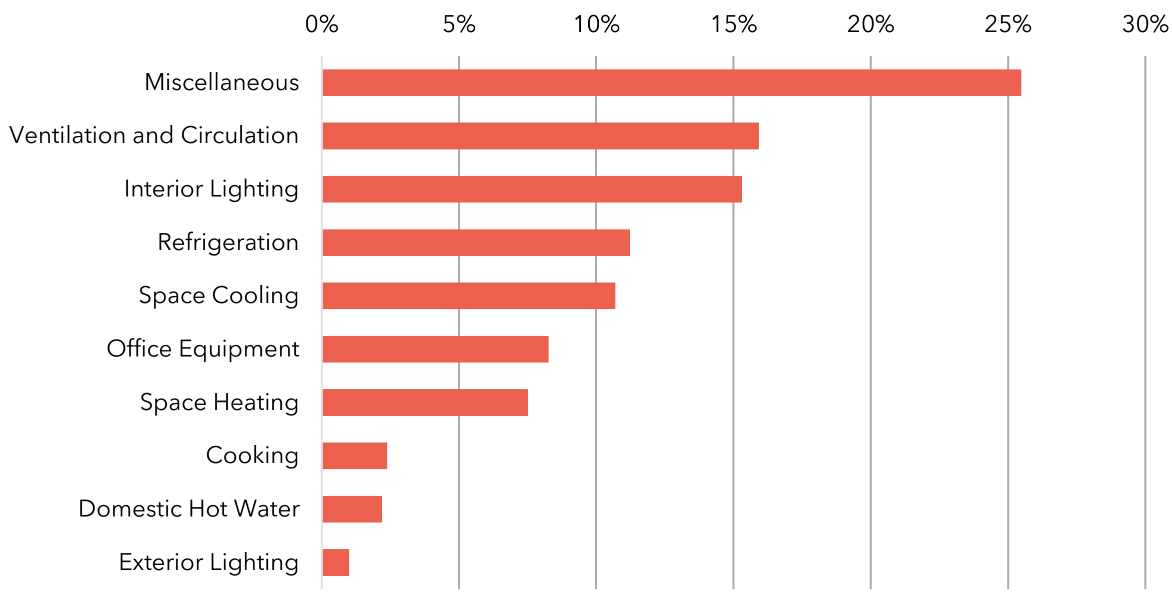
With the details provided by Duke Energy, Resource Innovations was able to identify and categorize some miscellaneous electric loads into an end use category we labelled as "plug loads." Nevertheless, there remains a large share of residential load classified as "residential miscellaneous – other," and no further data are available at this time to further describe this end use. "Residential miscellaneous – other" is one subcategory of the broader residential miscellaneous. Residential miscellaneous also include pool pumps, spas, and ceiling fans as discrete loads that we could identify with available data. Residential miscellaneous loads have historically lacked detail because of the plethora of possible items that might use electricity in this category; in our experience this is not an issue specific to Duke Energy. The disaggregated loads for the start year 2025 residential end uses are summarized in Figure 3-3.

Figure 3-3: DEI 2023 Residential End Uses, Baseline Consumption Shares



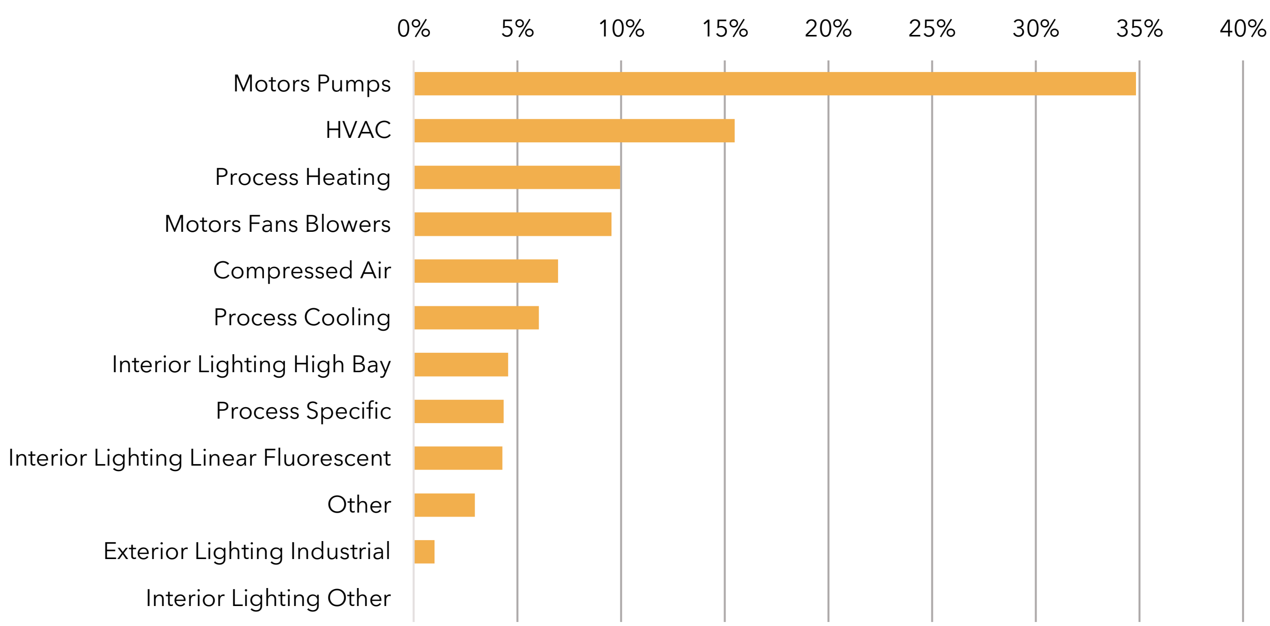
The commercial start year load shares were constructed with a combination of end use consumption shares from CBECS data, and our estimates of 2023 annual billed consumption by commercial customer type (e.g., building type or segment). Figure 3-4 presents a summary of the end use consumption data available for the commercial sector.

Figure 3-4: DEI Commercial End Uses, Baseline Load Shares



Industrial customer consumption shares are based on the 2018 EIA MECS survey and Duke Energy billed consumption in 2023. Figure 3-5 presents a summary of industrial customers' end use consumption.

Figure 3-5: DEI Industrial End Uses, Baseline Load Shares



In the base year 2023, the top end use consumption categories for each economic sector are as follows:

- ***Residential:*** Miscellaneous, space heating, space cooling
- ***Commercial:*** Miscellaneous, ventilation and circulation, interior lighting
- ***Industrial:*** Motors pumps, HVAC, and process heating

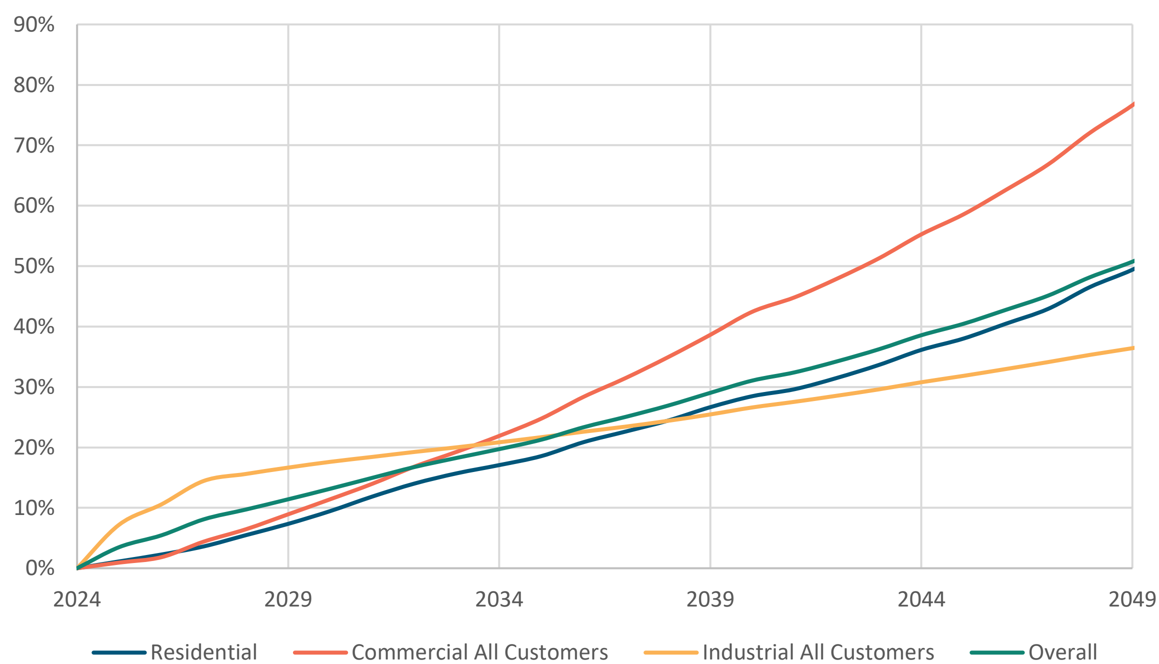
3.5. DEI Sales Forecast 2025 - 2049

3.5.1. DEI System Energy Sales

Duke Energy provided its 2022 and 2023 vintage sales forecast data to Resource Innovations. Our estimates of energy efficiency potential present savings opportunities relative to these forecasts. The forecast of baseline sales used to estimate potential does not include savings from future utility-sponsored energy efficiency,

DEI electricity sales for 2025 are forecasted to be 26,495 GWh, increasing to 38,586 GWh in 2049. This increase of 12,091 GWh represents a change of 46% over the period, or 1.5% average annual growth. The commercial sector is expected to account for the largest share of the increase, growing by 4,606 GWh or 2.3% annually, to reach 10,749 GWh (an increase of 75%) over the 25-year period. The industrial sector is expected to increase by 2,959 GWh to reach 13,828 GWh, a change of 27% over the 25-year period (1% annually). The residential sector is forecasted to increase by 4,526 GWh (48%) at an average annual growth rate of 1.6%. Figure 3-6 illustrates the growth rate of sales for each economic sector over the period of analysis. In 2049 the residential sector accounts for 36% of total electricity sales, the commercial sector 28% and the industrial sector 36%. This forecast includes the impact of adding back utility energy efficiency and solar impacts to establish an MPS baseline.

Figure 3-6: DEI Electricity Sales Growth over Base Year, by Economic Sector, for 2025 - 2049

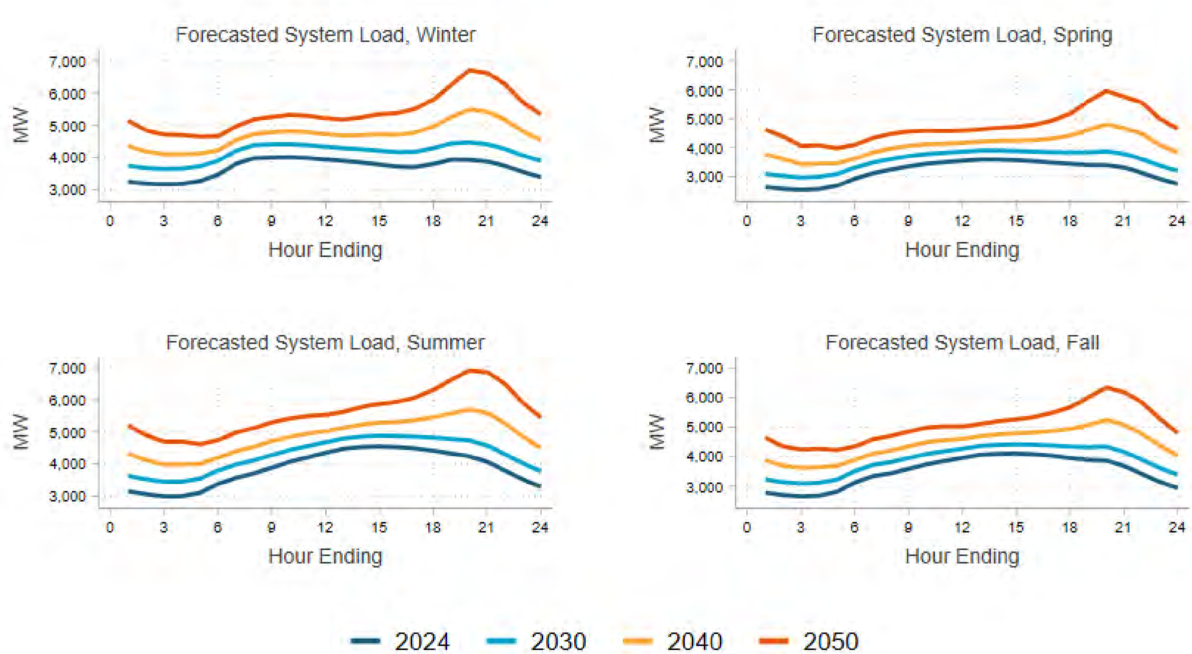


3.5.2. DEI System Demand

Estimating technical potential for demand response resources requires knowing how much load is available to be curtailed or shifted during system peak demand conditions. Demand response benefits accrue from avoiding costly investments to meet peak loads; load reductions have lower value if they occur outside the hours of peak system demand. Our estimates of market potential for demand response are based on when load reductions will most likely be needed throughout the year.

The primary data source used to determine when demand response resources will be needed was the DEI system load forecast. This forecast projects loads for all 8,760 hours of each forecast year available to represent the MPS study period (2025-2049). Figure 3-7 represents an initial inspection of the data. The figure shows the expected system load profiles for peak days during each season. Summer was defined as August weekdays; spring was defined as May weekdays; fall was defined as September weekdays; and winter as January weekdays.

Figure 3-7: DEI System Load Forecast by Year (2024, 2030, 2040 and 2050)

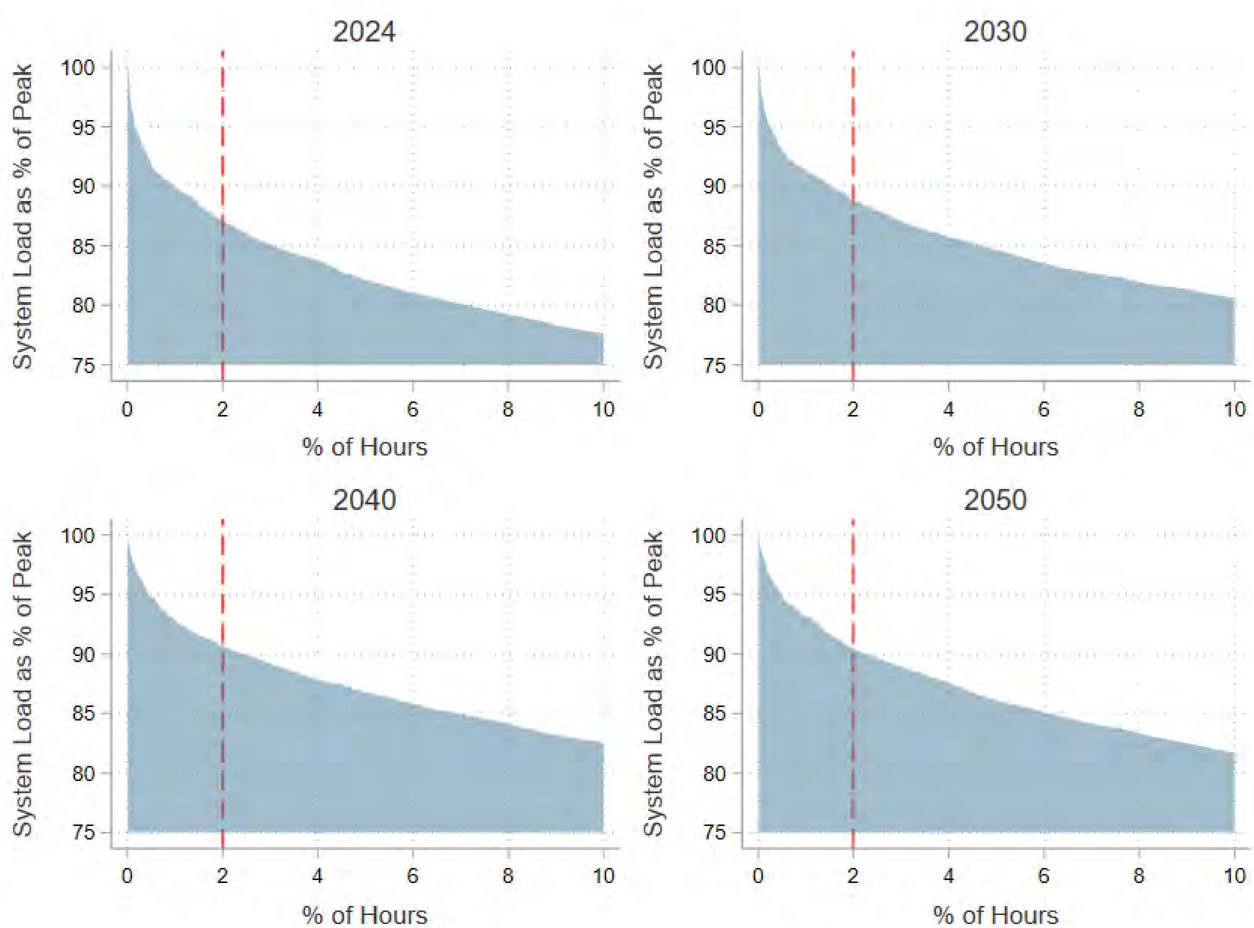


Several patterns are apparent from examining the figure above. First and foremost, forecasted peak loads are projected to increase over time. These data also indicate summer peak loads are slightly higher than winter peak loads. This potential study focuses on seasonal peak periods as defined by Duke Energy:

- Summer peak: August weekdays, hour-ending 15
- Spring peak: May weekdays, hour-ending 14
- Fall peak: September weekdays, hour-ending 15
- Winter peak: January weekdays, hour-ending 19

Though useful for assessing patterns in system loads, Figure 3-7 does not provide information about the concentration of peak loads. A useful tool to examine peak load concentration is a load duration curve, which is presented for 2024, 2030, 2040 and 2050 in: Figure 3-8. This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

Figure 3-8: DEI Forecasted Load Duration Curve by Year



The x-axis in Figure 3-8 is depicted as the cumulative percentage of hours. The orange dotted line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.[2] As depicted in the upper left panel of Figure 3-8, approximately 87% of DEI's system peak capacity is required to serve 2% of the hours in 2024. By 2050 (depicted in the lower right panel), approximately 91% of system peak is projected to be needed to serve the top 2% of hours. This means that, while

[2] Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

loads continue to grow over all hours, the number of hours of extreme usage are forecasted to be come slightly less concentrated over time.

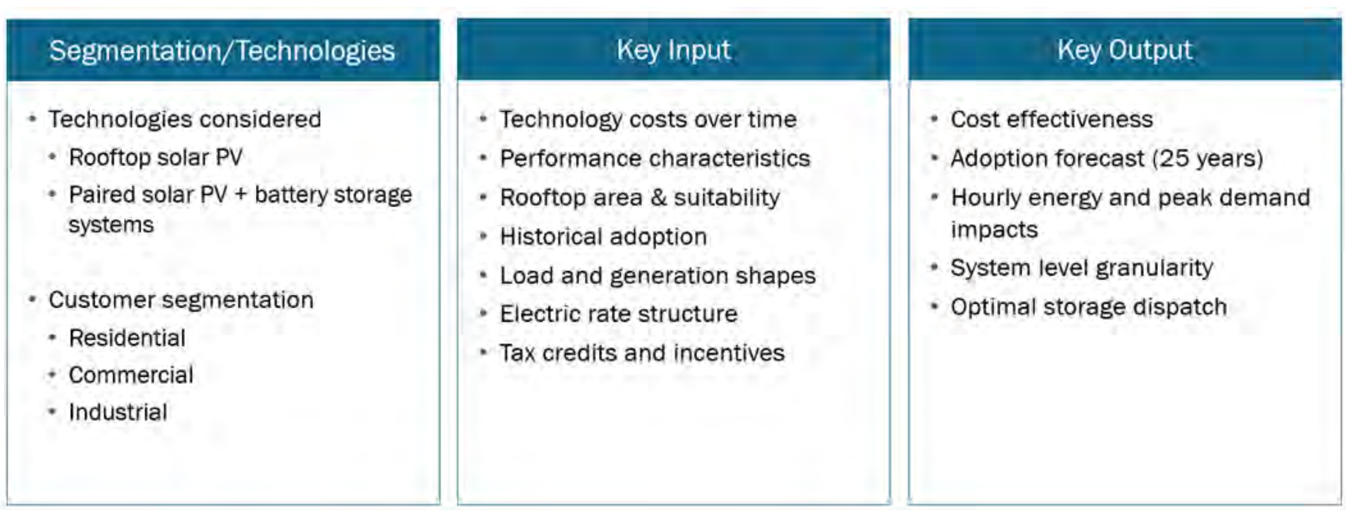
3.5.3. DEI Customer Opt-Outs

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for Indiana, which showed an opt-out rate of approximately 9.6% of commercial sales and 59.2% of industrial sales in the DEI service territory. We incorporated this opt-out rate into the MPS by excluding sales to non-residential customers that opted out, and we applied the applicable energy efficiency technologies and market adoption rates to the remaining customer base.

3.5.4. Market Description and DER-Specific Considerations

The DER analysis leveraged the customer segmentation and load disaggregation data assembled for the EE and DR analyses, and applied our DER model, SPIDER™ (Spatial Penetration and Integration of Distributed Energy Resources), to estimate system economics and adoption. This model dynamically responds to rapidly changing technologies and accounts for all key time-varying elements such as technology costs, incentives, tax credits, and electric rates. The general approach is presented in Figure 3-9.

Figure 3-9: DER Market Characteristics and Related Study Components



Additional data on current market conditions and related suitability for PV systems is described below in Table 3-7.

Table 3-7: Technical Input Assumptions for DER Measures

Data Item	Res	Com	Ind	Units	Source/Notes
Roof Area Suitability	30%	56%	82%	Suitable Area/Total Area	NREL Lidar Study (accounting for tilt, orientation, & shading)
Power Density	200	200	200	W/m2	Assumes 20% module efficiency
Average Home Size	2,017	N/A	N/A	Square Feet	EIA
PV Capacity Factor	15.8	14.7	14.7	(kWh AC/year) / (kW-DC*8760 hrs)	NREL PV Watts (30/10 degree tilt for res/nonres)
Energy Intensity	N/A	11.7	79.4	kWh / Square Foot	2018 CBECS & MECS
Average # Floors	1.37	2.52	2.2	Number of Floors / Building	2020 RECS, 2018 CBECS & MECS
Module to Roof Area Ratio	0.7	0.7	0.7	Fraction	NREL Lidar Study (racking configuration). Plus res “setback”
Currently Installed PV	36.5	69		MW-DC	Utility Interconnection Database (through Oct 2024)

4. Measure List

RI maintains a database of energy efficiency measures for MPS studies. Measure data are refined as new data or algorithms are developed for estimating measure impacts. The current list of savings opportunities, or “measures,” incorporates the measure list used in version 12 of the Illinois Technical Reference Manual, with additional supplemental measures from prior MPS studies. We added or subtracted measures at the request of project stakeholders and to follow the Indiana TRM, which in turn is linked to the Illinois TRM. At the outset of this study, RI used the Indiana TRM (tied to version 10 of the Illinois TRM) and responded to stakeholder request to incorporate updates contained in version 12 of the Illinois TRM. This section describes how the measure data is developed, maintained, and applied in the study for energy efficiency and DR services and products.

The EE measure data used in the 2023 MPS study includes a list of proposed measures that has been reviewed many times by many project stakeholders in multiple jurisdictions. Resource Innovations curates a database of EE measures that we update each time we conduct a market potential study. Updates for this project included sharing the measure list with the Indiana OSB members to solicit proposed measure additions. We requested, received, and responded to OSB input concerning measures to be included in the study. We also presented detailed information on the measure research process, and we requested feedback and comments from OSB members on the same. After conducting measure research, we provided all OSB stakeholders with data on the algorithm for estimating measure impacts for each measure in the study, as well as algorithm parameter values used to calculate the impact estimates. The OSB provided comments/responses concerning the parameter values, to which we also responded before proceeding with the subsequent tasks in the study.

