Indiana Michigan Power Company

INDIANA IRP TECHNICAL CONFERENCE

September 9, 2024

INDIANA MICHIGAN POWER
An AEP Company

Welcome & Introductions

I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Stacie Gruca | Manager, Regulatory Services

Austin DeNeff | Regulatory Consultant Senior

1898 & Co.

Brian Despard | Senior Project Manager

I&M IRP Planning

Greg Soller | Manager, Resource Planning

Dylan Drugan | Manager, Resource Planning

Mohamed Abukaram | Director, Resource Planning

I&M Infrastructure Development

Tim Gaul | Director, Regulated Infrastructure Development

I&M Load Forecasting

Trenton Feasel | Manager, Economic Forecasting

Agenda

Time (EST)	Agenda Topic	Lead
1:00-1:05	**Welcome & Introductions**	**Andrew Williamson**
1:05-1:10	**Going-In Capacity Position Review**	**Dylan Drugan**
1:10-1:35	**Load Forecast Assumptions and Methodology**	**Trenton Feasel**
1:35-1:45	**DSM Modeling Inputs**	**Dylan Drugan**
1:45-2:00	**Market Assessment of Existing and New Resources** • Queue Analysis Of New Resources	**Tim Gaul**
2:00-2:25	**Key Modeling Inputs** • Assumptions related to IRA credits, Cook, Hydro, and Storage	**Mohamed Abukaram**
2:25-2:40	**Release of Modeling Data**	**Dylan Drugan**
2:40-3:00	**Open Discussion** • Feedback From Stakeholders	**Andrew Williamson**

Preliminary PJM ELCC and FPR Forecasts

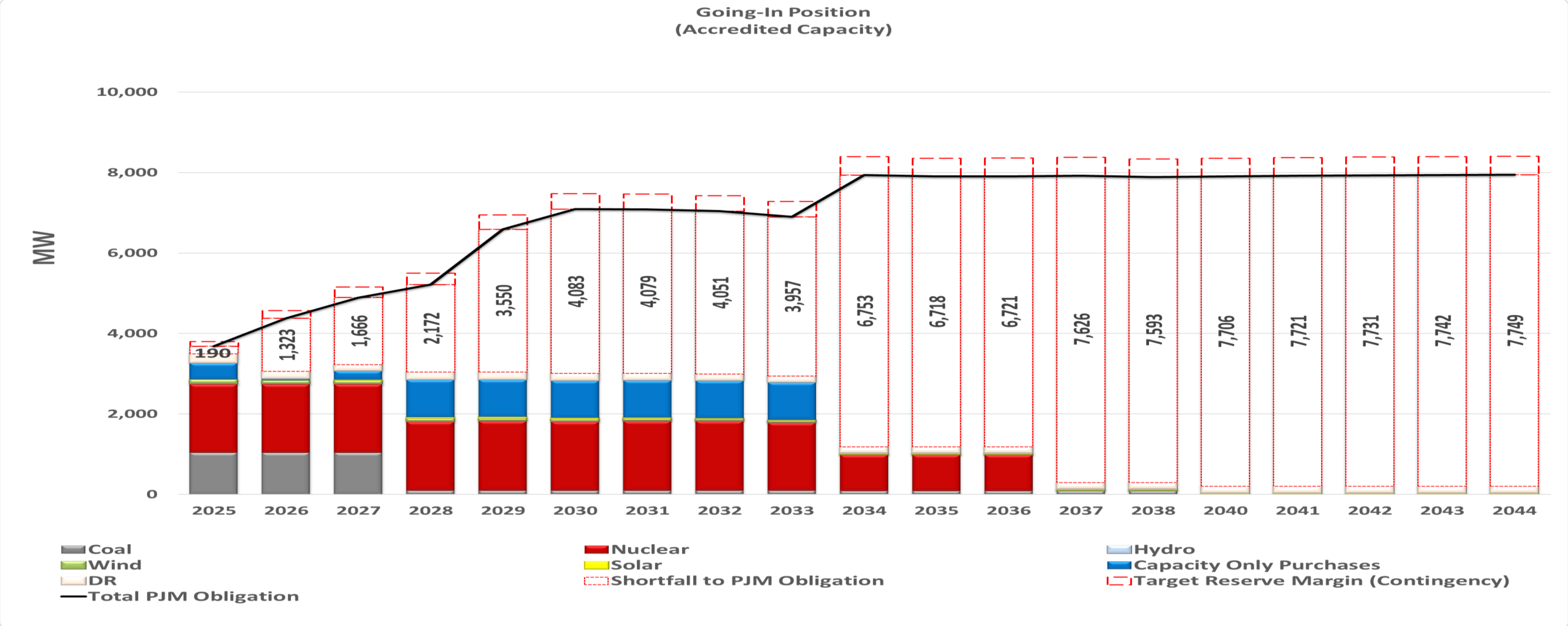
ELCC Class	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Onshore Wind	35%	33%	28%	25%	23%	21%	19%	17%	15%
Offshore Wind	61%	56%	47%	44%	38%	37%	33%	27%	20%
Fixed-Tilt Solar	7%	6%	5%	5%	4%	4%	4%	4%	3%
Tracking Solar	11%	8%	7%	7%	6%	5%	5%	5%	4%
Landfill Intermittent	54%	55%	55%	56%	56%	56%	56%	56%	54%
Hydro Intermittent	38%	40%	37%	37%	37%	37%	39%	38%	38%
4-hr Storage	56%	52%	55%	51%	49%	42%	42%	40%	38%
6-hr Storage	64%	61%	65%	61%	61%	54%	54%	53%	52%
8-hr Storage	67%	64%	67%	64%	65%	60%	60%	60%	60%
10-hr Storage	76%	73%	75%	72%	73%	68%	69%	70%	70%
Demand Resource	70%	66%	65%	63%	60%	56%	55%	53%	51%
Nuclear	95%	95%	95%	96%	95%	96%	96%	94%	93%
Coal	84%	84%	84%	85%	85%	86%	86%	83%	79%
Gas Combined Cycle	79%	80%	81%	83%	83%	85%	85%	84%	82%
Gas Combustion Turbine	61%	63%	66%	68%	70%	71%	74%	76%	78%
Gas Combustion Turbine Dual Fuel	79%	79%	80%	80%	81%	82%	83%	83%	83%
Diesel Utility	92%	92%	92%	92%	92%	93%	93%	93%	92%
Steam	74%	73%	74%	75%	74%	75%	76%	74%	73%

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

Delivery Year	Forecast Pool Requirement (% of Peak Load)
2026/27	93.67%
2027/28	92.69%
2028/29	92.75%
2029/30	93.47%
2030/31	92.96%
2031/32	92.72%
2032/33	92.10%
2033/34	89.99%
2034/35	87.09%

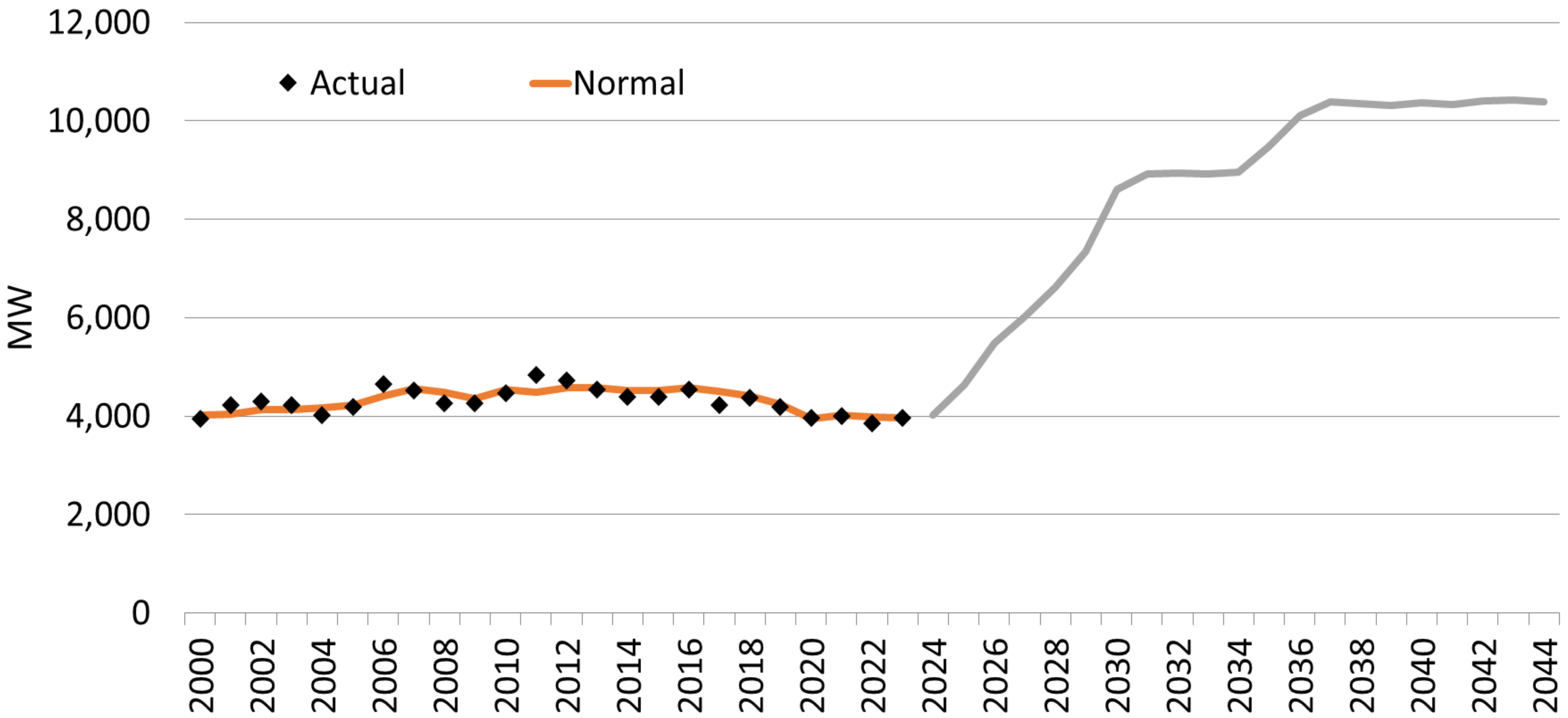
- I&M's forecasted capacity need is influenced by the accredited capacity PJM recognizes for I&M's resources (i.e., ELCC Class values) as well as by the load requirement PJM sets (i.e., the "FPR" or Forecast Pool Requirement).
- PJM's forecasted decline in ELCC class values for resources such as wind, solar, and storage is offset, in part, by a lower forecasted peak load requirement (i.e., a lower FPR).

