2022 Integrated Resource Plan (IRP)

Public Advisory Meeting #2

4/12/2022

aes Indiana

Agenda and Introductions

Stewart Ramsay, Managing Executive, Vanry & Associates

Agenda

Time	Topic	Speakers
Morning **Starting at 10:00 AM**	Virtual Meeting Protocols and Safety, Schedule	Chad Rogers, Senior Manager, Regulatory Affairs, AES Indiana
	Meeting #1 Recap	Erik Miller, Manager, Resource Planning, AES Indiana
	Load Scenarios	Mike Russo, Forecast Consultant, Itron Eric Fox, Director, Forecasting Solutions, Itron
	MPS Results & DSM Resources	Jeffrey Huber, Overall Project Manager and MPS Lead, GDS Associates
Break **12:00 PM – 12:30 PM**	Lunch	
Afternoon **Starting at 12:30 PM**	Current Generation Portfolio Overview	Kristina Lund, President & CEO, AES Indiana
	Replacement Resource Assumptions	Erik Miller, Manager, Resource Planning, AES Indiana
	IRP Portfolio Matrix & Scenario Framework	Erik Miller, Manager, Resource Planning, AES Indiana
	Final Q&A and Next Steps	

**Distribution System Planning was included on a prior distributed agenda. This topic will be covered in Public Advisory Meeting #3.*

Virtual Meeting Protocols and Safety

Chad Rogers, Senior Manager, Regulatory Affairs, AES Indiana

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IRP Team Introductions

AES Indiana Leadership Team

Kristina Lund, President & CEO, AES Indiana
Aaron Cooper, Chief Commercial Officer, AES Indiana
Brandi Davis-Handy, Chief Public Relations Officer, AES Indiana
Ahmed Pasha, Chief Financial Officer, AES Indiana
Tom Raga, Vice President Government Affairs, AES Indiana
Judi Sobecki, General Counsel and Chief Regulatory Officer, AES Indiana

AES Indiana IRP Planning Team

Joe Bocanegra, Load Forecasting Analyst, AES Indiana
Erik Miller, Manager, Resource Planning, AES Indiana
Scott Perry, Manager, Regulatory Affairs, AES Indiana
Chad Rogers, Senior Manager, Regulatory Affairs, AES Indiana
Brent Selvidge, Engineer, AES Indiana
Will Vance, Senior Analyst, AES Indiana

AES Indiana IRP Partners

Patrick Burns, PV Modeling Lead and Regulatory/IRP Support, Brightline Group
Eric Fox, Director, Forecasting Solutions, Itron
Jeffrey Huber, Overall Project Manager and MPS Lead, GDS Associates
Jordan Janflone, EV Modeling Forecasting, GDS Associates
Stewart Ramsey, Managing Executive, Vanry & Associates
Mike Russo, Forecast Consultant, Itron
Jacob Thomas, Market Research and End-Use Analysis Lead, GDS Associates
Melissa Young, Demand Response Lead, GDS Associates

AES Indiana Legal Team

Nick Grimmer, Indiana Regulatory Counsel, AES Indiana
Teresa Morton Nyhart, Counsel, Barnes & Thornburg LLP

Welcome to Today's Participants

ACES
Advanced Energy Economy
Barnes & Thornburg LLP
Boardwalk Pipelines
Butler University
CCR
CenterPoint Energy
Citizens Action Coalition
City of Indianapolis
Clean Grid Alliance
Develop Indy | Indy Chamber
Duke Energy
E&C
EDP Renewables NA
Energy Futures Group
Faith in Place
Fluence Energy
GDS Associates
Hallador Energy
Hoosier Energy
IBEW LOCAL UNION 1395
Indiana Chamber
Indiana Energy Association
Indiana Utility Regulatory Commission
IUPUI
NuScale Power
Office of Utility Consumer Counselor
Purdue - State Utility Forecasting Group
Rolls-Royce/ISS
Sierra Club
Wartsila

… and members of the AES Indiana team and the public!

Virtual Meeting Best Practices

Questions

→Your candid feedback and input is an integral part to the IRP process.

→Questions or feedback will be taken at the end of each section.

→Feel free to submit a question in the chat function at any time and we will ensure those questions are addressed.

Audio

→All lines are muted upon entry.

→For those using audio via Teams, you can unmute by selecting the microphone icon.

→If you are dialed in from a phone, press *6 to unmute.

Video

→Video is not required. To minimize bandwidth, please refrain from using video unless commenting during the meeting.

AES Purpose & Values

Accelerating the future of energy, together.

Safety first

Highest standards

All together

aes Indiana

Make your virtual environment safer

1\. Secure Your Accounts Use unique, complex passphrases and enable two-factor authentication wherever possible.

2\. Think before you click on a link, file, or attachment on your laptop and mobile.

3\. Know Your Network Protect your home network by changing default passwords; use a VPN when conducting sensitive transactions or on public WiFi.

4\. Protect your Device Patch your devices regularly and be mindful of connecting unauthorized hardware like USB drives.

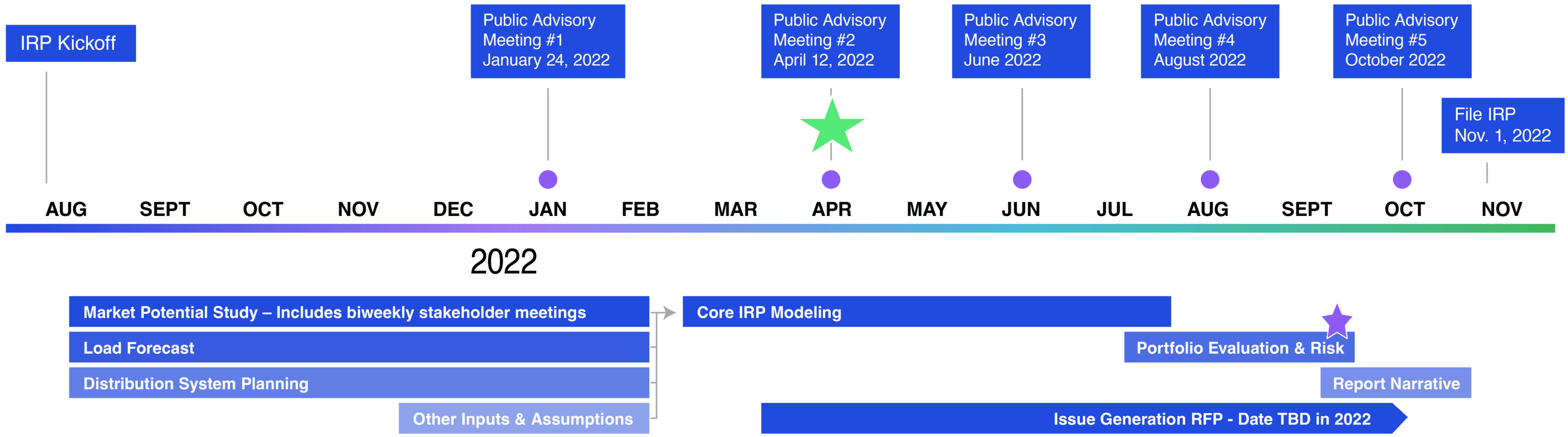
5\. Share Data Responsibly Control your social media settings and be mindful when posting publicly.

6\. Be Safe by Being Prepared Know the cyberattack types and report anything suspicious.

Meeting #1 Recap

Erik Miller, Manager, Resource Planning, AES Indiana

Updated 2022 IRP Timeline



● = Stakeholder Technical Meeting for stakeholders with executed NDAs held the week before each public stakeholder meeting

★ = Preferred Resource Portfolio selected

AES Indiana is available for additional touchpoints with stakeholders to discuss IRP-related topics.

Public Advisory Schedule

Public Advisory Meeting #1 – January 24, 2022

- 2022 IRP Schedule & Progress
- 2019 IRP Recap
- Load, EV, DG Forecasts
- MPS Overview

Public Advisory Meeting #2 – April 12, 2022

- Load Scenarios
- MPS Results & DSM Inputs
- Replacement Resource Assumptions
- IRP Portfolio Matrix & Scenario Framework

Public Advisory Meeting #3- June

- Portfolio Metrics & Scorecard Framework
- Overview of Reliability in Indiana
- Reliability Analysis
- Distribution System Plan

Public Advisory Meeting #4 - August

- Preliminary Modeling Results
- Risk Analysis
- Portfolio Metrics & Scorecard Review

Public Advisory Meeting #5 - October

- 2022 Modeling Insights
- Preferred Resource Portfolio & Short-Term Action Plan

Topics for meetings 3-5 are subject to change depending on modeling progress.

2022 Integrated Resource Plan (IRP)

Load Scenarios

Presented by Itron

Itron aes Indiana

Load Scenarios

High/Low Load Model Drivers

Mike Russo, Forecast Consultant, Itron

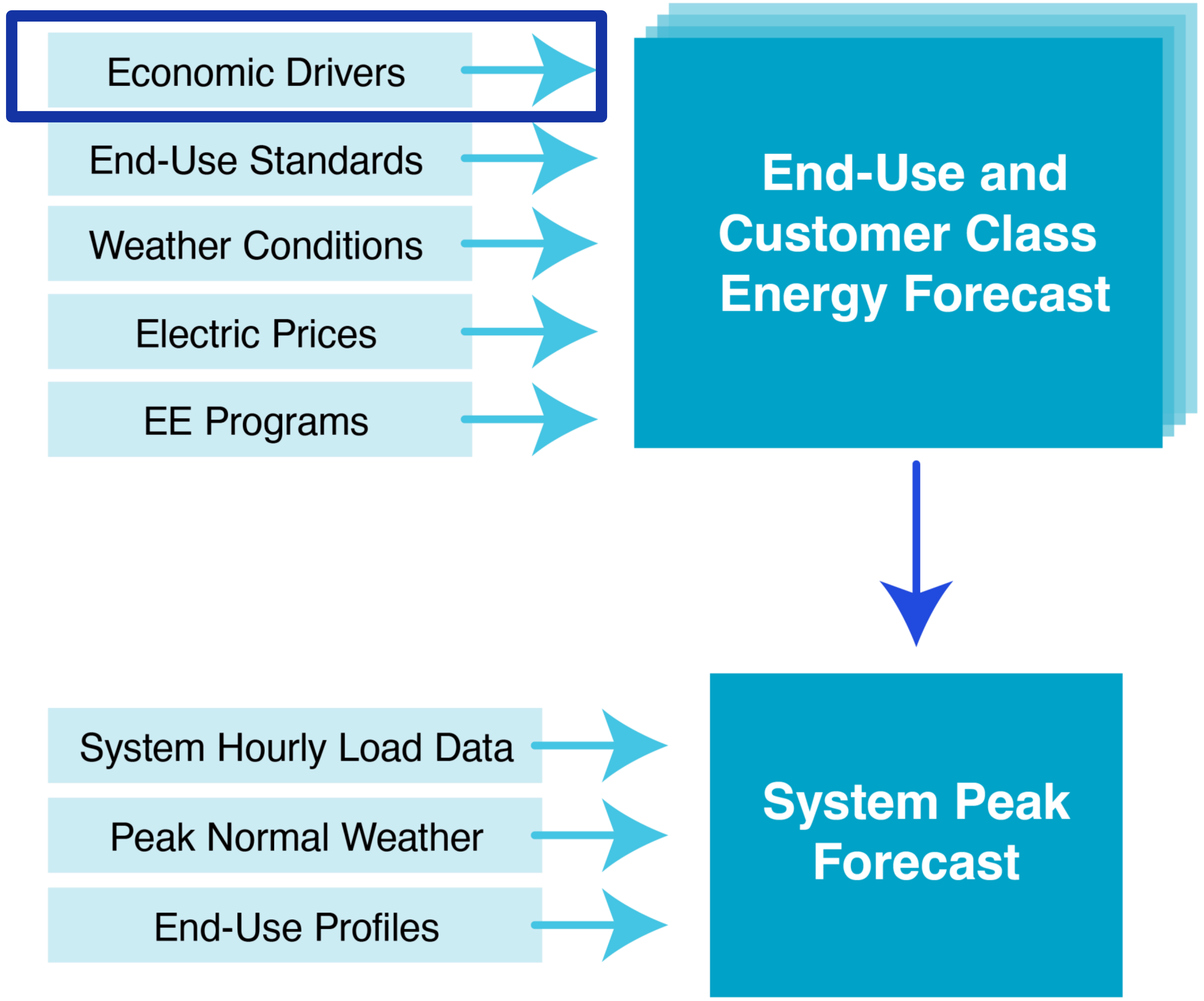
Modeling Approach

- Bottom-up Modeling Approach
- Estimate rate-class level sales and customer models from historical billed sales data
- Sales/energy driven by households, economic forecasts, expected weather conditions, price, and end-use efficiency improvements. End-use demand drives system peak demand

Monthly sales and customer models are estimated for:

- Residential
- Commercial
- Industrial
- Other (Lighting)

Monthly peak model driven by end-use energy forecasts



The baseline forecast excludes behind the meter solar, electric vehicle loads, and future EE program savings

Itron aes Indiana

Economic Based Scenarios

Baseline Forecast

- Baseline forecast models use economic concepts from Moody's Analytics Baseline Forecast, Aug 2021. Moody's defines their baseline forecast as "the probability that the economy will perform better than this projection is equal to 50%, the same as the probability that it will perform worse".

Low Forecast Scenario

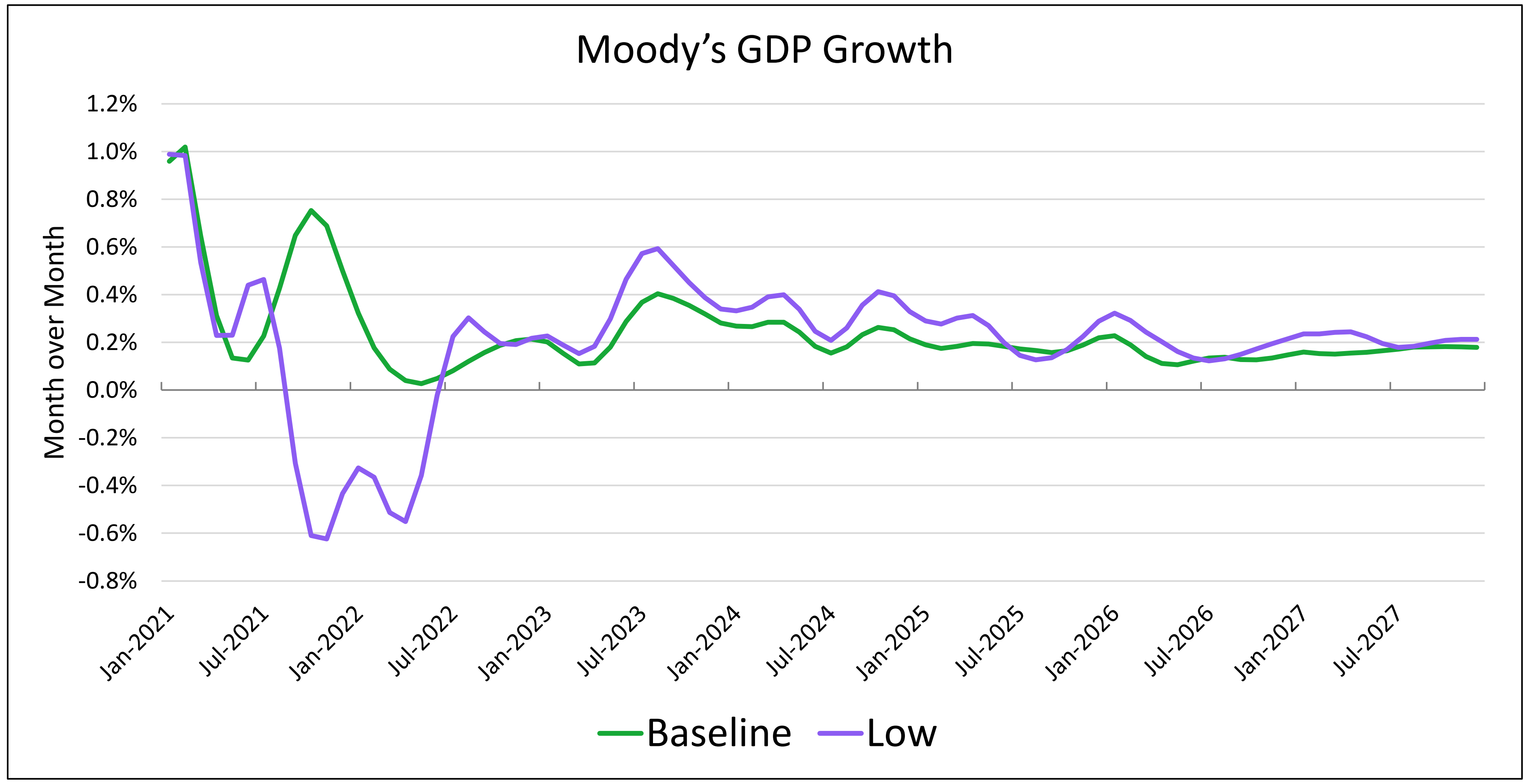
- Based on Moody's S3: Alternative Scenario 3 – Downside – 90th Percentile: In this scenario, there is a 90% probability that the economy will perform better, broadly speaking, and a 10% probability that it will perform worse.

High Forecast

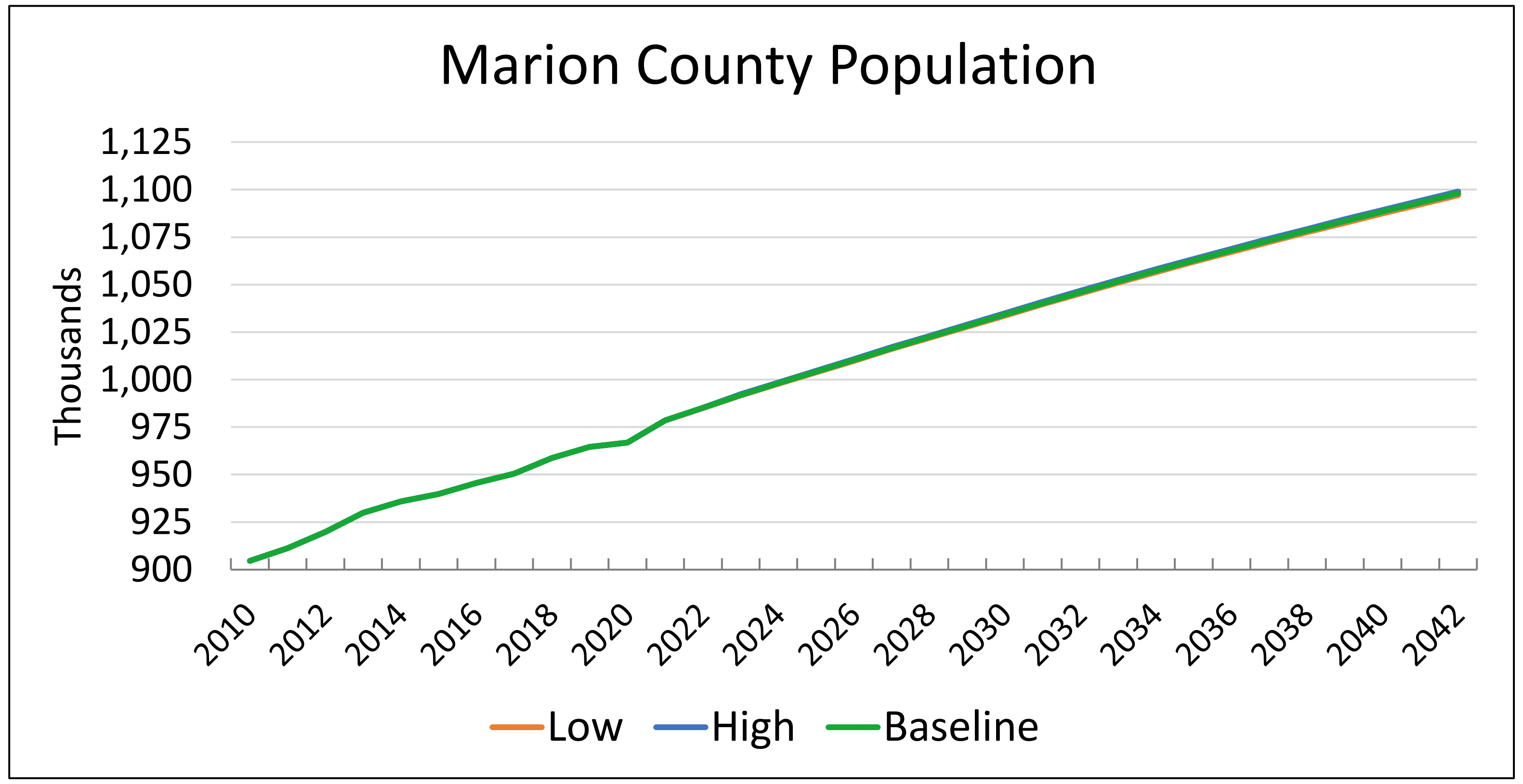
- Based on Moody's S1: Alternative Scenario 1 – Upside – 10th Percentile: In this scenario, there is a 10% probability that the economy will perform better, broadly speaking, and a 90% probability that it will perform worse.