Measures included in this study represent opportunities to reduce consumption across all major electricity end uses and customer types. The MPS does not include measures related to fuel switching (e.g., converting from gas space heating to electric space heating). This scope of measures is reasonable because the MPS applies the UCT to screen measures for economic potential; measures are assigned to utility-sponsored programs and screened to ensure they are cost-effective for Duke Energy to offer in a utility-sponsored program for energy efficiency.

The measures included in the study are those currently available for purchase in today’s market. The MPS does not speculate on future technologies but does include many nascent or novel savings opportunities such as smart panels, networked lighting controls, heat pump water heaters, and others. All measure impacts are modeled as a percentage reduction in baseline energy consumption. The MPS model also includes a stock and flow calculation for equipment burnouts or turnover. Future measure impacts are applied to a future baseline energy consumption estimate that reflects a continuation of historical and current trends. In this manner our estimates of savings potential are incremental to naturally occurring energy efficiency savings captured by the Duke Energy sales forecast.

The final measure list included energy efficiency technologies and products that enable DR opportunities. DR initiatives that do not rely on installing a specific technology, such as time-of-use rates and permanent load shifting, are not examined in the DR potential estimates.

4.1. Energy Efficiency Measures

RI's measure data represents savings opportunities for all electricity end uses and customer types. EE program measure offers are typically more specific than those required to assess EE potential. For example, Duke Energy programs have historically had multiple instances of LED lamps with varying characteristics (candelabra base, globe base, A-line, etc.). Although these distinctions are important during program delivery, this level of granularity is not necessary to identify the market potential for EE savings.

RI used a qualitative screening approach to assess emerging technologies for the Indiana service territory. The qualitative screening criteria that RI used included: difficult to quantify savings, no longer current practice, better measure available, immature, or unproven technology, limited applicability, poor customer acceptance, health and environmental concerns, and end-use service degradation. If we were able to identify specific products and generate estimates of measure savings for emerging technologies, then we added them to the measure list. RI updated its online measure database to support this study. RI's database contains the following information for each measure:

- Classification of measure by type, end use, and subsector
- Description of the base-case and the efficiency-case scenarios
- Measure life
- Savings algorithms and calculations per subsector, taking weather zones and subsectors into consideration
- Input values for variables used to calculate energy savings
- Measure costs
- Output to be used as input in RI's TEAPOT model

Detailed measure assumptions in this database were provided to Duke Energy and the Indiana OSB. As shown in Table 4-1, the study included 393 unique energy efficiency measures. Expanding the measures to account for all relevant combinations of segments, end uses, and construction types resulted in 9,431 measure permutations that we modeled against the market baseline.

Table 4-1: EE Measure Counts by Sector

Sector	Unique Measures	Permutations
Residential	115	1,780
Commercial	168	5,113
Industrial	110	2,538

4.2. Inflation Reduction Act Measure Development

The 2022 Inflation Reduction Act recently made available approximately $360 billion for investments to reduce greenhouse gas emissions and combat climate change. Major federal program included in the IRA are as follows:

- Home energy performance-based whole-house (HOMES) rebates through the Department of Energy (DOE)
- 179D Energy efficient commercial building deduction
- High-efficiency electric home rebate program (DOE)
- 25c Energy Efficient Home Improvement Credit

Resource Innovations developed an EE MPS modeling scenario around this legislation to address the potential magnitude of expected impacts the program could have on achievable market potential. Significant uncertainty remains concerning how the program will be implemented, but RI's analysis included the following procedures and assumptions, described below. We made assumptions in modeling IRA impacts, as follows:

- Develop additional, "IRA measures" to supplement the original measure list developed for the MPS.
    - HOMES includes a whole home retrofit measure that RI prepared for modeling.
    - Measure saves 20% for existing construction, incremental cost is assumed to be $10,000.
    - Measure applies to population in a manner consistent with income distribution; two versions were applied: HOMES for customer base with <80% area median income (AMI), HOMES for customer base with 80%-150% AMI income.
    - Included $1 per kWh in administrative costs for Duke Energy resource expenditures facilitate and support the HOMES program.
- Measures that qualify for the 25c Energy Efficiency Tax credit were modeled as a duplicate of the corresponding, existing Smart $aver measures; Duke Energy program incentives and rebates were applied to the measures' incremental costs, and those costs were further reduced by subtracted the capped tax credit amount for each measure prior to calculating customer payback times.
- Administrative costs from relevant Duke Energy programs, on a per-kWh basis, were used to account for the potential of increased program participation volume that may result from the IRA.

After developing these measures and cost-estimates, Resource Innovations applied the measures within our model to estimate the potential impacts and included these expected impacts from the IRA in the base achievable potential case.

4.3. DR Services and Products

RI and Duke Energy worked together to determine which DR products and services were included in the MPS, and addressed the following:

- **Direct load control.** Customers receive incentive payments for allowing the utility a degree of control over equipment, such as air conditioners or water heaters. This includes both switch-based programs and smart thermostat programs.
- **Emergency load response.** Customers receive payments for committing to reduce load if called upon to do so by the grid operator.
- **Economic load response:** Utilities provide customers with incentives to reduce energy consumption when marginal generation costs are higher than the incentive amount required to achieve the needed energy reduction.
- **Base interruptible DR**. Customers receive a discounted rate for agreeing to reduce load to a firm service level upon request.
- **Automated DR**. Utility dispatched control of specific end-uses at customer facilities.

4.4. DER Measure Input Assumptions

The DER measure list includes rooftop PV systems and battery storage systems charged from PV systems. PV systems utilize solar panels (a packaged collection of PV cells) to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter, a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted systems that face south-west, south, and/or, south-east. The potential associated with roof-mounted systems installed on residential, commercial, and industrial buildings was analyzed.

Distributed battery storage systems included in this study consist of behind-the-meter battery systems installed in conjunction with an appropriately sized PV system at residential and non-residential customer facilities. These battery systems typically consist of a DC-charged battery, a DC/AC inverter, and electrical system interconnections to a PV system. On their own battery storage systems do not generate or conserve energy but can collect and store excess PV generation to provide power during particular time periods, which for DR purposes would be to offset customer demand during the utility's system peak. The system specification is presented in Table 4-2.

Table 4-2. System Specifications

Specification	Value
Hours of Storage at Peak Capacity	2.5
Round-Trip Efficiency	90%
Ratio of Peak Storage Power to Peak Solar Power	1.0

5. Technical Potential

Technical potential relates to base year load shares and reference case load forecasts for 2025 to 2049. Measure savings impacts are applied to the baseline data to estimate technical potential. The technical potential scenario estimates the savings potential when all technically feasible energy efficiency measures are fully implemented, while accounting for equipment turnover. This savings potential can be considered the maximum reduction attainable with available technology and current market conditions (e.g., currently available technology, building stock, and end uses as reflected in Duke Energy forecasted sales). EE and DR potential scenarios that account for measures' costs and benefits and market adoption are discussed in subsequent report sections for economic potential and achievable potential, respectively.

5.1. Approach and Context

Technical potential represents a straightforward application of EE and DR measures to the baseline market context for Duke Energy Indiana. Technical potential is determined by the energy intensity of baseline consumption and the savings opportunities represented by EE and DR measures. Baseline conditions for electricity consumption inherently reflect historic and current economic conditions, the current configuration of the power system, policy context, and customer preferences.

Current and projected sales and load are based on the current and projected numbers of accounts served by economic sector. The types of loads present at these accounts are reflective of customers' economic sector, segment, and final demand for electricity services. Final demand for electricity is reflective of numerous, complex factors such as the set of available technologies that meet electricity end uses (e.g., HVAC for heating, cooling, and ultimately: comfort); the cost of technologies that produce electricity end uses; the price of electricity and other energy sources; customer demand for electricity services; and behavioral or other contextual factors that collectively drive customer decisions about energy consumption.

5.1.1. Energy Efficiency

Energy efficiency technical potential provides a theoretical maximum for electricity savings relative to the forecast baseline. Technical potential ignores all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt energy efficiency. For an EE potential study, technical potential refers to delivering less electricity to satisfy the same end uses. In other words, technical potential might be summarized as "doing the same thing with less energy, regardless of the cost."

RI applied estimated energy savings from equipment or non-equipment measures to all electricity end uses and customers. Since technical potential does not consider the costs or time required to achieve these electricity savings, the estimates provide an upper limit on savings potential. RI presents technical potential results as a single numerical value for the DEI service territory.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 5-1 below, while the core equation used in the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 5-2, below.

Equation 5-1: Core Equation for Residential Sector Technical Potential

Technical Potential of Efficient Measures = Total Number of Households × Base Case Equipment Energy Use Intensity (kWh/unit) × Saturation Share × Remaining Factor × Applicability Factor × Savings Factor

Where:

Base Case Equipment Energy Use Intensity = the electricity used per customer per year by each base-case technology in each market segment; efficient technologies are applied to reduce this base case equipment energy use intensity.

Saturation Share = the fraction of the electricity end use consumption that may be reduced by applying an efficient technology in each market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (i.e., it may not be possible to install a heat pump water heater for every home due to space constraints).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Equation 5-2: Core Equation for Nonresidential Sector Technical Potential

Technical Potential of Efficient Measures = Total Stock Sq. Footage by Building Type by EDC × Base Case Equipment Energy Use Intensity (kWh/unit) × Equipment Saturation Share × Remaining Factor × Applicability Factor × Savings Factor

Where:

Total Stock Square Footage by Building Type = the forecasted square footage level for a given building type (e.g., office buildings).

Base Case Equipment Energy Use Intensity = the electricity used per square foot per year by each base-case equipment type in each market segment. In other words, the base case equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Equipment Saturation Share = the fraction of the equipment electrical energy that is applicable for the efficient technology in each market segment. For example, for room air conditioners, the saturation share would be the fraction of all space cooling kWh in each market segment that is associated with room air conditioner equipment.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. For example, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (i.e., it may not be possible to install VFDs on all motors in each market segment).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

It is important to note that the technical potential estimate represents electricity savings potential at a specific point in time. In other words, the technical potential estimate is based on data describing *status quo* customer electricity use and technologies known to exist today. As technology and electricity consumption patterns evolve over time, the baseline electricity consumption will also change accordingly. For this reason, technical potential is a discrete estimate of a dynamic market. RI reported technical potential over a defined time period, based on currently known DR measures and observed electricity consumption patterns.

5.1.1.1.1. Addressing Naturally Occurring Energy Efficiency

Duke Energy's baseline sale forecast includes the impacts of efficiency actions that are expected to occur in the absence of utility intervention. RI worked with Duke Energy's forecasting group to understand how the sales forecasts incorporated two known sources of naturally occurring efficiency:

- **Codes and Standards:** The sales forecasts incorporated the impacts of known code changes. While some code changes have relatively little impact on overall sales, others— particularly the Energy Independence and Security Act (EISA) and other federal legislation—will have noticeable influence. Given the uncertainty associated with the implementation of the EISA backstop and current market trends, RI adjusted the future lighting baseline to the EISA-compliant standard.
- **Baseline Measure Adoption:** Sales forecasts typically exclude the projected impacts of future DR efforts, but account for baseline efficiency penetration.

By properly accounting for these factors, the potential study represents the difference between the anticipated adoption of efficiency measures because of DR efforts and the "business as usual" adoption rates absent any projected future impacts of utility-sponsored programs. This is true even in the technical and economic scenarios, where adoption was assumed to be 100%, and was particularly important in the achievable potential analysis, where RI estimated the measure adoption in a market featuring utility-sponsored programs.

5.1.2. Demand Response

The concept of technical potential applies differently to demand response than for energy efficiency. Technical potential for demand response is effectively the magnitude of loads that can be managed during conditions when grid operators need peak capacity, ancillary services, or when wholesale energy prices are high. Which accounts are consuming electricity at those times? What end-uses are in play? Can those end-use loads be managed? Large C&I accounts generally do not provide the utility with direct control over end-uses. However, businesses will forego virtually all electric demand temporarily if the financial incentive is large enough.

For residential and SMB accounts where DR means direct utility load control, technical potential for demand response is limited by the loads that can be controlled remotely at scale. RI produced disaggregated weather-responsive load for all 8760 hours. This approach identifies weather-responsive customer loads available at times when the different grid applications are needed can vary substantially. Instead of producing disaggregated loads for the average residential customers, the study was produced for several customer segments, thereby allowing the study to identify which customers were cost-effective to recruit and which were not.

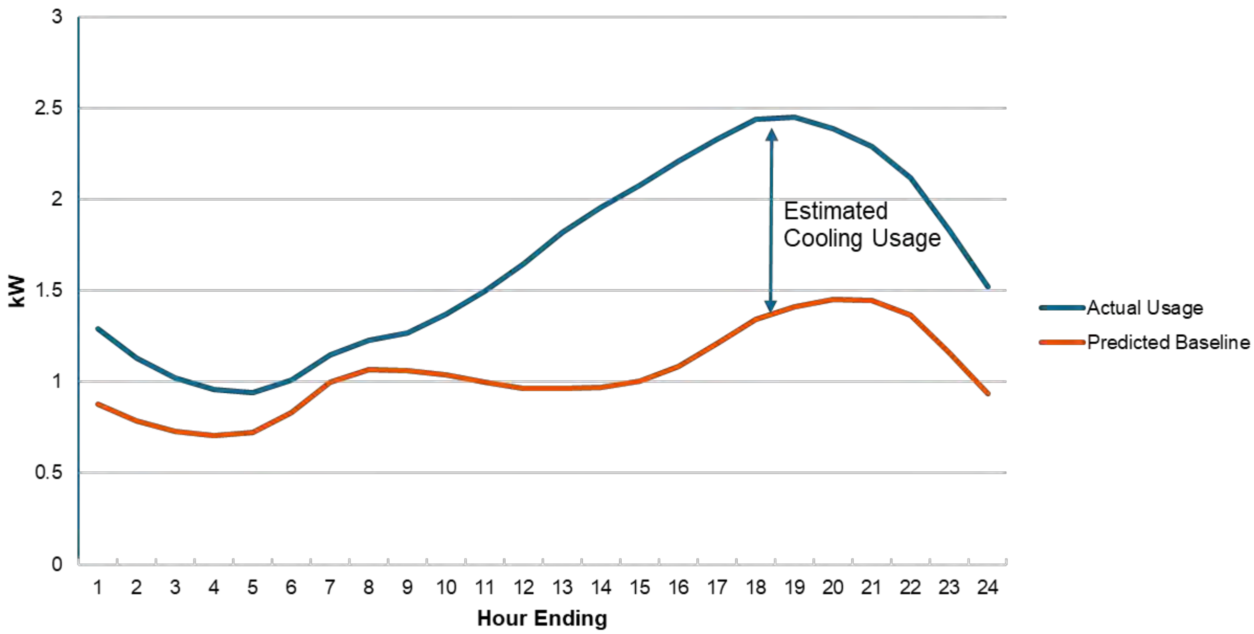
RI used interval data for all large C&I customers; and we used interval data from Duke Energy's load research sample for SMB and residential customers. Technical potential, in the context of DR, is defined as the total amount of load available for reduction that is coincident with the period of interest. In the context of this study, DR capacity is defined as the system peak hour for the summer, winter, fall, and spring seasons. Thus, four sets of capacity values are estimated.

As previously mentioned, all large C&I load is considered dispatchable, while residential and SMB DR capacity is based on specific end uses. For this study, it was assumed that summer DR capacity for residential customers would be comprised of air-conditioning (AC), pool pumps, water heaters, and managed electric vehicle charging. For small C&I customers, summer capacity would be based on AC load and water heaters. For winter capacity, both residential and small C&I DR capacity would be based on electric heating and water heaters. Fall and spring DR capacity for residential customers would be comprised of air-conditioning (AC), electric heating, pool pumps, water heaters, and managed electric vehicle charging. For small C&I customers, fall and spring capacity would be based on AC load, electric heating, and water heaters.

AC and heating load profiles for residential customers and AC load profiles for SMB customers were generated with the load research sample provided by Duke Energy. This sample included a customer breakout based on housing type for residential customers. Resource Innovations then used the interval data from these customers to create an average load profile for each customer segment.

The average load profile for each customer segment was combined with historical weather data and used to estimate hourly load as a function of weather conditions. AC and heating loads were estimated by first calculating the baseline load on days when cooling degree days (CDD) and heating degree days (HDD) were equal to zero, and then subtracting this baseline load. This methodology is illustrated by Figure 5-1 (a similar methodology was used to predict heating loads).

Figure 5-1: Methodology for Estimating Cooling Loads



This method was able to produce estimates for average AC/heating load profiles for the seven different customer segments within the residential and small C&I sectors.

Profiles for residential pool pump loads were estimated by utilizing utility-specific end-use load data provided by DEI. Profiles for residential water heater loads were estimated by using NREL's end-use load profile database.

For all eligible loads, the technical potential was defined as the amount that was coincident with system peak hours for each season, which are August from 2:00-3:00 PM for summer, January from 6:00-7:00 PM for winter, September from 2:00-3:00 PM for fall, and May from 1:00-2:00 PM for spring. As mentioned in Section 4.3, for technical potential there was also no measure breakout needed, because all measures will target the end-uses' estimated total loads.

5.1.3. Solar Photovoltaic Systems

To determine technical potential for PV systems, RI estimated the percentage of rooftop square footage that is suitable for hosting PV technology. Our estimate of technical potential for PV systems in this report is based in part on the available roof area and consisted of the following steps:

- Step 1: Outcomes from the forecast disaggregation analysis were used to characterize the existing and new residential, commercial, and industrial building stocks.

    - To calculate the total roof area for residential buildings, the average roof area per household is multiplied by the number of households.
    - For commercial and industrial buildings, RI calculated the total roof area by first dividing the load forecast by the energy usage intensity, which provides an estimate of the total building square footage. This result is then divided by the average number of floors to derive the total roof area.
- Step 2: The total available roof area feasible for installing PV systems was calculated. Relevant parameters included unusable area due to other rooftop equipment and setback requirements, in addition to possible shading from trees and limitations of roof orientation (factored into a "technical suitability" multiplier).
- Step 3: Estimated the expected power density (kW per square foot of roof area).
- Step 4: Estimated the hourly PV generation profile using NREL's PV Watts Calculator
- Step 5: Calculated total energy and coincident peak demand potential by applying RI's Spatial Penetration and Integration of Distributed Energy Resources (SPIDER) Model.

The methodology presented in this report uses the following formula to estimate overall technical potential of PVs:

Equation 5-3. Core Equation for Solar Technical Energy Potential

$$\text{PV Technical Energy Potential} = \text{Suitable Rooftop PV Area (Sq Ft)} \times \text{PV Power Density (kW-DC/Sq Ft)} \times \text{Generation Factor (kWh/kW-DC)}$$

Where:

- **Suitable Rooftop PV Area for Residential [Square Feet]:** Number of Residential Buildings times Average Roof Area Per Building times Technical Suitability Factor
- **Suitable Rooftop PV Area for Commercial [Square Feet]:** Energy Consumption [kWh] divided by Energy Intensity [kWh / Square Feet] divided by Average No. of Stories Per Building times Technical Suitability Factor
- **PV Power Density [kW-DC/Square Feet]:** Maximum power generated in Watts per square foot of solar panel.
- **Generation Factor:** Annual Energy Generation Factor for PV, from PV Watts (dependent on local solar irradiance)

5.1.4. Battery Storage Systems Charged from PV Systems

Battery storage systems on their own do not generate power or create efficiency improvements, but store power for use at different times. Therefore, in analyzing the technical potential for battery storage systems, the source of the stored power and overlap with technical potential identified in other categories was considered.

Battery storage systems that are powered directly from the grid do not produce annual energy savings but may be used to shift or curtail load during specific time periods. As the DR technical potential analyzes curtailment opportunities for the summer and winter peak period, and battery storage systems can be used as a DR technology, the study concluded that no additional technical potential should be claimed for grid-powered battery systems beyond that which can be attributed to DR.

Battery storage systems that are connected to on-site PV systems also do not produce additional energy savings beyond the energy produced from the PV system[3]. However, PV-connected battery systems do create the opportunity to store energy during period when the PV system is generating more than the home or business is consuming and use that stored power during utility system peak periods.

To determine the additional technical potential peak demand savings for "solar plus storage" systems, our methodology consisted of the following steps:

- Assume that every PV system included in PV Technical Potential is installed with a paired storage system.
- Size the storage system assuming peak storage power is equal to peak PV generation and energy storage duration is three hours.

Apply RI's hourly dispatch optimization module in SPIDER to create an hourly storage dispatch profile that maximizes the economic benefit from the customer perspective and accounts for a) customer hourly load profile, b) hourly PV generation profile, and c) battery peak demand, energy capacity, and roundtrip charge/discharge efficiency (illustrated in Table 4-2). This impact is different than that which might be expected if the storage were instead used for a demand response program.

5.2. DEI Energy Efficiency Technical Potential

This section provides the results of the DEI energy efficiency technical potential for each of the three segments.

[3] PV-connected battery systems experience some efficiency loss due to storage, charging, and discharging.

5.2.1. Summary

Table 5-1 summarizes the cumulative energy efficiency technical potential by sector. Cumulative impacts represent persistent impacts to the base DEI energy sales forecast and is not equal to the sum of annual incremental energy. This is due to the "rolloff" of energy efficiency retrofit measures as they reach the end of their effective useful lives, and their forecast impacts are superseded by impacts from replacing associated equipment with high efficiency equipment over time. The total energy saved over the period is represented by the sum of incremental annual energy saving and represents all energy efficiency potential captured over the study period.

Table 5-1: DEI Cumulative Energy Efficiency Technical Potential by Sector

Sector	Technical Potential (2025-2049)					
	Energy (GWh)	% of 2025 Base Sales	Demand (MW)			
			Spring	Summer	Fall	Winter
Residential	3,080	32%	890.6	918.4	788.7	497
Commercial	1,173	19%	351.6	345.9	347.5	188.7
Industrial	1,625	15%	213.9	214	214	190.4
Total	**5,878**	**22%**	**1,456**	**1,478**	**1,350**	**876**

5.2.2. Sector Details

Figure 5-2 summarizes the DEI residential sector energy efficiency technical potential by end use and customer segment.

Figure 5-2: DEI Residential EE Technical Potential– Cumulative 2049 by End-Use

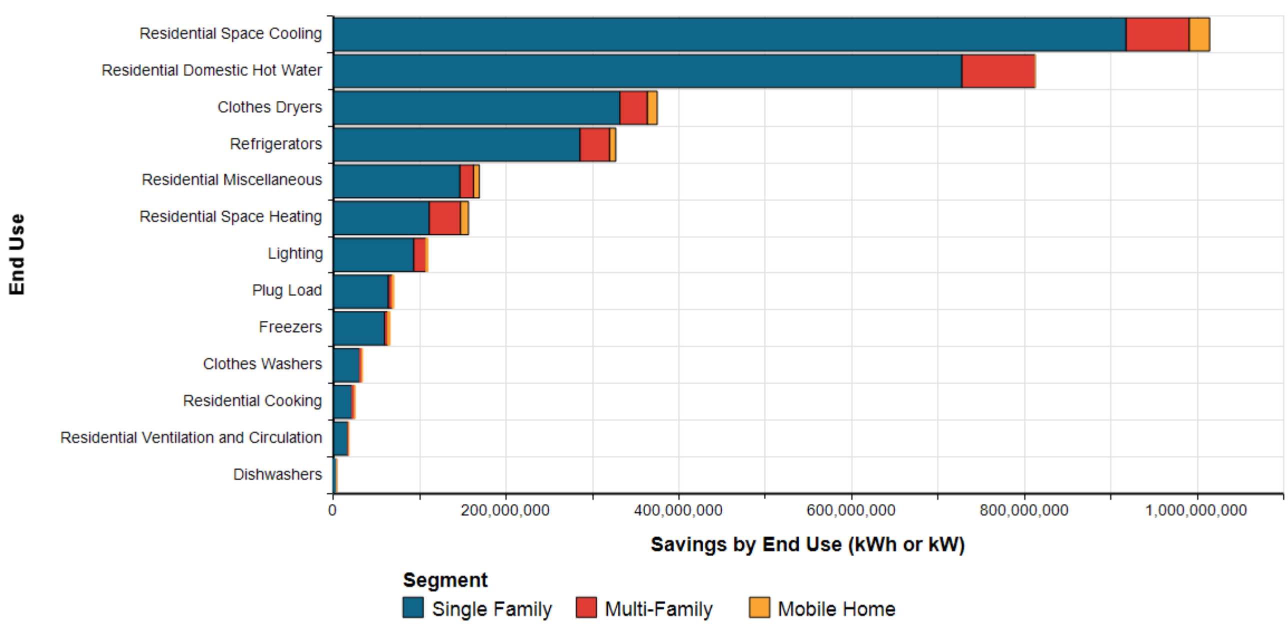


Figure 5-3 summarizes the DEI commercial sector EE technical potential by end use.