Capacity Needs Assessment (Preliminary Going-In Position)



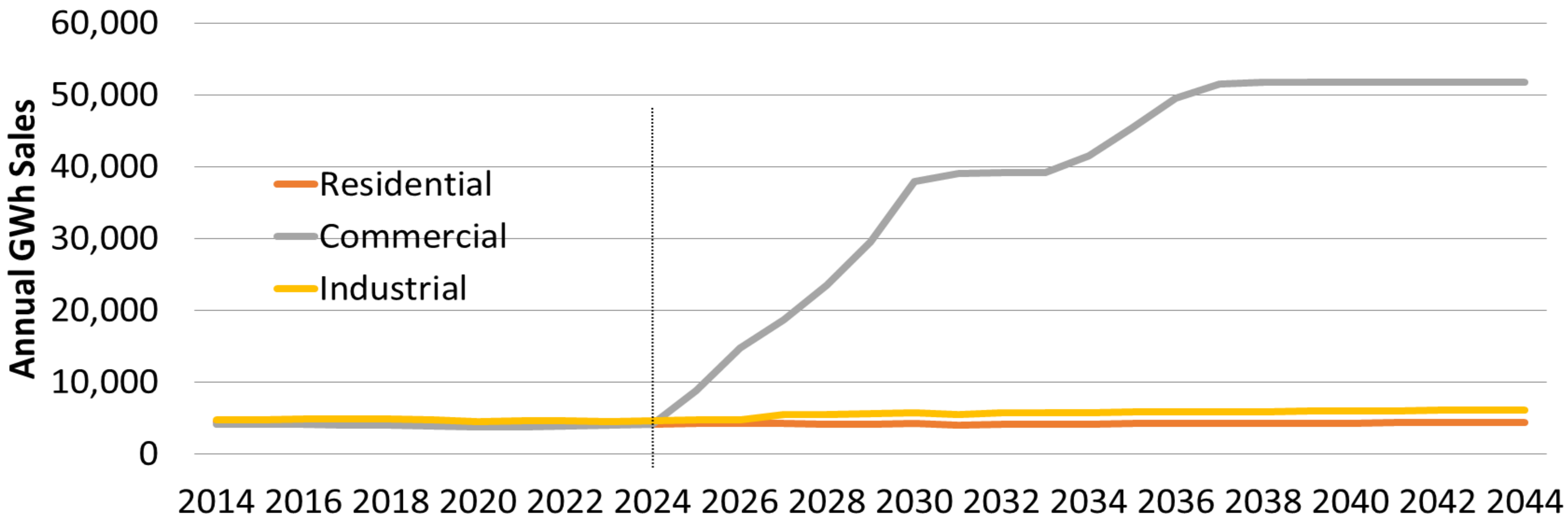
- To reasonably capture contingency risk around future uncertainties such as changes to load obligations and available capacity, a probabilistic risk analysis was performed to evaluate a 'Target Reserve Margin'.
- The analysis resulted in a Target Reserve Margin of 5% above the PJM load obligation by 27/28;
  - PJM Load Obligation is ~93% of peak load in 27/28 and, in turn, Target Reserve Margin is ~98% of peak load (~93% + 5%);
  - Additional 5% Target Reserve Margin results in planning for an additional ~450 MW above the PJM Load Obligation.

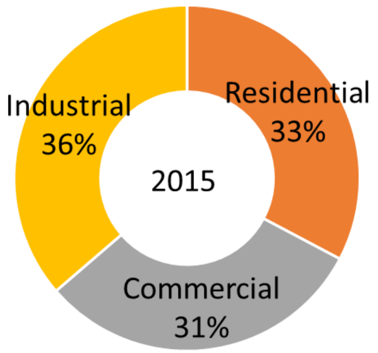
I&M Peak Demand Forecast

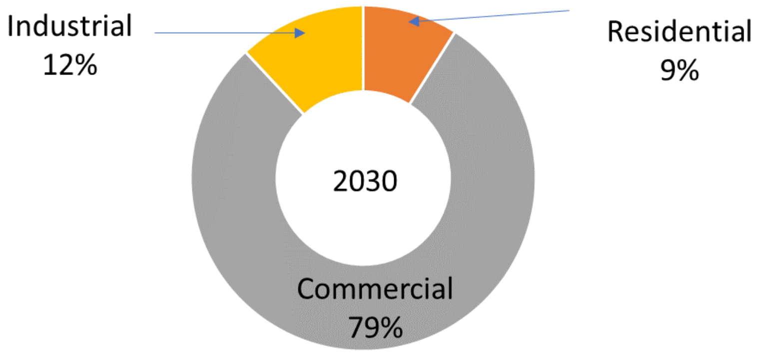


I&M's peak demand forecast is projected to grow at an 8.3% CAGR from 2024-2034, driven by the addition of hyperscaler data center loads in Indiana.

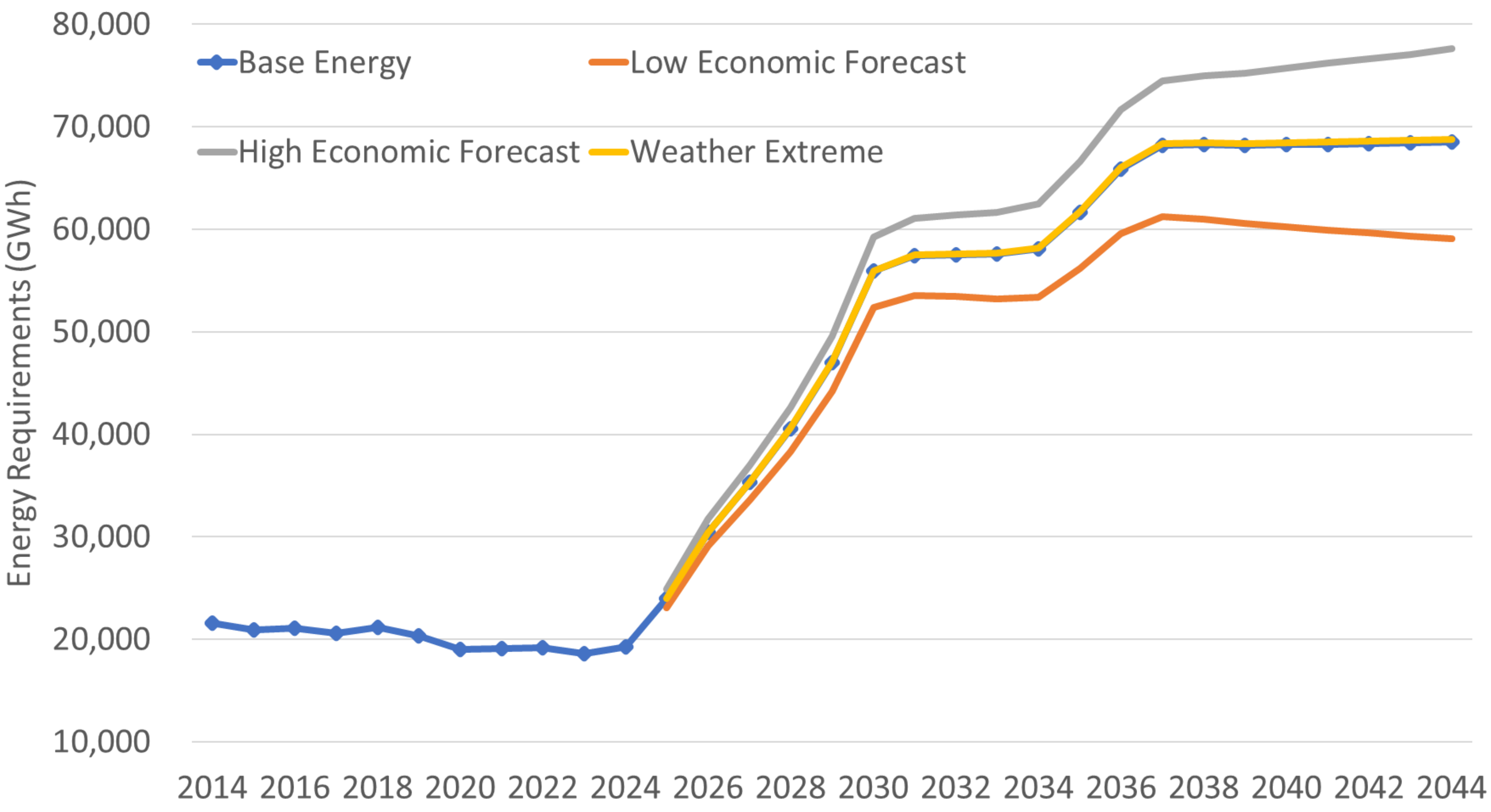
Indiana GWh Sales
(Weather Normalized History & Forecast)