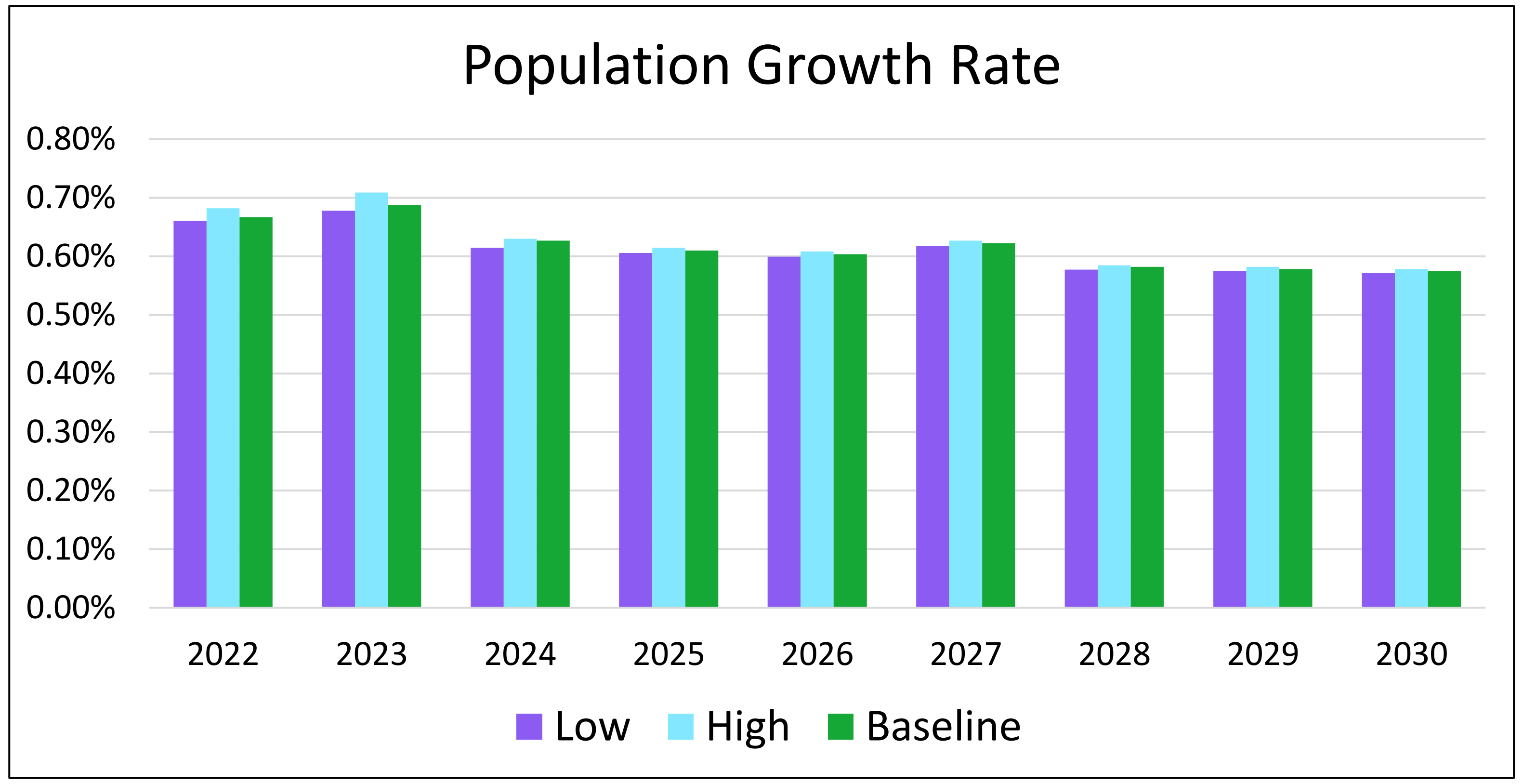
Construction of Scenario Economic Drivers

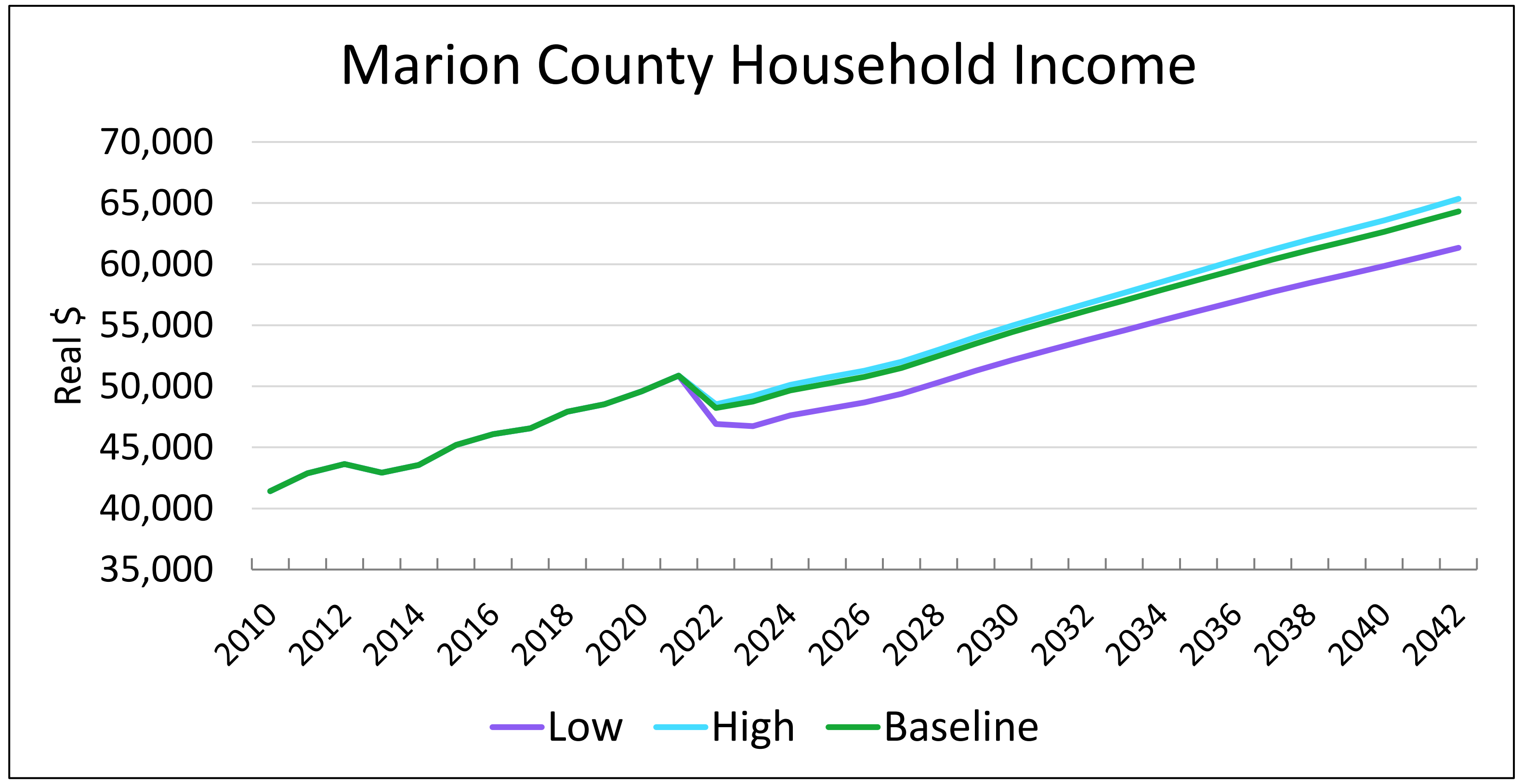
- Growth rates from the Moody's Low/High scenarios are applied to the Baseline economic variables beginning in January 2022
- The chosen methodology ensures the growth rates used are less than or equal to the Baseline growth rates in the Low case and greater than or equal to the Baseline growth rates in the High case.
  - If this adjustment were not made Low case growth rates would be greater than the baseline in certain years, as seen below. This could result in the Low load forecast exceeding the Baseline load forecast.

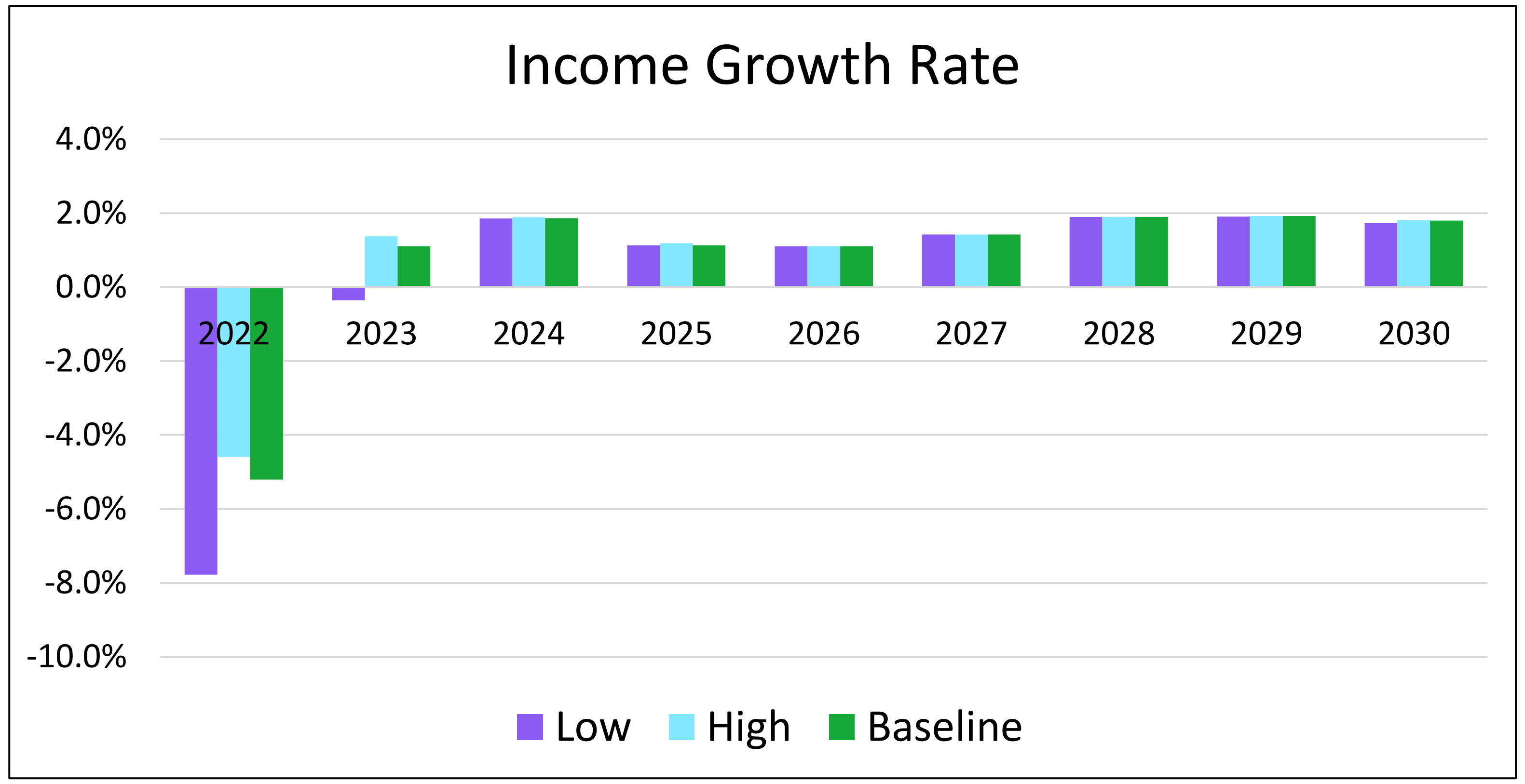


Residential Economic Drivers









→ Moody Analytics scenarios growth rates are noticeably different in the near-term but revert back to long-term growth rates.

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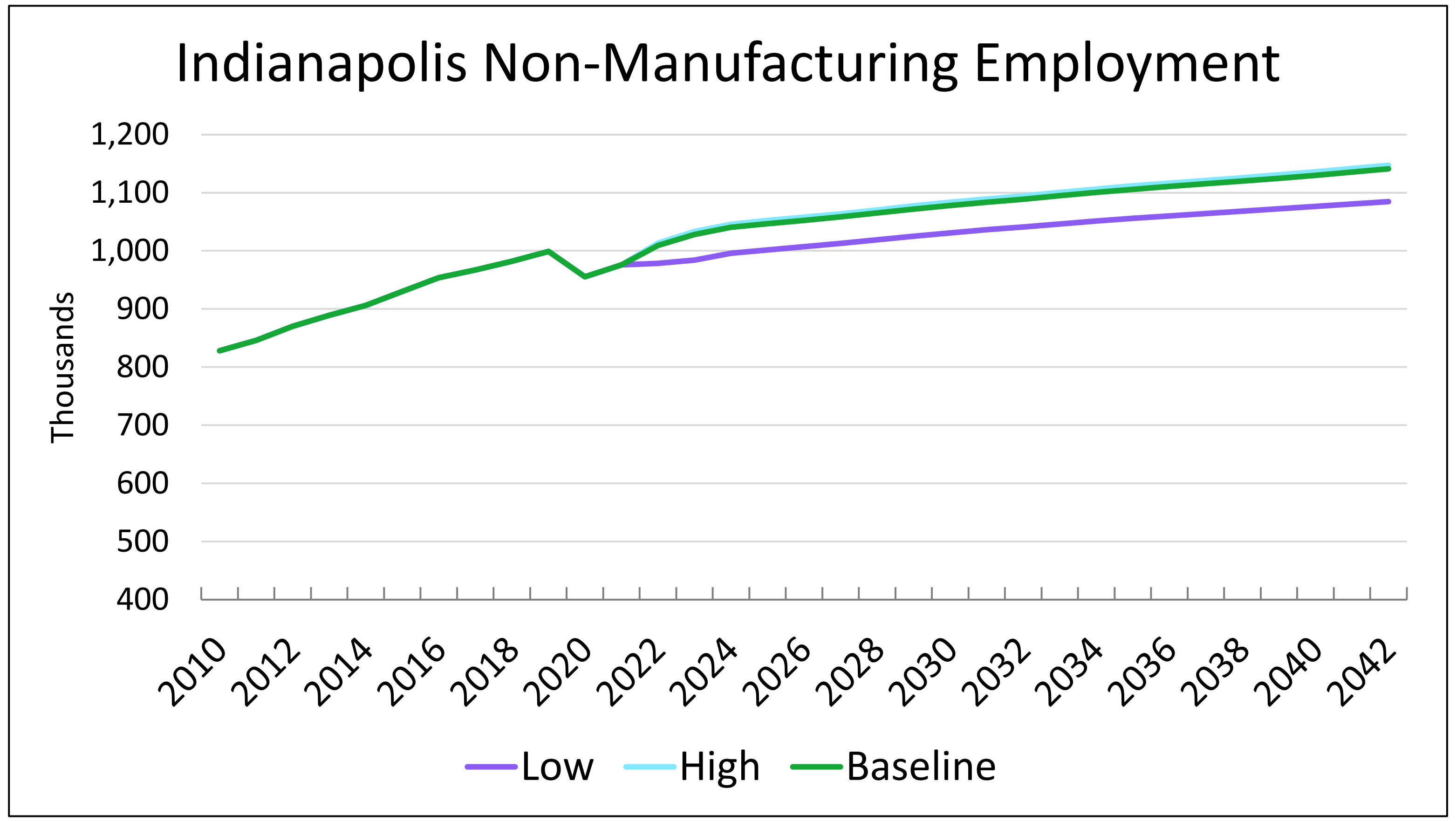
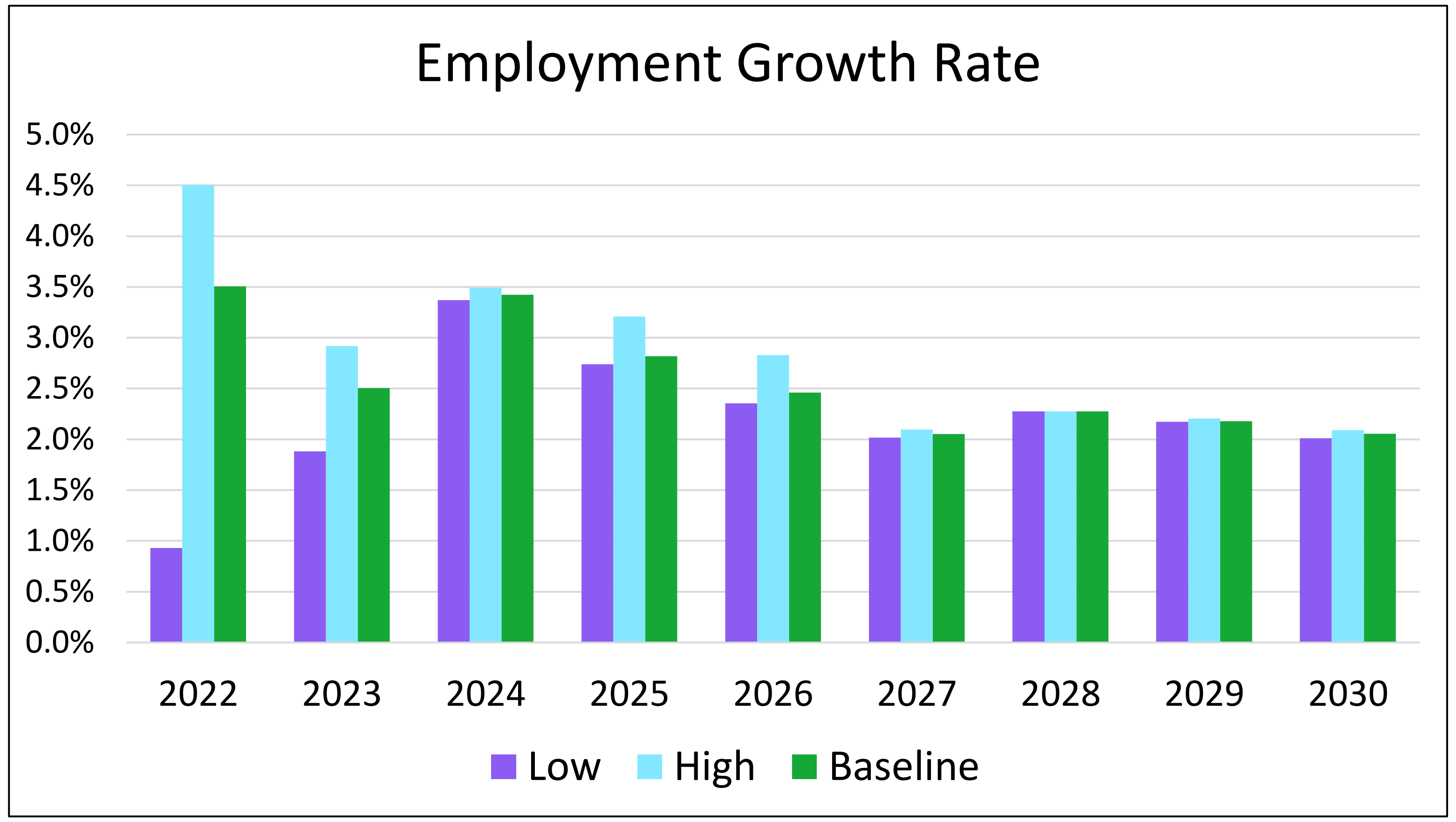
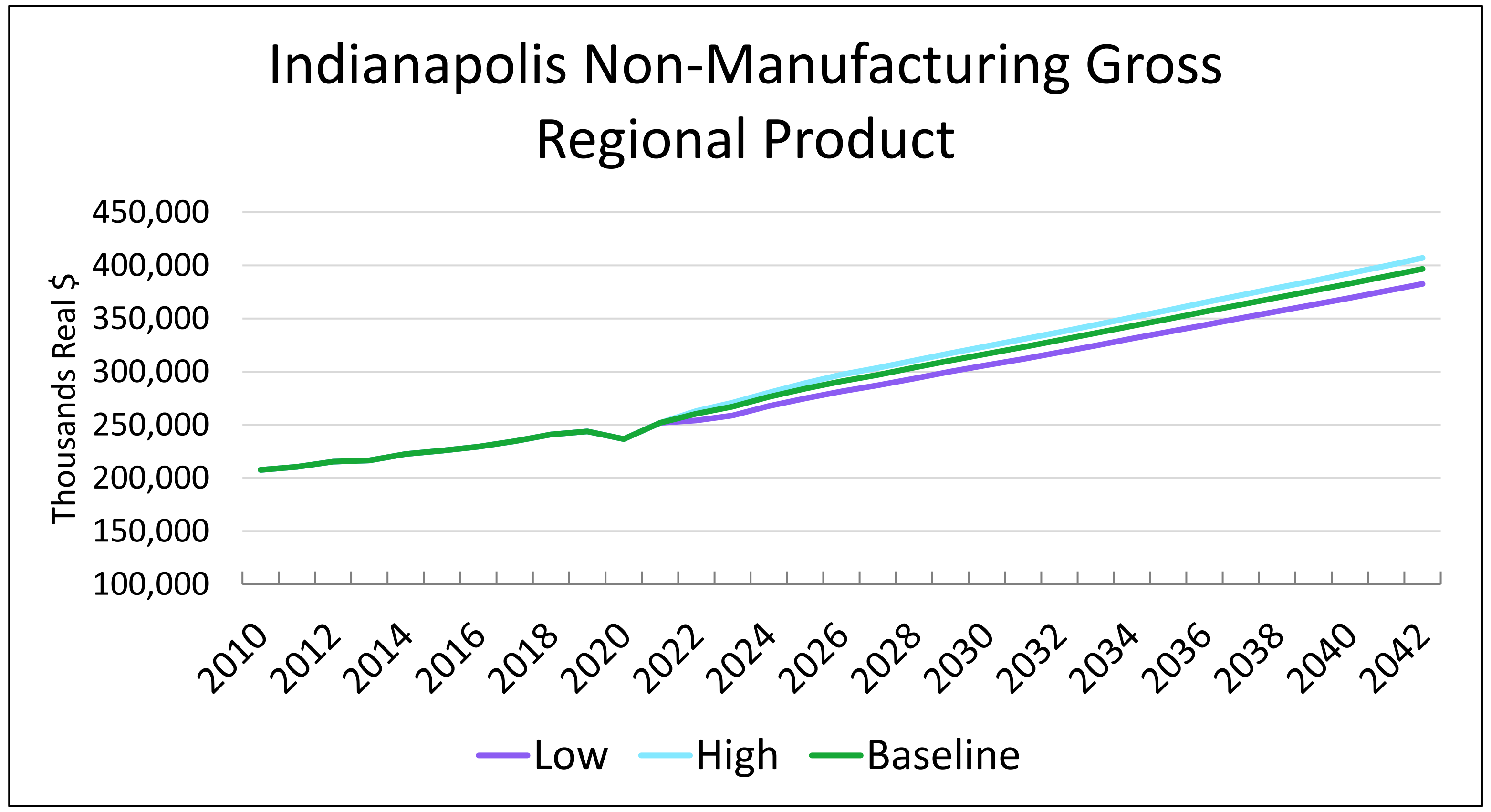
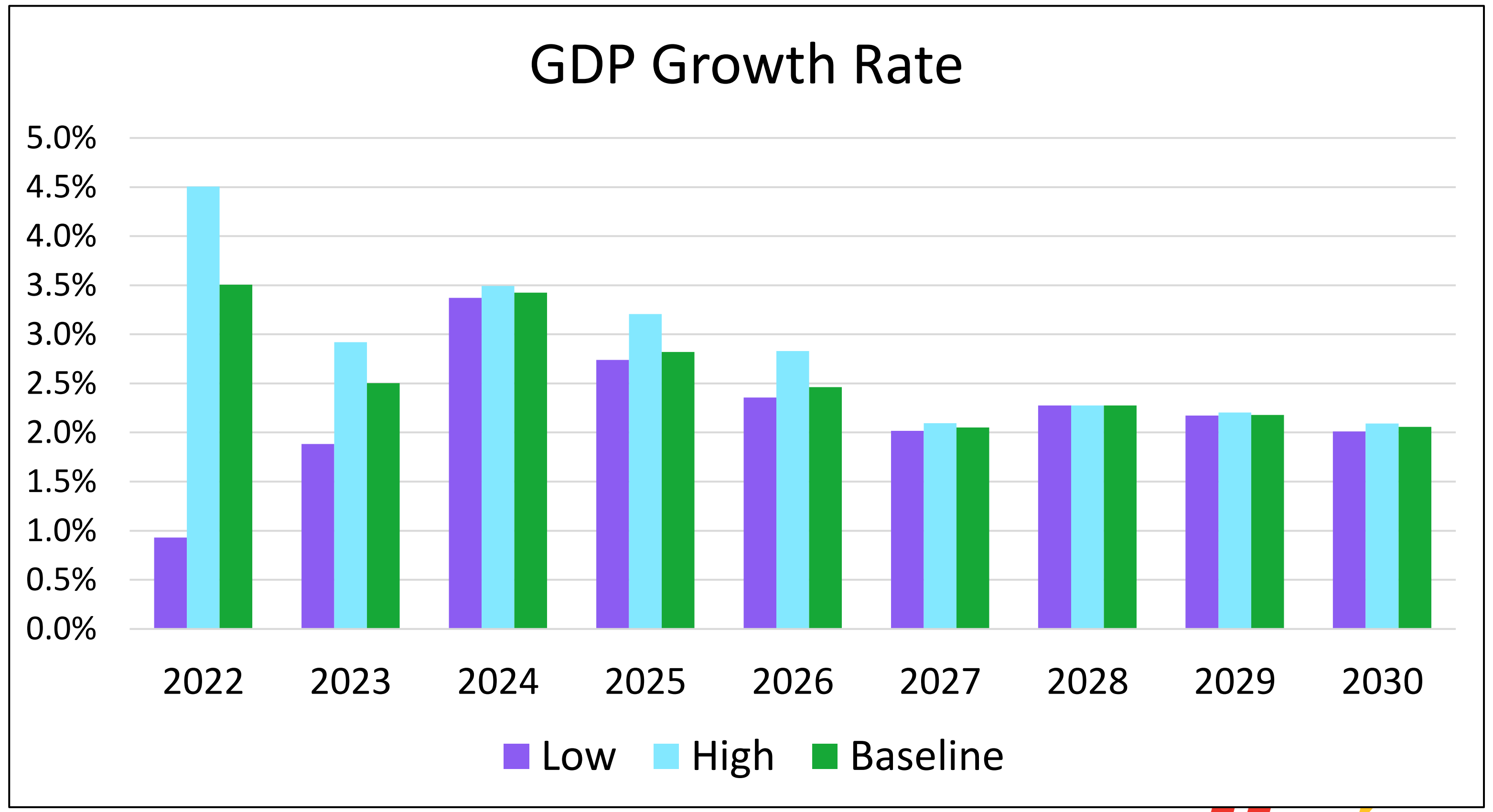
C&I Economic Drivers