Figure 5-3: DEI Commercial EE Technical Potential – Cumulative 2049 by End-Use

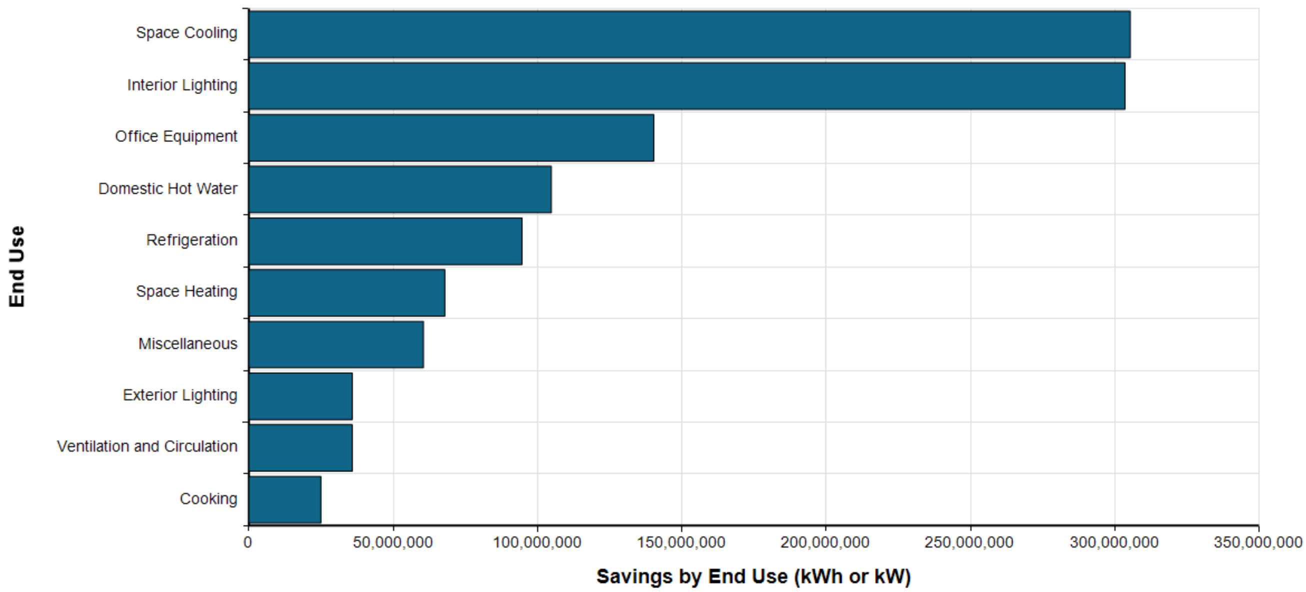


Figure 5-4 provides a summary of DEI energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-4: DEI Commercial EE Technical Potential – Cumulative 2049 by Segment

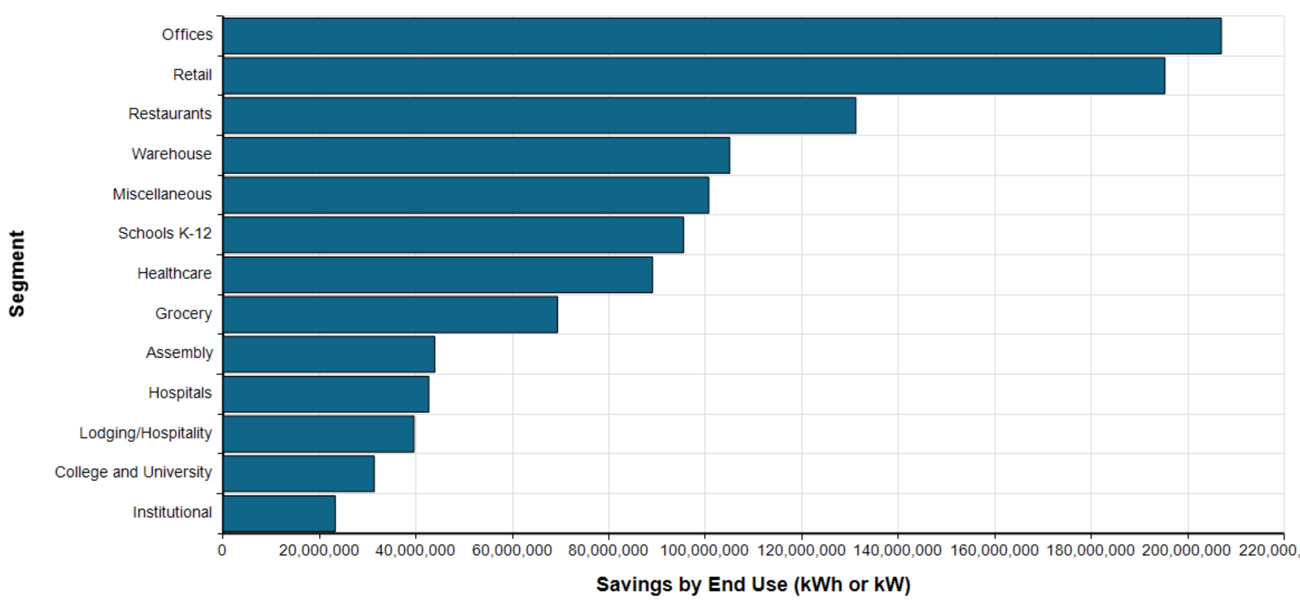


Figure 5-5 summarizes the DEI industrial sector energy efficiency technical potential by end use.

Figure 5-5: DEI Industrial EE Technical Potential – Cumulative 2049 by End-Use

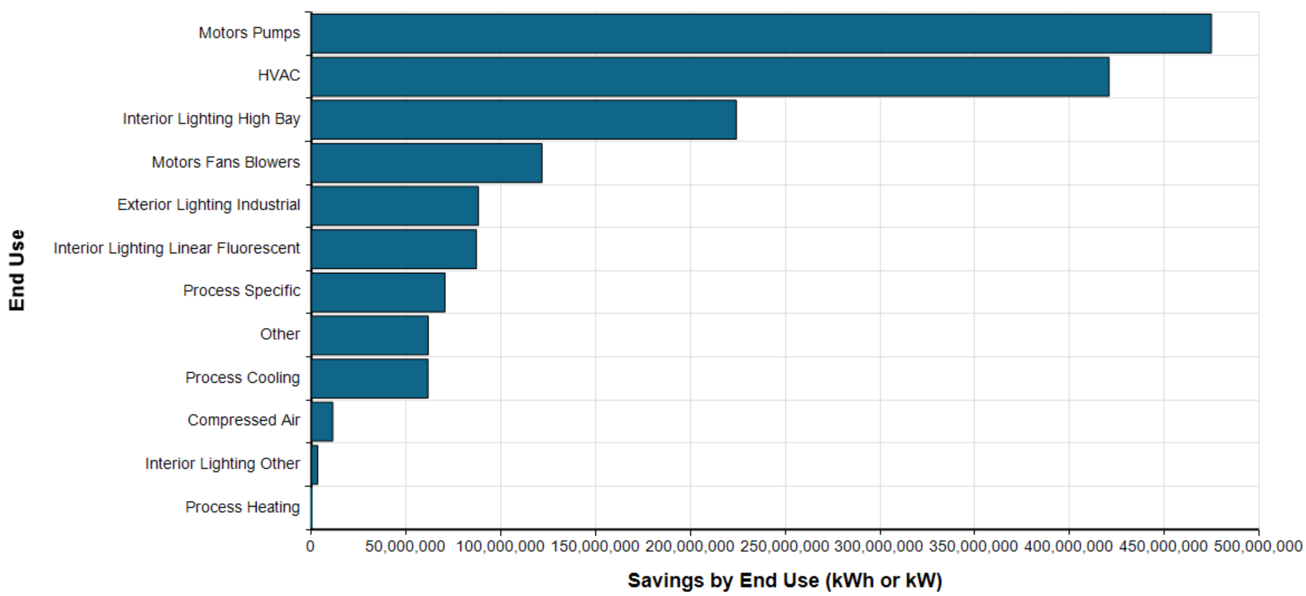
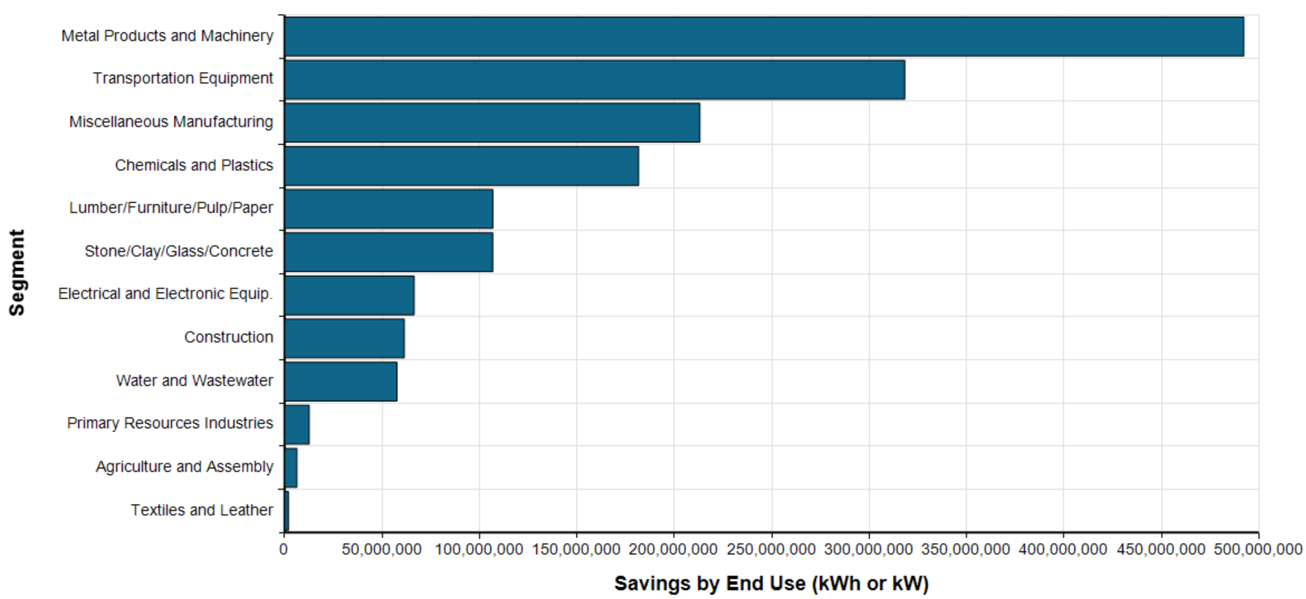


Figure 5-6 provides a summary of DEI energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-6: DEI Industrial EE Technical Potential – Cumulative 2049 by Segment



5.3. DEI Controllable Peak Load, by Customer Type

Technical potential for demand response is defined for each class of customers as follows:

- Residential & SMB customers – Technical potential is equal to the aggregate load for all end uses that can participate in Duke Energy's current programs plus DR measures not currently offered in which the utility uses specialized devices to control loads (*i.e.*, direct load control programs). This includes cooling, heating, and electric water heating loads for residential and small C&I customers. Pool pump loads, electric vehicle charging, and paired battery storage systems are also considered for residential and SMB sectors.
- Large C&I customers – Technical potential is equal to the total amount of load for each customer segment. This reflects the contractual nature of most large C&I programs and the fact that for a large enough payment and small enough number of events, we assume large C&I customers would be willing to reduce their usage to zero; technical potential includes all customers, even though many have opted out of the DR rider and are therefore not actually eligible to participate in Duke Energy programs.

As with the EE analysis, DR technical potential includes all customers, regardless of opt-out status or current participation in DR programs. Table 5-2 summarizes the seasonal DR technical potential by sector:

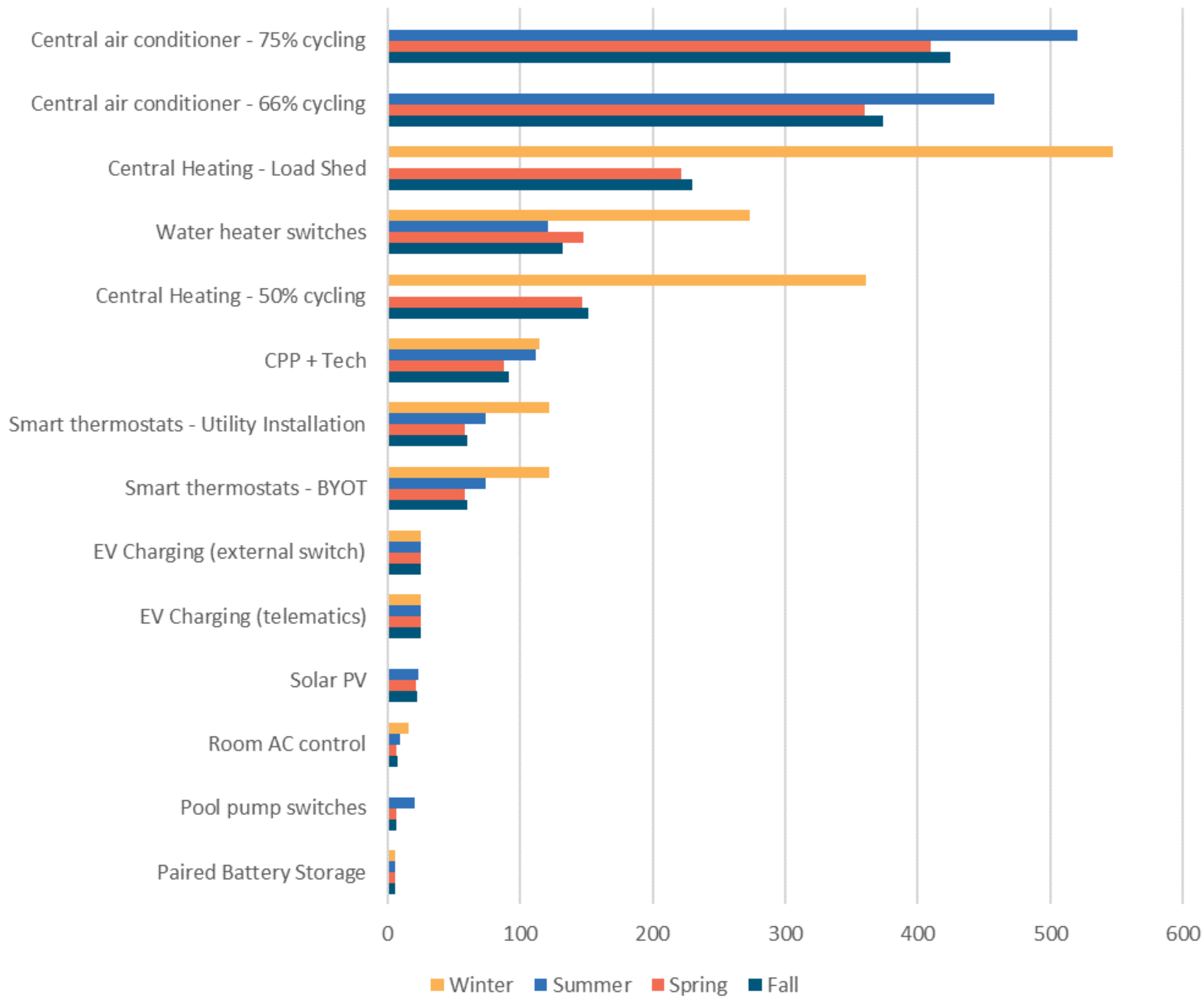
Table 5-2: DEI DR Technical Potential by Sector

Sector	Savings Potential			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Fall Peak Demand (MW)	Spring Peak Demand (MW)
Residential	1,469	1,612	1,616	1,581
SMB	176	63	204	209
Large C&I	2,514	1,893	2,312	2,317
Total	**4,159**	**3,568**	**4,133**	**4,107**

5.3.1. Residential

Residential technical potential is summarized by measure and season in Figure 5-7.

Figure 5-7: Residential DR Technical Potential by Measure and Season

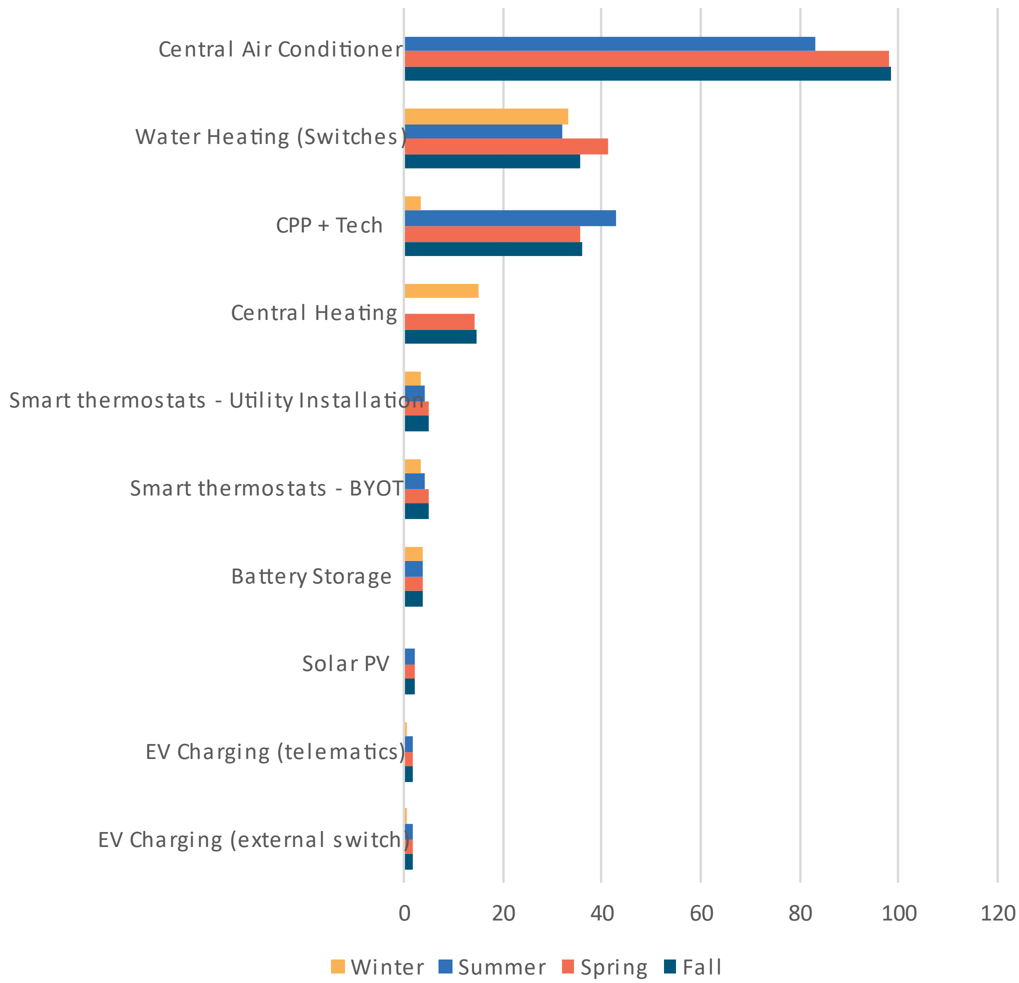


5.3.2. Non-Residential

5.3.2.1. Small C&I Customers

For small C&I technical potential, Resource Innovations looked at cooling and heating loads, water heating and EV charging. Small C&I technical potential is provided in Figure 5-8.

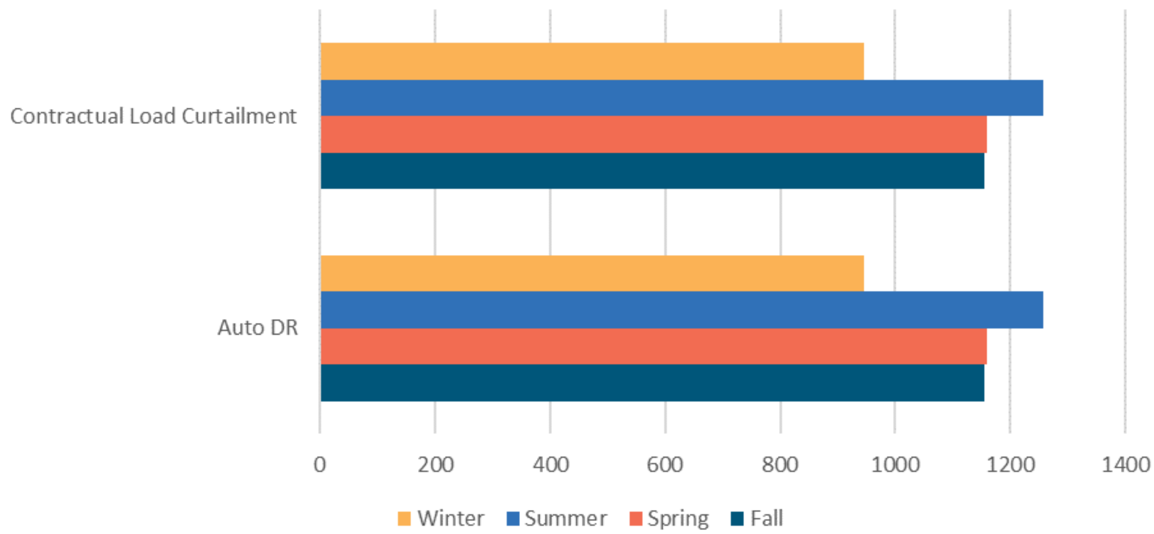
Figure 5-8: Small C&I DR Technical Potential by Measure and Season



5.3.2.2. Large C&I Customers

Figure 5-9 provides the technical potential for large C&I customers, broken down by measure and season. EV charging and battery storage had zero or negligible potential and were not included in the chart.

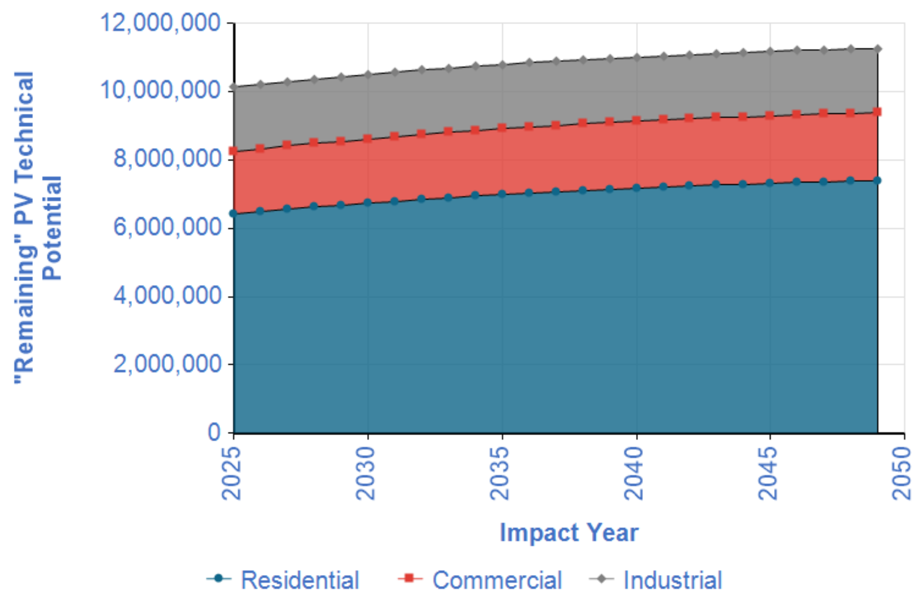
Figure 5-9: Large C&I DR Technical Potential by Measure and Season



5.4. Distributed Energy Resources

As described in the Executive Summary, RI presents two different views of DER technical potential: one is based on the nameplate capacity of installed PV, and PV paired with storage systems. The result of the nameplate technical capacity for PV energy reductions is presented below in Figure 5-10:

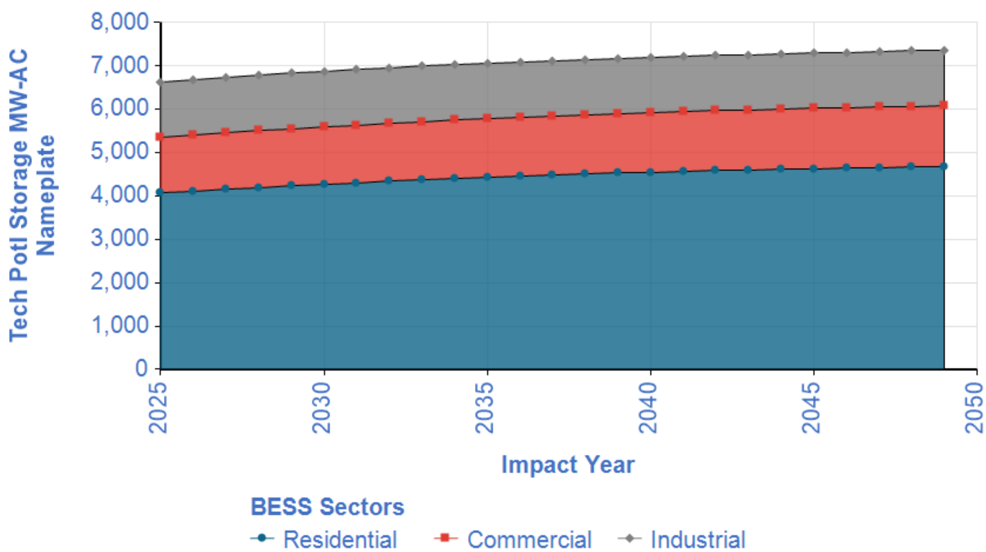
Figure 5-10: Nameplate PV Technical Potential "Remaining."