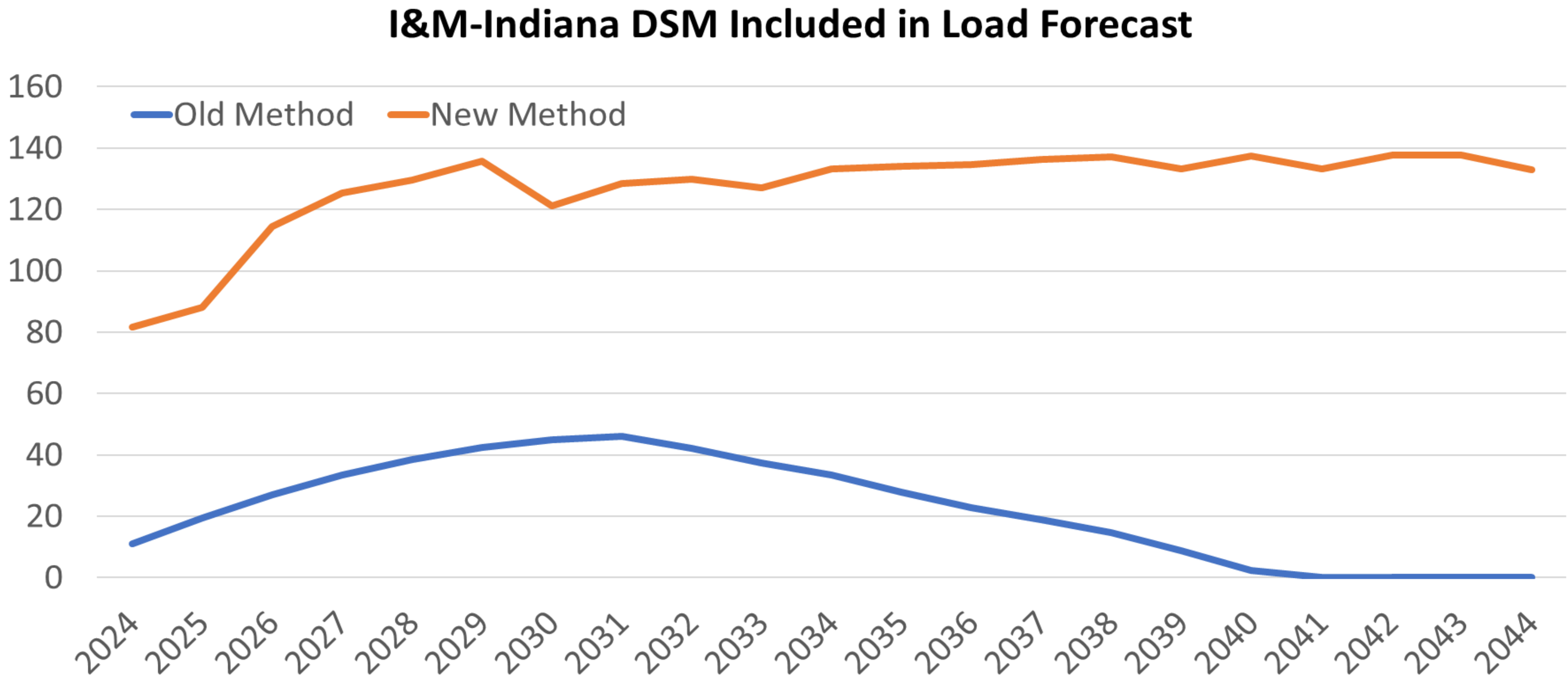




Load Forecast Scenarios

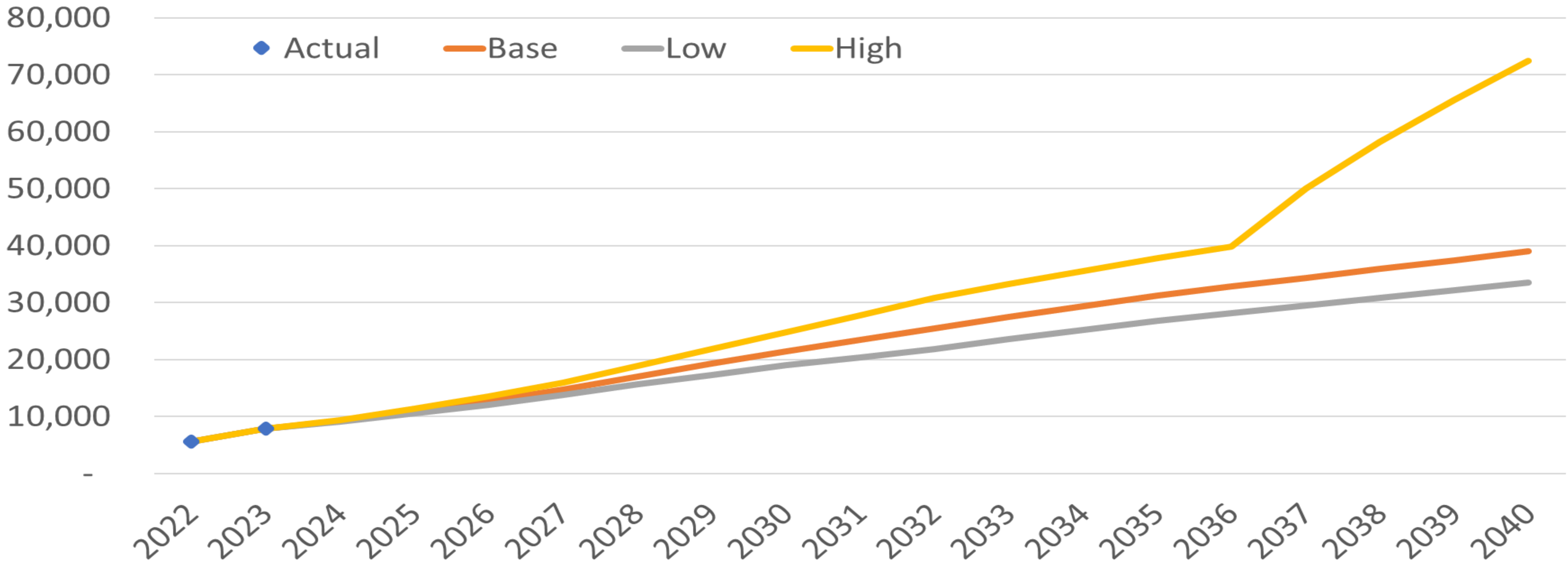


Controlling for DSM/EE



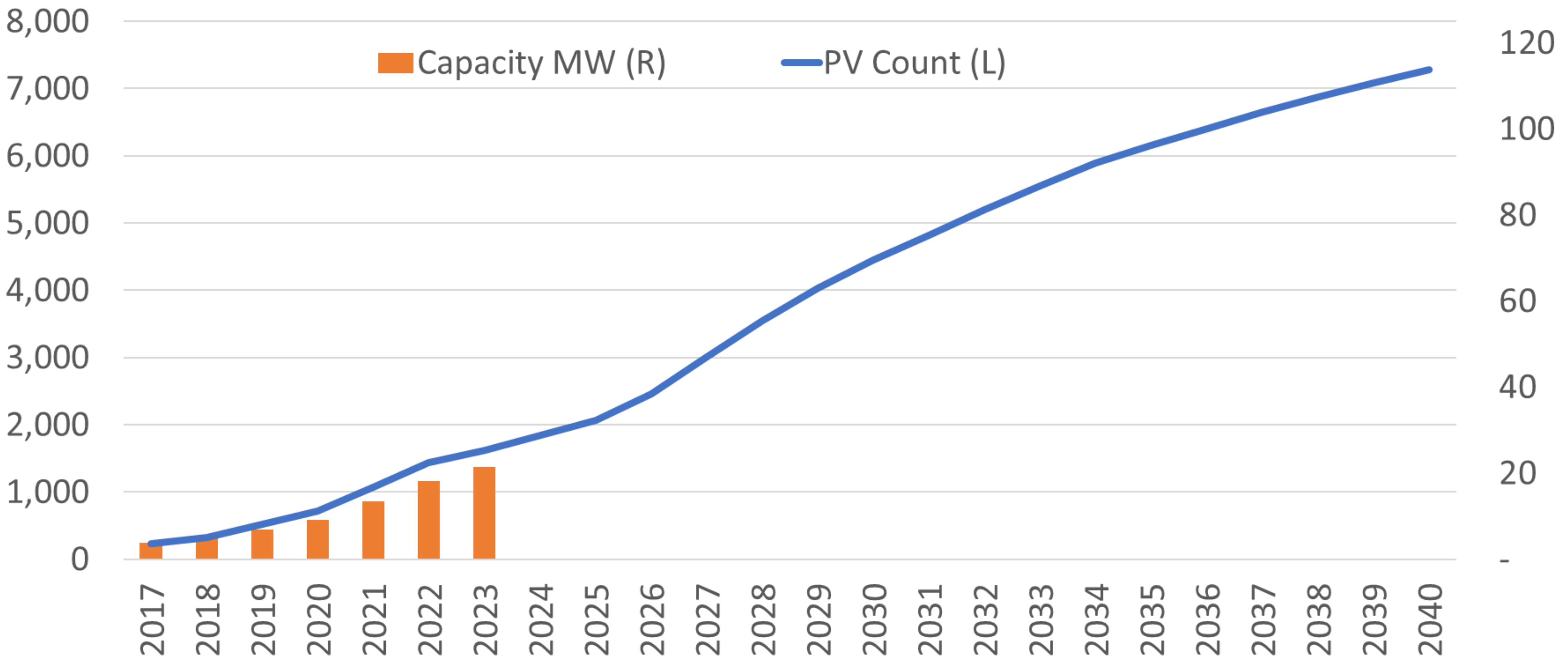
Per Rockport Unit 2 Declination of Jurisdiction Settlement in CN 45546, I&M now explicitly accounts for DSM programs in its econometric model as an additional independent variable. This has led to DSM having a greater impact on the forecast than the prior degradation approach. DSM was a post model adjustment in the "Old Method" and degraded over time. DSM is used as an explanatory variable in the "New Method" and does not reflect the degradation in the "Old Method."

Indiana Electric Vehicle Count Forecast



Despite projected 12% annual growth over the next decade, EVs will make up a small portion of the roughly 1.8M vehicles in the I&M Indiana territory. There is upside to the should affordability improve and/or mandates occur, as illustrated by the high forecast scenario.

Indiana Solar Forecast



At the end of 2023, customer-owned solar reached a total nameplate capacity of 21 MW, or about 0.5% of I&M's 2023 peak. Adoption is projected to continue increasing as costs are projected to fall. By 2040, customer-owned solar is projected to decrease retail energy by about 0.4%.

Market Potential Study Savings and DSM Inputs for IRP

Energy Efficiency

- RAP and Enhanced RAP Potential Savings were provided for input into the IRP using 6 total bundles and a few minor adjustments:
  - 1 non-residential bundle, 3 residential market rate bundles, and 2 income-qualified bundles
  - 3 residential bundles include behavior, low/medium cost, and high-cost measures
  - 2 income-qualified bundles include traditional income-qualified program savings as well as additional potential impacts from federal funded programs
  - EE impacts were adjusted to reflect net savings (not gross) at the generation level (line loss adjustments)
  - Avoided transmission and distribution capacity benefits were treated as a reduction in annual program costs
  - Each sector bundle has its own 8,760 shape based on measure mix

Demand Response

- RAP provided for 2 bundles that includes 14 programs / sub-segments. Bundles are sector-based.
- Each DR program type was modeled separately with its own seasonal MW potential and annual cost profile.
- Avoided transmission and distribution capacity benefits were treated as a reduction in annual DR program cost.
- Residential
  - DLC Central AC Switch, DLC Thermostat, DLC Water Heating, DLC EV Charging, EV Rate, Behavioral (iControl), Time of Use Rate, Critical Peak Pricing Rate
- C&I
  - DLC Thermostat, Curtailable Rate, Real Time Pricing Rate, Time of Use Rate, Critical Peak Pricing Rate, Capacity Bidding

EE Bundles

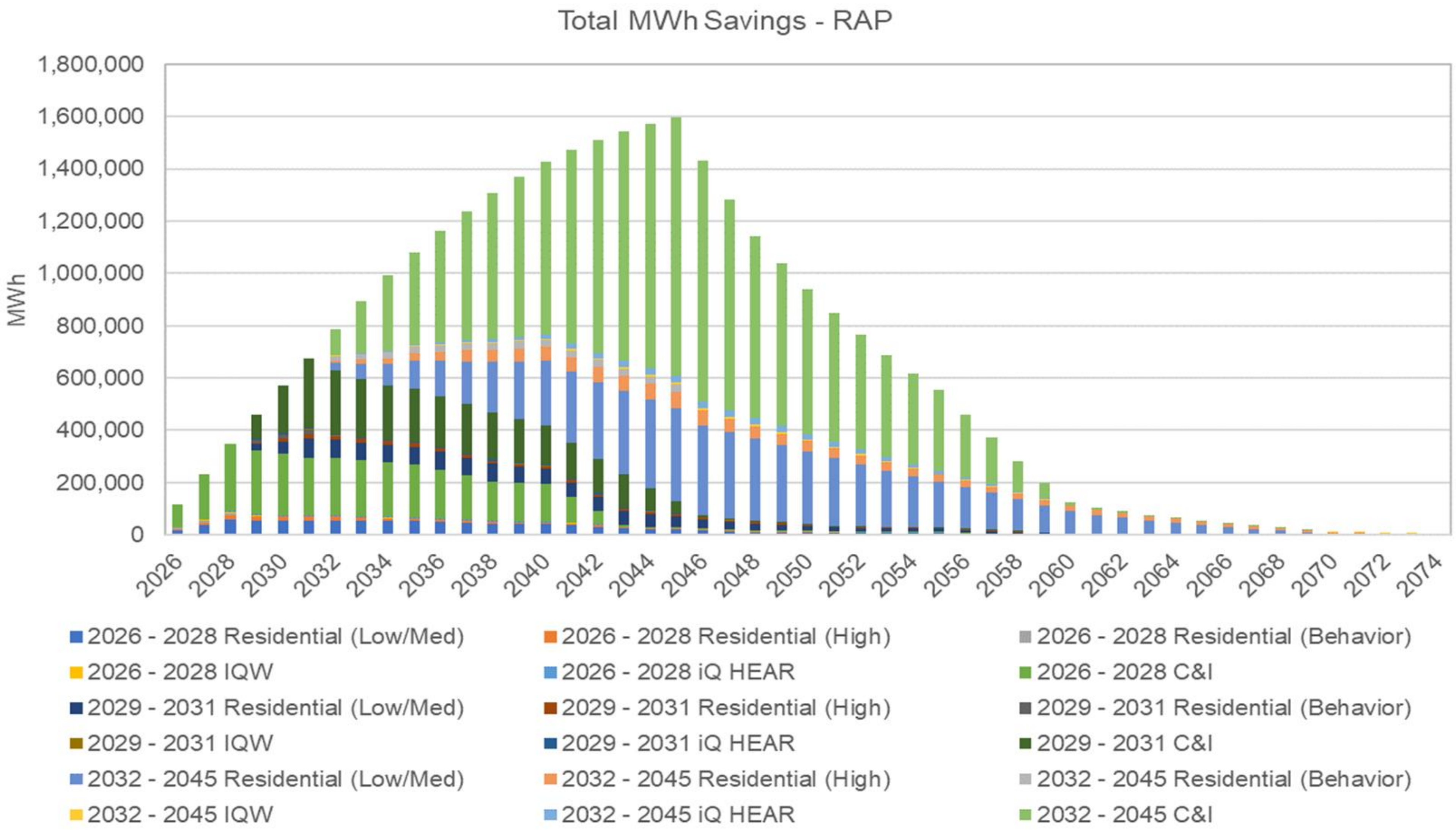
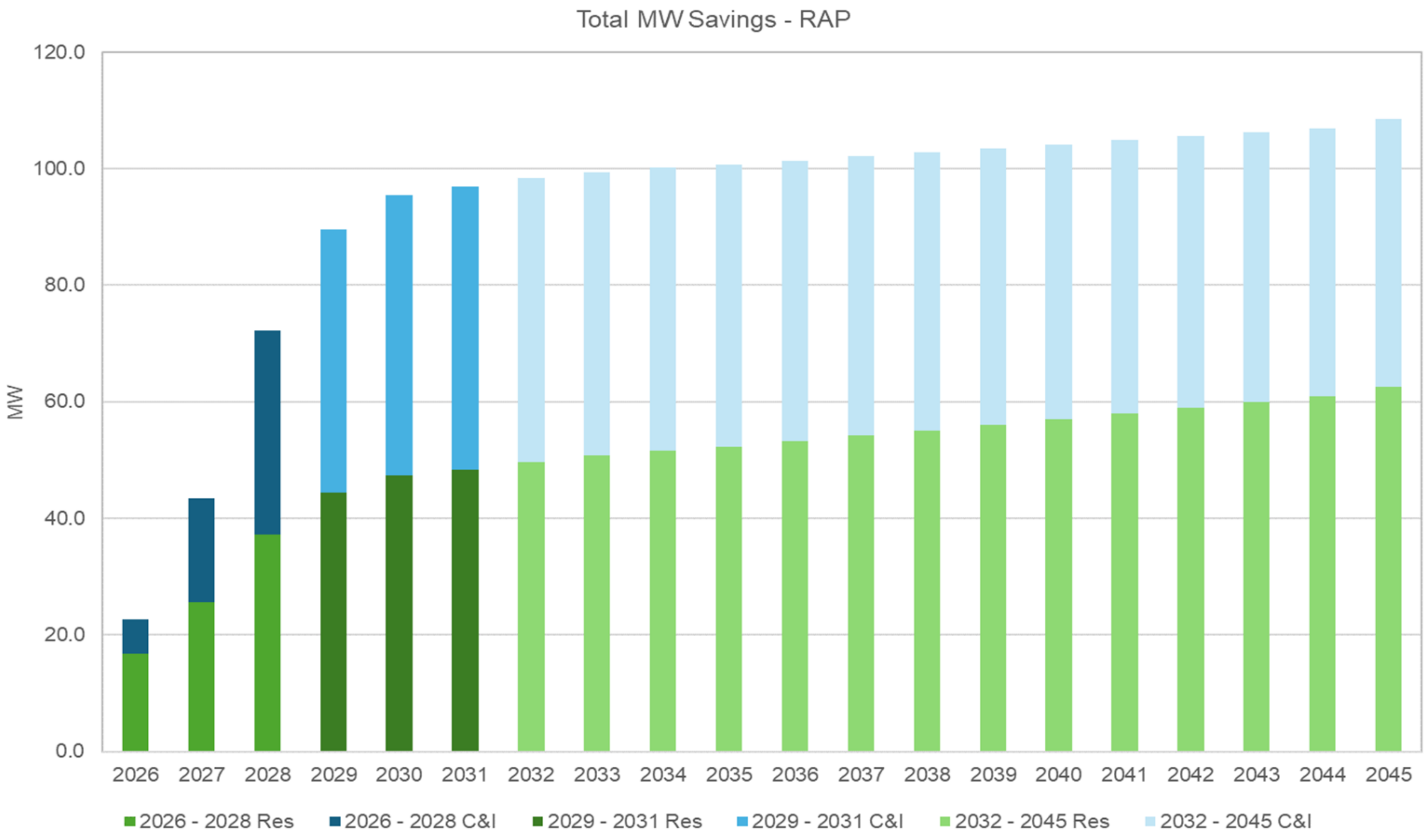