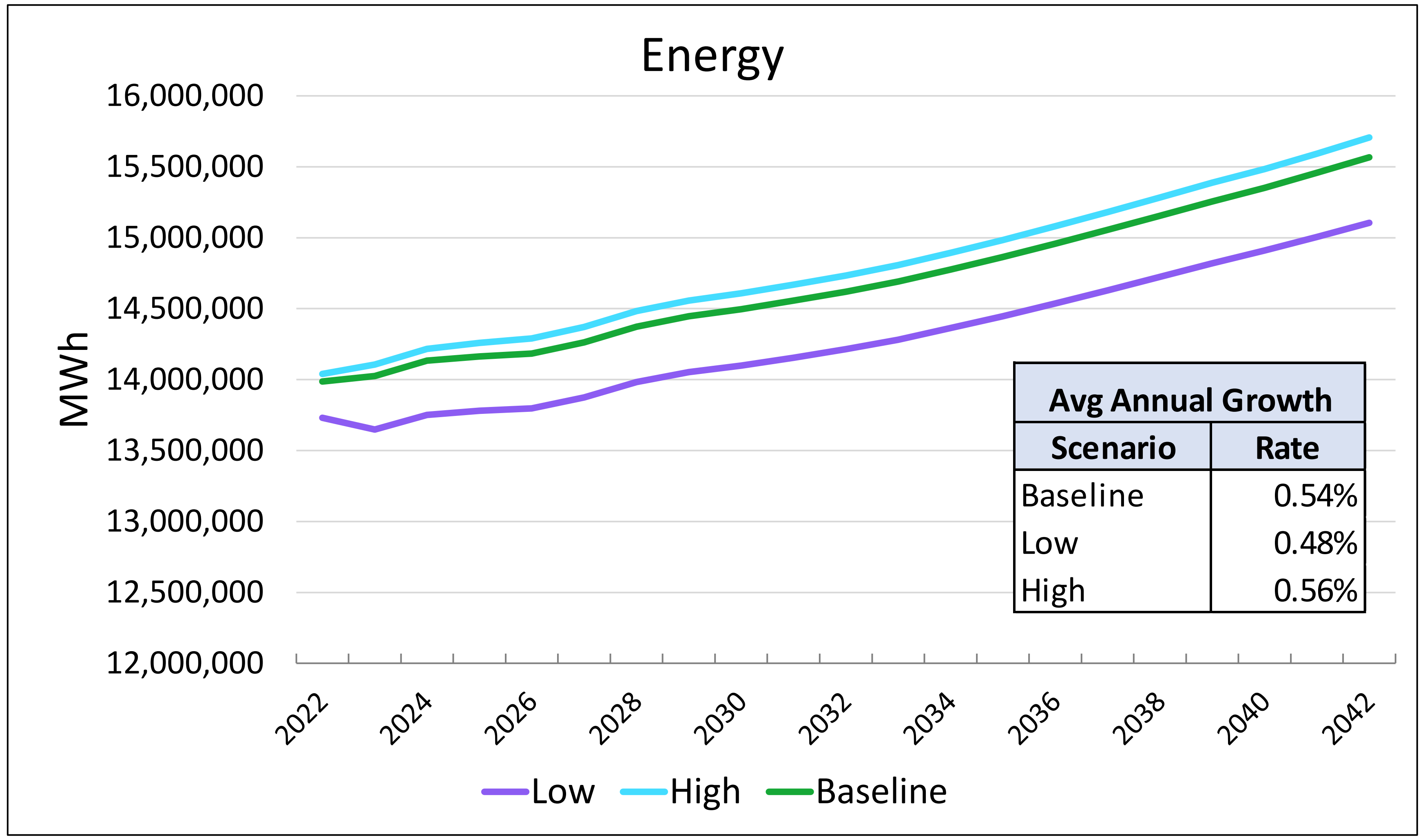


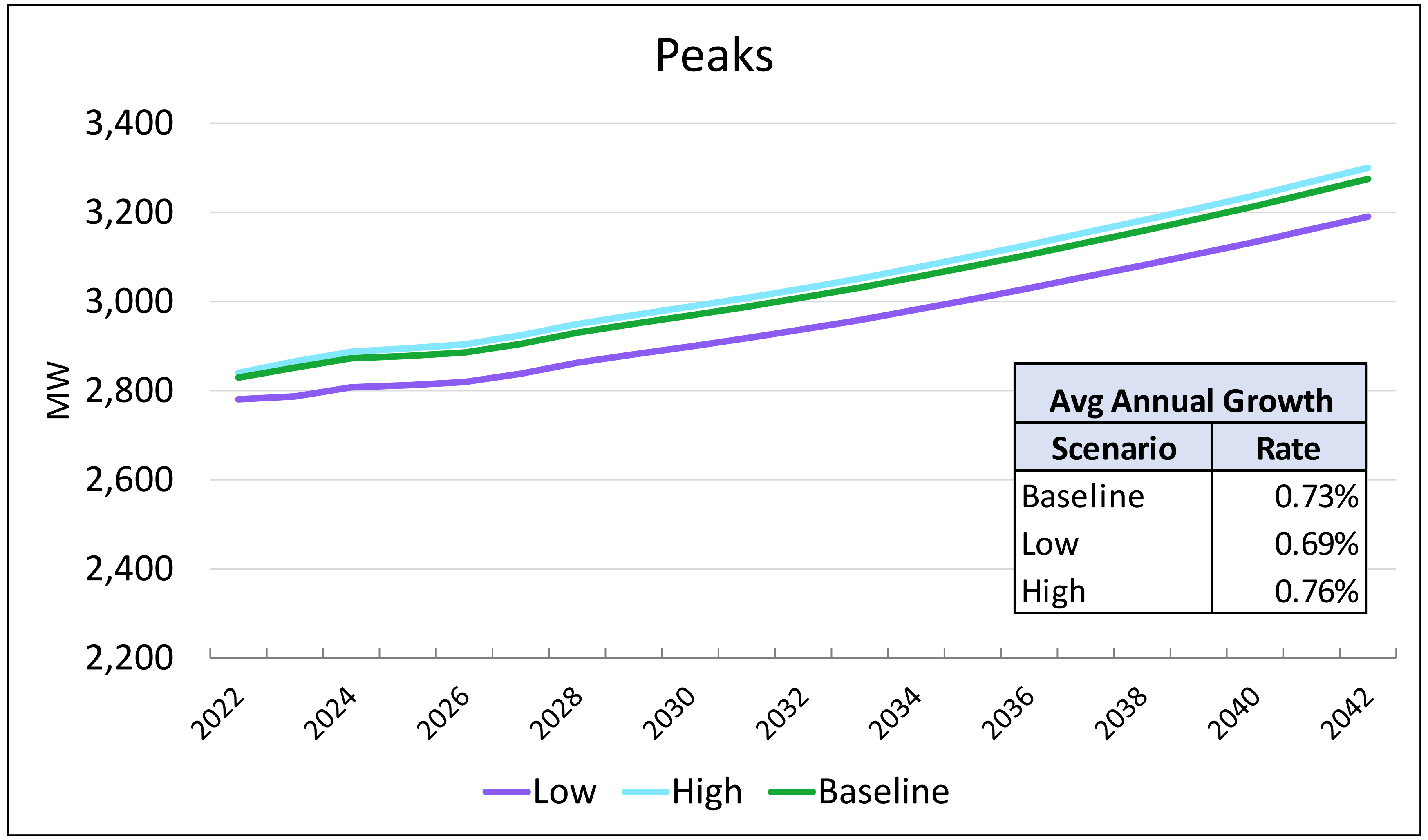




Forecast Scenarios

Energy & Peak Forecast





- Models updated to include actuals through Dec 2021
- Forecasts excludes energy efficiency programs (EE), electric vehicles, and solar impact
- Low forecast results in a reduction of 461,928 MWh and 84 MW by 2042
- High forecast results in an increase of 139,270 MWh and 26 MW by 2042

2022 Integrated Resource Plan (IRP)

DSM Market Potential Study Introduction

Presented by IRP Partners

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

brightline GROUP

aes Indiana

MPS Results & DSM Resources

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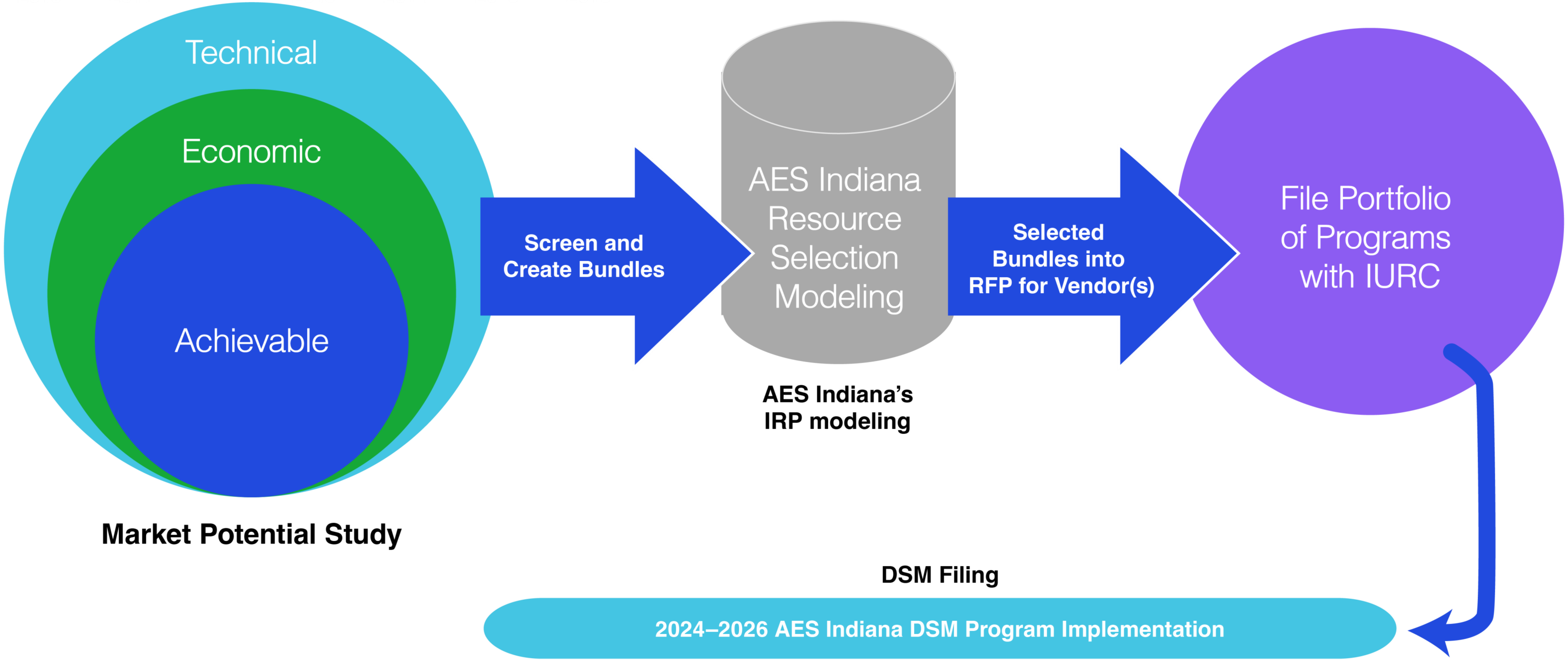
Introduction to the DSM Process in the IRP

IURC Rules – 170 IAC 4-7-8-c-4
"Analysis showing Supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis."



Agenda

- → MPS Recap
- → Energy Efficiency Potential
  - Overview of results
  - Sector-level results
  - Program potential
- → Demand Response Potential
  - Overview of results
  - Sector-level results
- → Developing DSM IRP Inputs

DSM Market Potential Study

MPS Recap

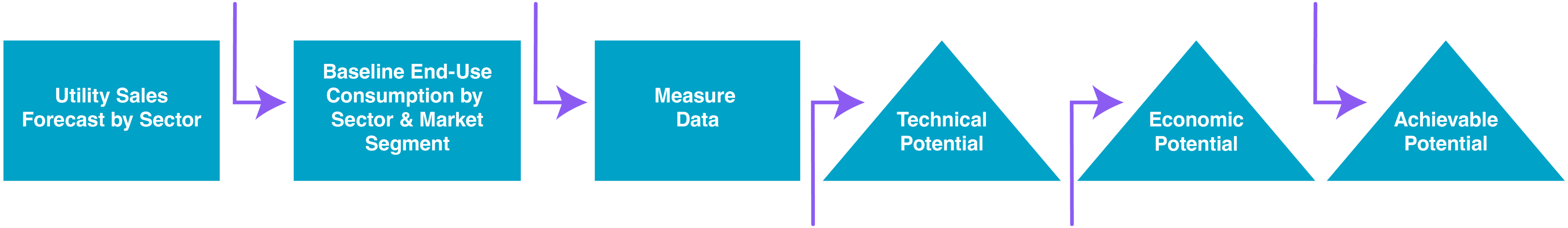
Jeffrey Huber, Overall Project Manager and MPS Lead, GDS Associates

Overall Market Potential Study Process

LOAD DISAGGREGATION
Sales by Market Segment
Consumption by End Use

DATA COLLECTION
New & Existing Primary Data,
Secondary Data Collection

MARKET ADOPTION
Historical Performance Short-term
and Long-term Market Barriers



TECHNOLOGY CHARACTERISTICS
Energy, Capacity, and Therm Unit Savings
Saturation Shares Codes and Standard
Updates Applicability Interactions

COST-EFFECTIVENESS
Load Shapes Avoided Cost Benefits
Measure Costs/Price Trends

Energy Efficiency Potential Types

TECHNICAL POTENTIAL

All technically feasible measures are incorporated to provide a theoretical maximum potential.

ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the UCT Test. Only cost-effective measures are included.

ACHIEVABLE POTENTIAL

Cost-effective energy efficiency potential that can practically be attained in a real-world program delivery case, assuming that a certain level of market penetration can be attained.