When expressed as a share of DEI baseline consumption, these PV technical potential estimates represent approximately 70%, 38%, and 18% of residential, commercial, and industrial sales (all customers, respectively).

Paired storage nameplate technical potential is equivalent to the nameplate MW-AC of solar PV, assuming storage systems are sized according to max PV capacity. These impacts are shown below in Figure 5-11.

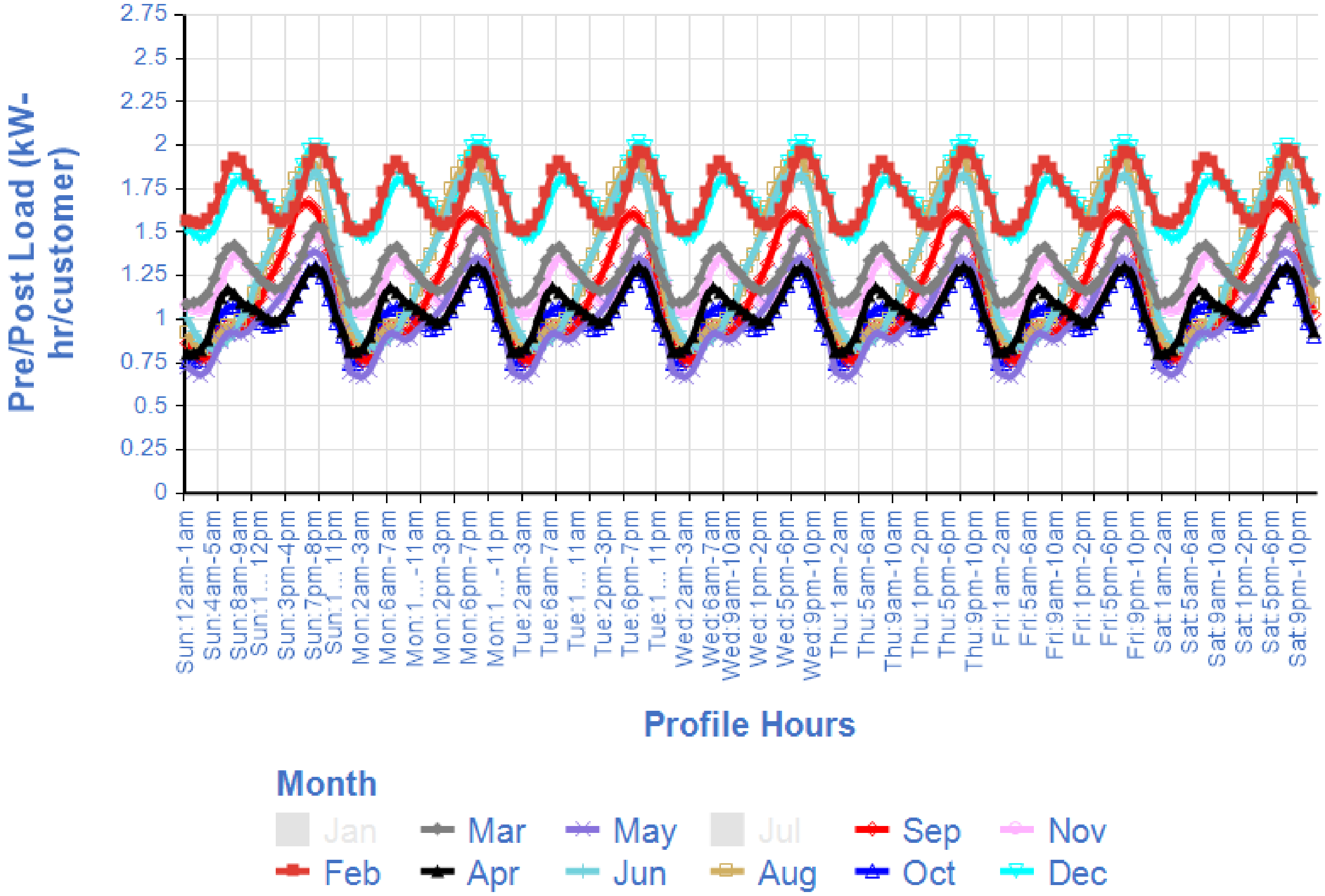
Figure 5-11: Paired Storage Nameplate Technical Potential



5.4.1. DER Grid Impacts of Technical Potential

The grid impacts of paired storage technical potential are heavily influenced by how customers are expected to dispatch their systems in the current market environment, with existing rate structures and load shapes. RI compiled monthly load shape data for each DEI customer class for use as a baseline description of energy consumption patterns. Figure 5-12 provides an example for the residential customer class.

Figure 5-12: Monthly Average Load Shapes for DEI Residential Customers (Hourly)



RI's SPIDER model contains a linear program that incorporates current DEI customer rate schedules to calculate optimal dispatch of the batter to maximize customer benefits. Analytical results demonstrate the optimal pre- and post-system installation rates for each customer class, summarized below in Table 5-3.

Table 5-3: Summary of Optimal Pre- and Post-Installation Rate Schedules

Sector	System Type	Pre-Installation Rate	Post-Installation Rate*
Residential	Solar + Storage	DEI - 6 (Residential Electric Service)	DEI - 6 (Residential Electric Service) + 73 (Renewable Energy Project Adjustment)
Commercial	Solar + Storage	DEI - 10 (Low Load Factor Service Secondary)	DEI - 10 (Low Load Factor Service Secondary) + 73 (Renewable Energy Project Adjustment)
Industrial	Solar + Storage	DEI - 12 (High Load Factor Service Secondary)	DEI - 12 (High Load Factor Service Secondary) + 73 (Renewable Energy Project Adjustment)

In additional to these rates, RI modeled optional TOU rates 10.4 and 12.4, but pairing storage with a solar system pushed customer economics in the direction of the non-TOU rate as the optimal post-installation rate.

Figure 5-13 provides an example of the optimal hourly dispatch characteristics RI estimated using DEI rates and class load shapes:

Figure 5-13: Example of Optimal Hourly Battery Dispatch for DER Grid Impacts of Paired Storage

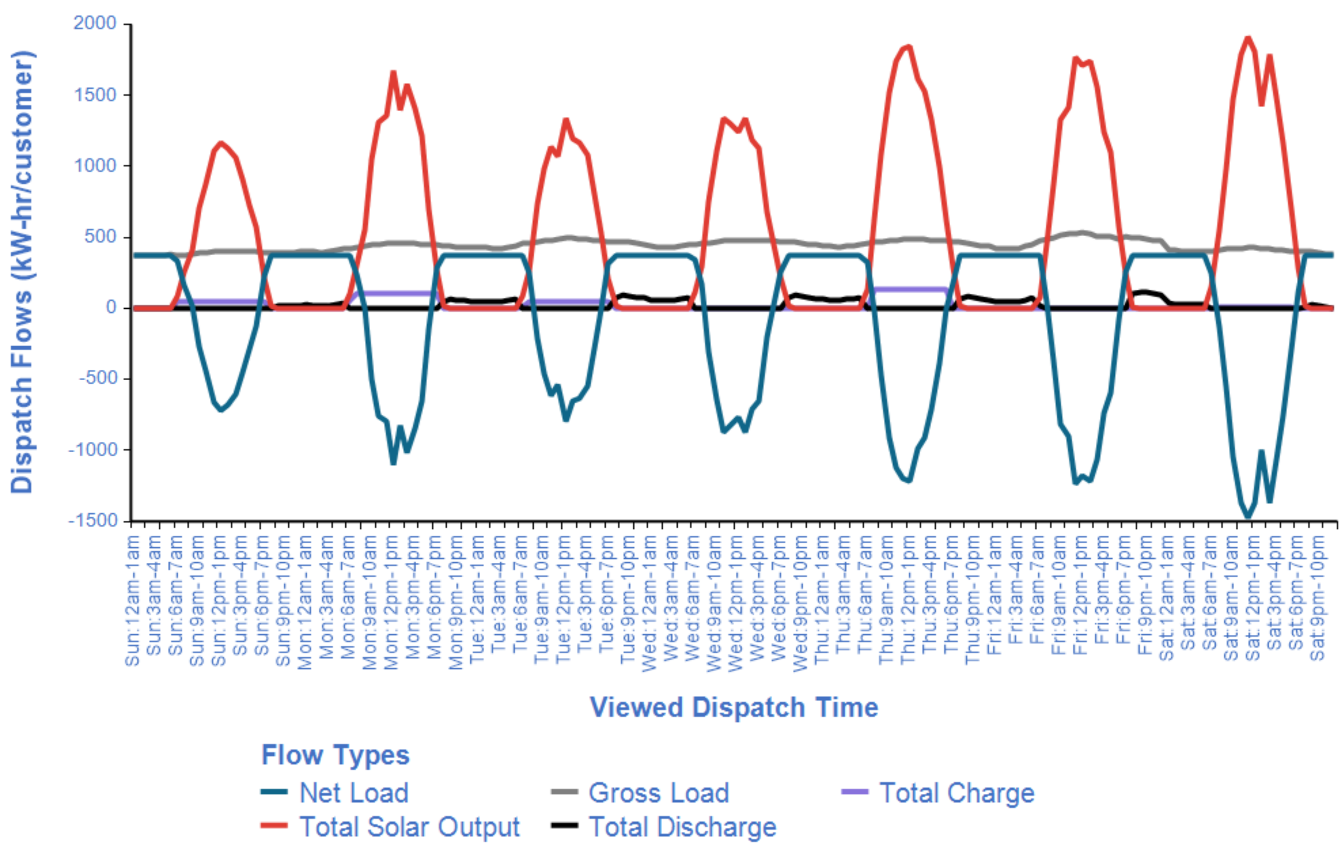


Figure 5-14 contains the results of expected grid impacts for DER technical potential as estimated by baseline consumption patterns, and optimal customer battery dispatch under current DEI rates.

Figure 5-14: Grid Impact of Paired Storage Technical Potential

Year	Residential				Commercial				Industrial			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2025	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.68	1.11	-23.85
2026	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.74	1.11	-23.93
2027	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.77	1.11	-23.98
2028	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.78	1.11	-23.99
2029	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.79	1.11	-24.01
2030	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2031	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2032	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2033	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2034	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2035	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2036	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2037	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2038	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2039	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2040	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2041	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2042	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2043	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2044	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2045	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2046	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2047	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2048	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2049	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02

6. Economic Potential

Economic potential compares the expected costs and benefits of energy and demand savings provided by EE and DR measures and applies the utility cost test (UCT) to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1. The economic potential is the sum of the energy savings associated with all measure permutations passing the economic screening.

The benefits of EE and DR measures under the UCT test represent avoided utility costs that result from energy and demand savings. These include avoided energy generation costs, avoided transmission and distribution costs, and avoided costs associated with lower peak capacity demands. The DEI system is a summer-planning system.

6.1. DR Cost-Effective Screening Criteria

RI applied the UCT test in this study, as directed by Duke Energy and stakeholders. The UCT is calculated by comparing the total avoided electricity production and delivery costs of a measure to the cost of offering that measure in a utility-sponsored program. The utility cost is the cost of offering incentives and program administrative costs. UCT screening requires inputs for measure incentive rates and utility administrative costs. Resource Innovations used actual program cost data from Duke Energy's 2023 program cycle.

For EE screening, the UCT test is applied to each energy efficiency measure based on installation of the measure in the first year of the study (i.e., avoided cost benefits begin in year one and extend through the useful life of the measure; incremental costs are incurred in year one). By using DSMore outputs for lifetime avoided cost benefits, the screening aligns with Duke Energy's avoided cost forecast and allows for a direct comparison of measure costs with these avoided cost benefits. The screening included measures with a UCT ratio of 1.0 or higher for determining economic potential.

For this analysis, the non-incentive and incentive costs for each sector is detailed in Table 6-1. These values are based on the actual DR program spending from Duke Energy and represent reasonable cost estimates in today's dollars with current technology.

Table 6-1: Utility Costs for DR Measure Screening

Sector	Measure	Recruitment Incentive	Utility Costs on Equip & Install	Acquisition Marketing	Recurring Incentive	5 Year Recurring Capital Expenditure	Admin Recurring Cost	Maintenance Marketing	Based on Existing Duke Program
Residential	Central air conditioner - 75% cycling	$35.00	$303.59	$123.50	$10.00	$3.79	$28.26	$11.20	Yes
	Central Heating - Load Shed								Yes
	Central air conditioner - 66% cycling	$25.00	$303.59	$123.50	$7.50	$3.79	$28.26	$11.20	Yes
	Central Heating - 50% cycling								Yes
	Water heater switches	$5.00	$277.22	$93.02	$6.00	$3.47	$19.61	$1.85	Yes
	Pool pump switches								No
	Room AC control	$25.00	$277.22	$0.00	$7.50	$3.47	$28.26	$11.20	No
	Smart thermostats - Utility Installation	$0.00	$334.00	$47.28	$25.00	$4.18	$42.63	$0.45	Yes
	Smart thermostats - BYOT	$75.00	$0.00	$2.09	$25.00	$0.00	$42.63	$0.45	Yes
	CPP + Tech	$0.00	$334.00	$144.00	$50.00	$4.18	$42.63	$0.45	No
	EV Charging (telematics)	$0.00	$0.00	$0.00	$50.00	$0.00	$0.00	$11.20	No
	EV Charging (external switch)	$0.00	$258.00	$0.00	$50.00	$3.23	$28.26	$11.20	No
	Solar PV	$3,600.00	$0.00	$47.28	$0.00	$0.00	$28.26	$11.20	No
	Paired Battery Storage	$0.00	$0.00	$50.00	$325.73	$0.00	$100.00	$11.20	No
Small C&I	Central Air Conditioner	$90.00	$185.00	$145.00	$86.00	$2.31	$72.00	$0.00	Yes
	Central Heating								No
	Water Heating (Switches)								No
	Smart thermostats - Utility Installation	$90.00	$175.00	$145.00	$86.00	$2.19	$72.00	$0.00	No
	Smart thermostats - BYOT	$90.00	$0.00	$145.00	$86.00	$0.00	$72.00	$0.00	No
	CPP + Tech	$0.00	$175.00	$145.00	$86.00	$2.19	$72.00	$0.00	No
	EV Charging (telematics)	$0.00	$175.00	$0.00	$86.00	$2.19	$72.00	$0.00	No
	EV Charging (external switch)								No
	Solar PV	$0.00	$2,500.00	$100.00	$0.00	$31.25	$72.00	$0.00	No
	Battery Storage	$0.00	$0.00	$100.00	$2,335.96	$0.00	$100.00	$0.00	No
Large C&I	Auto DR	$0.00	$738.00	$145.00	$147.82	$9.23	$246.56	$0.00	No
	Contractual Load Curtailment	$0.00	$370.00	$145.00	$147.82	$4.63	$246.56	$0.00	No
	EV Charging (telematics)	$0.00	$175.00	$145.00	$86.00	$2.19	$72.00	$0.00	No
	EV Charging (external switch)								No
	Paired Battery Storage	$0.00	$0.00	$145.00	$0.00	$0.00	$100.00	$0.00	No

The cost of enrolling customers from each customer segment is compared to the marginal benefits provided by enrolling customers in that segment. Because DR programs are called relatively infrequently, very little benefit is derived from avoided energy costs to the point where they are insignificant. Instead, DR derives its value from avoided generation capacity and avoided transmission and distribution capacity. RI also assumes an attrition rate of 7.5% annually with a measure life of 15 years.

6.2. DEI Energy Efficiency Economic Potential

This section provides the results of the DEI energy efficiency economic potential for each of the three sectors.

6.2.1. Summary

Table 6-2 summarizes the DEI's cumulative energy efficiency economic potential by sector and levelized cost associated with the identified potential:

Table 6-2: DEI EE Cumulative Economic Potential by Sector

Sector	Economic Potential (2025-2049)					
	Energy (GWh)	% of 2025 Base Sales	Demand (MW)			
			Spring	Summer	Fall	Winter
Residential	2,686	28%	812	839	718	410
Commercial	1,101	18%	339	334	336	169
Industrial	1,469	14%	194	194	194	172
Total	**5,255**	**20%**	**1,345**	**1,367**	**1,247**	**752**

6.2.2. Sector Details

Figure 6-1 summarizes the DEI residential sector energy cumulative efficiency economic potential by end use.

Figure 6-1: DEI Residential EE Economic Potential – Cumulative 2049 by End-Use

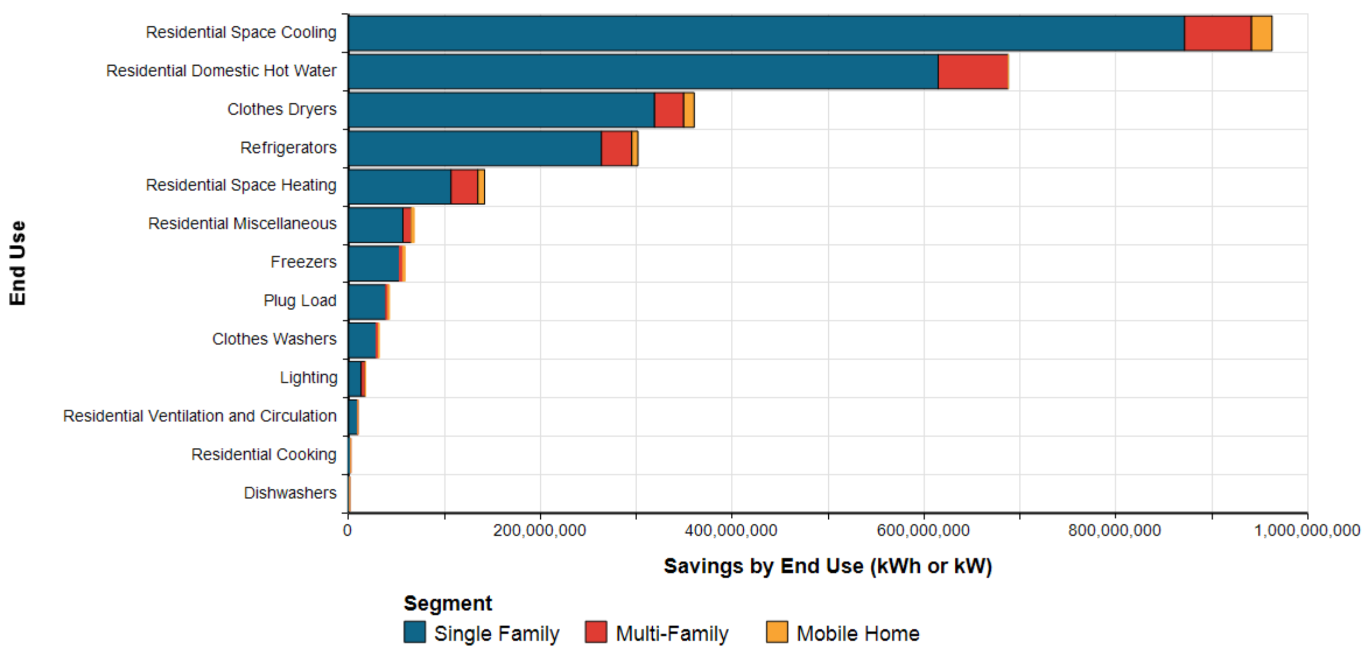


Figure 6-2 summarizes the DEI commercial sector EE economic potential by end use.

Figure 6-2: DEI Commercial EE Economic Potential – Cumulative 2049 by End-Use

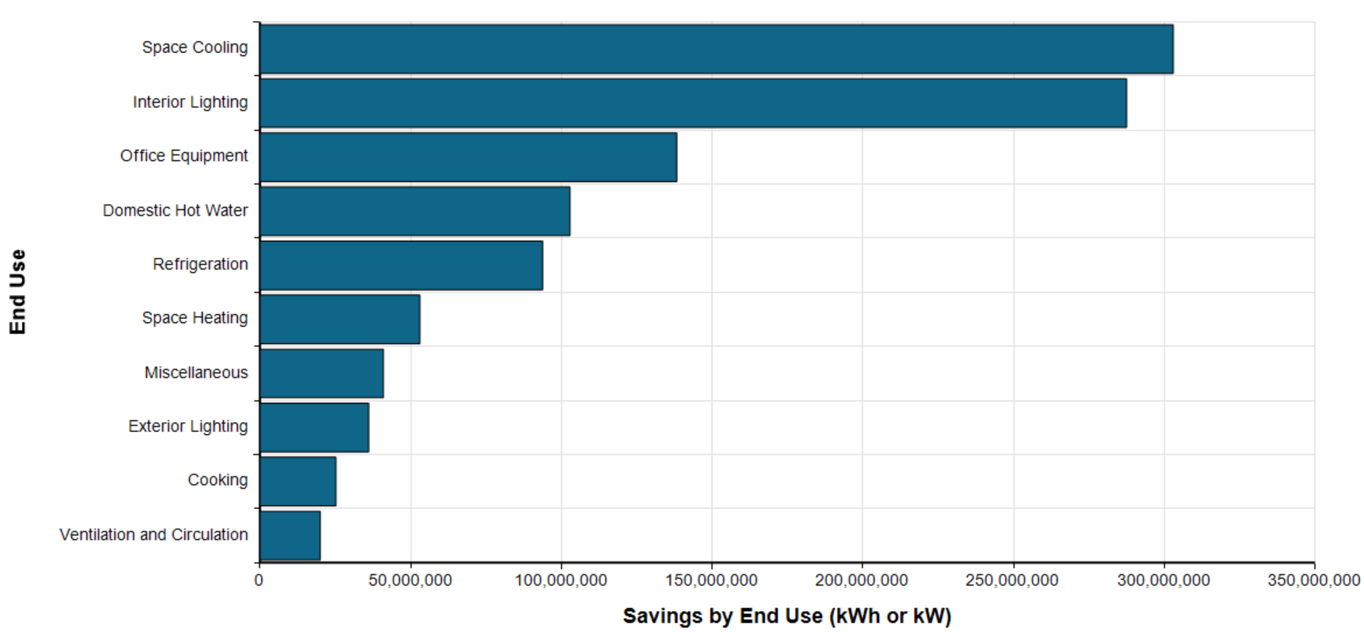


Figure 6-3 provides a summary of DEI energy efficiency economic potential contributions by commercial facility types analyzed in this study.