Chart reflects cumulative savings potential available to be selected by the model.

DR Bundles by Sector



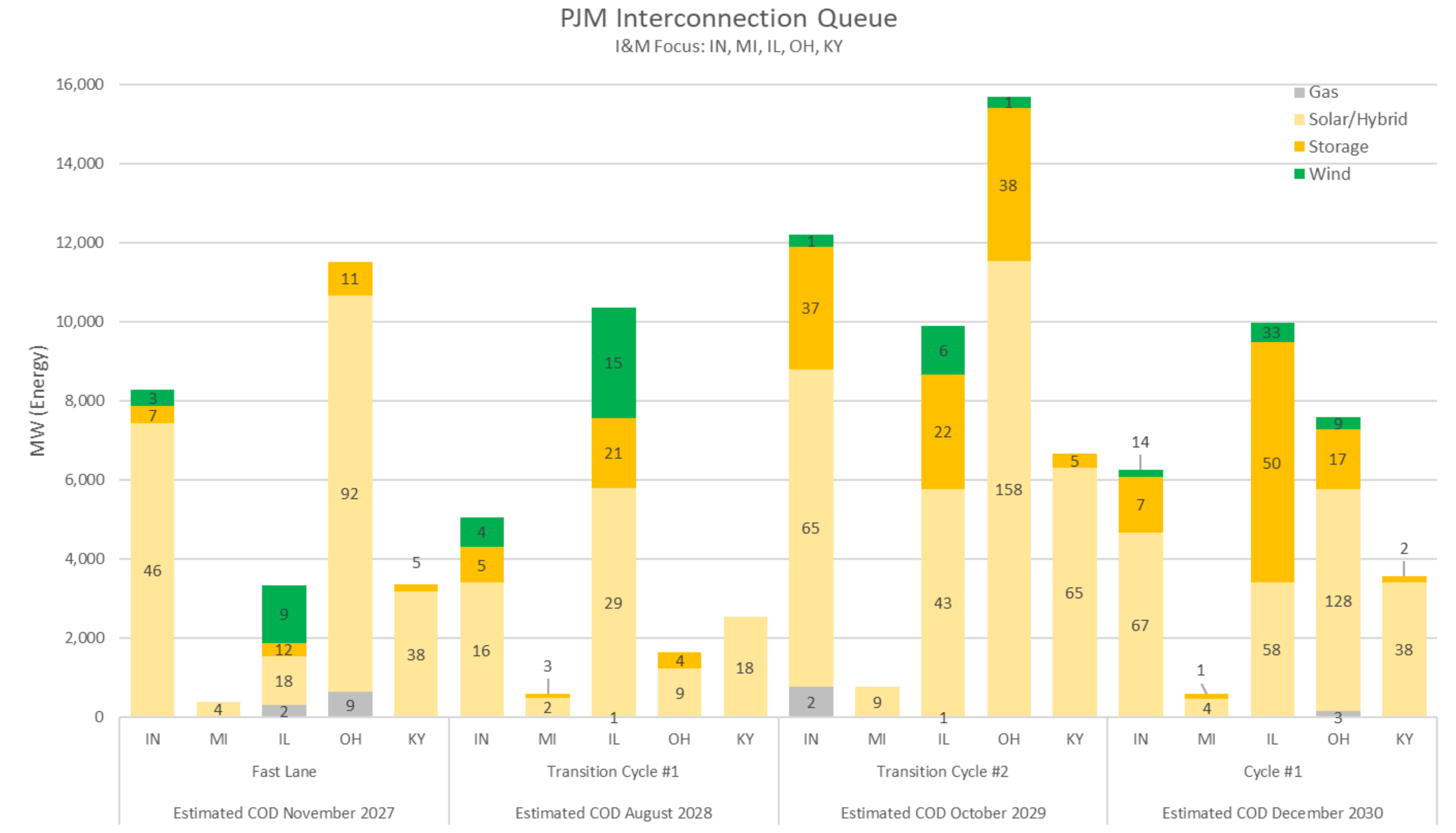
- Preliminary chart that reflects cumulative savings potential for cost-effective measures only;
- However, all DR potential will be available to be selected in model;
- In addition, DER measures (solar and solar + storage) are also being developed and will be available for model selection.

CVR Inputs

First Full Year In-Service	# of CVR Projects	Annual Projected Energy Savings (kWh)	Annual Projected Demand Savings (kW)	Sum of Capital Cost	Sum of Annual O&M Cost
2025	25	25,949,992	695	$20,504,336	$386,059
2026	34	31,731,801	1,105	$27,418,013	$525,040
2027	14	16,230,802	436	$11,729,327	$216,193
2028	6	4,942,409	158	$3,174,476	$92,654
2029	10	9,560,529	354	$7,056,004	$154,424
2030	1	1,506,137	19	$565,204	$15,442

- CVR useful life is 20 years. Project annual energy and demand savings will be included in the model for 20 years from “First Full Year In-Service”;
- All CVR savings shown above will be forced into the model.

Resource Availability – IN, MI, IL, OH, KY



NOTE: Stacked Bar Chart Labels Represent Project Counts

Illustrative Example of Resource Modeling Parameters (Solar)

Nameplate Capacity (MWs)	Block Size	Asset Life	First Year Available	Cumulative Build Limit through 2030 (MW)	Cumulative Build Limit 2031+ (MW)	Overnight Build Cost ($/kW)	Levelized Carrying Charge Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/kW-yr)	Hourly Energy Shape	ELCC
600	150	35	2028	1,200	4,800	Under Development	~9%	$15	N/A	Yields ~22% capacity factor	4% - 11%

Values shown for illustrative purposes only. Final inputs are still under development.