Types of Energy Efficiency Potential

Not Technically Feasible	TECHNICAL POTENTIAL		
Not Technically Feasible	Not Cost-Effective	ECONOMIC POTENTIAL	
Not Technically Feasible	Not Cost-Effective	Market & Adoption Barriers	ACHIEVABLE POTENTIAL

MAXIMUM ACHIEVABLE POTENTIAL (MAP)

Incentives set up to 100% of incremental cost

REALISTIC ACHIEVABLE POTENTIAL (RAP)

Incentives based on historical levels

Key Methodological Assumptions for MAP/RAP

01

Adoption Rates

Method for determining both the short-term and long-term adoption levels by key market segments

02

Incentives

Historical incentives are a key driver of the Realistic Achievable Potential (RAP) scenario

03

Non-Incentive Costs

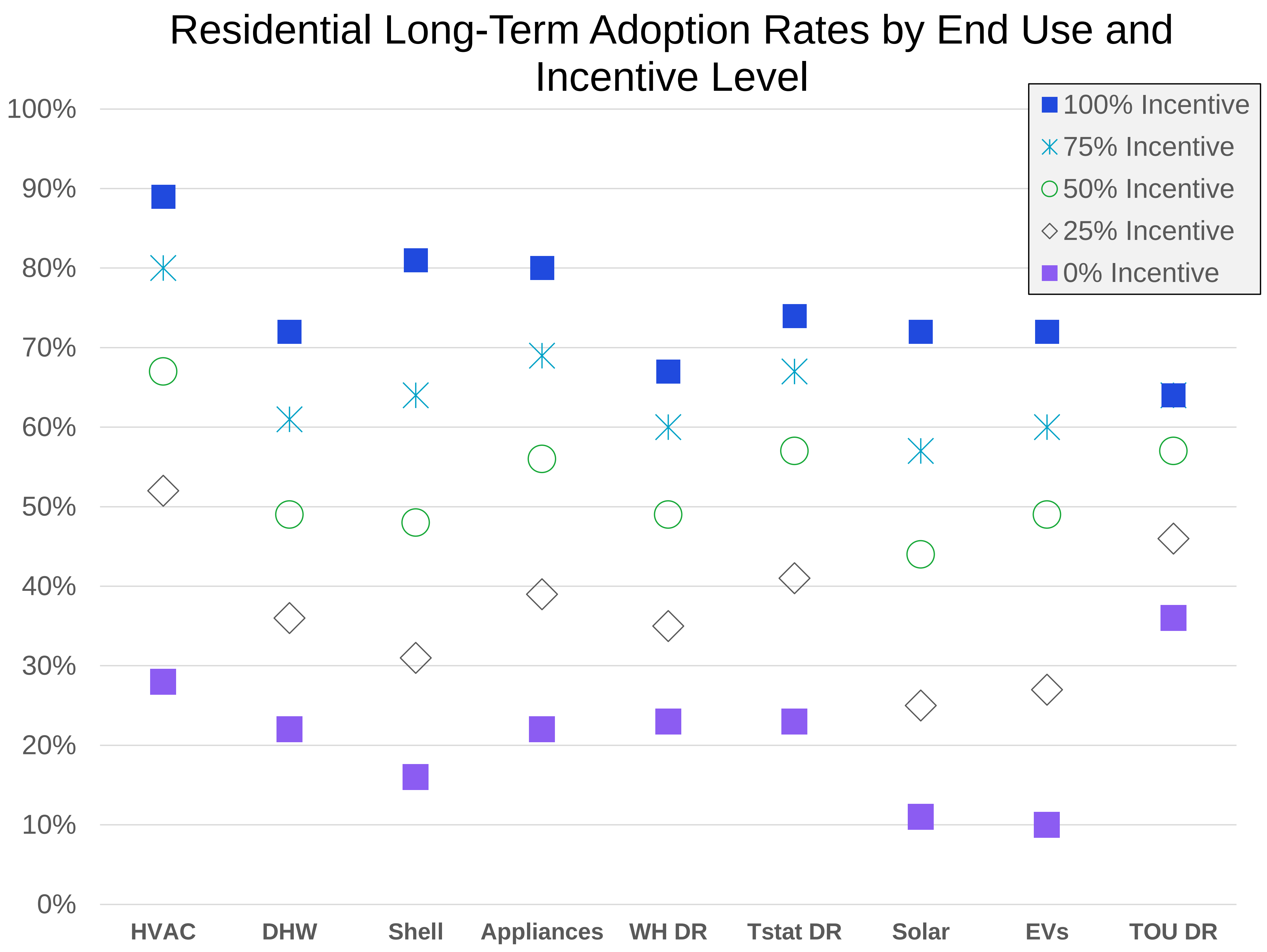
Non-Incentive costs are included at both the MAP/RAP level

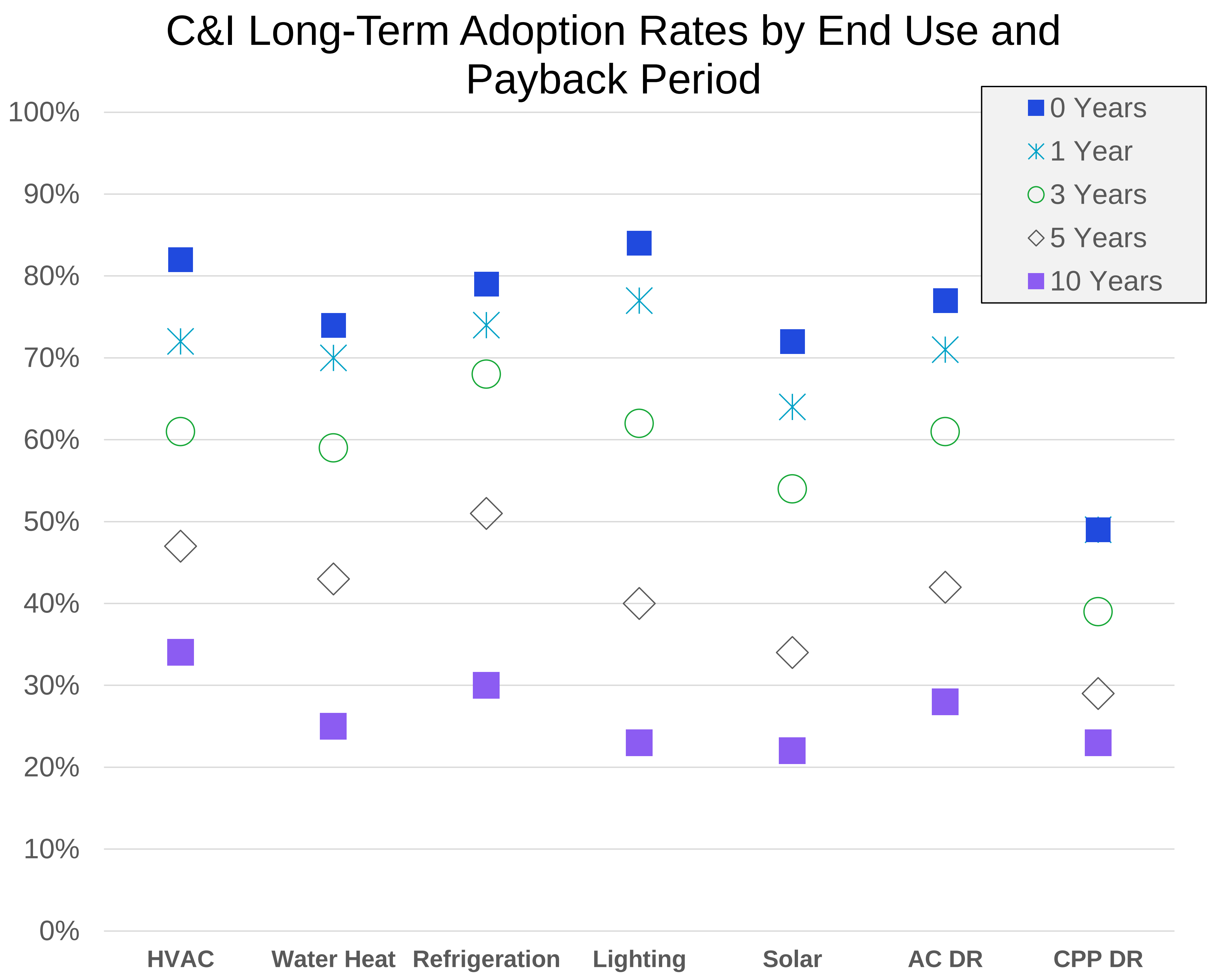
04

Program Mapping & NTG

Evaluated NTG results were incorporated to assess Program RAP

Willingness to Participate (WTP) Results





*** WTP data gives an indication of the relationship between utility intervention and customer acceptance/adoption of EE technologies*

DSM Market Potential Study Results

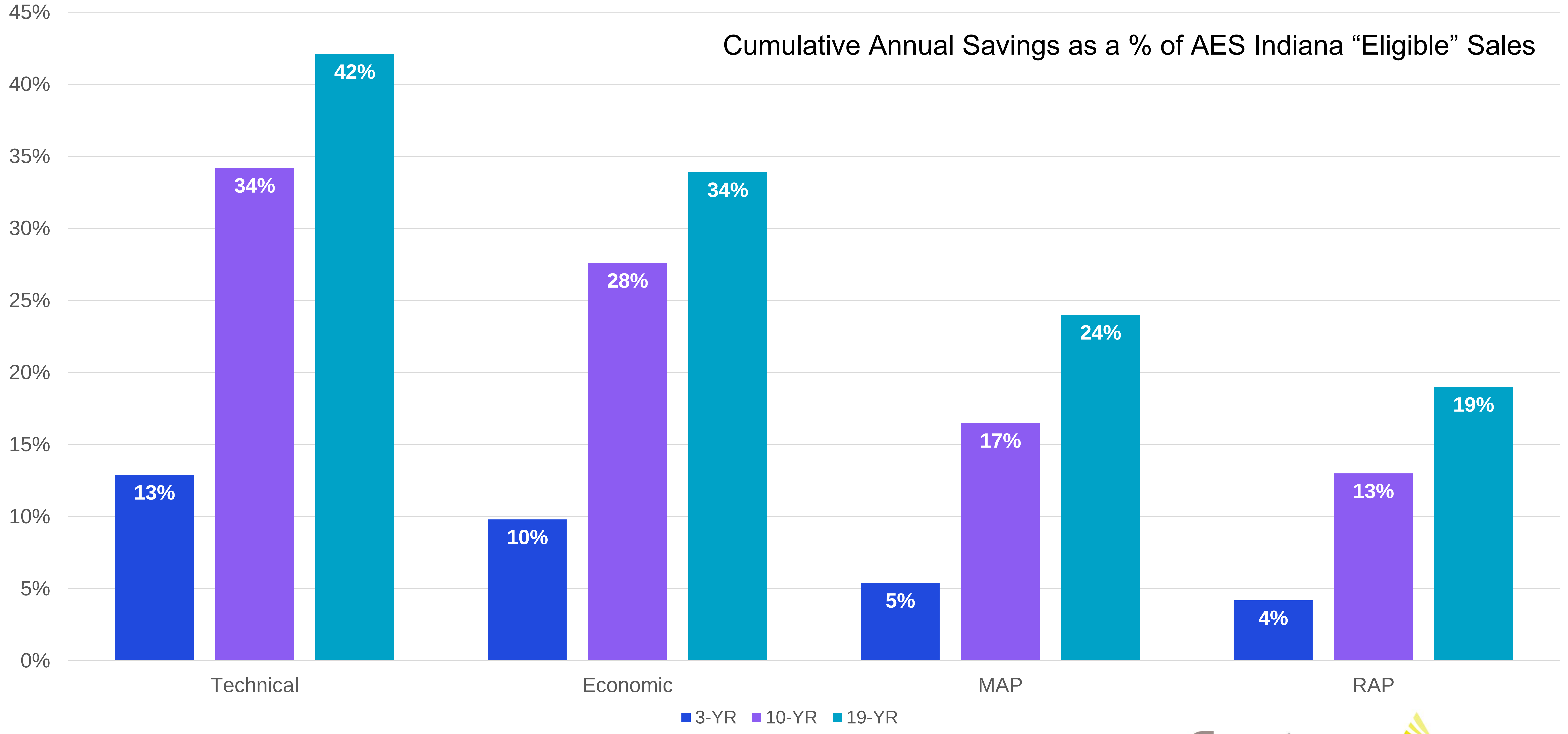
Energy Efficiency (EE) Potential

Initial Comments

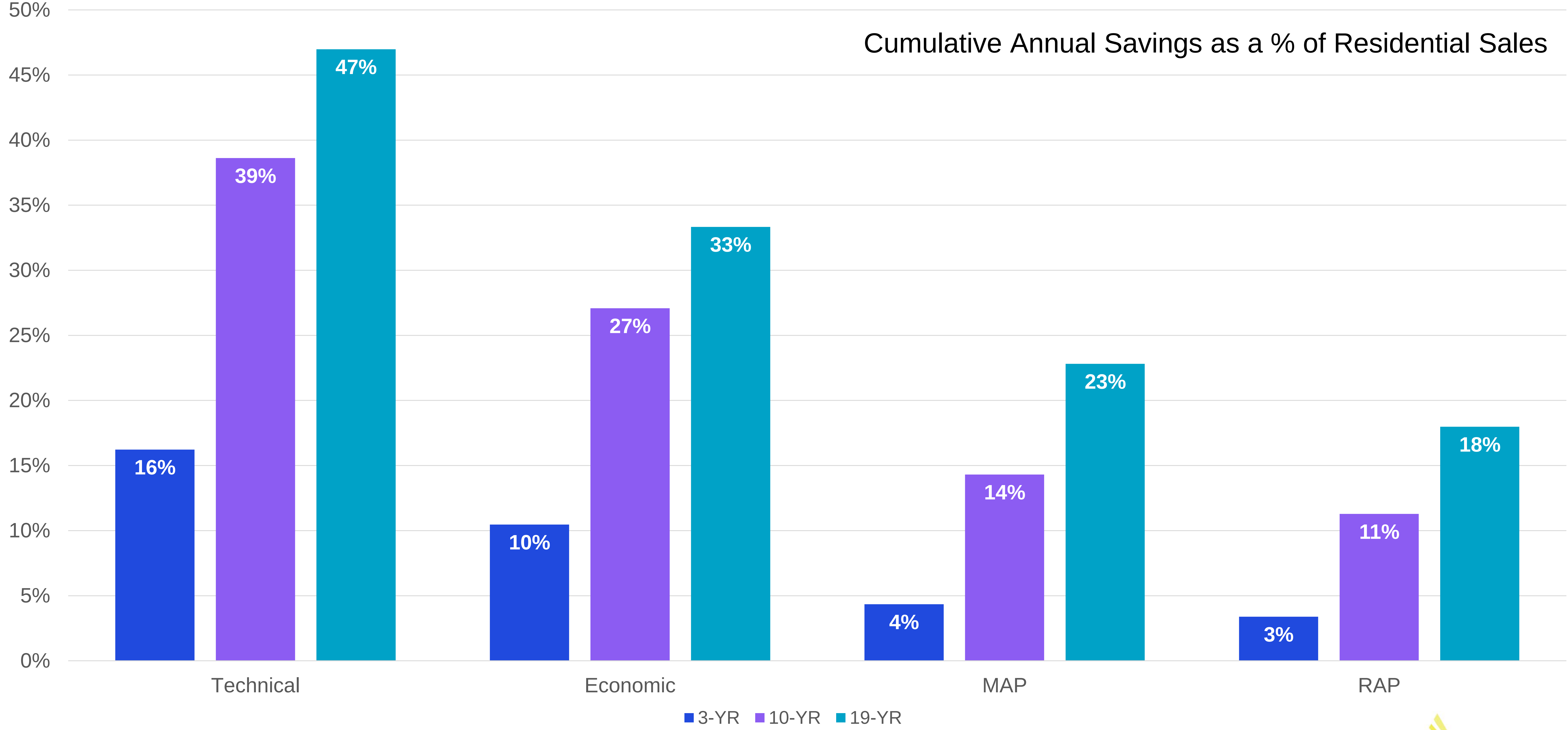
Overall Comments (all sectors):

- → All savings are gross
- → Economic Screening is the UCT Test using current incentive levels and no administrative costs
- → Measure assumptions (savings / costs) are based on a review of current evaluated savings as well as savings from approved sources (i.e., EM&V results, Illinois TRM, MEMD, etc.)
- → Technical & Economic potential is a phased-in potential; *i.e. opportunities are dependent on stock turnover*
- → RAP scenario is based on current incentive levels and associated long-term adoption rates (informed by primary market research)
- → MAP scenario examines ability to move incentive levels higher than historical; *does not examine lowering incentives for measures that do not currently screen as cost-effective.*

Overview of Results – Cumulative Annual



Residential Sector Results



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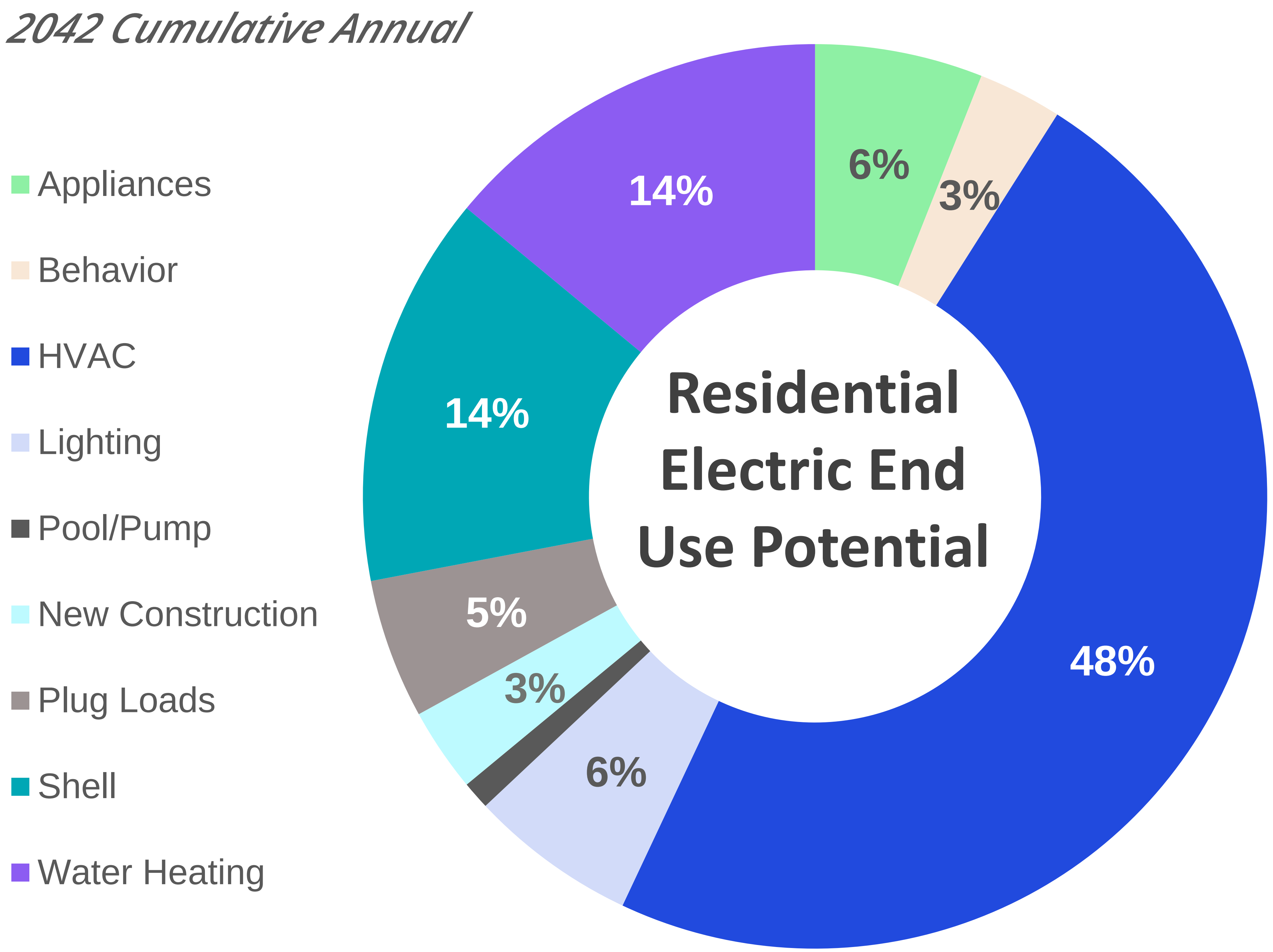
Residential Maximum Achievable Potential (MAP)