Figure 6-3: DEI Commercial EE Economic Potential – Cumulative 2049 by Segment

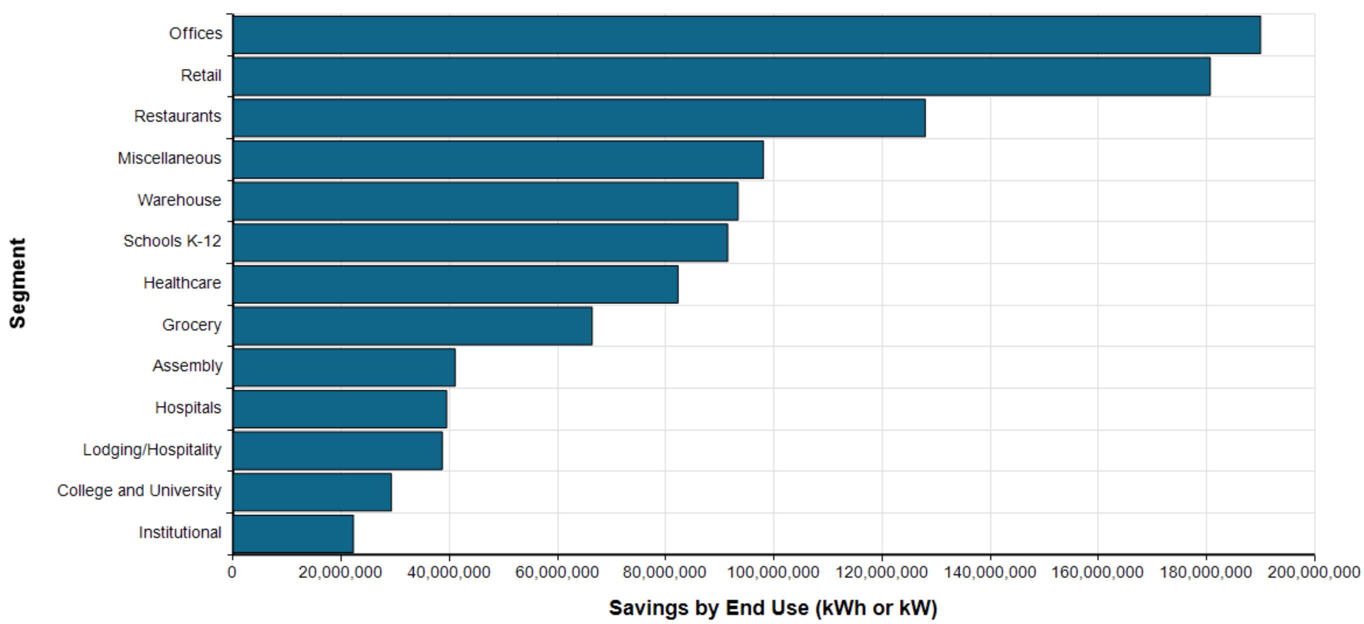


Figure 6-4 summarizes the DEI industrial sector energy efficiency economic potential by end use.

Figure 6-4: DEI Industrial EE Economic Potential – Cumulative 2049 by End-Use

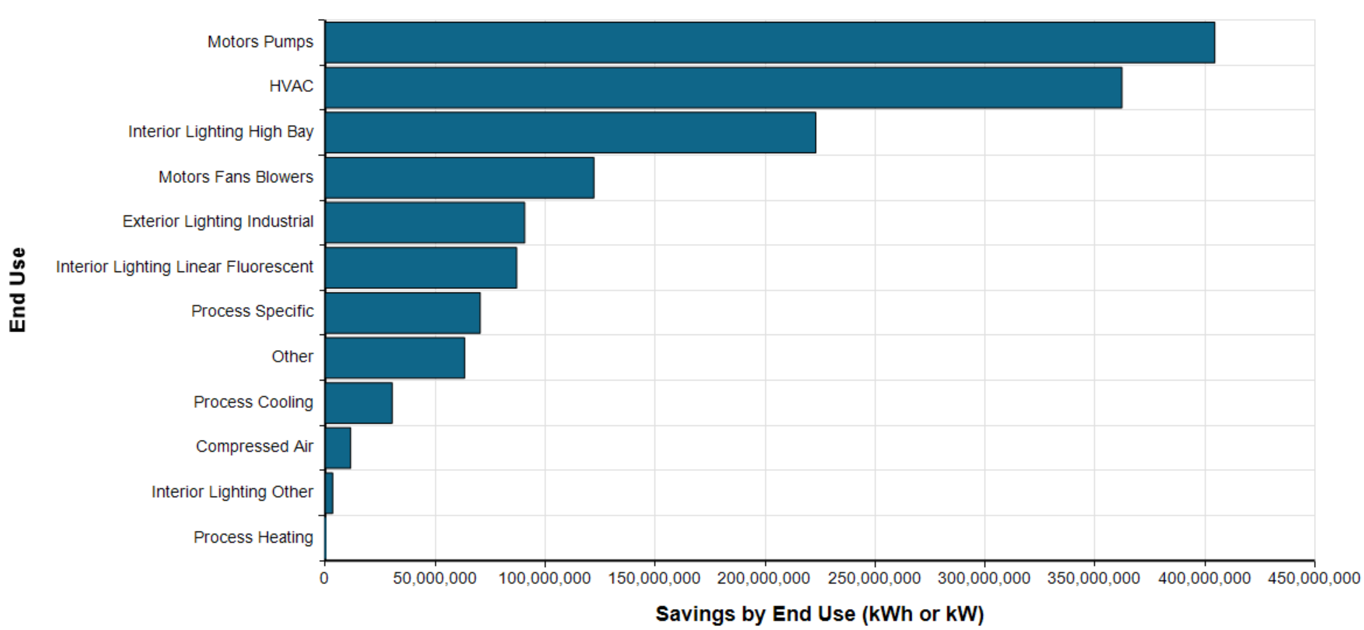
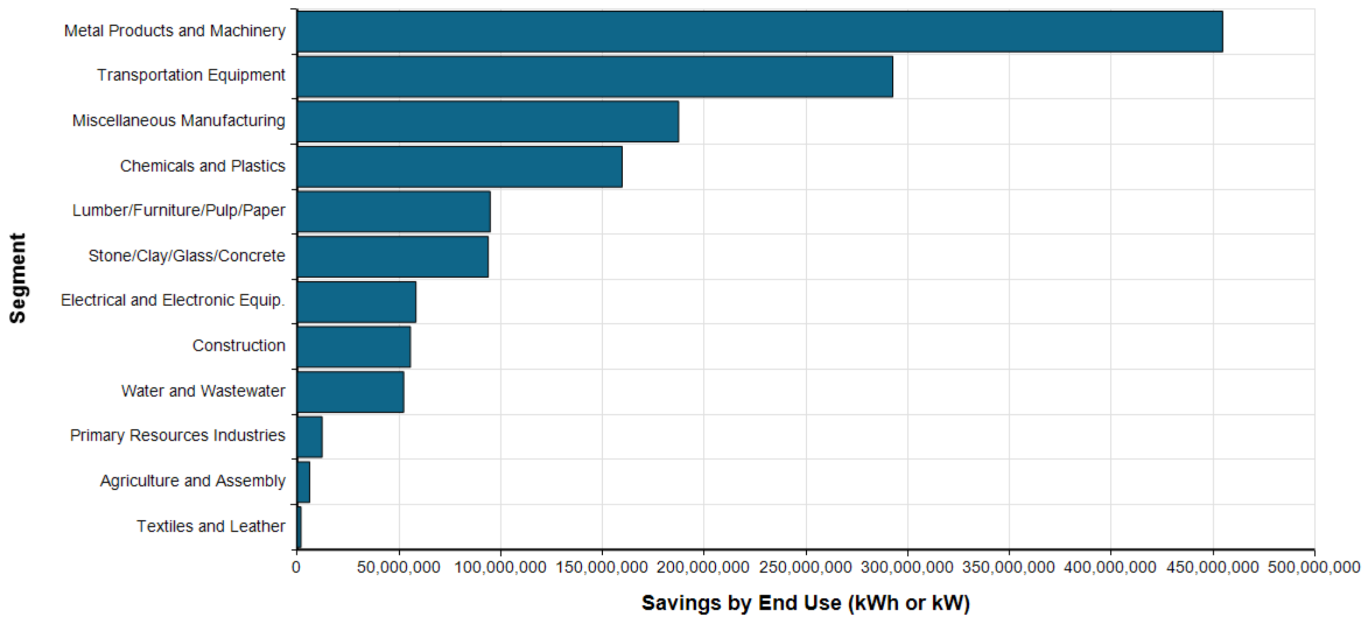


Figure 6-5 provides a summary of DEI energy efficiency economic potential contributions by industrial facility types analyzed in this study.

Figure 6-5: DEI Industrial EE Economic Potential – Cumulative 2049 by Segment



6.3. DEI Demand Response Economic Potential

DR cost-effectiveness screening for economic potential determines whether the benefits of enrolling a marginal customer for a given customer segment into a demand response program will outweigh the costs. This study uses UCT as screening criteria that considers program administrative and incentive costs. Since economic potential ignores the participation rate in the program (this is considered when determining the achievable potential), cost-effectiveness screening at this point only considers whether a marginal customer for a given customer segment is worth pursuing for participation in the program.

Each measure was screened using a “100% summer” avoided capacity forecast, as well as a seasonal avoided capacity forecast. The larger of these two avoided capacity values were then used as the final avoided cost for economic screening. Table 6-3 shows the economic potential by sector and season.

Table 6-3: DEI DR Economic Potential by Sector

Sector	Savings Potential			
	Summer (Agg MW)	Winter (Agg MW)	Fall (Agg MW)	Spring (Agg MW)
Residential	1,369	1,571	1,526	1,494
SMB	119	51	153	160
Large C&I	2,513	1,893	2,312	2,317
Total	**4,002**	**3,514**	**3,991**	**3,970**

Figure 6-6 presents the aggregate capacity each customer segment would be able to provide during the four seasonal peaks. Most of these customer segments produced a positive marginal net benefit, indicating that there is substantial, cost-effective DR potential available in DEI's territory. Similar figures are presented subsequently for SMB and LCI customers in Figure 6-7 and Figure 6-8, respectively. Any seasonal data missing from these graphs indicate a economic potential value of zero.

Figure 6-6: DEI Seasonal Residential Economic DR Potential (MW)

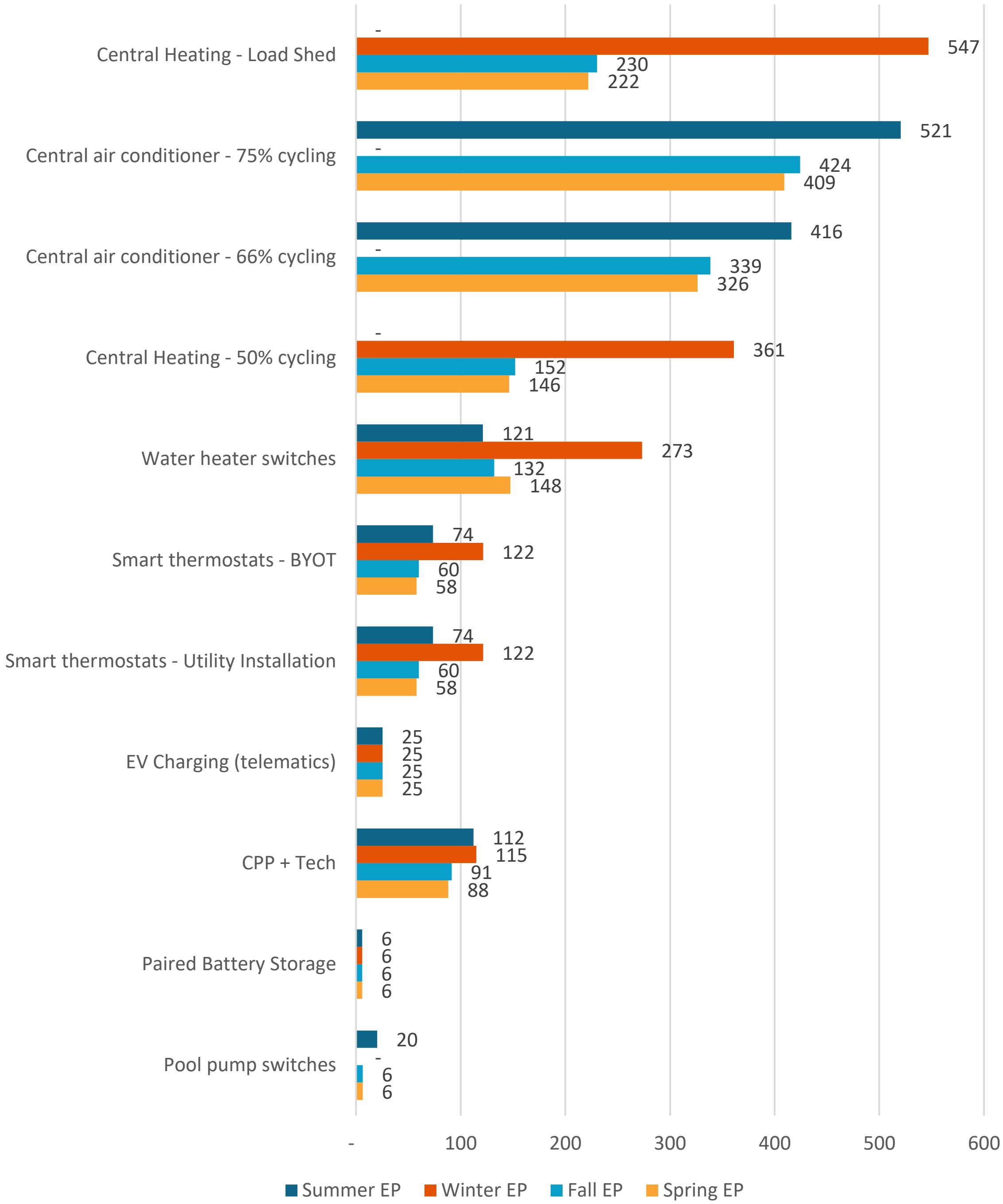


Figure 6-7: DEI SMB Economic Potential Results (MW)

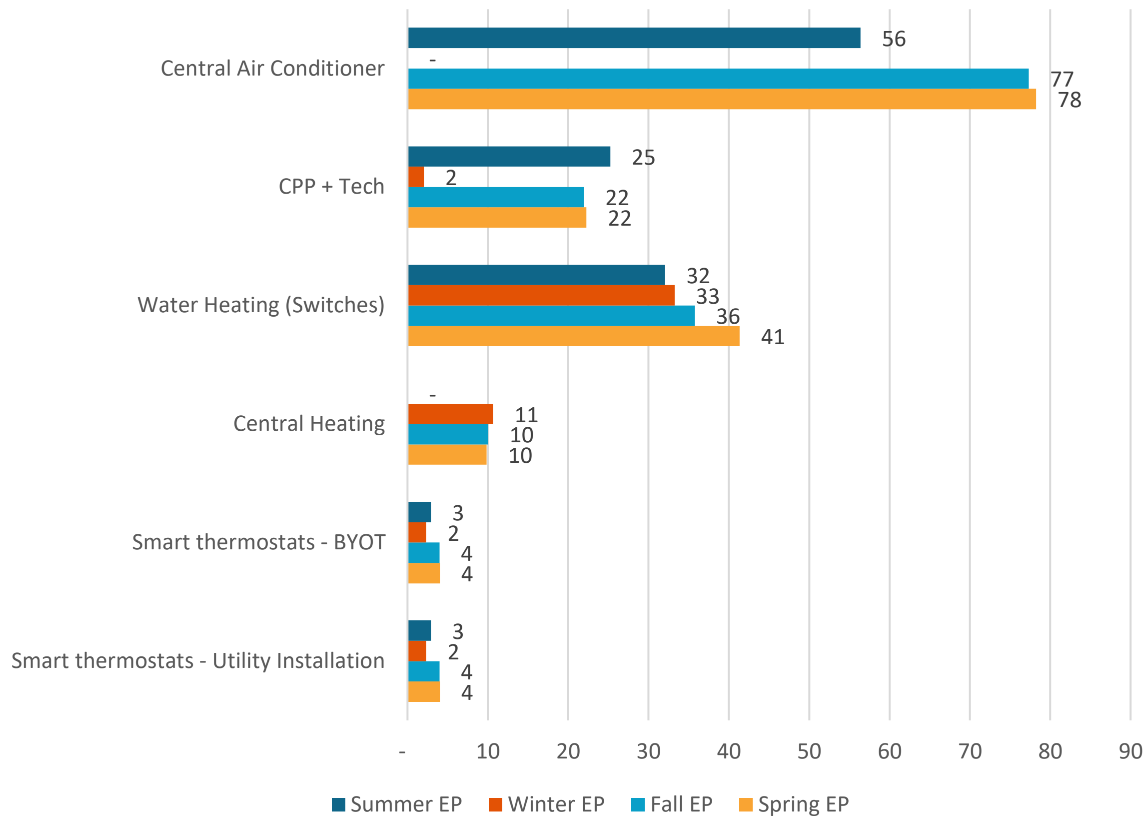
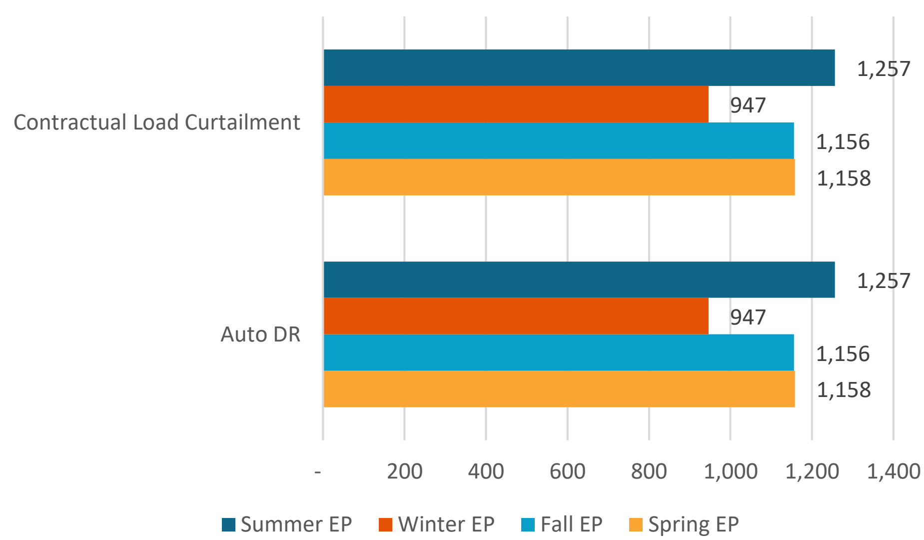


Figure 6-8: DEI Large C&I Economic Potential Results (MW)



6.4. Distributed Energy Resources

Economic potential compares the expected costs and benefits of energy and demand savings provided by solar systems and applies the utility cost test (UCT) to determine whether they meet the scenario screening criterion of a benefit-cost ratio greater than 1.

For this analysis, the incentives and administrative costs for each sector is detailed in Table 6-4, with other cost assumptions for the PV technology. These values represent reasonable cost estimates in today's dollars with current technology. As indicated below, solar with paired storage does not pass the UCT cost test when customers are assumed to dispatch optimally under current loads and rate schedules. This analysis does not account for the effects of a possible demand response program for existing batteries. The solar and paired storage forecast of nameplate capacity was analyzed by RI to estimate the impact of demand response incentives on expected program participation. This analysis is a component of the demand response potential estimates, whereas this section focuses on forecasted customer adoption and grid impacts at baseline.

Table 6-4: Key Assumptions for PV Economic Potential

Data Item	Res	Comm	Ind	Units	Source/Notes
PV Lifetime	20	20	20	Years	NREL
PV Cost	3,072	2,184	2,184	$/kW-DC	NREL, RI, DEI ($2025), assuming 1.15 DC/AC Ratio. Forecast cost declines
PV O&M Cost	21	15	15	$/year/kW-DC	NREL ($2025). Forecast cost declines
PV Utility Cost Test	1.14	1.53	1.53	dimensionless	In 2025, Assuming incentive of 30% of purchase price, 5% admin as % of incentives
Storage Lifetime	10	10	10	Years	NREL
Storage Cost	813	347	347	$/kWh	NREL ($2025) Assuming 3 hours of storage at peak capacity. Forecast cost declines.
Storage O&M	20	8	8	$/Year/kWh	NREL
Storage Utility Cost Test	0.0	0.0	0.0	dimensionless	Assuming dispatched economically by customer (this does not account for full dispatch per a possible Demand Response program, which is being analyzed separately)

7. Achievable Market Potential

Achievable market potential estimates customer adoption rates for cost-effective measures in a market featuring utility-sponsored programs. In this MPS RI developed customer adoption rates that are independent of historic Duke Energy program participation trends. These were calibrated to start 2023 Duke Energy program performance, but future adoption of measures cost-effectively offered by Duke Energy programs is driven by customer payback. Customer payback describes the number of years required for a customer to save an amount of energy equal to the value of measure first costs (minus incentive payments from utility programs). Utility-sponsored programs are typically focused on addressing market barriers and thereby boosting customer adoption of energy efficiency.

Customers may forego cost-effective EE and DR for a variety of reasons, some of which may include customer preferences for benefits arising from other types of investments; time and effort required to engage with program administration or to satisfy program requirements; high initial costs, lack of time to identify, evaluate, acquire, and install new measures; long investment payback times; payback uncertainty; or even for the inconvenience. Customers may need to overcome non-economic barriers such as: lack of knowledge about electricity consumption and associated technology; principal-agent issues, a.k.a. “split incentive,” problems; inability to capture non-market benefits; or economic conditions that potentially limit availability of some measures, increase measure costs, or affect customers’ incomes. In addition to these economic tradeoffs and market barriers, economic research increasingly demonstrates the strong role that human behavior plays in purchase decisions.

The EE/DR program lifecycle is designed explicitly to address the need for adaptive management of utility programs and to continuously improve program performance against market barriers. It also engages stakeholders to collaborate with utilities around program iterations and offer ideas from outside perspectives. The scope of this MPS does not include program design, as Duke Energy has been offering EE and DR programs for over a decade and has consistently followed the adaptive management principles of the EE/DR program lifecycle: market assessment, program design, program implementation, program evaluation, and adaptation. This study represents the market assessment component of this adaptive management cycle.

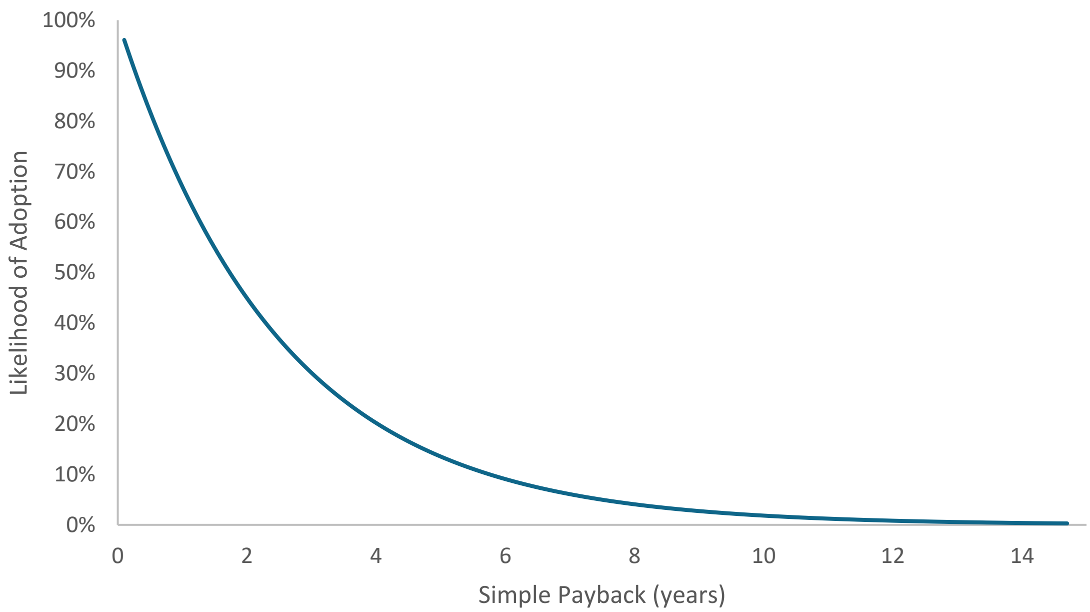
7.1. Customer Adoption

Duke Energy programs follow the EE/DR lifecycle of market analysis, program design, program implementation, program evaluations, stakeholder engagement, and adaptation. As the result of the EE/DR lifecycle process and the efforts of Duke Energy, stakeholders, and customers to erode market barriers, RI developed market adoption curves that reflect assumptions for the influence of DR bill savings on customer adoption rates.