IRA Tax Credit Inputs

Investment Tax Credits (ITC)

- ITC applied to Solar, Storage and SMNR
- Schedule of ITC
  - 2025-36: 30% credit
  - 2037: 22.5%
  - 2038: 15%
  - 2039+: 0%

Production Tax Credits

- PTC applied to Wind
- Schedule of PTC
  - 2025-36: applied to all new build wind for the first 10 years of life (~ in the range of $40/MWh-$58/MWh)
  - 2037: PTC reduced by 25%
  - 2038: PTC reduced by 50%
  - 2039+: No PTC applied to new builds from this year onwards

Carbon Capture Storage Tax Credits

- Credit applied to Carbon Capture Storage technologies for every MWh produced
- Schedule of Carbon Capture Storage Tax Credits
  - 2025-36: applied to all new build CC with CCS for the first 12 years of life (~ in the range of $29/MWh-$44/MWh)
  - 2037+: No CCS tax credits applied to new build from this year onwards

Cook Subsequent License Renewal (SLR) Analysis

<u>Cook Relicensing Optimization</u>

- U1 Current License Expiration Q4 2034;
- U2 Current License Expiration Q4 2037;
- Model will optimize the decision to retire or relicense while considering economics and reliability.

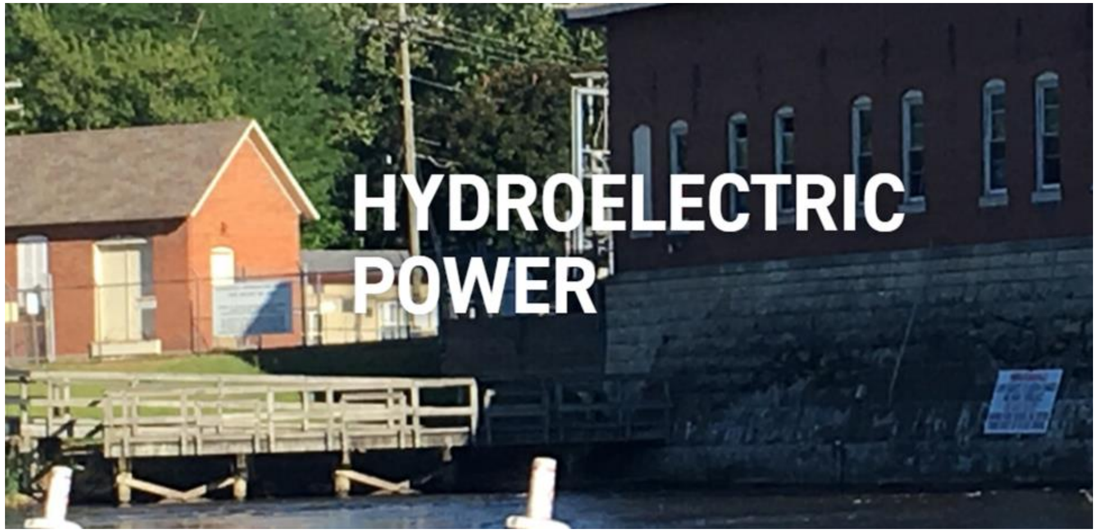
<u>Costs Considered in Cook Relicensing Analysis</u>

- **<u>NOTE:</u>** these are estimates in 2023 Dollars and do not include items such as AFUDC, Overhead Costs, Cost Escalations, etc.;
- **Subsequent License Renewal (SLR) Cost**: $42.5M;
- **One-Time inspection Costs after SLR received:** $20M;
- **Dry Cask Fuel Storage Pad Extension Cost:** $4.1M (this cost reflects discounts available through DOE funding) ;
- **Capital Improvement Costs to support an additional 20 years of life:** $250M;
- On-Going Capital Costs (OGC) and Fixed Operations & Maintenance (FO&M) Cost schedules.

Hydro Subsequent Renewed Operating License Analysis

Hydro Relicensing Optimization

- Analysis only performed on Hydro units that have license expirations occurring withing the next 10 years;
- Elkhart Current License Expiration Q4 2030;
- Mottville Current License Expiration Q4 2033;
- Model will optimize the decision to retire or relicense while considering economics and reliability.



Costs Considered in Hydro Relicensing Analysis

- **NOTE:** These are estimates and do not include items such as AFUDC, Overhead Costs, Cost Escalations, etc.;
- Operating License Renewal Cost:
  - $1M for Elkhart and $1M for Mottville;
- On-Going Capital Costs (OGC) and Fixed Operations & Maintenance (FO&M) Cost schedules;
- Decommissioning Costs:
  - Elkhart: $262M
  - Mottville: $115M

Storage Modeling Inputs & Methodology (Utility Scale)

Utility Scale Storage Resource Options

Modeling Steps

- Storage resources are dispatched against Fundamental Market Prices in an hourly chronological production cost model run;
- The Generation and Charge Costs are extracted and placed as inputs in the Expansion Planning Optimization;

Day Ahead, Real Time, and Ancillary Services Market Revenue

- Value in the Ancillary Service and RT Energy Markets are captured through Fixed Cost reductions in the Expansion Planning Optimization. Additional volatility in the DA Market is captured in the same fashion.

Utility - Scaled Storage Options Specs per Block					
Technology	Power (MW)	Duration	Capacity (MWh)	RTE%	Expected Life (years)
Lithium - Ion	50	4	200	87%	20
Lithium - Ion	50	6	300	87%	20
Lithium - Ion	50	8	400	87%	20
Lithium - Ion	50	10	500	87%	20
Iron - Air	20	100	2000	40%	20

Storage Modeling Inputs & Methodology (Distribution-Sited)

Distribution Storage Resource Options

Modeling Steps

- Distribution Storages Resources are dispatched against Fundamental Market Prices in an hourly chronological production cost model run;
- The Generation and Charge Costs are extracted and placed as inputs in the Expansion Planning Optimization.

2 Use Cases

- **"Thermal" Use Case**
  - Storage placed at stations nearing thermal overload conditions. Storage adds additional capacity at station and defers the need for upgrades (e.g., upgrading to a larger transformer);
  - Capital cost of storage will be reduced by estimated deferred cost of distribution upgrade;
  - Storage restricted from receiving energy revenues in peak months (mid-July to mid-August) but can receive energy revenues in the remaining months.
- **"Reliability" Use Case**
  - Storage placed at stations that have had historical reliability issues.
  - 50% of storage capacity always reserved to address reliability events. Remaining 50% of capacity can be used for energy market.
  - Capital cost of storage will be reduced by estimated Avoided Customer Minutes of Interruption (CMI) savings from improved reliability.

Distribution Storage Resource Option Specs

Target Station(s)	Technology	Power (MW)	Capacity (MWh)	RTE%	Direct Capital Est ($M	Need By (Date)	Expected Life (years)	Primary Use Case
County Road 4	Lithium - Ion	3	12	87%	$18	4/1/2028	20	Thermal
Robison Park	Lithium - Ion	3	12	87%	$18	12/1/2028	20	Thermal
Colfax	Lithium - Ion	3	12	87%	$18	6/1/2029	20	Thermal
Summit	Lithium - Ion	4	16	87%	$24	6/1/2028	20	Thermal
Beech Rd	Lithium - Ion	3	12	87%	$18	6/1/2033	20	Thermal
Pleasant-Yoder	Lithium - Ion	1	4	87%	$6	12/31/2028	20	Reliability
Whitaker-Elk	Lithium - Ion	3	12	87%	$18	12/31/2028	20	Reliability

Note*: The Direct Capital Est is deducted by Deferred Capital Cost for Thermal use cases and CMI Savings for Reliability use cases

Release of Modeling Data

- I&M is currently preparing for the release of ***finalized*** modeling data. It is in the process of testing and validating its inputs for quality and accuracy.

- I&M is targeting the release of modeling data by ***October 1st***. Data to be released includes:
    - Load forecast data
        - I&M will receive an updated load forecast in September and will present results at 2nd Stakeholder Meeting;
    - Fundamentals data related to power prices, fuel costs, etc.;
    - Resource inputs related to installed cost, performance characteristics, build size, etc.;
    - Short-term Capacity Purchase data;
    - DSM inputs (EE, DR, CVR);
    - Modeling constraints such as build limits;
    - Market Energy Imports/Exports.

- Finalized data inputs will be released by October 1st after receiving feedback from the 2nd Stakeholder Meeting.

Open "Office Hours" to Answer Modeling Questions

- The modeling team will hold regular meetings to work through and answer modeling related questions.
    - I&M requests that questions are submitted 3 days in advance of meeting;
    - I&M is targeting monthly meetings of 60-90 minutes.