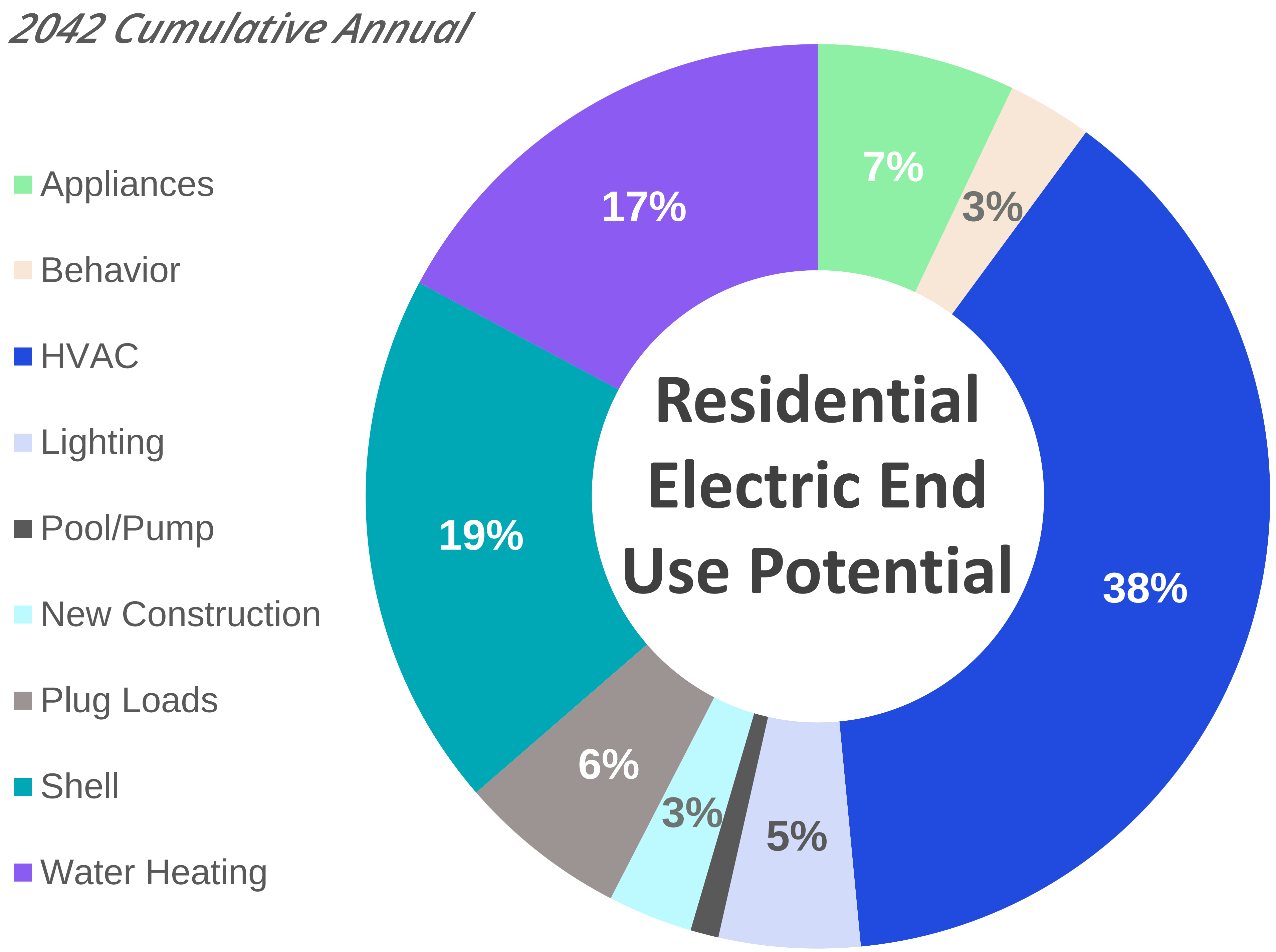


23%

Residential cumulative annual maximum achievable potential as a percentage of forecasted sales in 2042

(compared to 35% by 2039 in 2019 MPS; difference attributable to lower economic potential, updated saturation data and adoption rates)

Residential Realistic Achievable Potential (RAP)

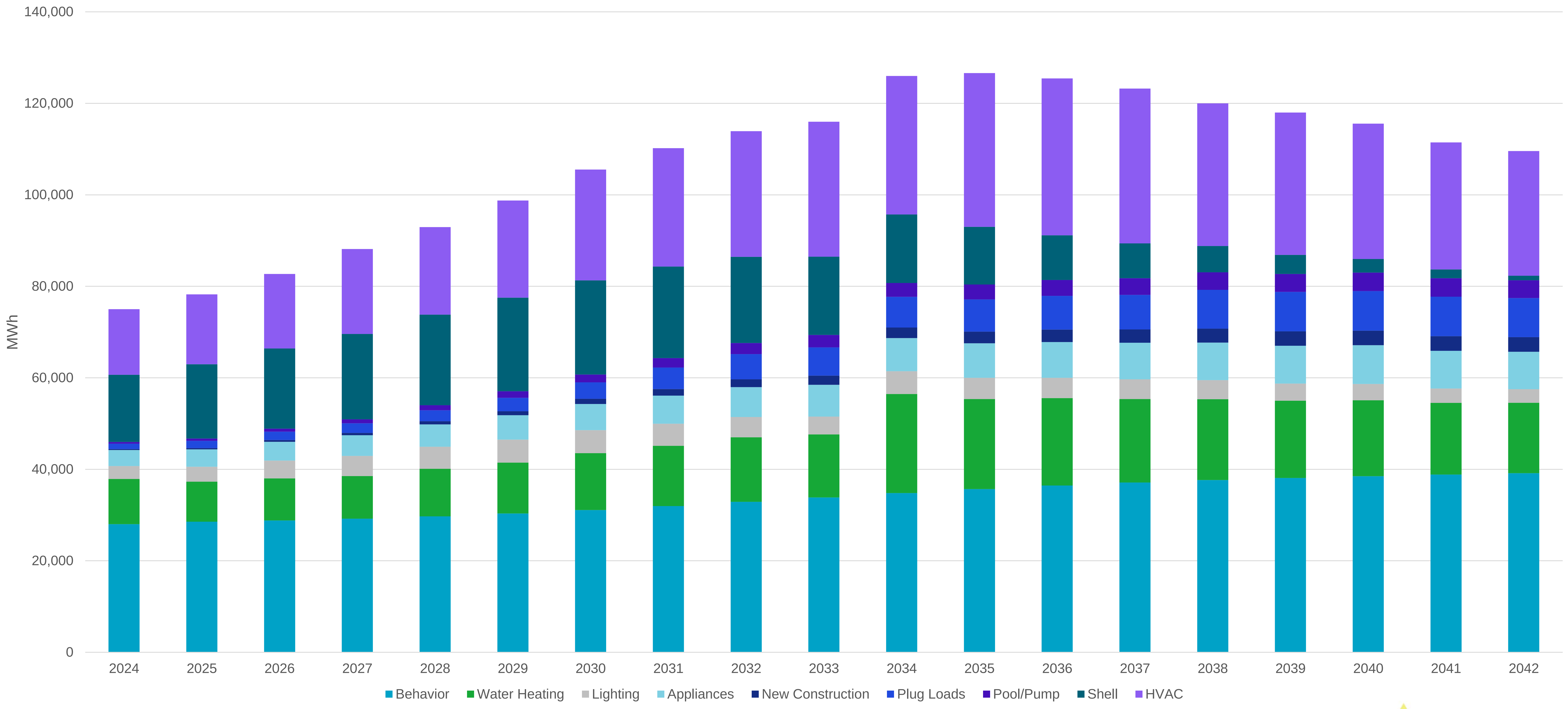


18%

Residential cumulative annual realistic achievable potential as a percentage of forecasted sales in 2042

(compared to 24% by 2039 in 2019 MPS; difference attributable to lower economic potential, updated saturation data and adoption rates)

Residential Incremental Annual Savings by End Use



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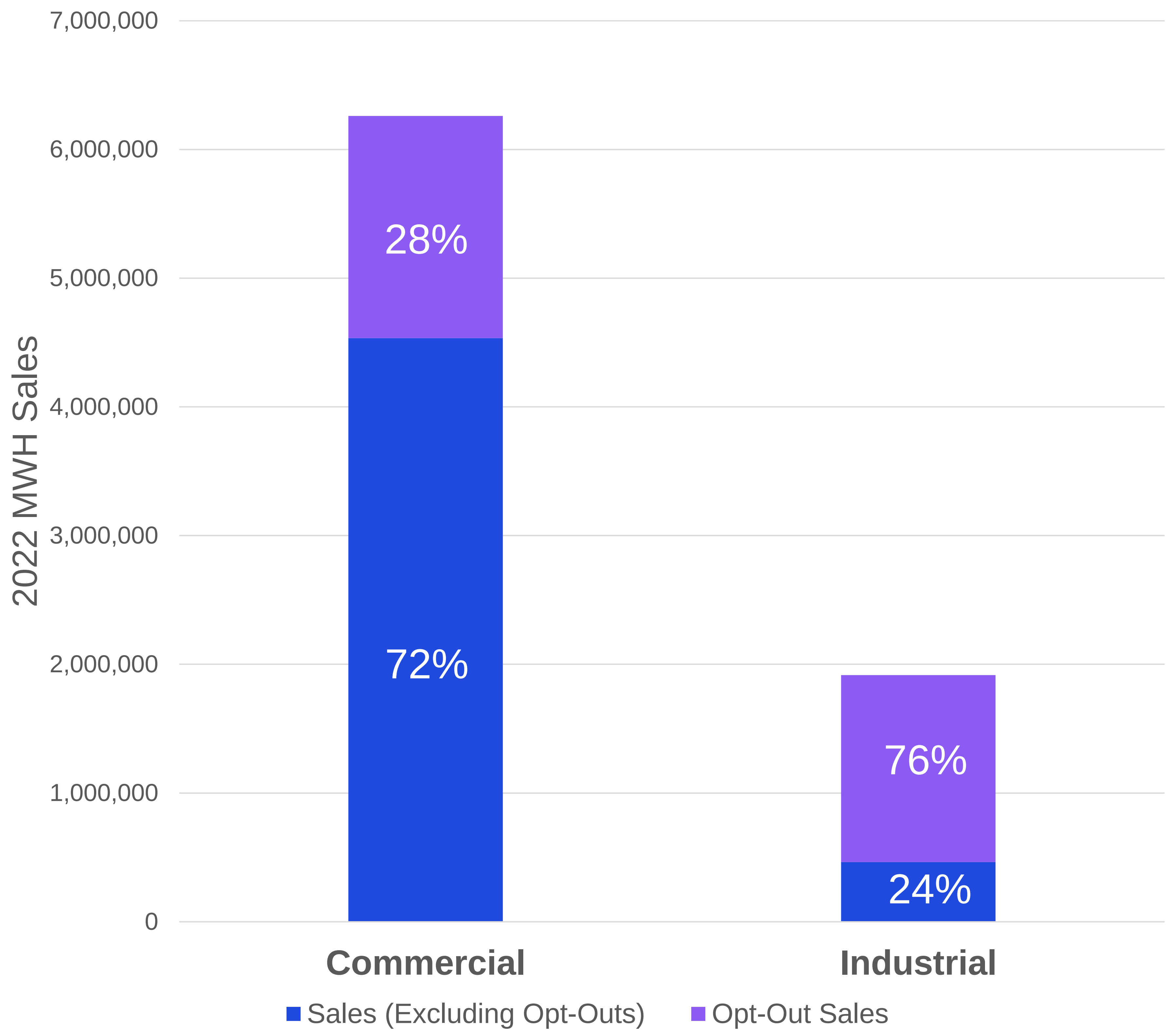
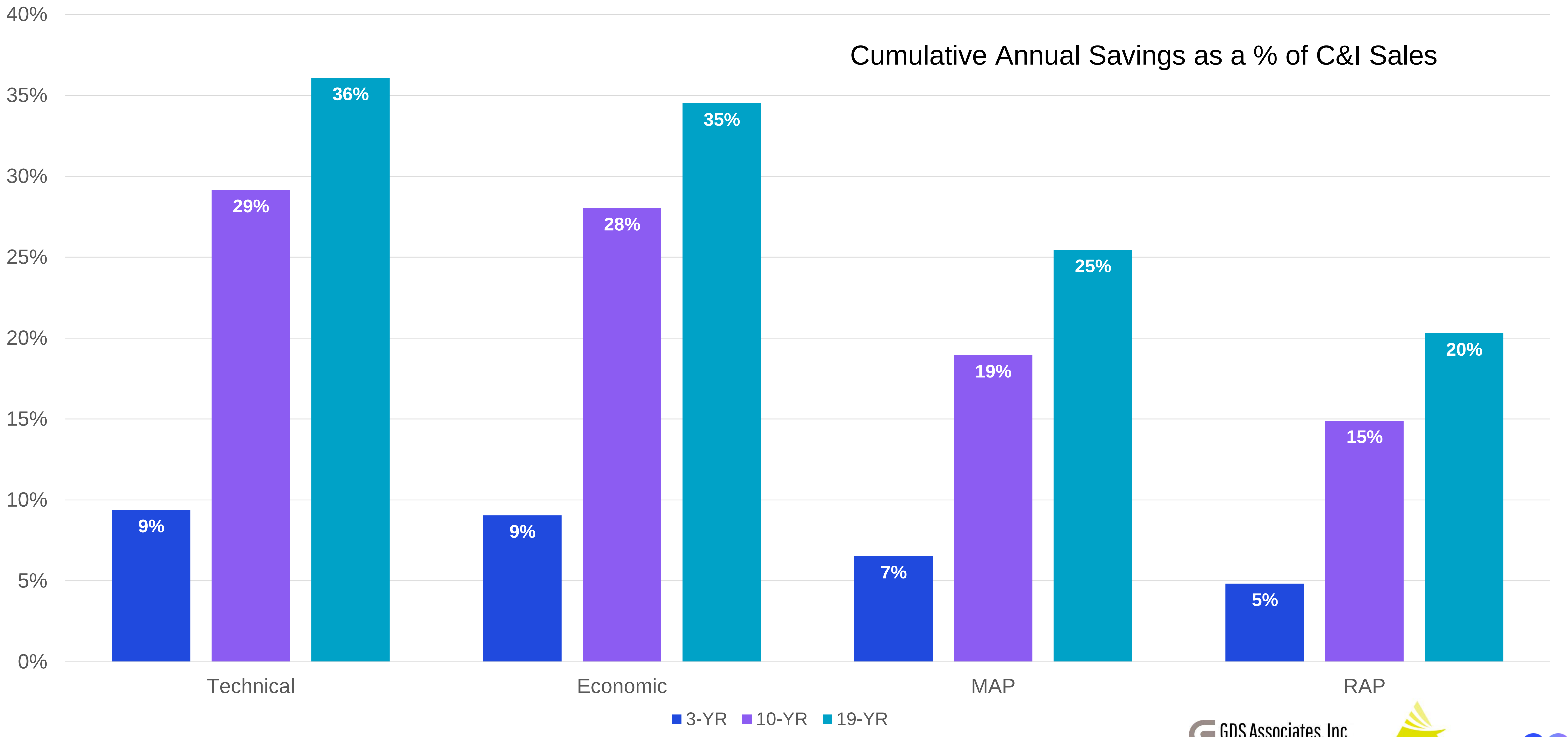
C&I Opt-Outs



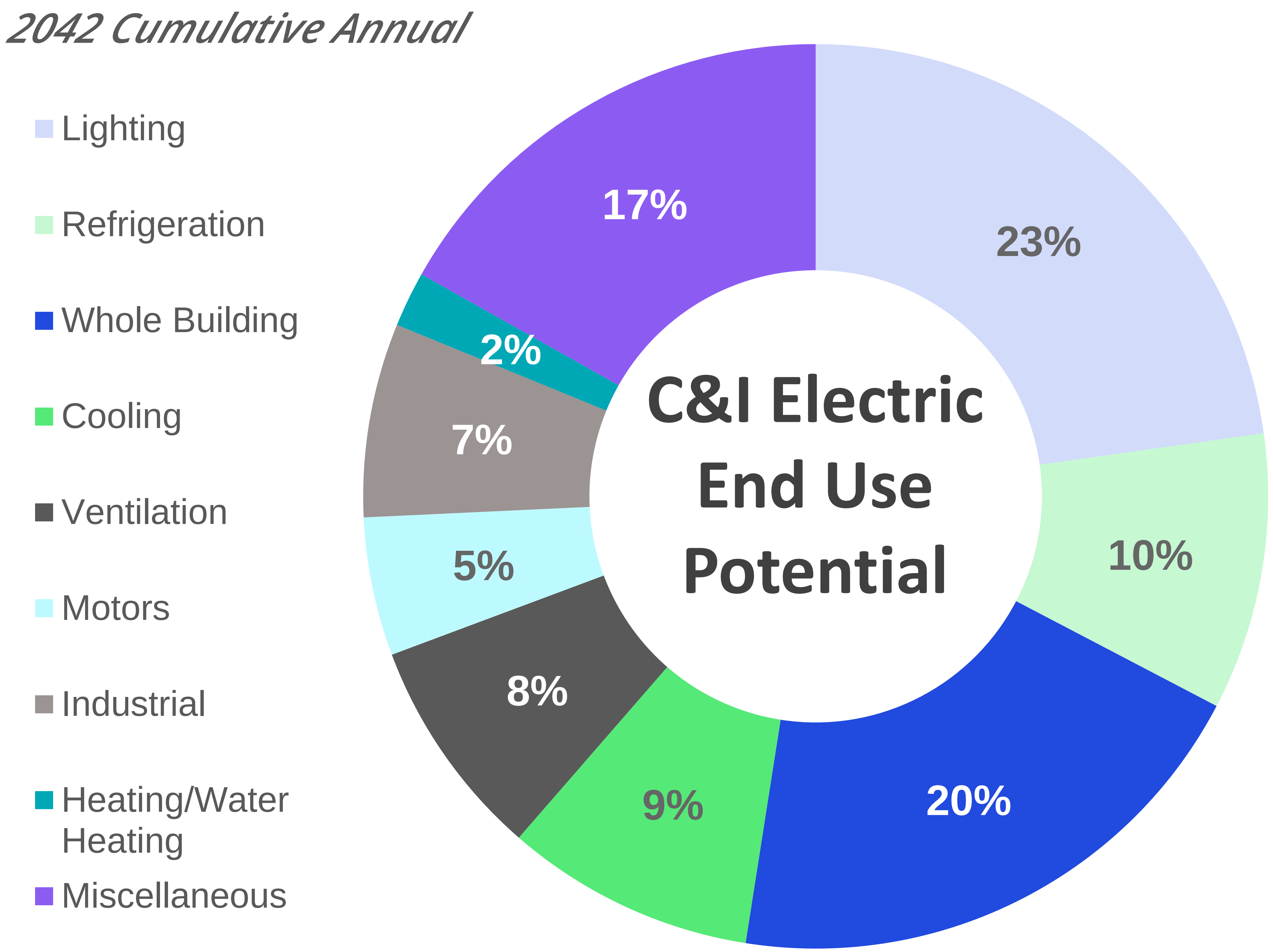
C&I “Opt-Out Sales” Adjustment

- MPS uses only “eligible” sales for electric energy efficiency potential, removing sales from C&I customers who opt-out of the energy efficiency rider.
- 28% of Commercial Sales were from opt-out customers in 2022
- 76% of Industrial Sales were from opt-out customers in 2022
- Savings (as a % of sales) are relative to “eligible” sales in subsequent slides

C&I Sector Results



C&I Maximum Achievable Potential (MAP)



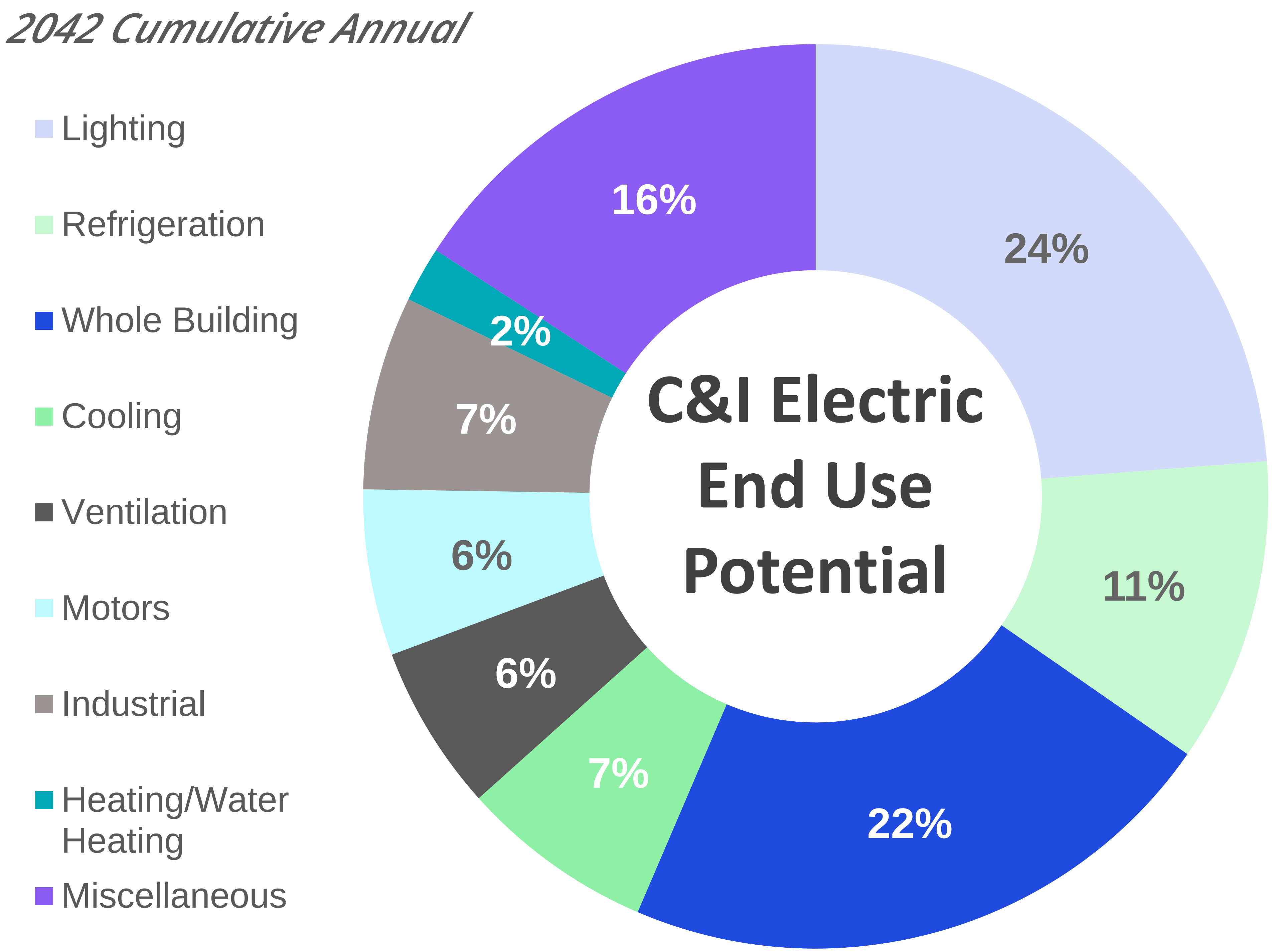
25%

C&I cumulative annual maximum achievable potential as a percentage of forecasted sales in 2042