We apply customer payback acceptance curves to all cost-effective measures, which addresses one major market barrier: time preferences for money. Customers value immediate monetary savings much more than future savings, whether due to economic of behavioral factors. Additional barriers may exist, they may lead to lower-than-expected adoption rates, and payback acceptance curves may not fully describe the impacts of market barriers. The magnitude or degree of influence market barriers currently exert in the Indiana service territory is not readily measured by existing data, though EM&V reports describe ongoing efforts to cost-effectively identify and address them though the EE/DR lifecycle.

The payback acceptance function that was applied is presented below in Figure 7-1. This function relates measures' simple payback time, in years, to the likelihood of the measure being adopted by a typical customer. At one year payback 67% of customers are estimated to adopt the measure; 45% would adopt at payback of two years, 30% would adopt at payback of three years, and adoption likelihood drops to 14% or lower after five or more years.

Figure 7-1: Payback Acceptance Curve for Achievable Potential



We used the customer payback acceptance curve to represent the ideal case of well-informed, rational customer decisions with low transaction costs. Owing to these MPS parameters and focus, we describe our estimates as expected EE and DR potential in a market featuring utility-sponsored programs and incentives. The estimates assume adaptive program management is applied to successfully lower market and non-market barriers to customer adoption over time; the customer payback acceptance approach addresses only the barriers of investment costs and opportunity costs.

7.2. Achievable Market Potential Scenarios

The achievable market potential scenarios reflect customer adoption of measures that are cost-effective for Duke Energy to offer within an existing program. Customer adoption rates are independent of the program design, as previously described, except for reducing customer first costs by the utility incentive amount. The three scenarios developed for this study are as follows:

- **Base** – reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program.
- **High Incentive** – doubles current incentive rates, if not already 100%, with a cap at 75% of the measure incremental cost; applies utility avoided cost benefits from the base scenario. The model also includes an incentive backstop that limits the incentive increase to the maximum in this range if the increase would otherwise lead to a measure being not cost-effective.
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates.

7.3. Market Diffusion

Achievable market potential describes a subset of customers expected to take advantage of Duke Energy EE and DR programs. Data concerning individual customer purchases of EE and DR equipment are not widely available and may be sparse in their coverage of EE and DR measure opportunities. EPA's ENERGY STAR program estimates the market penetration of certified products, and EIA's periodic market assessments provide the primary basis for understanding current market penetration of EE technology.

In addition to these sources, Duke Energy conducts residential appliance saturation surveys (RASS) to better understand the energy consumption of residential customers in the Duke Energy service territory. Commercial and industrial building and equipment baselines are limited to the modeling and analysis available from EIA, Duke Energy forecasting, and Duke Energy customer data.

We apply the Bass diffusion model to estimate technology market penetration from customer adoptions over time. The Bass model is a widely accepted description of how new products and innovations spread through an economy over time. It was originally published in 1969, and in 2004 was voted one of the top 10 most influential papers published in the 50-year history of the peer-reviewed publication *Management Science*[4]. More recent publications by Lawrence Berkeley National Laboratories have illustrated the application of this model to conservation and demand management (CDM) in the energy industry[5].

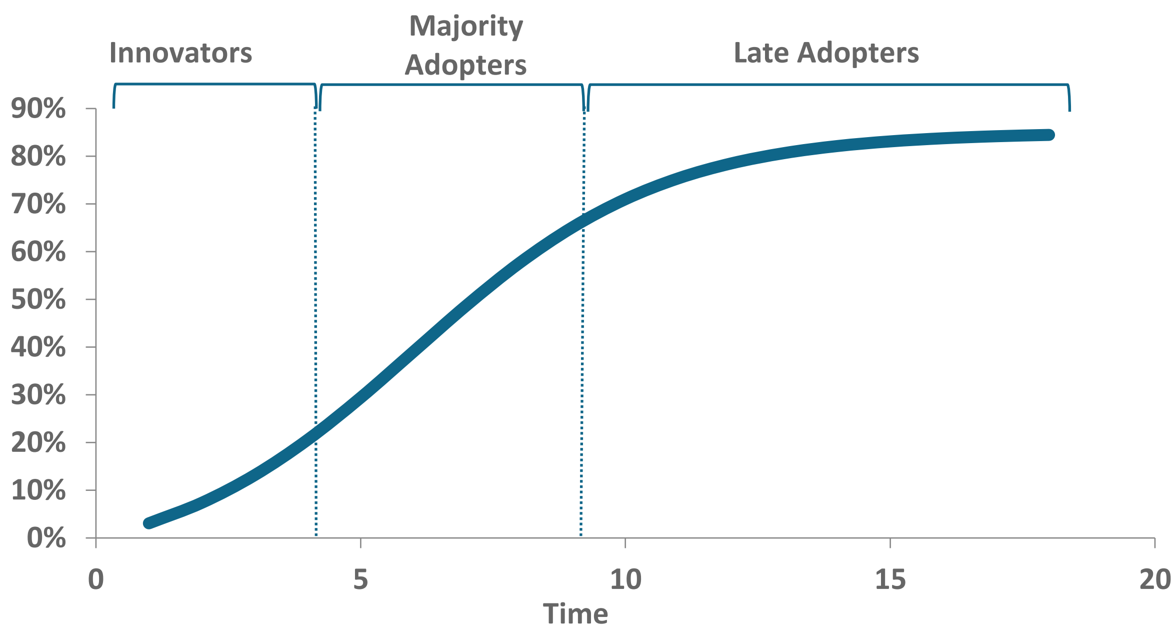
RI applied general technology diffusion curves describing expected market familiarity with EE and DR measures, which will be enhanced by the ongoing efforts of Duke Energy and stakeholders. The curves represent effective program marketing and sophisticated customer recruitment of cost-effective measures that meet customer payback acceptance criteria.

[4] Bass, F. 2004. Comments on "A New Product Growth for Model Consumer Durables the Bass Model" (sic). *Management Science* 50 (12_supplement): 1833-1840. http://pubsonline.informs.org/doi/abs/10.1287/mnsc.1040.0300. Accessed 01/08/2016.

[5] Buskirk, R. 2014. Estimating Energy Efficiency Technology Adoption Curve Elasticity with Respect to Government and Utility Deployment Program Indicators. LBNL Paper 6542E. Sustainable Energy Systems Group, Environmental Energy Technologies Division. Ernest Orlando Lawrence Berkeley National Laboratory. http://escholarship.org/uc/item/2vp2b7cm#page-1. Accessed 01/14/2016.

According to product diffusion theory, the rate of market adoption for a product changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of cumulative market saturation is illustrated in Figure 7-2.

Figure 7-2: Bass Model Cumulative Market Penetration



The Bass Diffusion model is a mathematical description of how the rate of new product diffusion in a market changes over time. Figure 1 depicts the cumulative market adoption with respect to time, $S(t)$. The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters. The following equation describes this relationship:

$$\frac{dS(t)}{dt} = \left(p + \frac{q}{m} * S(t-1)\right) * (m - S(t-1))$$

Where:

$\frac{dS(t)}{dt}$ = the rate of adoption for any discrete time period, t

p = external influences on market adoption

q = internal influences on market adoption

m = the maximum market share for the product

$S(t-1)$ = the cumulative market share of the product, from product introduction to time period *t-1*

Marketing is the quintessential external influence. The internal influences are characteristics of the product and market; for example: the underlying market demand for the product, word of mouth, product features, market structure, and other factors that determine the product's market performance. RI's approach applied literature reviews and analysis of secondary data sources to estimate the Bass model parameters. We then extrapolated the model to future years; the historic participation and predicted future market evolution serve as the program adoption curve applied to each proposed offering.

7.4. DR Achievable Market Potential

Duke Energy offered DR programs for over 10 years, covering a variety of approaches for load management such as direct utility control; contractual programs for guaranteed load drop and emergency load management; and load control programs that incentivize economic load response. These offer types are described in Table 7-1.

Table 7-1: DR Technologies covered by Duke Energy Programs

Type of DR	Sector	Technology
Utility controlled loads	Residential	▪ Central AC switches ▪ Smart thermostat ▪ Water heater switches
	Non-Residential	▪ HVAC controls (EMS) ▪ Smart thermostat ▪ Auto DR for process loads ▪ Backup generation
Contractual	Non-Residential	▪ Emergency Load Response ▪ Economic Load Response

7.4.1. Participation Rates for DR Programs

While economic potential examines marginal net benefits provided by customers, achievable program potential considers the estimated participation rate and how that affects the overall cost-effectiveness of the customer segment. The magnitude of DR resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DR? What are details of specific offers and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed?

For certain DR measures, an additional component of participation relates to the mutual exclusivity of the measures themselves. The achievable potential from measures under the same program, and that target the same customers, are reduced by one another. A customer who enrolls his/her central air-conditioner in a 66% shed load control offering cannot also enroll in the 75% shed offering. To account for the mutual exclusivity of specific measures, the study applied an adjustment to the numbers of eligible customers based on the known distribution of the population under existing programs.

For program-based DR, participation rates are calculated as a function of the incentives offered to each customer group. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DR potential from that segment should be included in the achievable program potential. The following subsections describe how marketing/incentive level, participation rates, and technology costs are handled by this study.

7.4.2. Marketing and Incentive Levels for Programs

Several underlying assumptions are used to define three different marketing levels. The number of marketing attempts and the method of outreach are varied by marketing level, as described in Table 7-2. The enhanced case assumes a high marketing level for program-based DR, while the base case assumes a medium marketing level (the low marketing level was not utilized for this study). Within each marketing level, the participation rate for each customer segment is a function of the incentive level.

The specific tactics included in the low, medium, and high marketing scenarios are not prescriptive but are instead designed to provide concrete details about the assumptions used in the study. There is a wide range of strategies and tactics that can attain the same enrollment levels and the best approach for a jurisdiction is best developed through testing and optimizing the mix of marketing - tactics and incentives.

Table 7-2: Marketing Inputs for Residential Program Enrollment Model

Input	Marketing Level			
	No Marketing	Low	Medium	High
Number of marketing attempts (Direct mail)	0	5	5	8
Outreach mode	No marketing	Direct mail	DM + phone	DM + phone + door-to-door
Installation required (%)	0%	100%	100%	100%
Attrition Rate	7%	7%	7%	7%

The incentive level and marketing inputs for each scenario determine the participation rate, assuming that the incentive is uniform across all customer segments within a given customer class.

7.4.3. Participation Models

The participation models for the residential and nonresidential customer segments use a bottom-up approach to estimate participation rates. These estimates have been crosschecked with mature programs in other jurisdictions to ensure that the estimated participation rates are reasonable.

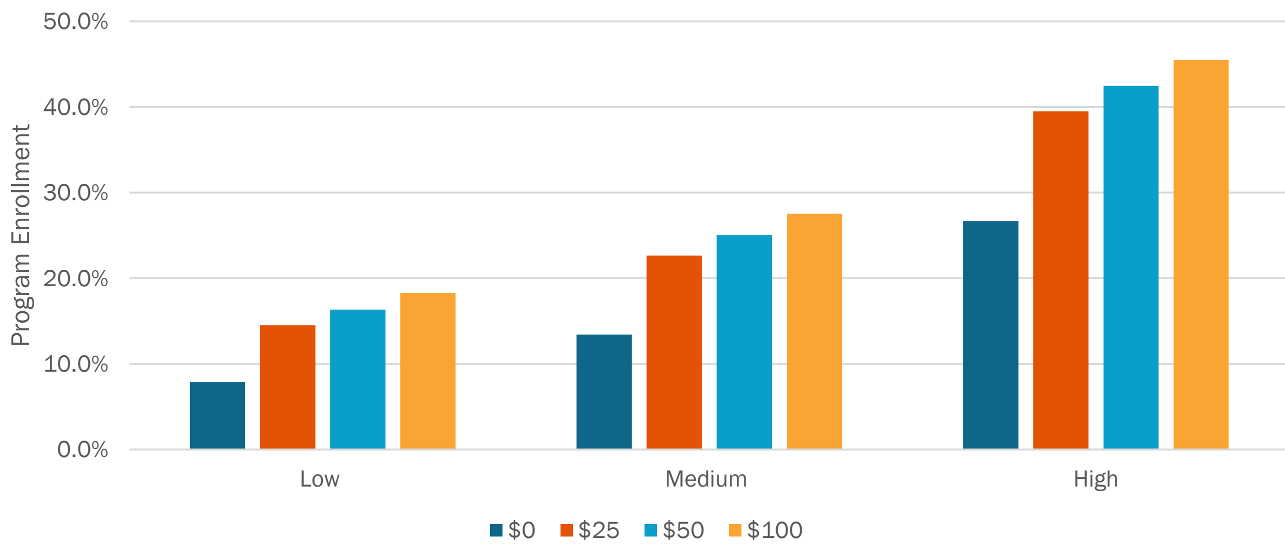
Many DR potential studies rely on top-down approaches which benchmark programs against enrollment rates that have been attained by mature programs. However, aggregated program results often do not provide enough detail to calibrate achievable program potential. In many cases, programs are not marketed to all customers, either because it is not cost-effective to market to all customers or budgets are capped by regulators. Enrollment rates are a function of specific offers and the extensiveness of marketing over many years. They also vary based on the degree to which DR resources are utilized and tend to be higher when payments are high but actual events are infrequent, particularly among large C&I customers.

The RI approach to estimate participation rates involves five steps. The initial step required some modification due available data:

- Estimate an econometric choice model based on who has and has not enrolled in DR programs. The goal is to estimate the pre-disposition or propensity of different customers to participate in DR based on their characteristics. Because micro-level acquisition marketing data were not provided, we relied on differences in participation rates by usage level. This information is based on prior micro-level analysis of program participation by RI.
- Incorporate information about how different offer characteristics influence enrollment likelihood. What is the incremental effect of incentives? How do requirements for on-site installation affect enrollment rates? The two questions above have been analyzed using mature market specific data for residential customers. In each case, regression coefficients describe the incremental effect of each of the above factors on participation rates. It is important to note that while this element of the participation model was derived using non-Duke Energy specific data, it is only being used to determine the incremental impact of additional incentives on participation (i.e., how does increasing the sign-up incentive increase participation in DR programs). The underlying assumption is that customers’ response to incremental financial incentives is similar across various geographic regions. Finally, as will be described in subsequent steps, the final participation model is calibrated too, so the baseline level of enrollment reflects the DEI territory.
- Incorporate information about how marketing tactics and intensity of marketing influence participation rates. What is the effect of incremental acquisition attempts? Is there a bump in enrollment rates when phone and/or door-to-door recruitment is added to direct mail recruitment? This relies on data from side-by-side testing designed to explicitly quantify the effect of marketing tactics on enrollment rates.
- Calibrate the models to reflect actual enrollment rates attained by programs in DEI territory used for benchmarking.
- Predict participation rates using specific tactics and incentive levels for programs with and without installation requirements. The enrollment estimates were produced for low, medium, and high marketing levels, where specific marketing tactics are specified for each scenario. All estimates reflect enrollment rates for eligible customers.

As a demonstration of how marketing level and incentive affects participation in DR programs, Figure 7-3 shows an example of how the range of participation rates for each marketing level varies at several different incentive levels.

Figure 7-3: Example of Program Enrollment Under Different Marketing and Incentive Levels



Other than residential water heaters, the predicted participation rates were applied to DR measures using the model's outputs as a function of the customer incentive, after calibrating for similar programs. Participation for residential water heaters was estimated as a percentage of the participation for AC cycling load control measures. The reason for this is both measures are currently offered by DEI under the same program, and customers must enroll their AC units to be eligible for enrolling their water heaters. Program data shows that approximately 12% of customers who enroll their ACs in demand response also enroll their water heaters.

7.4.4. Scenario Analysis

Base and Enhanced scenarios were constructed for the DR potential analysis. Base and Enhanced scenarios assume different levels of customer incentive and marketing efforts/costs. The Base Scenario aligns with current Duke Energy offerings for measures covered by existing programs, and assumes conservative incentive and marketing for new measures, while the Enhanced Scenario assumes more aggressive expansion. Major assumptions for both scenarios are listed below:

Program Potential - Base

- Assume load control will target applicable, curtailable end uses, such as AC/heating loads, water heaters, pool pumps, etc.
- Include incentives for solar PV and paired battery storage
- Medium marketing level for DR programs

Program Potential - Enhanced

- 50% higher incentives DR programs compared to current levels, resulting in larger participation
- Increase program marketing and outreach budgets (high marketing level)

7.5. DEI Energy Efficiency Program Potential

This section provides the results of the DEI EE achievable program potential for the portfolio, and the residential & non-residential sectors.

7.5.1. Summary

Table 7-3 and Table 7-4 summarize the short-term (5-year), medium (10-year) and long-term (25-year) DEI portfolio EE program potential for the base, high incentive, and the high avoided cost scenarios. Impacts are presented as both cumulative impacts and annual incremental impacts at each time step. The cumulative impact's view is important when using MPS results for resource planning purposes because it accounts for how the incremental addition of EE savings will impact the overall system load and load impacts likely to occur as measures reach the end of their useful lives. Annual impacts align with how utilities report their EE achievements in annual cost recovery filings.

Table 7-3: DEI EE Program Potential – Energy Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	244,600	214,301	200,437
High Incentive	Annual Incremental Energy (MWh)	277,521	251,706	231,005
High Avoided Cost	Annual Incremental Energy (MWh)	254,363	216,096	200,812
Base	Cumulative Energy (MWh)	820,509	1,577,248	1,703,116
High Incentive	Cumulative Energy (MWh)	963,366	1,874,902	2,188,708
High Avoided Cost	Cumulative Energy (MWh)	858,177	1,653,518	1,742,073

Table 7-4: DEI EE Program Potential – Demand Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	48	42	42
High Incentive	Annual Incremental Spring Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	49	42	42
Base	Annual Incremental Summer Peak Demand (MW)	47	41	42
High Incentive	Annual Incremental Summer Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	49	42	42
Base	Annual Incremental Fall Peak Demand (MW)	44	38	38
High Incentive	Annual Incremental Fall Peak Demand (MW)	53	46	45
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	45	39	39
Base	Annual Incremental Winter Peak Demand (MW)	55	44	39
High Incentive	Annual Incremental Winter Peak Demand (MW)	58	51	43
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	57	44	39
Base	Cumulative Spring Peak Demand (MW)	156	307	347
High Incentive	Cumulative Spring Peak Demand (MW)	201	401	476
High Avoided Cost	Cumulative Spring Peak Demand (MW)	162	319	353
Base	Cumulative Summer Peak Demand (MW)	155	304	344
High Incentive	Cumulative Summer Peak Demand (MW)	201	402	475
High Avoided Cost	Cumulative Summer Peak Demand (MW)	159	314	349
Base	Cumulative Fall Peak Demand (MW)	144	283	322
High Incentive	Cumulative Fall Peak Demand (MW)	185	369	440
High Avoided Cost	Cumulative Fall Peak Demand (MW)	149	293	327
Base	Cumulative Winter Peak Demand (MW)	176	335	326
High Incentive	Cumulative Winter Peak Demand (MW)	190	367	401
High Avoided Cost	Cumulative Winter Peak Demand (MW)	183	350	335

We assigned measures to Duke Energy programs for all achievable market potential scenarios; programs apply to either residential or non-residential customers, so we will combine the commercial and industrial economic sectors in subsequent reporting. Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures, less utility incentives.

Table 7-5 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

Table 7-5: DEI Participation and Program Costs by Scenario (cumulative through 2029)

Scenario	Program Sector	Program Incentives ($M)	Program Admin ($M)	Participant Costs ($M)	Levelized Cost ($/kWh)
Base	Residential	$118.47	$85.53	$269.17	$0.12
Base	Non-Residential	$24.93	$27.26	$58.17	$0.03
Base	Total	$143.41	$112.80	$327.34	$0.08
High Incentive	Residential	$330.95	$96.68	$210.65	$0.22
High Incentive	Non-Residential	$72.57	$33.16	$48.38	$0.05
High Incentive	Total	$403.53	$129.84	$259.03	$0.14
High Avoided Cost	Residential	$171.46	$93.90	$392.01	$0.14
High Avoided Cost	Non-Residential	$25.03	$27.29	$58.40	$0.03
High Avoided Cost	Total	$196.48	$121.20	$450.41	$0.11

7.5.2. Residential Program Details

Table 7-6 and Table 7-7 summarize the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base, high incentive, and high avoided cost scenarios. Impacts are presented as both cumulative impacts and annual incremental impacts over the stated time horizon (5 years, 10 years, or 25 years):

Table 7-6: EE Residential Program Potential – Energy Savings

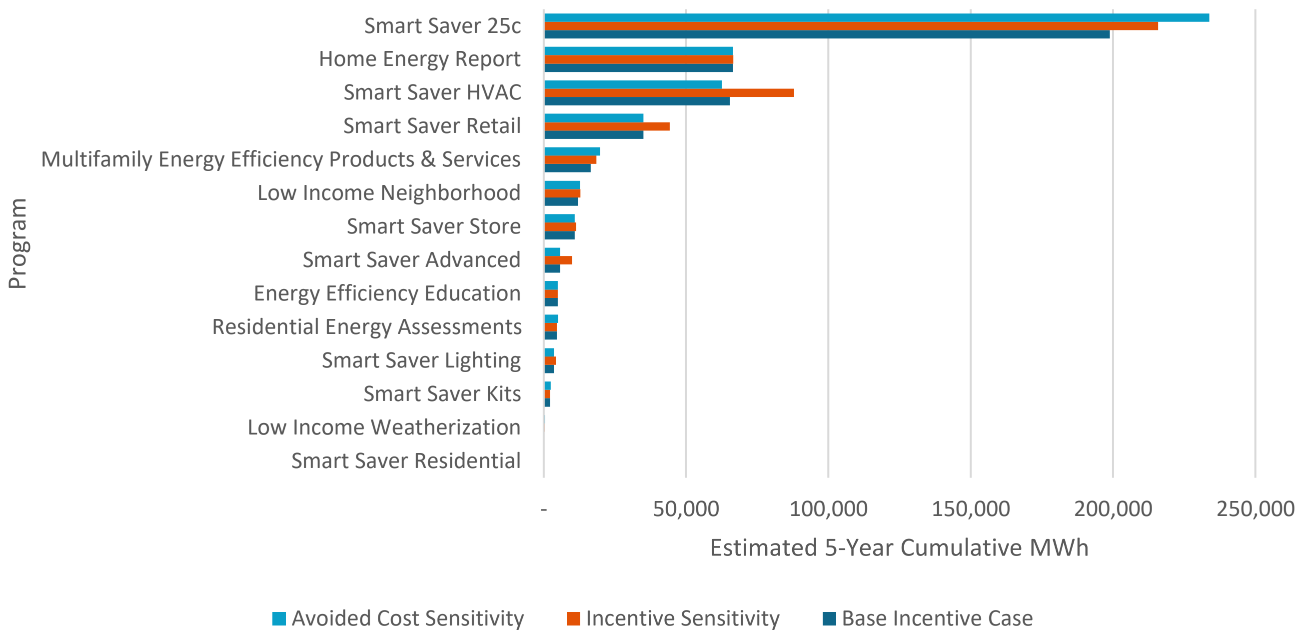
Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	156,108	123,487	129,120
High Incentive	Annual Incremental Energy (MWh)	170,154	141,569	143,233
High Avoided Cost	Annual Incremental Energy (MWh)	165,782	125,192	129,446
Base	Cumulative Energy (MWh)	426,633	813,778	853,847
High Incentive	Cumulative Energy (MWh)	483,907	941,143	1,120,630
High Avoided Cost	Cumulative Energy (MWh)	463,964	889,582	892,462

Table 7-7: EE Residential Program Potential – Demand Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	32	25	28
High Incentive	Annual Incremental Spring Peak Demand (MW)	38	29	32
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	33	25	28
Base	Annual Incremental Summer Peak Demand (MW)	32	25	28
High Incentive	Annual Incremental Summer Peak Demand (MW)	39	30	32
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	33	25	28
Base	Annual Incremental Fall Peak Demand (MW)	28	22	25
High Incentive	Annual Incremental Fall Peak Demand (MW)	34	26	28
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	29	22	25
Base	Annual Incremental Winter Peak Demand (MW)	43	31	29
High Incentive	Annual Incremental Winter Peak Demand (MW)	43	35	31
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	45	31	29
Base	Cumulative Spring Peak Demand (MW)	87	169	184
High Incentive	Cumulative Spring Peak Demand (MW)	115	230	264
High Avoided Cost	Cumulative Spring Peak Demand (MW)	92	181	190
Base	Cumulative Summer Peak Demand (MW)	87	170	185
High Incentive	Cumulative Summer Peak Demand (MW)	118	235	268
High Avoided Cost	Cumulative Summer Peak Demand (MW)	92	180	190
Base	Cumulative Fall Peak Demand (MW)	76	148	162
High Incentive	Cumulative Fall Peak Demand (MW)	101	201	232
High Avoided Cost	Cumulative Fall Peak Demand (MW)	81	158	167
Base	Cumulative Winter Peak Demand (MW)	121	229	210
High Incentive	Cumulative Winter Peak Demand (MW)	123	235	253
High Avoided Cost	Cumulative Winter Peak Demand (MW)	129	245	219

Figure 7-4, illustrates the relative contributions to the overall residential program potential by program for the base, incentive sensitivity, and avoided energy cost sensitivity scenarios.