Release of Modeling Data

Getting Set Up for PLEXOS Modeling Runs

1. Energy Exemplar to issue licenses to stakeholders;
   - Users will activate license via a web link to be provided by Energy Exemplar.

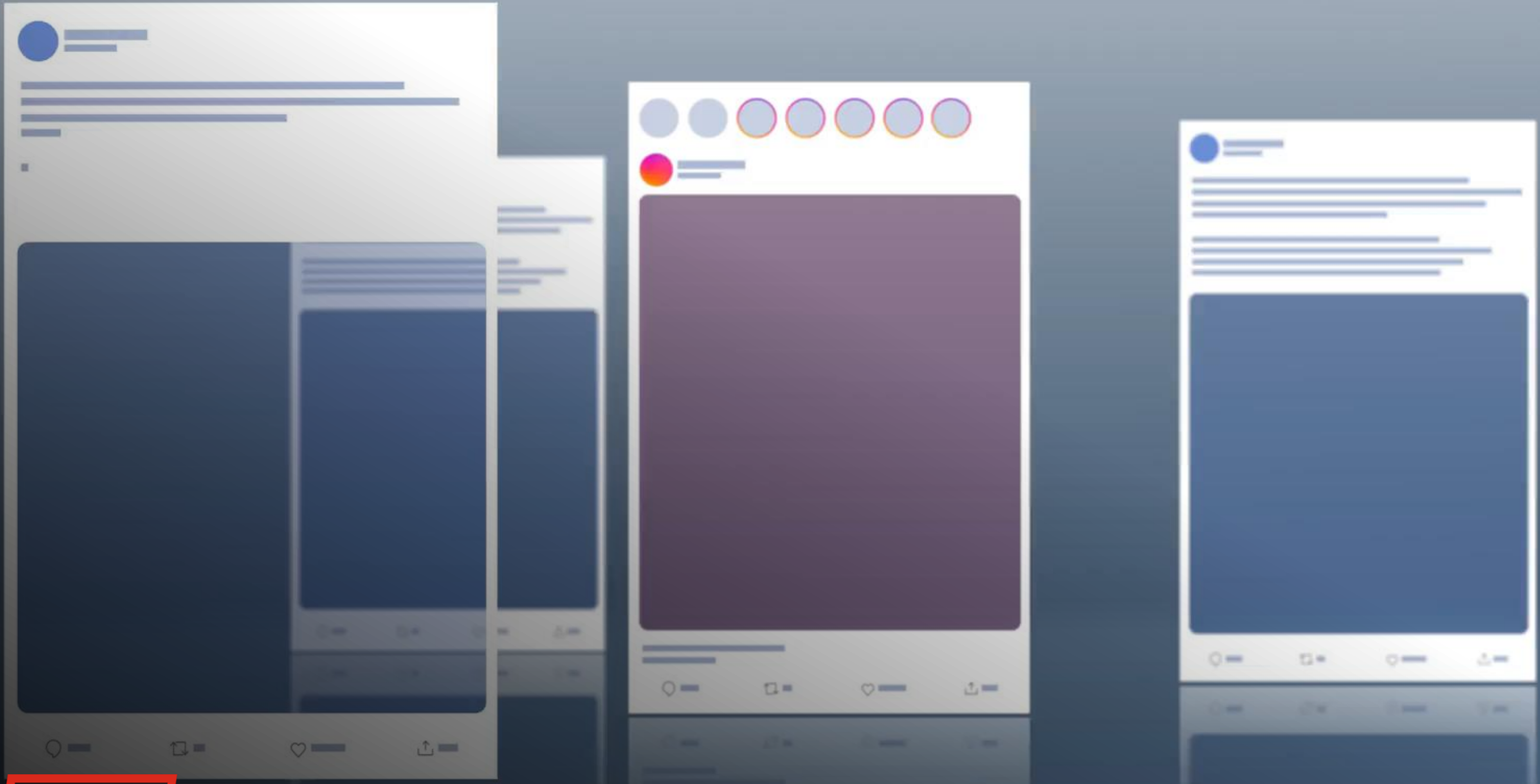
2. Energy Exemplar to assist users in downloading PLEXOS software to computers;
   - PLEXOS software must be installed on the users' computers.

3. I&M will transfer modeling data to an external Teams site;
   - Modeling data will consist of a single .xml file and accompanying CSV files that will hold all inputs to be used in PLEXOS;
   - Users can upload .xml file into PLEXOS and all data inputs will be automatically populated;
   - Once .xml file is uploaded, users can begin making model runs.

Energy Exemplar Customer Support

- **Limited Support (includes up to 8 hours of energy analyst support):**
  - This type of license includes on-line trainings through the Client Portal, Self-Help Guides, Q&A's, email/phone support requests (support@energyexemplar.com), one-on-one web meetings;
  - Energy analysts will provide direct support to an intervenor to answer any questions they may have on the functionality of PLEXOS;
  - Any and all data questions need to be addressed by the I&M modeling team.

Feedback and Discussion



APPENDIX

Market Scenarios

Scenario	Load	Gas Price	Environmental Regulations
Base	Base	Base	Pre-EPA 111d 2023 Proposed Rules
High Economic Growth	High	High	
Low Economic Growth	Low	Low	
Enhanced Environmental Regulations (EER)	Base	Base	EPA 111d 2023 Proposed Rules

Proposed Market Sensitivities

Sensitivities	Load	Gas Price	Environmental Regulations
Base under EPA 111d Requirements	Base	Base	EPA 111d 2024 Final Rules
Base with High IN Load	High	Base	Pre-EPA 111d 2023 Proposed Rules
Base with Low IN Load	Low	Base	
Rockport Unit 1 Retires 2025	Base	Base	
Rockport Unit 1 Retires 2026	Base	Base	
Exit OVEC ICPA in 2030	Base	Base	
High Technology Cost	Base	Base	
Proposed Stakeholder Sensitivities	TBD	TBD	TBD

Portfolio Performance Indicators

IURC Pillar	IRP Objective	Performance Indicator	Metric Description
Reliability	Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers.	Energy Market Exposure – Purchases	Cost and volume exposure of market purchases (Costs and MWhs % of Internal Load) in 2033 and 2044
		Energy Market Exposure - Sales	Revenue and volume exposure of market sales (Revenues and MWhs % of Internal Load) in 2033 and 2044
		Planning Reserves	Target Reserve Margin
Affordability	Maintain focus on cost and risks to customers	Net Present Value Revenue Requirement (NPVRR) Levelized Rate ($/MWh)	Portfolio 30yr NPVRR Portfolio 30yr Levelized Rate (NPVRR/Levelized Energy)
		Near-Term Rate Impacts (CAGR)	7-year CAGR of Annual Rate
		Portfolio Resilience	Range of Portfolio NPVRR and associated Rate Impact ($/MWh) (at rqd IRP Planning Period) costs dispatched across all Scenarios
Resiliency	Maintain diversity of resources and fleet dispatchability	Resource Diversity	Diversity Index inclusive of Capacity and Energy Diversity
		Fleet Resiliency	% Dispatchable Capacity of Company Peak Load
(Grid) Stability	Maintain fleet of flexible and dispatchable resources	Fleet Resiliency	% Dispatchable Capacity of Company Peak Load
Environmental Sustainability	Maintain focus on portfolio environmental sustainability benefits and compliance costs	Emissions Change	CO_2, NO_x, SO_2 emissions change compared to 2005 levels
		Total Portfolio Costs (NPVRR)	Considered under Affordability Pillar above

Fundamentals Enhanced Environmental Regulation (EER) Scenario

Scenario

Scenario Models EPA's 111d Rule Changes

- Proposed Rule Published May 11, 2023

Generators impacted:

- Exiting coal units
- Existing natural gas units >300 MW
- New gas units

Scenario Summary:

- ~50% power price increase on expiration of IRA credits mid-2040s

Dispatchable Generation Options

Existing coal units' options to continue operation past 2032 must:

- Limit capacity factor to 20%, retire by 2035
- Blend 40% Natural Gas with coal, retire by 2040
- Install CCS