(compared to 36% by 2039 in 2019 MPS ; primary difference in assumed MAP incentive assumptions and associated adoption levels)

***Other includes potential associated with cooking, compressed air, behavioral and other miscellaneous loads (elevators, vending machines, etc.)*

C&I Realistic Achievable Potential (RAP)



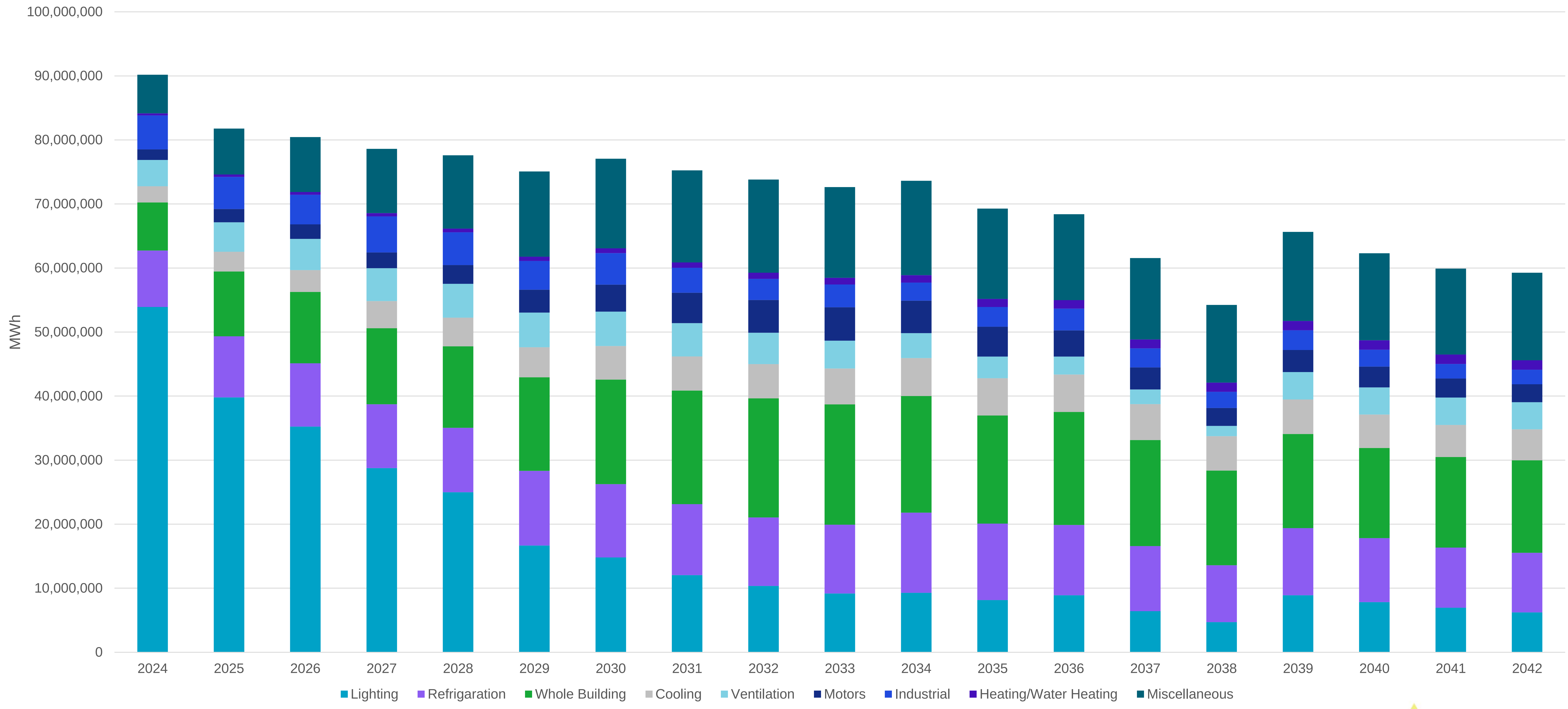
20%

C&I cumulative annual maximum achievable potential as a percentage of forecasted sales in 2042

(compared to 19% by 2039 in 2019 MPS)

***Other includes potential associated with cooking, compressed air, behavioral and other miscellaneous loads (elevators, vending machines, etc.)*

C&I Incremental Annual Savings by End Use



Developing Program Potential from RAP

Key differences between RAP and Program Potential:

Program Potential applies the most recent evaluated net-to-gross (“NTG”) ratios to the RAP (overall reduction due to NTG <1.0).

Residential Program	NTG Ratio
Efficient Products	80%
Home Energy Reports	100%
School Kits	63%
Income-Qualified Weatherization	89%
Appliance Recycling	70%
Multifamily	98%
Demand Response	100%
C&I Programs	**NTG Ratio**
Prescriptive	74%
Custom	80%
Strategic Energy Management	100%

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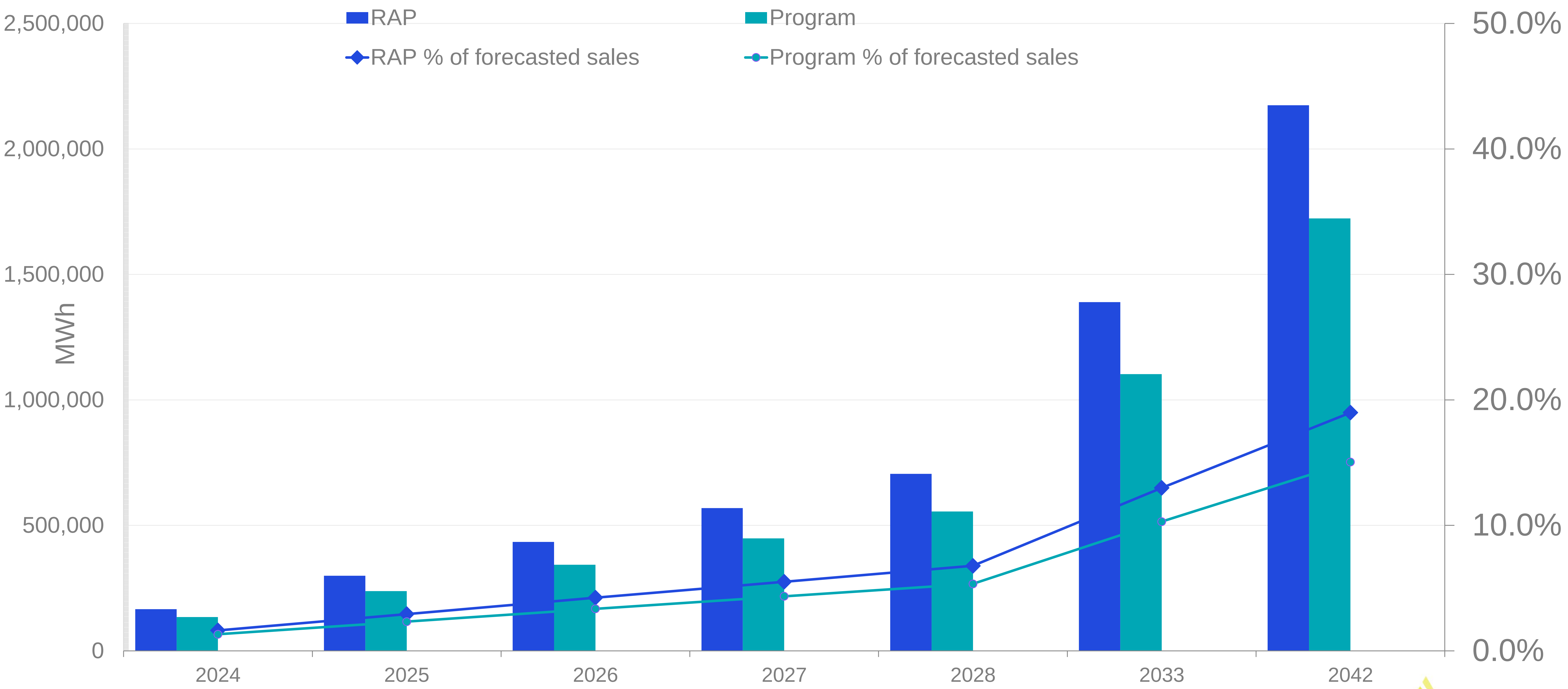
Comparison of RAP and Program Potential



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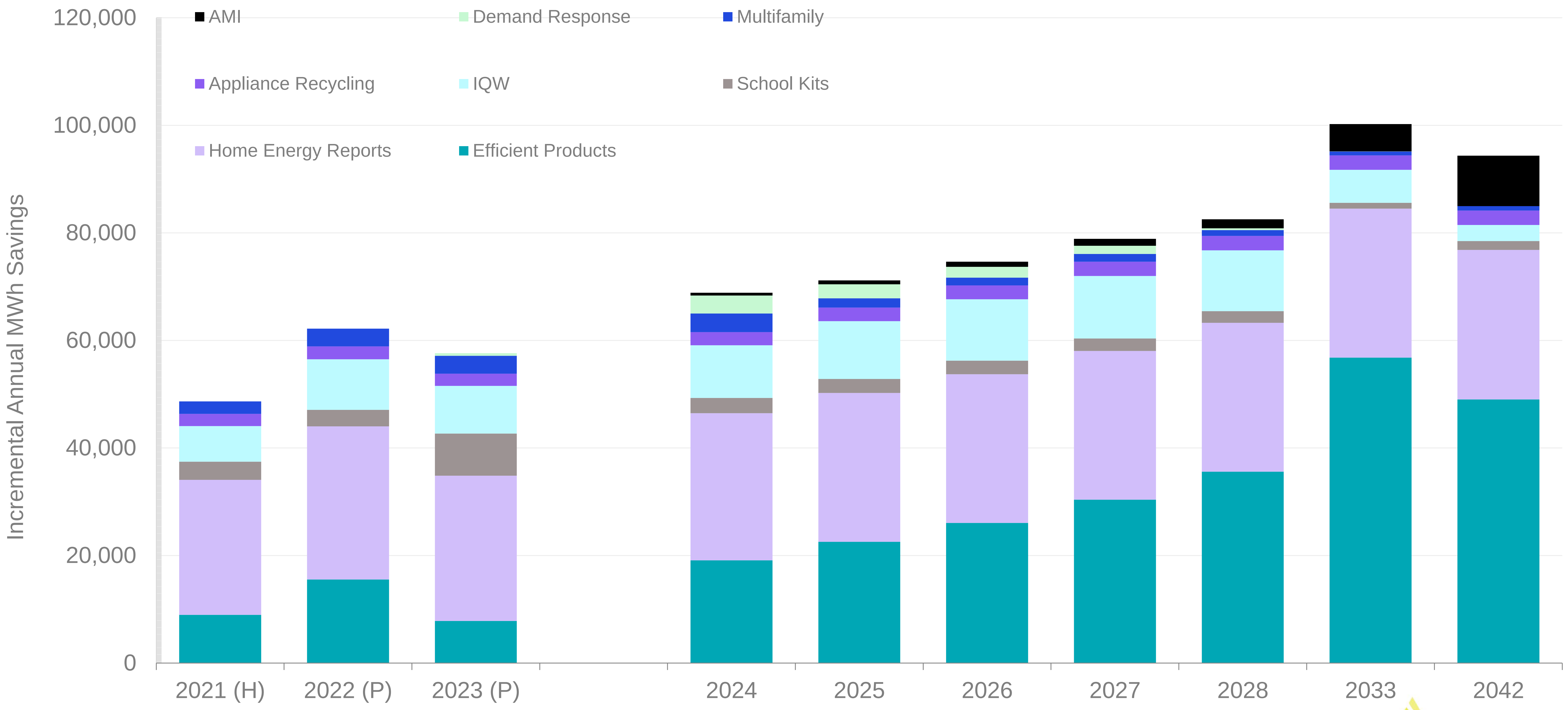
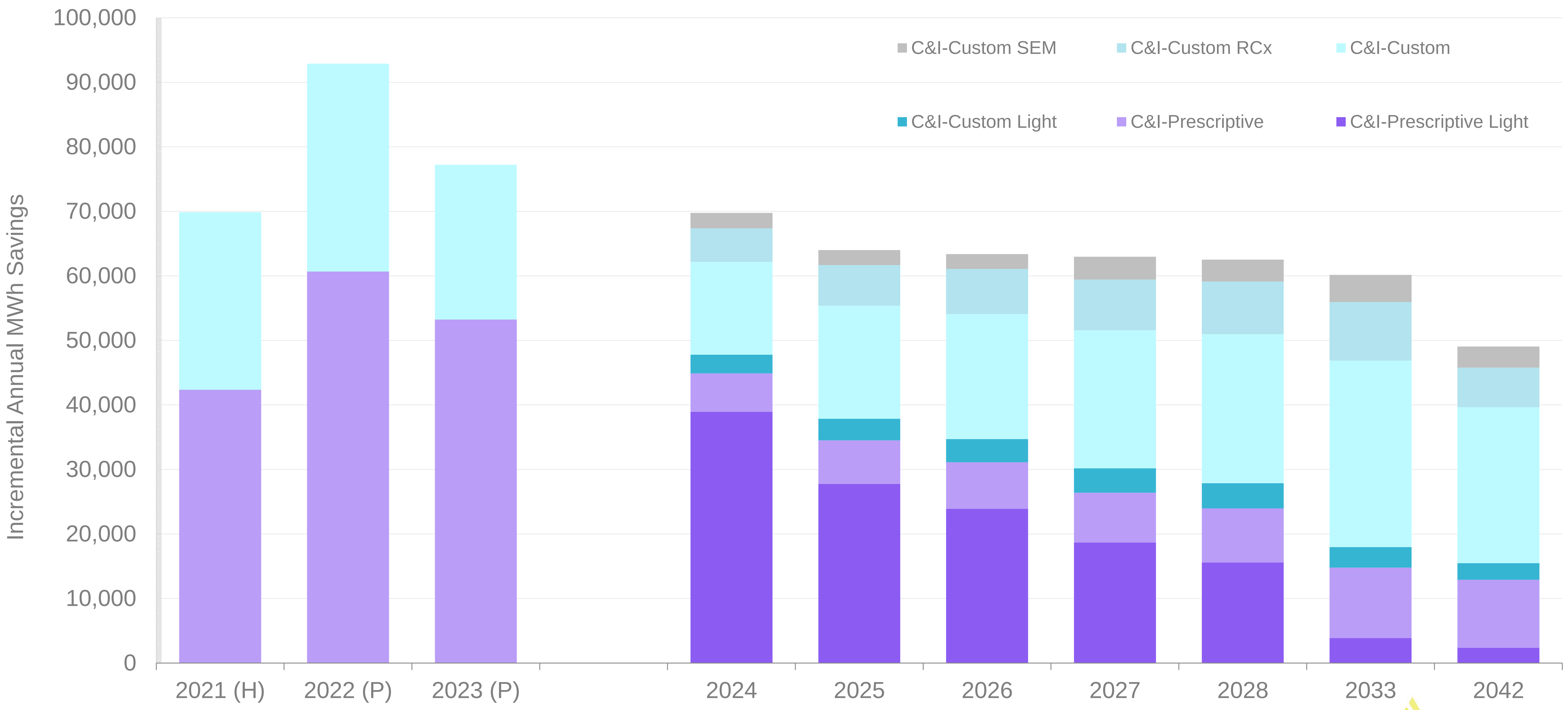
Annual Residential Program Potential



Annual C&I Program Potential

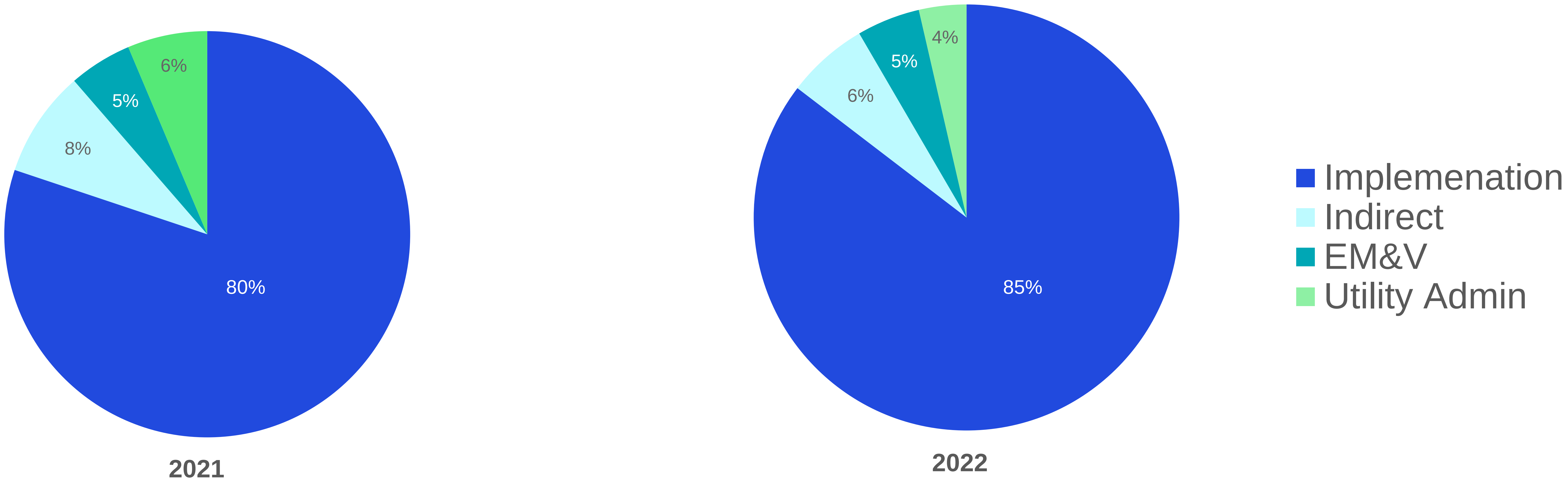


Program Potential Non-Incentive Costs

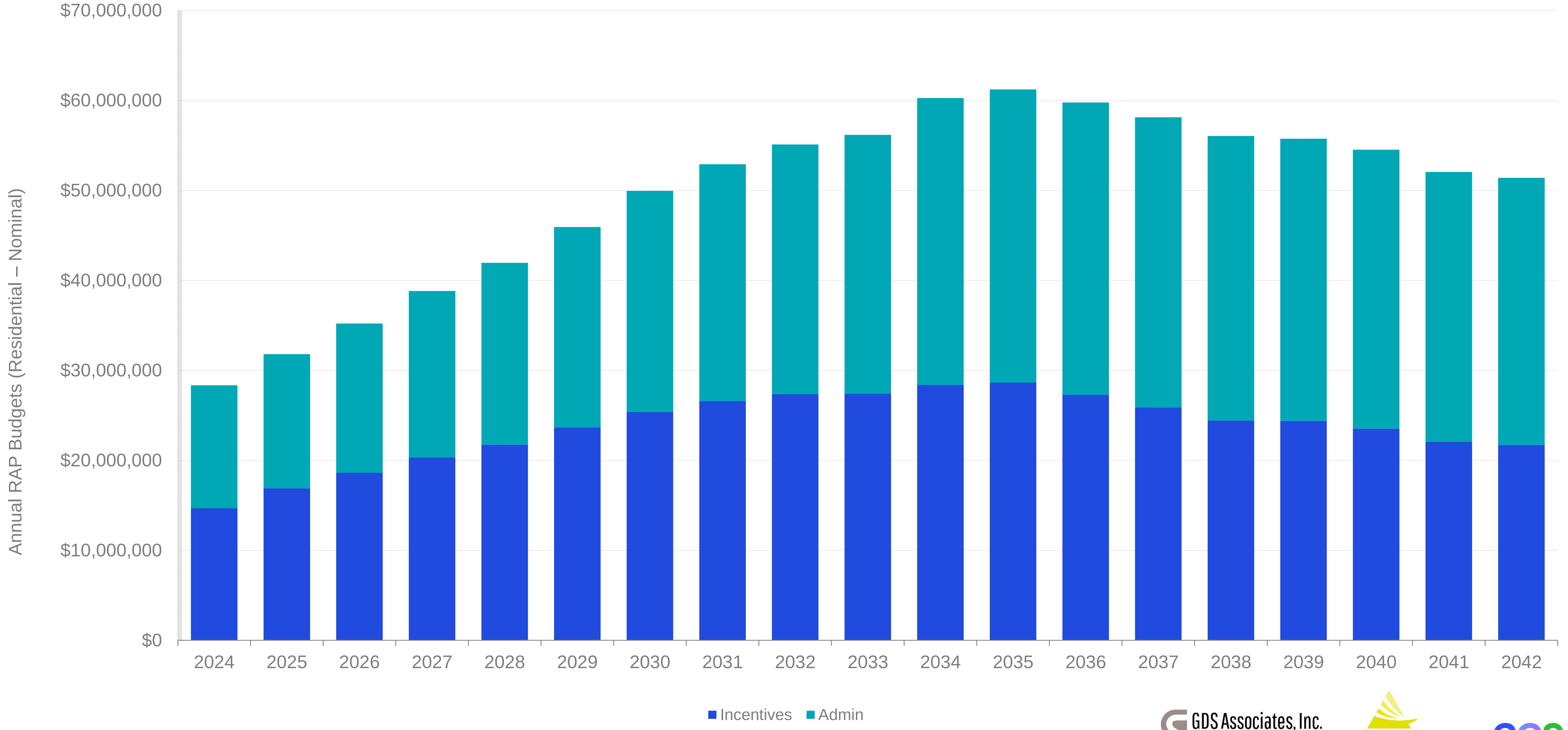
Non-Incentive costs were developed using recent 2021-2022 actual program cost data. Program non-incentive costs were calculated on a gross $ per first-year kWh saved. Non-incentive costs were developed for each sector, and by program when possible.