Figure 7-4: DEI Residential 5-Yr Cumulative Potential by Program



Detailed program results for the short-term residential EE programs are provided in Table 7-8.

Table 7-8: DEI Residential Program Potential (cumulative through 2029)

Program Scenario	Metric	Low Income Neighborhood	Low Income Weatherization	Energy Efficiency Education	Multifamily Energy Efficiency Products & Services	Residential Energy Assessments	Home Energy Report	Smart Saver 25c	Smart $aver
Base	Energy (MWh)	11,997	192	4,889	16,536	4,548	66,540	198,888	123,042
High Incentive		12,940	303	4,956	18,544	4,621	66,633	215,833	160,077
High Avoided Cost		12,830	479	4,897	19,913	5,078	66,540	233,844	120,379
Base	Spring kW	1,758	38	309	2,190	959	12,994	42,510	25,769
High Incentive		1,997	60	314	2,504	965	13,030	60,968	34,852
High Avoided Cost		1,871	92	310	2,631	1,031	12,994	48,032	25,412
Base	Summer kW	1,513	39	231	1,931	988	13,274	42,595	26,572
High Incentive		1,769	62	235	2,260	993	13,314	62,783	36,347
High Avoided Cost		1,597	94	232	2,277	1,041	13,274	46,966	26,310
Base	Fall kW	1,420	35	270	1,934	832	11,714	36,719	23,258
High Incentive		1,629	54	274	2,220	837	11,746	52,647	31,563
High Avoided Cost		1,509	84	271	2,315	889	11,714	41,128	22,977
Base	Winter kW	2,836	48	2,093	4,655	1,212	17,304	62,419	30,824
High Incentive		3,139	75	2,119	5,554	1,225	17,325	53,465	40,171
High Avoided Cost		3,028	147	2,095	5,375	1,334	17,304	69,402	30,207
Base	Program Cost ($Thousands)	13,259	192	1,351	5,667	360	9,672	130,221	43,715
High Incentive		15,151	369	1,369	8,498	401	9,679	245,170	101,570
High Avoided Cost		14,705	791	1,353	6,858	457	9,672	184,409	42,837
Base	Levelized Cost ($/kWh)	$0.27	$0.25	$0.07	$0.08	$0.02	$0.04	$0.16	$0.09
High Incentive		$0.29	$0.30	$0.07	$0.11	$0.02	$0.04	$0.28	$0.16
High Avoided Cost		$0.28	$0.41	$0.07	$0.08	$0.02	$0.04	$0.19	$0.09

To analyze the costs and benefits of the program potential scenarios, RI used several common test perspectives in the MPS, consistent with the California Standard Practice Manual[6]:

- Total resource cost (TRC): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to that measure's incremental cost. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Utility cost test (UCT): Calculated by comparing total avoided electricity production and avoided delivery costs from installing a measure, to the utility's cost of delivering a program containing that measure. Costs include incentive and non-incentive costs.

[6] California Standard Practice Manual: Economic Analysis of Demand-Side Program and Projects. California Public Utilities Commission. San Francisco, CA. October 2001.

- Participant cost test (PCT): Calculated by dividing electricity bill savings for each installed measure, by the incremental cost of that measure. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Ratepayer Impact Measure (RIM): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to the utility's revenue impacts from lost sales and program delivery.

RI shows achievable program potential estimates and benefits cost ratios according to current administrative cost data provided to RI by Duke Energy. Detailed program design is not part of this scope of work; RI examined the components of the administrative costs provided by Duke Energy and applied them on a dollar-per-kilowatt-hour basis.

Table 7-9Table 7-9 provides the net benefits expressed as millions of dollars, and benefit-to-cost ratios by program for base scenario:

Table 7-9: DEI Cost-Benefit Results – Residential Programs (cumulative through 2029)

Cost-Effectiveness Test	Low Income Neighborhood	Low Income Weatherization	Energy Efficiency Education	Multifamily Energy Efficiency Products & Services	Residential Energy Assessments	Home Energy Report	Smart Saver 25c	Smart $aver
UCT Net Benefits ($M)	-$6.21	$0.05	$1.26	$9.58	$1.97	$27.99	$182.37	$80.40
UCT Ratio	0.56	1.26	1.93	2.74	3.25	3.89	2.43	2.79
TRC Net Benefits ($M)	-$6.21	-$0.94	$1.26	$6.72	$1.97	$27.99	-$31.12	$28.56
TRC Ratio	0.56	0.21	1.93	1.80	3.25	3.89	0.91	1.29
PCT Net Benefits ($M)	$8.85	-$0.71	$3.28	$12.94	$2.44	$35.66	$54.56	$70.74
PCT Ratio	7.71	0.28	N/A	3.26	5.21	N/A	1.18	1.84
RIM Net Benefits ($M)	-$15.06	-$0.23	-$2.02	-$6.23	-$0.47	-$7.66	-$85.68	-$42.18
RIM Ratio	0.35	0.52	0.56	0.71	0.86	0.83	0.78	0.75

7.5.3. Non-Residential Program Details

Table 7-10 and Table 7-11 summarize the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative Non-residential energy efficiency program potential for the base and enhanced scenarios, presented as both cumulative and annual incremental impacts over the stated time horizon (5 years, 10 years, or 25 years):

Table 7-10: DEI EE Non-Residential Program Potential – Energy Savings

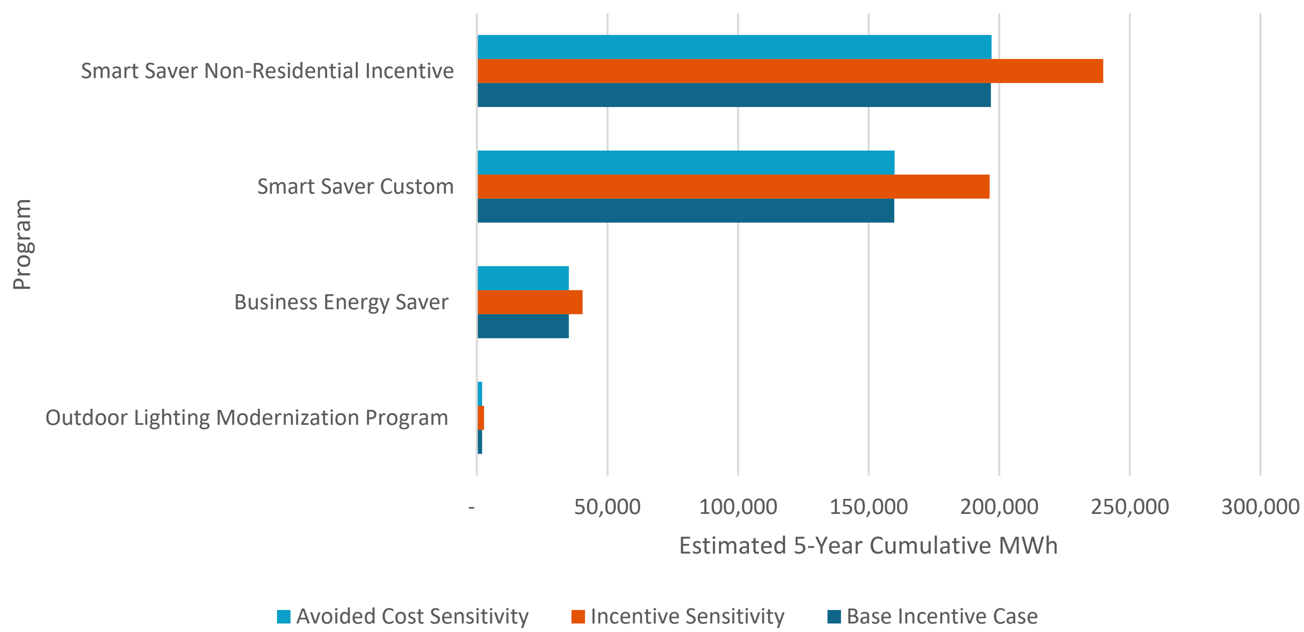
Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	88,492	90,814	71,317
High Incentive	Annual Incremental Energy (MWh)	107,366	110,137	87,772
High Avoided Cost	Annual Incremental Energy (MWh)	88,581	90,904	71,366
Base	Cumulative Energy (MWh)	393,876	763,470	849,269
High Incentive	Cumulative Energy (MWh)	479,459	933,758	1,068,078
High Avoided Cost	Cumulative Energy (MWh)	394,214	763,937	849,610

Table 7-11: DEI EE Non-Residential Program Potential – Demand Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	16	17	14
High Incentive	Annual Incremental Spring Peak Demand (MW)	20	21	18
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	16	17	14
Base	Annual Incremental Summer Peak Demand (MW)	15	16	14
High Incentive	Annual Incremental Summer Peak Demand (MW)	19	20	17
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	15	16	14
Base	Annual Incremental Fall Peak Demand (MW)	16	16	14
High Incentive	Annual Incremental Fall Peak Demand (MW)	19	20	17
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	16	16	14
Base	Annual Incremental Winter Peak Demand (MW)	12	13	10
High Incentive	Annual Incremental Winter Peak Demand (MW)	15	16	12
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	12	13	10
Base	Cumulative Spring Peak Demand (MW)	70	138	164
High Incentive	Cumulative Spring Peak Demand (MW)	86	171	212
High Avoided Cost	Cumulative Spring Peak Demand (MW)	70	138	164
Base	Cumulative Summer Peak Demand (MW)	68	134	159
High Incentive	Cumulative Summer Peak Demand (MW)	83	166	207
High Avoided Cost	Cumulative Summer Peak Demand (MW)	68	134	159
Base	Cumulative Fall Peak Demand (MW)	68	135	160
High Incentive	Cumulative Fall Peak Demand (MW)	84	168	208
High Avoided Cost	Cumulative Fall Peak Demand (MW)	68	135	160
Base	Cumulative Winter Peak Demand (MW)	54	105	116
High Incentive	Cumulative Winter Peak Demand (MW)	67	132	148
High Avoided Cost	Cumulative Winter Peak Demand (MW)	54	105	116

Figure 7-5 illustrates the relative contributions to the overall non-residential program potential by program for the base, incentive sensitivity, and avoided energy cost sensitivity scenarios.

Figure 7-5: Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario



Detailed program results for the short-term non-residential EE programs are provided in Table 7-12.

Table 7-12: DEI Non-Residential Program Potential (cumulative through 2029)

Program Scenario	Metric	Smart $aver Custom	Business Energy Saver	Smart Saver Non-Residential Incentive	Outdoor Lighting Modernization
Base	Energy (MWh)	159,862	35,234	196,801	1,979
High Incentive		196,403	40,558	239,780	2,719
High Avoided Cost		159,957	35,243	197,035	1,979
Base	Spring kW	21,317	8,003	40,484	0
High Incentive		26,189	9,399	50,365	0
High Avoided Cost		21,331	8,005	40,518	0
Base	Summer kW	21,308	7,573	38,711	0
High Incentive		26,176	8,930	48,354	0
High Avoided Cost		21,322	7,575	38,743	0
Base	Fall kW	21,320	7,593	39,211	0
High Incentive		26,196	8,962	48,985	0
High Avoided Cost		21,334	7,595	39,243	0
Base	Winter kW	19,000	5,676	29,058	456
High Incentive		23,434	6,598	36,637	626
High Avoided Cost		19,011	5,677	29,087	456
Base	Program Cost ($Thousands)	20,870	3,988	29,106	290
High Incentive		40,711	8,271	60,759	716
High Avoided Cost		20,922	3,994	29,200	290
Base	Levelized Cost ($/kWh)	$0.03	$0.03	$0.04	$0.04
High Incentive		$0.05	$0.05	$0.06	$0.06
High Avoided Cost		$0.03	$0.03	$0.04	$0.04

Table 7-13 provides the net benefits and benefit-to-cost ratios by program for base scenario:

Table 7-13: DEI Cost-Benefit Results – Non-Residential Programs (through 2029)

Cost-Effectiveness Test	Smart Saver Custom	Business Energy Saver	Smart Saver Non-Residential Incentive	Outdoor Lighting Modernization Program
UCT Net Benefits ($M)	$86.11	$18.68	$106.79	$1.14
UCT Ratio	5.05	6.12	4.90	4.92
TRC Net Benefits ($M)	$63.79	$13.57	$76.20	$0.60
TRC Ratio	2.46	2.55	2.31	1.72
PCT Net Benefits ($M)	$138.53	$21.49	$151.16	$1.41
PCT Ratio	5.34	3.94	4.46	2.83
RIM Net Benefits ($M)	-$74.73	-$7.92	-$74.96	-$0.81
RIM Ratio	0.59	0.74	0.64	0.64

7.6. DEI DR Achievable Market Potential

This section presents the estimated overall achievable market potential for DR opportunities. The results are provided by season and are further broken down by customer segment. All results presented reflect the projected achievable DR potential by 2049.

7.6.1. DEI Seasonal Peaking Capacity

Table 7-14 and Table 7-15 provide the overall peak capacity results for the base and enhanced scenario respectively. Most of the peak capacity potential comes from residential customers in all four seasons for the base case. For the enhanced case, most of the peak capacity potential comes from residential customers in the summer and winter seasons, and from SMB customers during the fall and spring seasons.

Table 7-14: DEI DR Peak Capacity Achievable Potential- Base Scenario

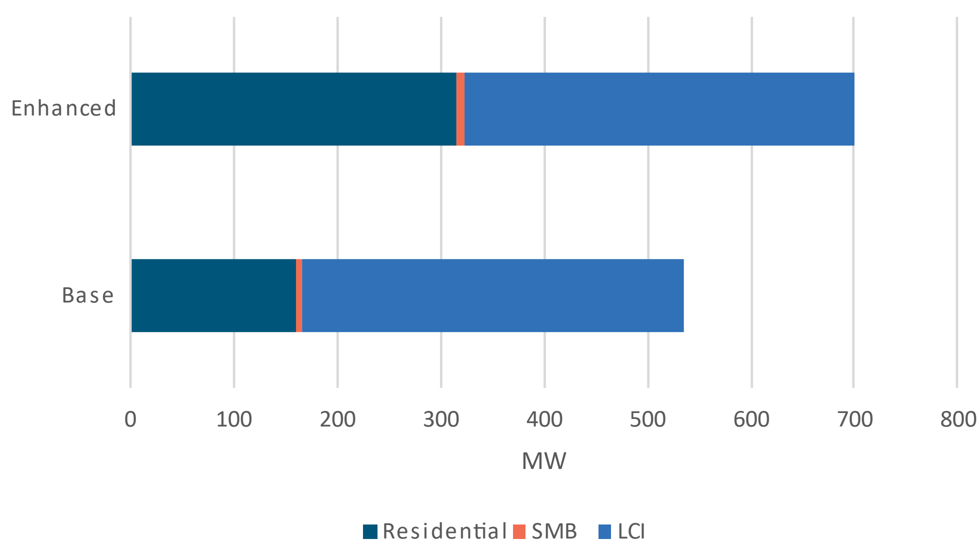
Sector	Savings Potential			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Fall Peak Demand (MW)	Spring Peak Demand (MW)
Residential	159	138	163	158
SMB	6	2	8	9
Large C&I	370	183	315	320
Total	**535**	**322**	**487**	**487**

Table 7-15: DEI DR Peak Capacity Achievable Potential- Enhanced Scenario

Sector	Savings Potential			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Fall Peak Demand (MW)	Spring Peak Demand (MW)
Residential	316	278	331	320
SMB	8	3	11	11
Large C&I	376	187	321	326
Total	**699**	**468**	**663**	**657**

Figure 7-6 presents the overall peak capacity results, broken down by sector and the two scenarios. The capacity is what is expected to be available during the peak hour of system demand.

Figure 7-6 DEI DR Peak Capacity Achievable Potential



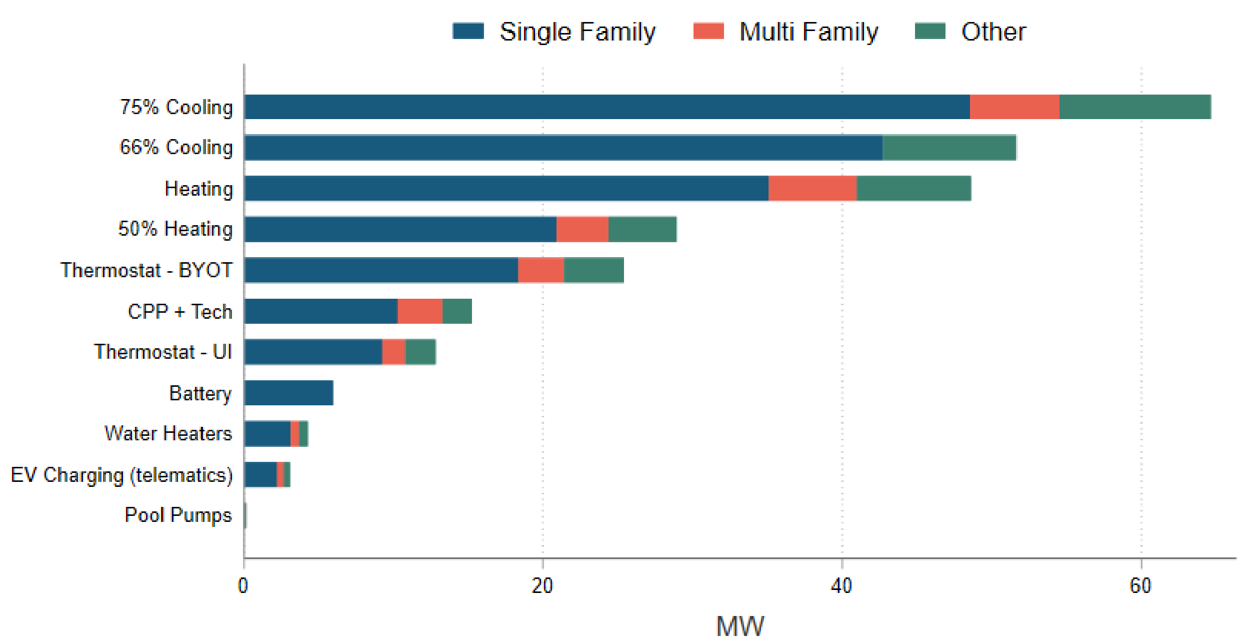
7.6.2. Results by Customer Segment

A total of 11 different customer segments were individually analyzed. This includes 3 segments for residential customers, 4 segments for SMB customers, and 4 segments for large commercial and industrial customers. This section presents the segment-level results, focusing on the customer segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are similar across the two scenarios that were studied, with the main difference being the magnitude of the overall resources being larger for the enhanced scenario due to higher participation rates across all sectors and the inclusion of additional residential end uses dramatically increasing the residential DR capacity. For the sake of simplicity, only the results for the base scenario are presented in this section. Most of the customer segments are cost-effective under the base case assumptions to pursue for DR enrollment.

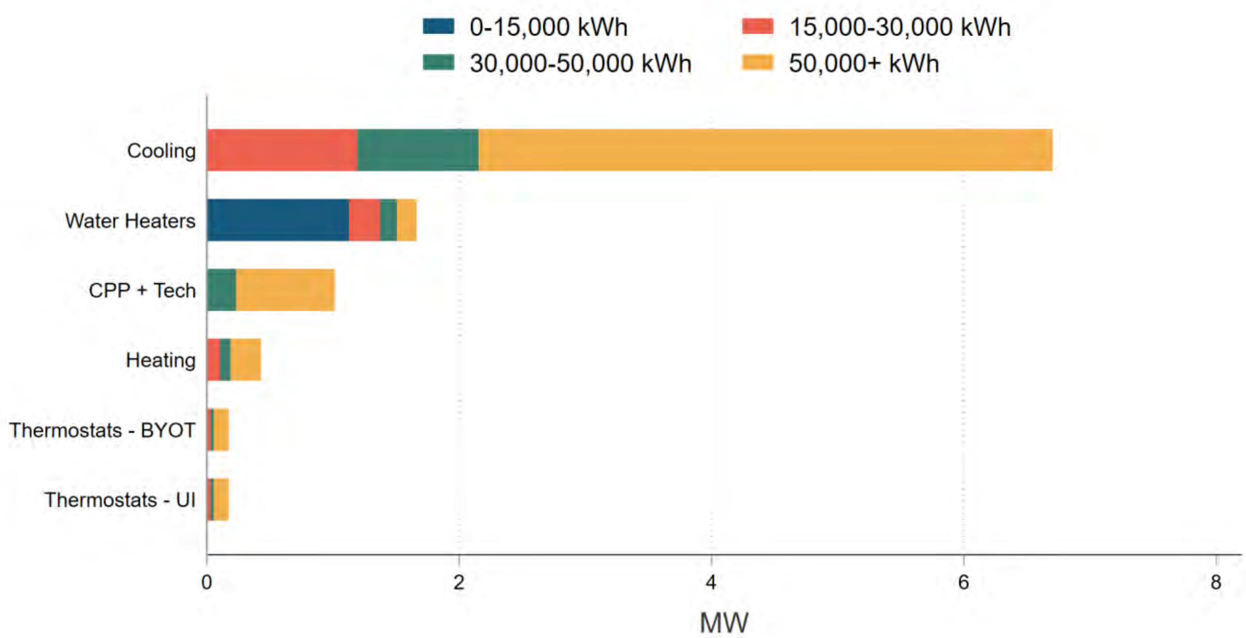
For the residential sector, shown below in Figure 7-7, single-family customers provide the greatest demand response resources. This is not surprising since they tend to have the greatest load available for load reduction, making it possible to enroll significant capacity per marginal dollar spent on acquisition marketing, equipment, and installation costs.

Figure 7-7: Residential Achievable Potential



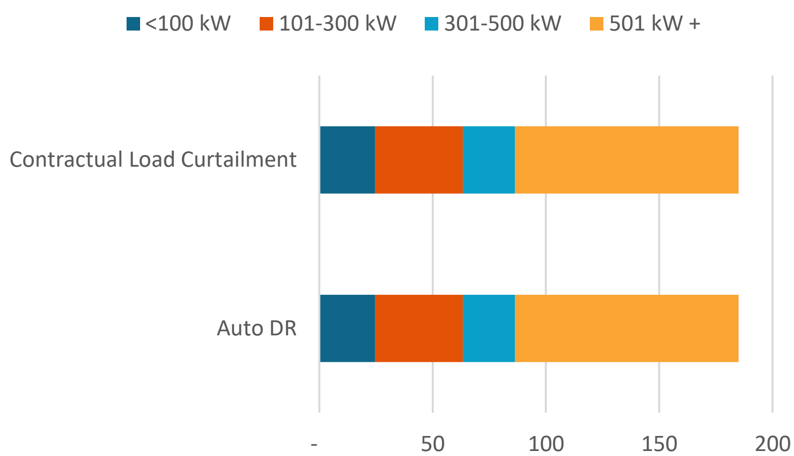
SMB customers do not provide much DR capacity comparably, due to their being a relatively small portion of the overall system load and having lower participation rates. Results for this segment are shown below in Figure 7-8. The largest consumption bin provides the greatest potential.