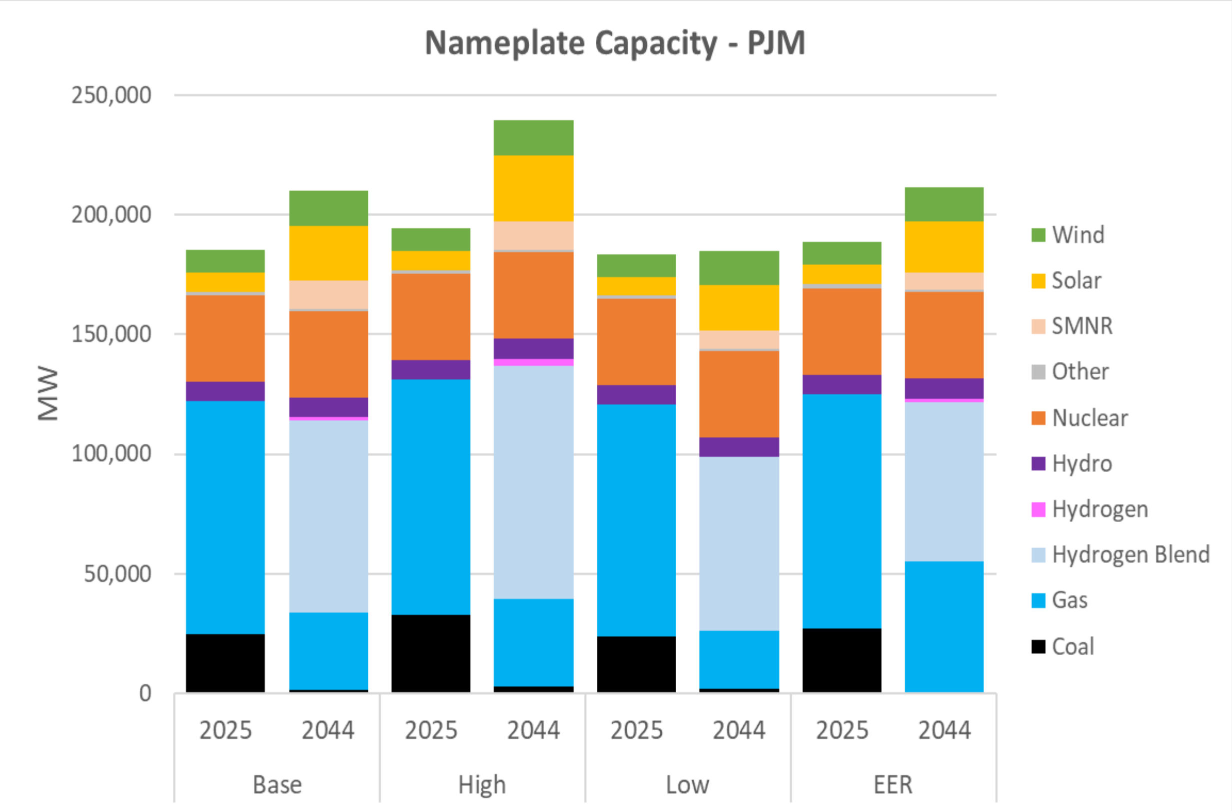
Existing Natural Gas Units >300 MW and 50% Capacity Factor:

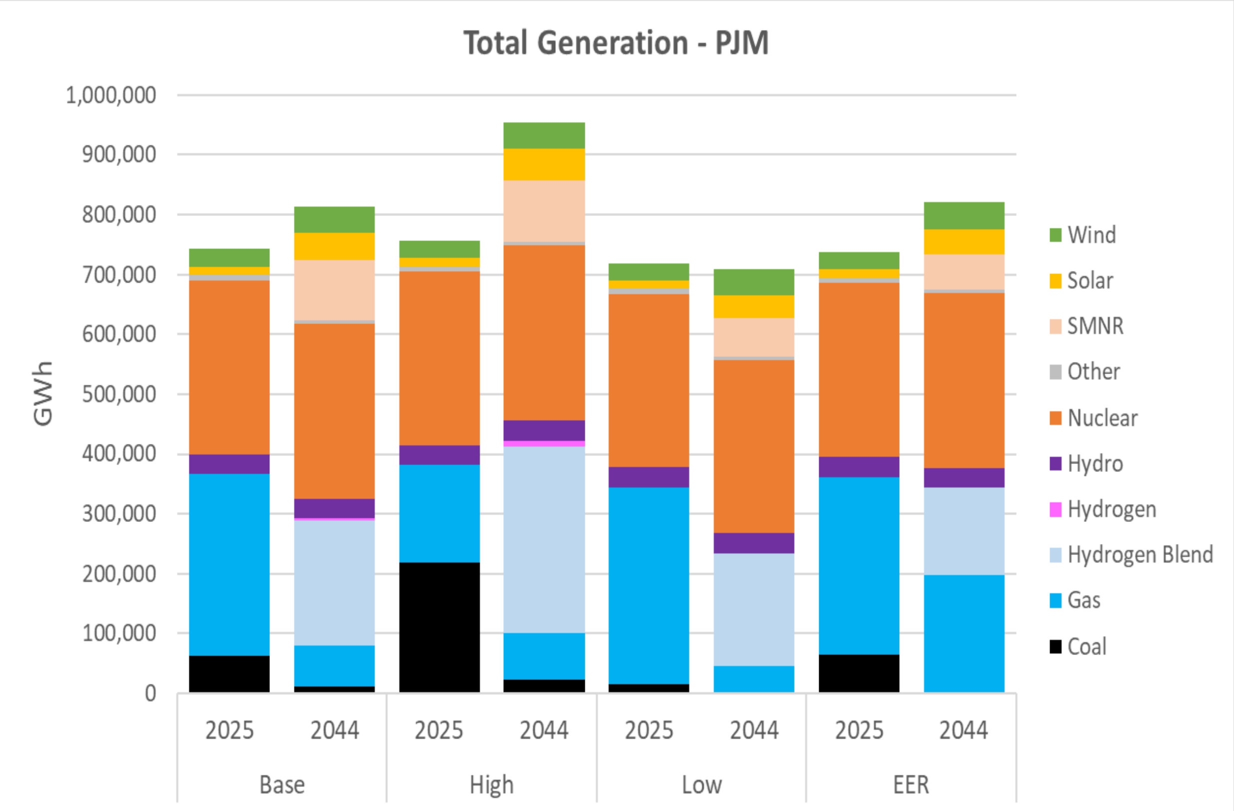
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

New Gas Units:

- Adhere to carbon emission performance standard
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

PJM Supply Mix Changes

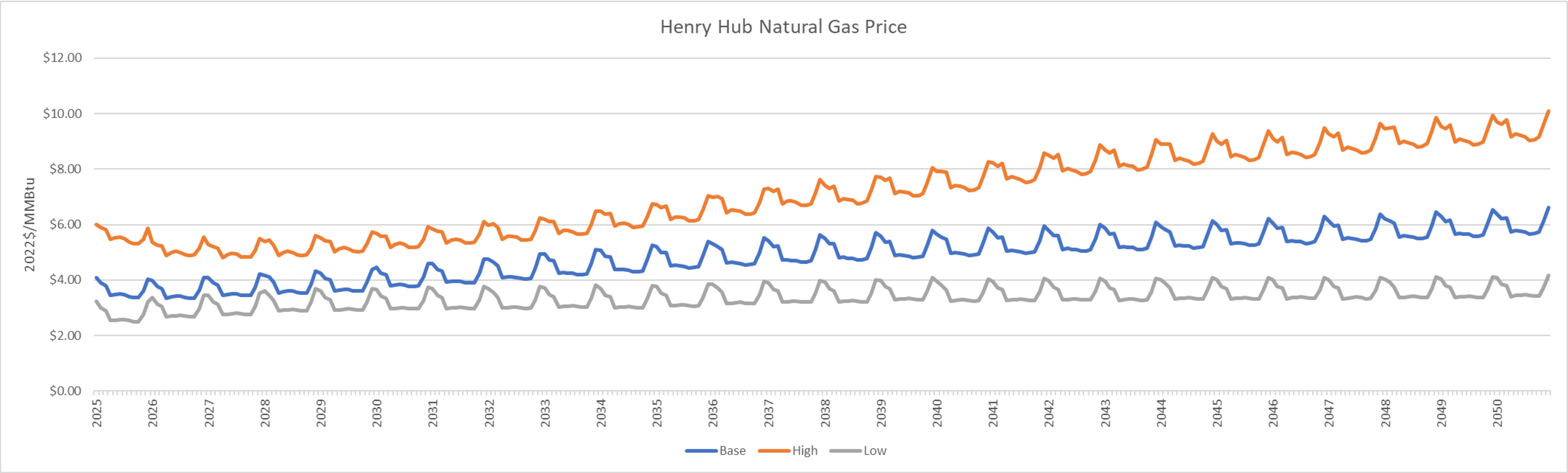




- Under all scenarios, coal is replaced primarily by NG/Hydrogen Blend units
- Solar sees significant growth in the long term
- Wind growth is moderate

- Nuclear and natural gas generation dominate the supply mix
- Natural gas/Hydrogen Blend units provide reliable, dispatchable generation as coal plants are retired

Natural Gas Inputs



- Base case assumes that natural gas demand will increase as natural gas replaces coal
- High and Low cases have similar assumptions to Base except for WTI prices and LNG exports
    - High case assumes higher WTI prices and LNG exports
    - Low case assumes lower WTI prices and LNG exports

PJM Market Prices

- Under all scenarios, energy prices are mainly influenced by natural gas prices
- Peak/Off-Peak spread averages are as follows:
    - Base: $2.71/MWh
    - High: $3.89/MWh
    - Low: $1.47/MWh
    - EER: $2.69/MWh