Historical non-incentive cost categories include:

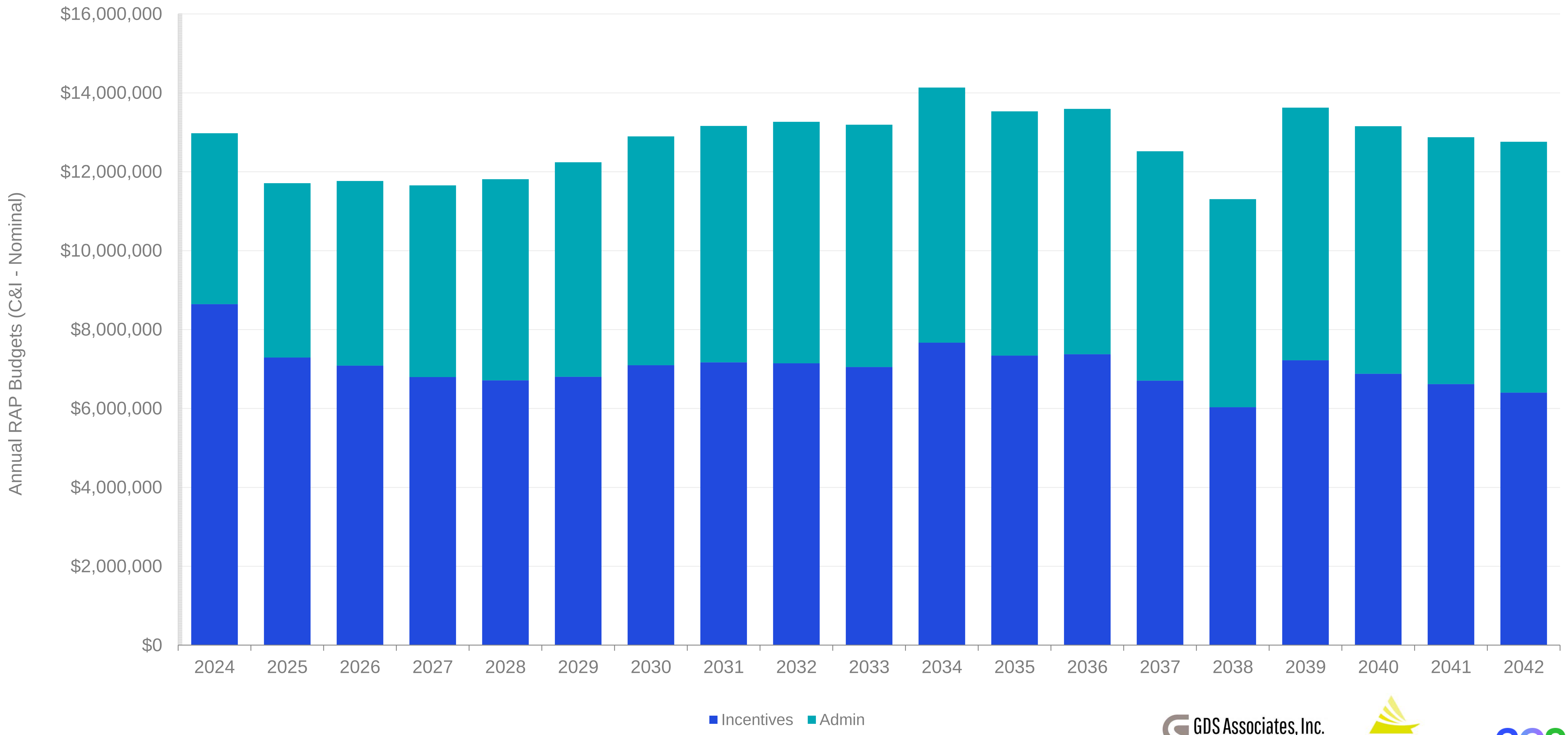
- Implementation
- Utility admin
- Indirect
- EM&V



Residential Program Potential Annual Costs



C&I Program Potential Annual Costs



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DSM Market Potential Study Results

Demand Response (DR) Potential

Demand Response Overview

Measures Considered

Demand Response includes Direct Load Control (DLC), Behavior DR, Time of Use (TOU) Rates, Capacity Bidding, Demand Bidding and Interruptible Agreements.

→ In the residential sector, DLC includes central air conditioning, room air conditioning, electric space heating, water heating, smart appliances, and pool pumps

→ In the nonresidential sector, DLC includes air conditioning, electric space heating, lighting, and water heating

DR Hierarchies

DR analysis will account for interactive effects as additional types of demand response programs are added to the mix. The hierarchy for demand response programs in the base case for the four market sectors is as follows:

Residential

1. Direct Load Control
2. Behavior DR
3. TOU

Small C&I

1. Direct Load Control
2. Capacity Bidding
3. TOU

Large C&I

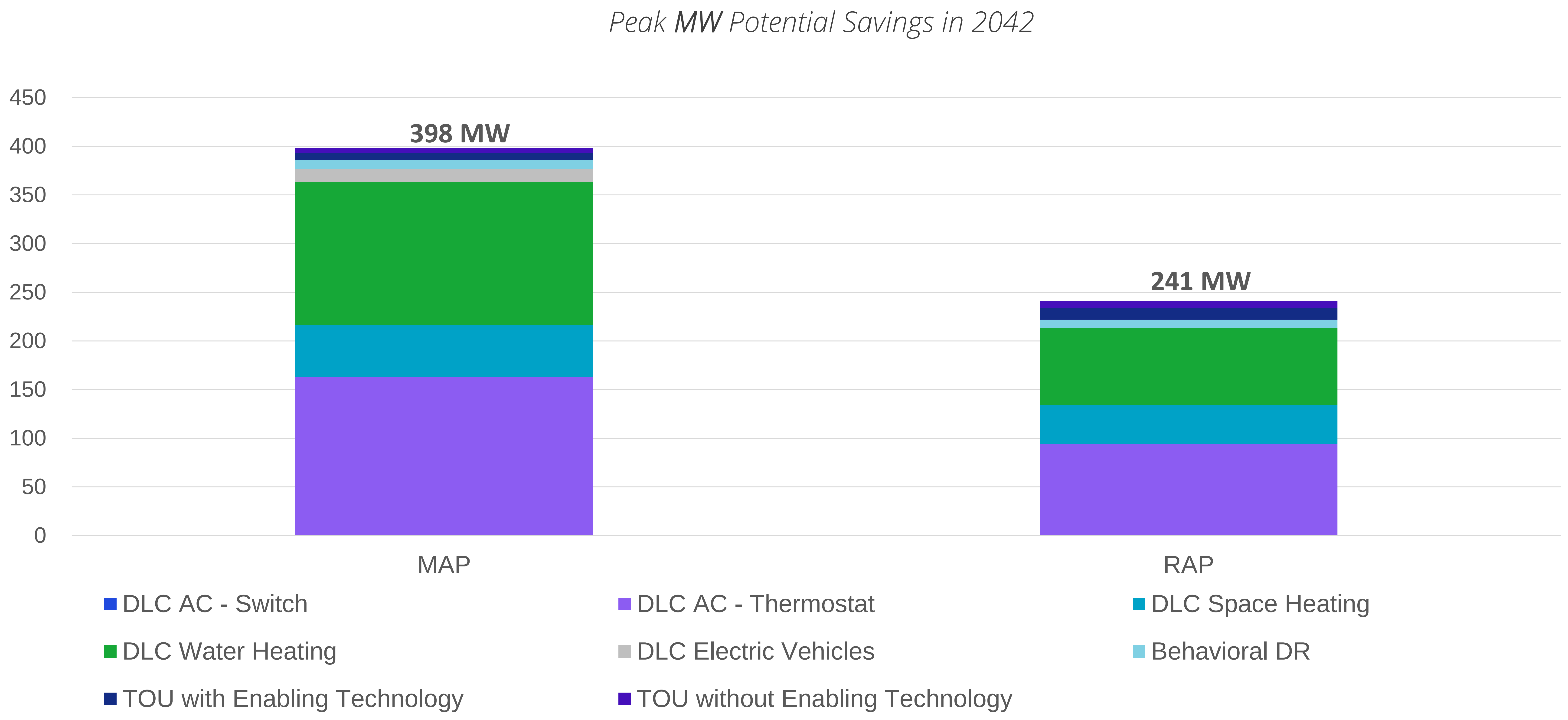
1. Interruptible Agreements
2. Capacity Bidding
3. TOU

Demand Response Programs Considered

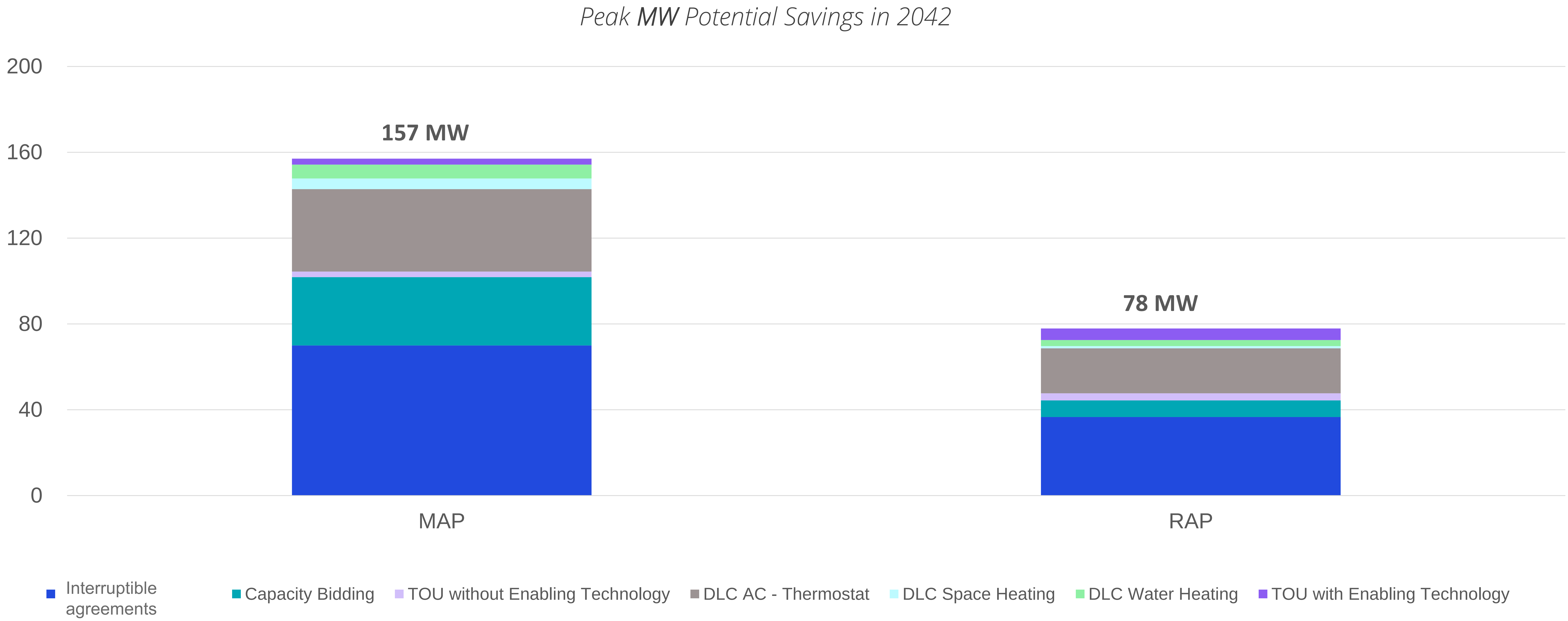
- →Direct Load Control ("DLC") – Central ACs
- →DLC – Room ACs
- →DLC – Smart Appliances
- →DLC – Water Heaters
- →DLC – Electric Space Heat
- →DLC – Lighting

- →Battery Energy Storage
- →Electric Vehicle Charging
- →Interruptible Agreements
- →Demand Bidding
- →Capacity Bidding
- →Time of Use Rates
- →Behavior DR

Residential Demand Response MAP/RAP Results

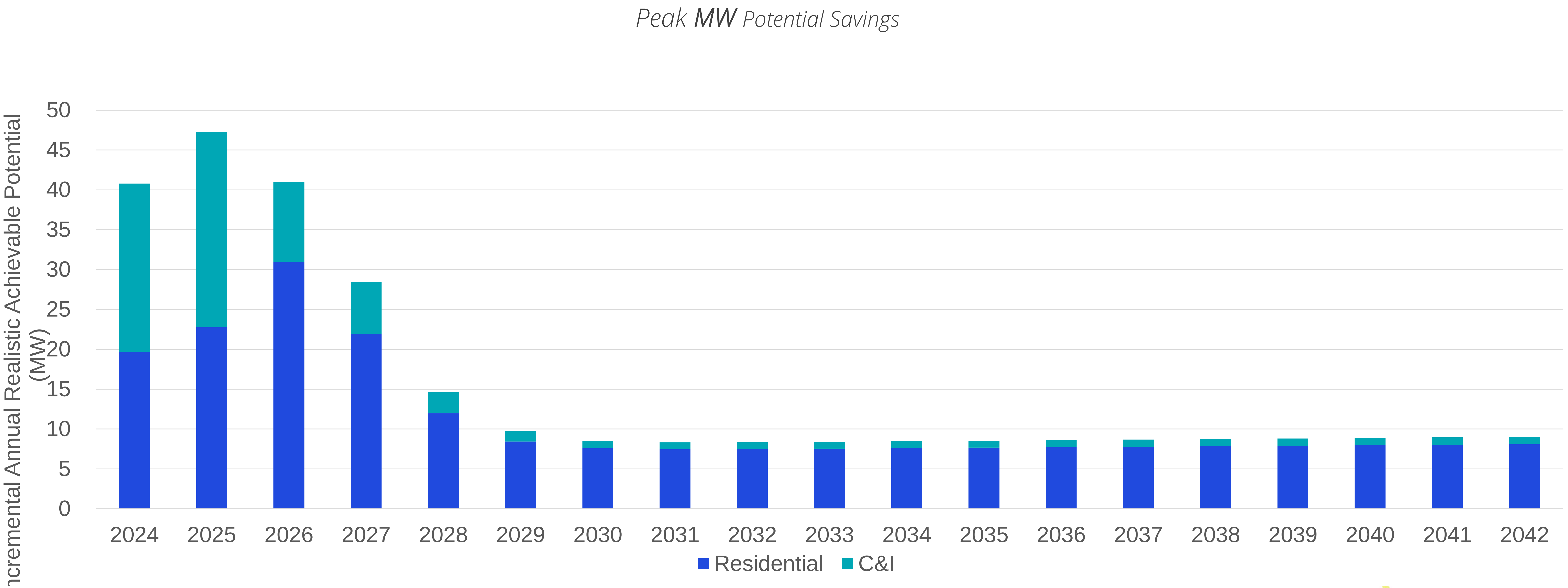


C&I Demand Response MAP/RAP Results



Annual Demand Response (RAP – by Sector)

INCREMENTAL ANNUAL



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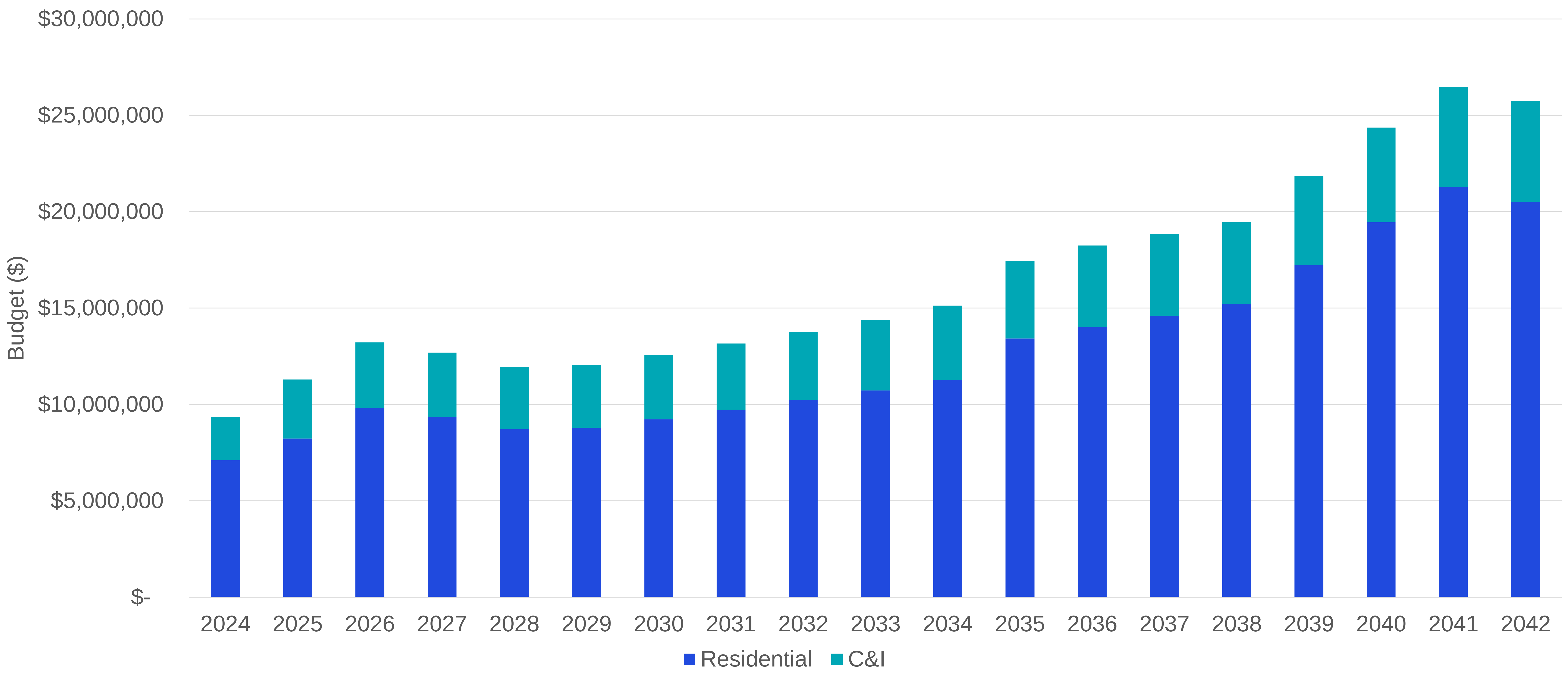
Annual Demand Response Budgets (by Sector)



DSM Market Potential Study

Developing DSM IRP Inputs

IRP Inputs – Energy Efficiency

Reference Case

→ EE Inputs for reference case will align with the Program RAP Potential

→ EE Inputs will be provided over three different vintages

- 2024-2026 (3 years)
- 2026-2028 (3 years)
- 2029-2042 (13 years)