Figure 7-8: Achievable Potential Results for SMB Demand Response



LCI customers provide the highest DR among the three sectors. Results for this segment are shown below in Figure 7-9. The largest consumption bin provides the greatest potential. The participation rate presented here represents the percentage of the overall peak period load from each customer segment that would be available for curtailment if DR programs are able to reduce participation barriers over time so that potential DR participants can easily capture the economic benefits of utility-sponsored DR offers (e.g. overcoming relevant economic, technical, regulatory, and behavioral barriers (see Section 7.1). The LCI achievable potential excludes the current (as of 2024) 235 MW “at generator,” or 219 MW “at-meter” enrolled capacity.

Figure 7-9: Achievable Potential Results for LCI Demand Response



7.6.3. Key Findings

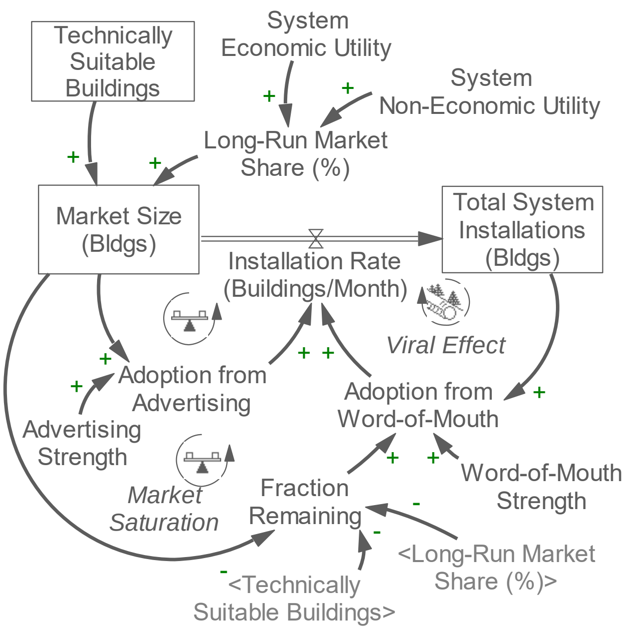
The overall DR potential is estimated to be 535 MW of peak seasonal capacity for the base scenario and 699 MW for the enhanced scenario. The extent to whether this potential can be attained in a cost-effective manner depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These estimates rely upon assumptions around the future value of capacity.

The customer segment-level analysis of the program- and pricing-based DR potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DR programs as well as greater willingness to shed a higher percentage of their load.

7.7. DER Achievable Potential

Achievable market potential estimates customer adoption rates for cost-effective measures in a market featuring utility-sponsored programs. We calibrated start year adoptions to historic adoptions for solar PVs, but future adoption is driven by modeling Bass diffusion in a system dynamics framework that enables capturing complex DER market dynamics for any future scenario (presented as a simplified Stock and Flow diagram in Figure 7-10). The approach enables time-varying factors such as costs, investment tax credits, etc.

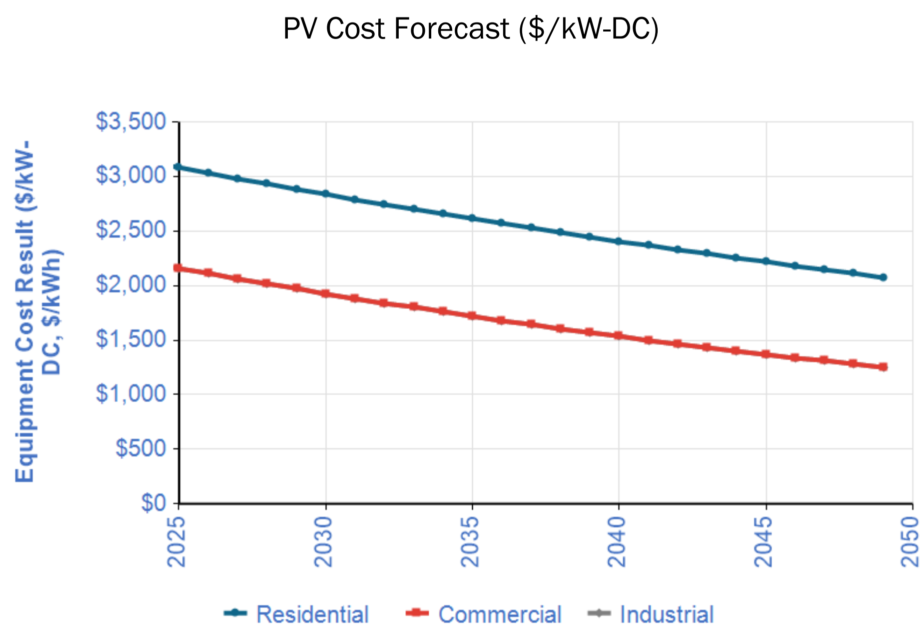
Figure 7-10. Stock and Flow Diagram

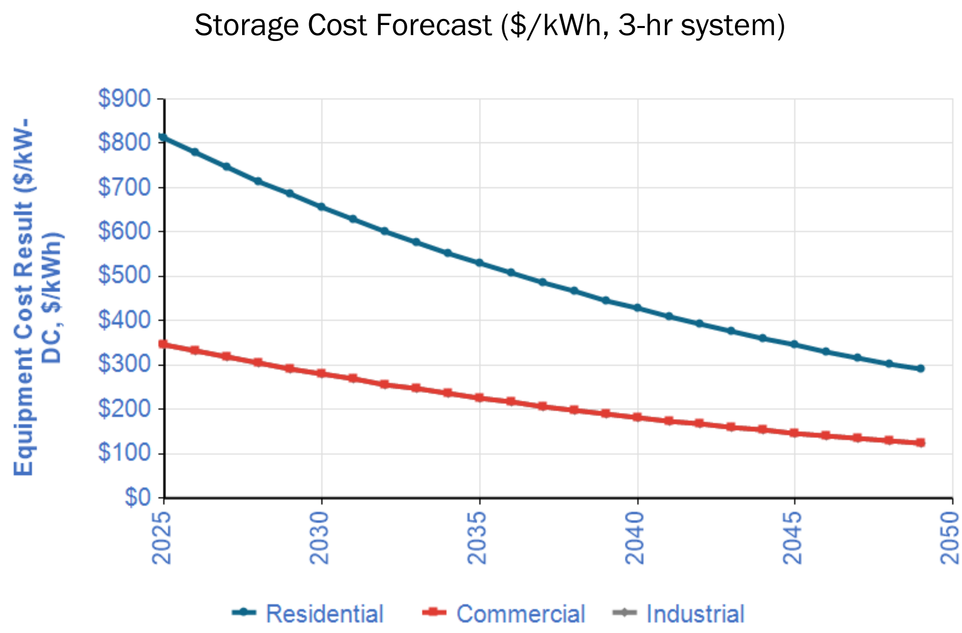


7.8. Forecast Cost Impact

The PV cost and storage cost are forecasted to decline through the end of the study year, which ultimately impacts adoption forecasts by decreasing the payback time. The detailed PV cost forecast and storage cost forecast are displayed in Figure 7-11.

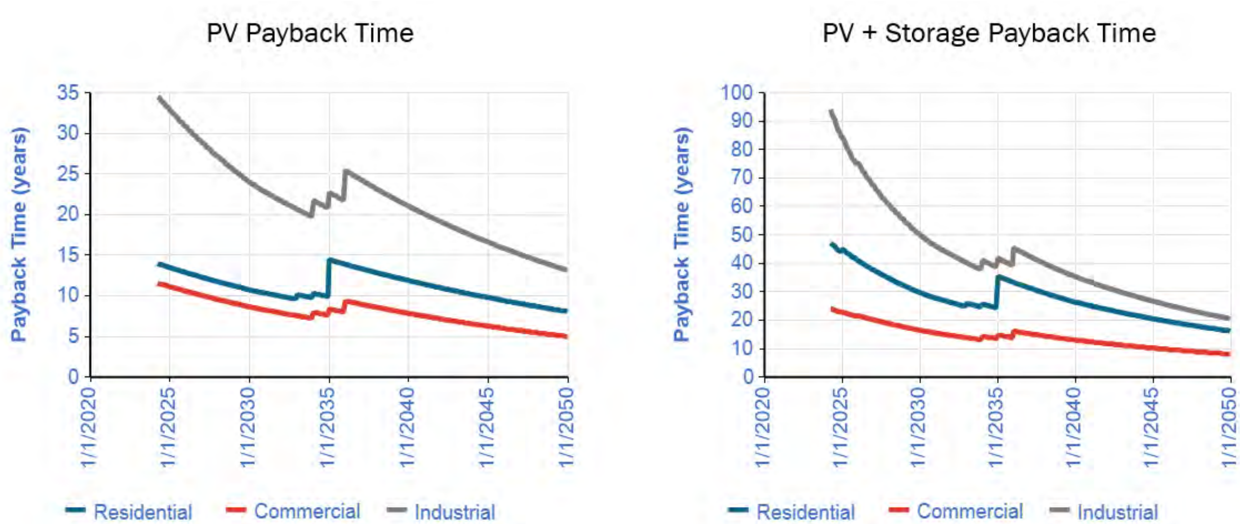
Figure 7-11. Forecast Cost for PV and Storage





The decline in the future costs suggests a decreasing trend in payback time over time. However, due to the phase-out of the investment tax credit (ITC), there is a notable increase in payback time from 2033 through 2035, without any utility incentives. The payback time forecast is presented in Figure 7-12.

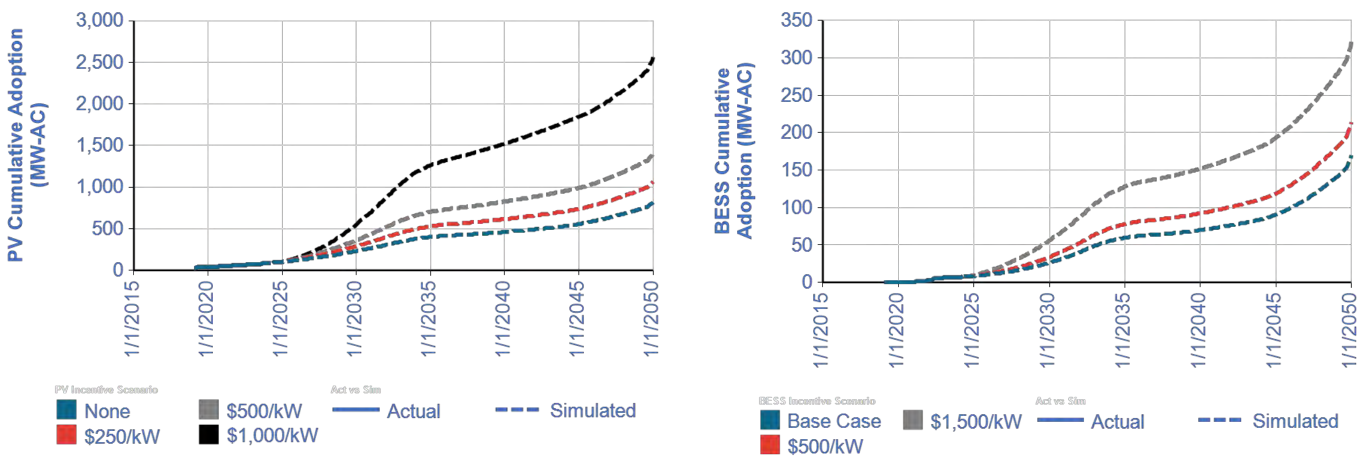
Figure 7-12. Payback Time Forecast (No Utility Incentives)



7.8.1. Achievable PV/Storage Forecast Scenarios with Utility Incentives

RI conducted three scenarios on incentives and provided DER forecasts with incentives of $250/kW, $500/kW, and $1,000/kW for PV installations. Paired storage installations examined a high and low case for incentives at $500 per kW and $1,500 per kW. Figure 7-13 presents the DER forecasts with the three incentive scenarios. This figure also illustrates expected changes to adoption that result from the expiration of the Energy Efficiency Income Tax Credit in 2033.

Figure 7-13: PV and Paired Storage Forecasts with a Range of Utility Incentives for Installation



Appendix A All Customers APS

Duke Energy's energy efficiency programs in Indiana include an "opt-out" provision approved by the Indiana Utilities Commission. This provision allows non-residential customers receiving electric service at a single site demanding more than 1 megawatt of electric capacity to opt out, along with all accounts in contiguous property. This opt-out provision exempts the customer from the cost recovery mechanism but also eliminates that customer's eligibility for participation in the program.

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for Indiana, which showed an opt-out rate of approximately 9.6% of commercial sales and 59.2% of industrial sales in the DEI service territory. We incorporated this opt-out rate into the MPS by excluding sales to non-residential that opted out, and we applied the applicable energy efficiency technologies and market adoption rates to the remaining customer base; the results of this analysis are reported in Section 7.

Resource Innovations also estimated achievable potential with the full customer base as a sensitivity. Table 7-16 presents the results of achievable market potential when all Duke Energy customers are included in the analysis.

Table 7-16: DEI Energy Efficiency Achievable Potential with All Customers

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	253,644	261,385	231,924
Base	Annual Incremental Spring Peak Demand (MW)	46	49	47
Base	Annual Incremental Summer Peak Demand (MW)	46	48	47
Base	Annual Incremental Fall Peak Demand (MW)	43	45	43
Base	Annual Incremental Winter Peak Demand (MW)	49	50	42
Base	Cumulative Energy (MWh)	890,727	1,688,706	1,930,627
Base	Cumulative Spring Peak Demand (MW)	156	301	371
Base	Cumulative Summer Peak Demand (MW)	154	296	366
Base	Cumulative Fall Peak Demand (MW)	148	285	350
Base	Cumulative Winter Peak Demand (MW)	153	287	309

Appendix B Combined Heat and Power

The CHP analysis created a series of unique distributed generation potential models for each primary market sector (commercial and industrial). Only non-residential customer segments whose electric and thermal load profiles allow for the application of CHP were considered. The technical potential analysis followed a three-step process to make this determination. Minimum facility electricity consumption thresholds were determined for each non-residential customer segment by applying power-to-heat ratios to customer billing data. The facilities that were of sufficient size were matched with the appropriately sized CHP technology.

To determine the minimum threshold for CHP suitability, a thermal factor was applied to potential candidate customer loads to reflect thermal load considerations in CHP sizing. CHP size is usually dictated by the thermal load to achieve improved efficiencies. The study collected electric and thermal intensity data from other recent CHP studies and market analysis. Commercial customers, the thermal load is commonly made up of water heating, space heating, and space cooling (in the case of an absorption chiller). Table 7-17, on the following page, presents the values for thermal factors used to estimate technical potential.

Table 7-17: CHP Thermal Factors by Segment and Prime Mover

	Microturbines	Fuel Cells	Reciprocating IC Engines	Reciprocating IC Engines	Gas Turbines	Gas Turbines
Application	250-500 kW	250-500 kW	0.5 - 1 MW	1 - 5 MW	5 - 20 MW	>= 20 MW
Assembly	0.75	0.77	0.82	0.94	0.94	1.15
College and University	0.60	0.62	0.66	0.75	0.75	0.92
Grocery	0.17	0.17	0.19	0.21	0.21	0.26
Healthcare	0.22	0.22	0.24	0.27	0.27	0.33
Hospitals	0.41	0.42	0.45	0.52	0.52	0.63
Institutional	0.79	0.81	0.87	0.99	0.99	1.21
Lodging/Hospitality	0.41	0.42	0.45	0.51	0.51	0.62
Miscellaneous	0.33	0.33	0.36	0.41	0.41	0.50
Office	0.59	0.60	0.65	0.74	0.74	0.90
Restaurants	0.41	0.43	0.45	0.52	0.52	0.64
Retail	0.34	0.35	0.37	0.43	0.43	0.52
Schools K-12	0.69	0.71	0.76	0.86	0.86	1.06
Warehouse	0.68	0.69	0.74	0.85	0.85	1.04
Agriculture and Assembly	1.20	1.24	1.32	1.51	1.51	1.85
Chemicals and Plastics	0.74	0.76	0.81	0.93	0.93	1.14
Construction	1.48	1.52	1.63	1.85	1.85	2.27
Electrical and Electronic Equip.	0.29	0.29	0.31	0.36	0.36	0.44
Lumber/Furniture/Pulp/Paper	1.09	1.12	1.19	1.36	1.36	1.67
Metal Products and Machinery	0.29	0.29	0.31	0.36	0.36	0.44
Miscellaneous Manufacturing	1.48	1.52	1.63	1.85	1.85	2.27
Primary Resources Industries	0.38	0.39	0.42	0.48	0.48	0.59
Stone/Clay/Glass/Concrete	2.45	2.52	2.69	3.07	3.07	3.76
Textiles and Leather	0.85	0.87	0.93	1.06	1.06	1.30
Transportation Equipment	0.48	0.49	0.53	0.60	0.60	0.74
Water and Wastewater	0.33	0.33	0.36	0.41	0.41	0.50
Other	0.68	0.70	0.75	0.86	0.86	1.05

RI used the utility-provided customer data to categorize all non-residential customers by segment and size. Customers with annual loads below the consumption thresholds indicated by power-to-heat ratios are not expected to have the consistent thermal loads necessary to support CHP.

In general, internal combustion engines are the prime mover for systems under 500kW with gas turbines becoming progressively more popular as system size increases above that. Based on the available load by customer, adjusted by the estimated thermal factor for each segment, CHP technologies were assigned to utility customers in a top-down fashion (*i.e.,* starting with the largest CHP generators).

Interaction of Technical Potential Impacts

As described above, the technical potential was estimated using separate models for EE, DR, and CHP systems. However, there is interaction between these technologies; for example, a more efficient HVAC system would result in a reduced peak demand available for DR curtailment. Therefore, after development of the independent models, the interaction between EE, DR, and CHP was incorporated as follows:

- The EE technical potential was assumed to be implemented first.
- For CHP systems, the EE technical potential was incorporated in a similar fashion, adjusting the baseline load used to estimate DSRE potential.

For CHP systems, the reduced baseline load from EE resulted in a reduction in the number of facilities that met the annual energy threshold needed for CHP installations. Installed DR capacity was assumed to not impact CHP potential as the CHP system feasibility was determined based on energy and thermal consumption at the facility. It should be noted that CHP systems not connected to the grid could impact the amount of load available for curtailment with utility-sponsored DR. Therefore, CHP technical potential should not be combined with DR potential but used as independent estimates. Table 7-18 presents technical potential for CHP in the DEI jurisdiction.

Table 7-18: DEI Technical Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	14	54,163
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	21	166,602
Commercial	Institutional	4	1	3,158
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	11	26,376
Commercial	Offices	117	145	378,410
Commercial	Restaurants	0	0	0
Commercial	Retail	58	21	57,643
Commercial	Schools K-12	72	37	106,082
Commercial	Warehouse	82	136	359,941
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	86	578,329
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	2	15,248
Industrial	Lumber/Furniture/Pulp/Paper	10	40	258,168
Industrial	Metal Products and Machinery	24	36	242,121
Industrial	Miscellaneous Manufacturing	91	206	1,351,797
Industrial	Primary Resources Industries	1	2	13,781
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	71	459,425
Industrial	Water and Wastewater	0	0	0
Total		568	830	4,071,243

CHP Economic Potential

RI conducted cost research for CHP prime movers and used research on the technology type to identify the appropriate technologies for each segment. Utility costs for existing CHP incentives, utility avoided energy costs, and Installation and O&M costs were used to estimate UCT ratios for CHP technologies at each eligible Duke Energy account.

Baseline energy consumption for CHP economic potential is adjusted by applying results from the EE potential study. Therefore, the baseline energy consumption for CHP economic potential at each account is higher than the baseline energy consumption for technical potential at each account. This is because EE technical potential is larger than EE economic potential. When the EE technical potential and economic potential results are applied to baseline account consumption in the CHP potential, the CHP scenario baseline is higher if energy efficiency impacts are lower. Therefore, the total CHP economic potential is higher than the technical potential. Economic Potential for DEI is presented below in Table 7-19.

Table 7-19: DEI Economic Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	14	54,678
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	21	167,877
Commercial	Institutional	4	1	3,194
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	11	26,766
Commercial	Offices	117	145	386,565
Commercial	Restaurants	0	0	0
Commercial	Retail	58	21	58,229
Commercial	Schools K-12	72	37	106,713
Commercial	Warehouse	82	136	363,813
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	86	586,437
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	2	15,516
Industrial	Lumber/Furniture/Pulp/Paper	10	40	262,662
Industrial	Metal Products and Machinery	24	36	244,531
Industrial	Miscellaneous Manufacturing	91	206	1,375,140
Industrial	Primary Resources Industries	1	2	13,811
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	71	465,706
Industrial	Water and Wastewater	0	0	0
Total		568	830	4,131,638

CHP Achievable Potential

This analysis describes the physical and economic factors that may contribute to facilities' energy savings through the installation of CHP technologies. The data available for characterizing CHP opportunities are limited to representative values for each commercial and industrial segment. These values represent general segment characteristics and describe the order of magnitude for likely drivers of CHP potential in each segment.

The question of which specific facilities are more or less likely to adopt CHP potential bears further research. CHP installations are large projects that are inherently site-specific. Assuming CHP is technical feasible and economic at a given location, there are other important considerations for whether CHP should go forward. Resource Innovations' understanding is that Duke Energy is currently working through a variety of channels to gauge customer interest in CHP technology. Without further research on the topic, we identified project payback period as a potential criterion for screening eligible. Based on our estimates of cost for CHP prime movers and technical feasibility, we find that payback periods for cost-effective CHP program offers made by Duke Energy should be expected to range from 5.9 to 13.1 years among Duke Energy customers.

As in the energy efficiency potential analysis, we apply a payback acceptance curve to these values to generate an estimate of customer adoption. Customer adoption rates range from a low of 1% to a high of 30% for some segments. The results of Achievable Potential analysis for all customers and eligible customers are presented in the following tables, Table 7-20 and Table 7-21.

Table 7-20: DEI Achievable Potential for CHP (All Customers)

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	1	2,787
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	2	14,021
Commercial	Institutional	4	0	57
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	0	0
Commercial	Offices	117	4	11,468
Commercial	Restaurants	0	0	0
Commercial	Retail	58	0	8
Commercial	Schools K-12	72	1	1,729
Commercial	Warehouse	82	5	12,938
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	21	141,419
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	0	761
Industrial	Lumber/Furniture/Pulp/Paper	10	12	78,547
Industrial	Metal Products and Machinery	24	2	14,287
Industrial	Miscellaneous Manufacturing	91	32	212,773
Industrial	Primary Resources Industries	1	0	1,600
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	8	54,192
Industrial	Water and Wastewater	0	0	0
Total		568	87	546,587

Eligible customers exhibit slightly higher achievable potential compared to all customers. This difference stems from varying impacts of EE adjustments on baseline energy consumption levels. Eligible customers experience a smaller reduction in their baseline energy consumption due to the EE adjustments. Consequently, their baseline energy consumption for CHP applications remains higher relative to all customers. This higher baseline supports a slightly greater potential for CHP installations among eligible customers as they are more likely to meet the necessary energy consumption thresholds conducive to CHP deployment.

Table 7-21: DEI Achievable Potential for CHP (Eligible Customers)

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	1	2,911
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	2	14,529
Commercial	Institutional	4	0	67
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	0	0
Commercial	Offices	117	5	12,231
Commercial	Restaurants	0	0	0
Commercial	Retail	58	0	10
Commercial	Schools K-12	72	1	1,912
Commercial	Warehouse	82	5	13,152
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	21	146,303
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	0	761
Industrial	Lumber/Furniture/Pulp/Paper	10	12	79,672
Industrial	Metal Products and Machinery	24	2	15,183
Industrial	Miscellaneous Manufacturing	91	33	217,296
Industrial	Primary Resources Industries	1	0	1,600
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	9	58,390
Industrial	Water and Wastewater	0	0	0
Total		568	90	564,017