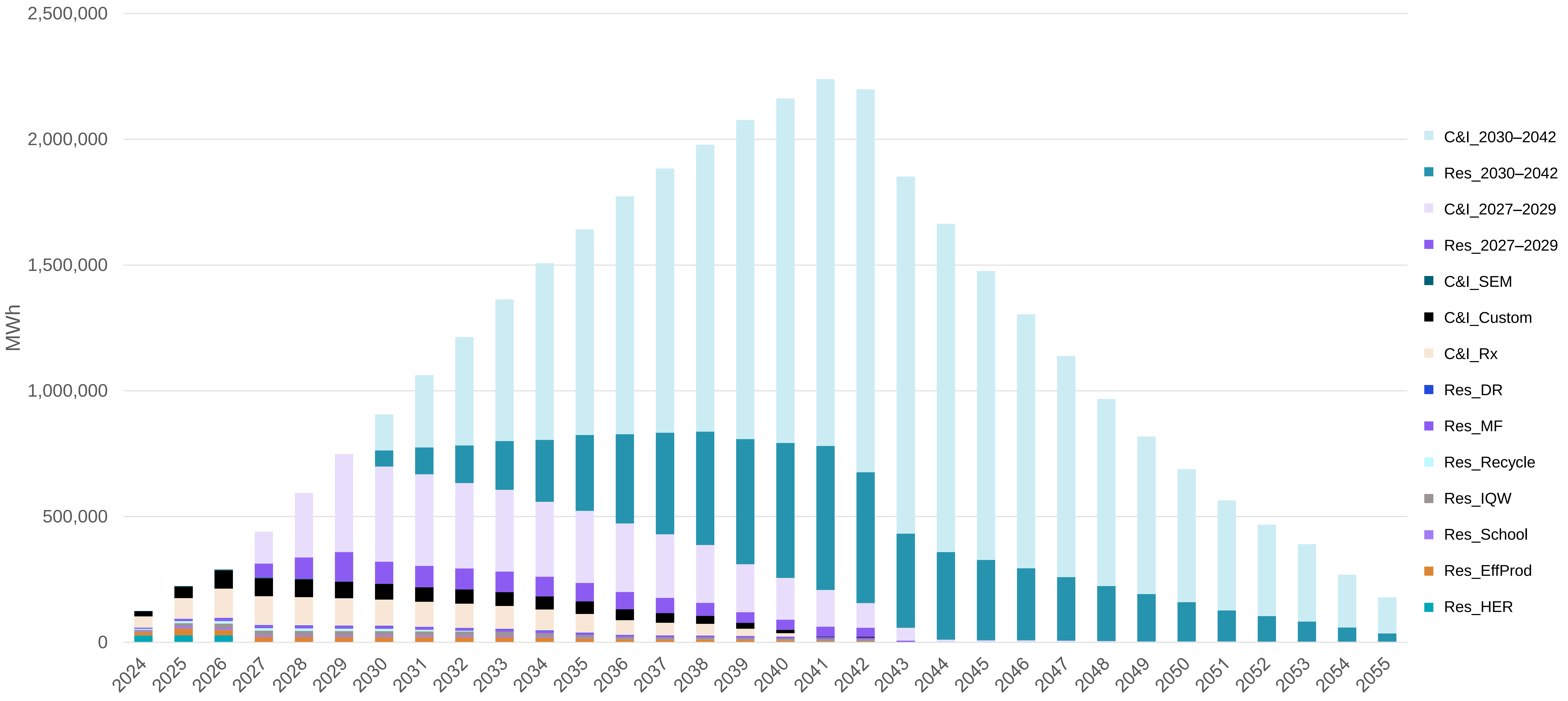
→ For 2024-2026 Vintage, EE Inputs will be bundled to closely resemble program offerings

- For remaining vintages, EE Inputs will be aggregated at the sector level

→ EE Costs will include utility costs (incentives and non-incentive costs) and will be adjusted to reflect the NPV impacts of T&D benefits.

→ *2023 will be "hard coded" to align with current approved DSM Plan savings and costs*

IRP Inputs – Energy Efficiency



IRP Inputs – Energy Efficiency

Time Differentiated Savings

→ Within a bundle/vintage, the EE Savings are broken out by end-use

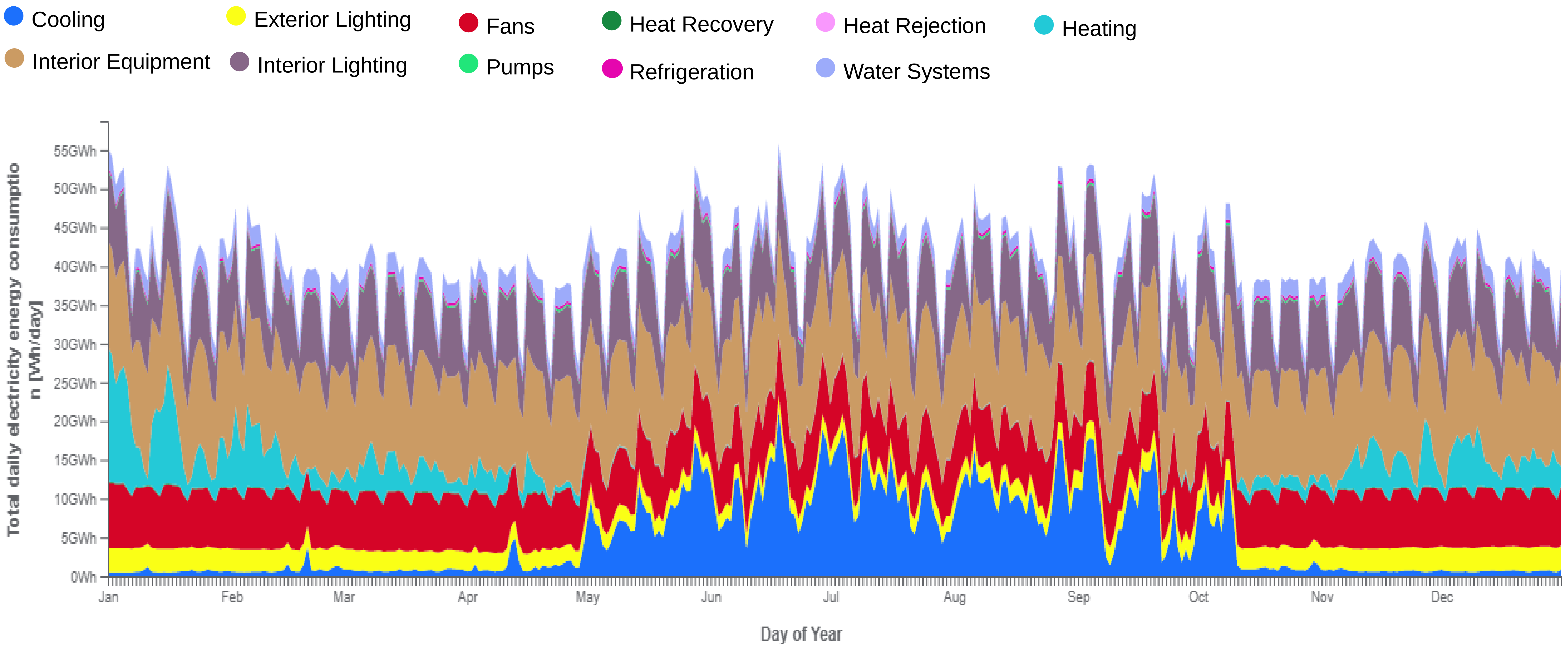
→ Saving by end-use are mapped to 8,760 end-use load shape data, developed by National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Lab (LBL).

- Residential sector includes 33 end-uses
- Nonresidential sector includes 11 end-uses

→ Hourly savings shapes are provided so that the model captures the timing of savings relative to the AES Indiana system and peak periods.

IRP Inputs – Energy Efficiency

Example Commercial Loadshape Data



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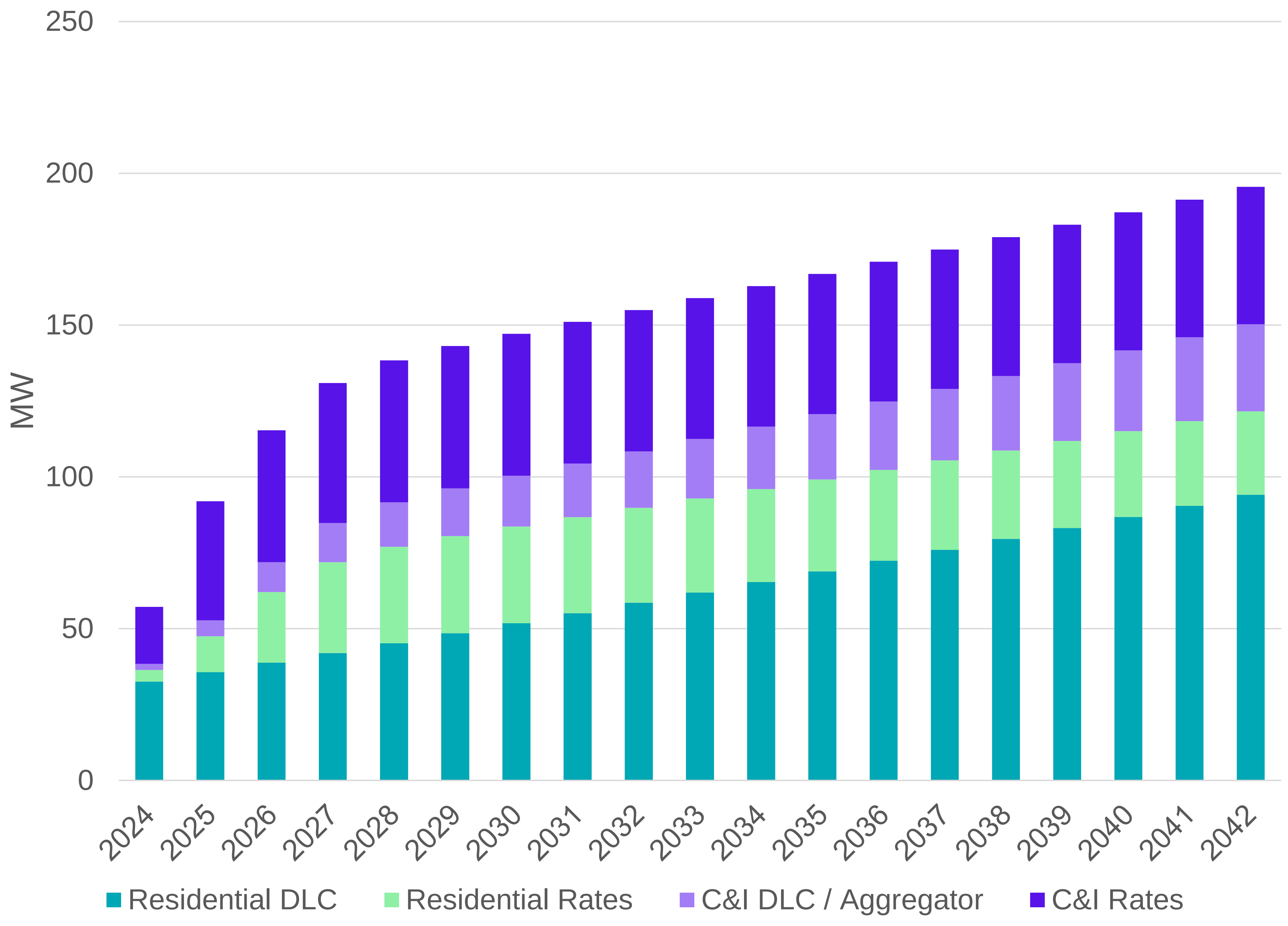
IRP Inputs – Demand Response

→Bundles for demand response follow the same vintages as Energy Efficiency

→Demand response bundles created for four categories

- Residential DLC
- Residential Rates
- C&I DLC/Aggregator
- C&I Rates

→DR bundles will include savings for both summer and winter peak, with summer peak savings potentially generally more significant



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Break for Lunch

Current Generation Portfolio Overview

Kristina Lund, President & CEO, AES Indiana

Current Portfolio

AES Indiana

Gradual change to the AES Indiana portfolio over time

2009-2015

Signed 100 MW PPA at Hoosier Wind Park in NW Indiana, 200 MW PPA at Lakefield Wind Farm in Minnesota and 96 MW PPA for solar in Indianapolis through Rate REP

2016

Retired 260 MW of coal at Eagle Valley

2016

Finalized refuel of 630 MW of coal-fired generation at Harding Street to natural gas

2018

Eagle Valley 671 MW Gas-Fired Combined Cycle Plant Completed

2021-2023

Retired (Unit 1) 220 MW of coal at Petersburg; Plans to retire (Unit 2) 401 MW of coal at Petersburg in 2023

2023 – 2024

Plans to complete 195 MW Hardy Hills Solar project and 250 MW + 180 MWh Petersburg Energy Center solar + storage project

Capabilities and Infrastructure

Largest sites have valuable capabilities and infrastructure for the energy transition

Petersburg

Experienced, skilled labor force, land, interconnection, water rights, water treatment, natural gas pipelines already present on site

Harding Street

Experienced, skilled labor force, land, interconnection, location near load center, rail, water rights

Eagle Valley

New plant, highly efficient, flexible for future grid changes

AES Indiana seeks to partner with Pike County and City of Indianapolis to drive customer value and community impact of Petersburg and Harding Street Sites.

Replacement Resource Assumptions

Erik Miller, Manager, Resource Planning, AES Indiana

Commercially Available Replacement Resources

DSM/EE

- EE & DR Measures bundled into traunches for planning model selection

Wind

- Land-Based Wind

Solar

- Utility-Scale
- C&I
- Residential

Storage

- Utility-Scale standalone
- Solar + Storage

Natural Gas

- CCGT
- CT
- Reciprocating Engine/ICE
- Pete Refuel

Key Replacement Resource Assumptions for IRP Modeling

Replacement Resource Assumptions are the key inputs that the planning model uses for selecting replacement resources when energy or capacity is needed.

Replacement Resource Assumptions include:

→ Overnight Capital Cost to construct ($/kW) – Costs associated with development and construction of resource

→ Operating Cost:

- Fixed Operation & Maintenance (FOM) – Costs incurred whether plant is operating or not, e.g. staff cost, regular maintenance, administrative costs
- Variable Operation & Maintenance (VOM) – Costs associated with electricity production, e.g. repair and replacement of parts

→ Operating Characteristics:

Operating Characteristics		
Solar & Wind	**Storage**	**CT or CCGT (Natural Gas)**
Generation Profiles	Ramp Rates	Heat Rates
Effective Load Carrying Capability (ELCC)	Capacity Accreditation	Ramp Rates
MW Limits	MW and MWh Limits	Capacity Accreditation
Asset Useful Life	Asset Useful Life	MW Limits
		Asset Useful Life

Methodology for Replacement Resource Cost Assumptions

Overview

- AES Indiana used a combination of Sargent & Lundy's (S&L) RFP review, Bloomberg New Energy Finance (BNEF), National Renewable Energy Labs (NREL) and Wood Mackenzie data to benchmark the starting year assumptions for replacement resources in this IRP.
- Replacement Resource capital cost forecasts were calculated by averaging forecasts from NREL, BNEF and Wood Mackenzie or from S&L.

Sargent & Lundy's (S&L) review of AES Indiana's 2019 RFP

- AES Indiana contracted S&L to administer the Company's 2019 All-source RFP for generation.
- As follow up to this work, S&L summarized the cost and operating components for the resources included in the 2019 All-source RFP to inform the 2022 IRP.
- To supplement this review, S&L also reviewed and sourced their internal databases and a comprehensive list of public data sources.
- Resources reviewed:
  - Solar
  - Wind
  - Solar + Storage
  - Standalone 4-hr Storage
  - Combustion Turbine (Frame and Aeroderivative)
  - Combined Cycle Gas Turbine
  - Reciprocating Engine
- Cost components reviewed:
  - Capital Cost ($/kWac)
  - Interconnection Cost ($/kWac)
  - Cost of Tax Equity ($/kWac)
  - FOM ($/kWac)
  - VOM ($/MWh)
  - Capacity Factor (%)
  - Curtailment (%)
  - Property Tax ($/kWac)
  - Max Capacity per year (MW)

2022 All-Source Generation RFP

AES Indiana is conducting an all-source RFP

- Positions AES Indiana to efficiently procure generation consistent with final IRP Preferred Resource Portfolio
- Informs IRP process in considering Replacement Resource Costs sensitivities
- RFP offers requested for Commercial Operation Date (COD) of 2025-2027
- Incorporate invitation for projects leveraging remaining uncommitted Petersburg Unit 2 injection rights
- Issue RFP mid-April

Department of Commerce Anti-Dumping/Countervailing Duties (AD/CVD) investigation

- Preliminary decision 150 days
- Repercussions for solar industry
- Creates uncertainty for developers – particularly in near-term
- Issue resolution for 2025-2027 COD projects – address uncertainty around solar in RFP

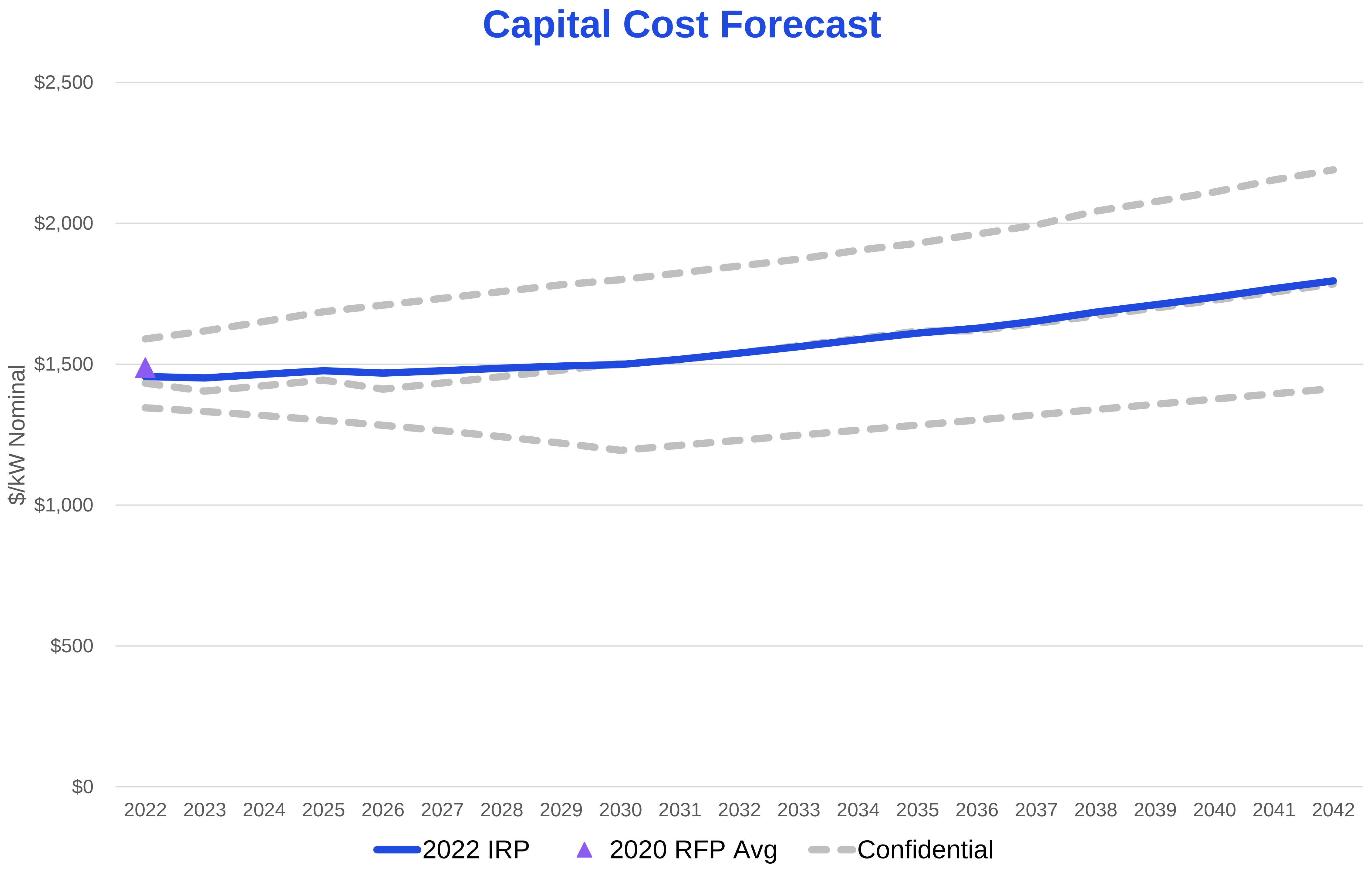
AES Indiana

Sources for Replacement Resource Cost Assumptions

Primary Assumption	Wind	Solar	Storage	Solar + Storage	CCGT	Frame CT	Aero CT	Reciprocating Engine
Capital Cost	BNEF, NREL, Wood Mack & 2020 RFP	BNEF, NREL, Wood Mack & 2020 RFP	BNEF, Wood Mack & 2020 RFP	BNEF, NREL, Wood Mack & 2020 RFP	BNEF, NREL, Wood Mack & 2020 RFP	BNEF, NREL, Wood Mack & 2020 RFP	Sargent & Lundy	Sargent & Lundy
Fixed O&M	Company Assets	Company Assets	Company Assets	Company Assets	Company Assets	Company Assets	Sargent & Lundy	Sargent & Lundy
Variable O&M	N/A	N/A	N/A	N/A	Company Assets	Company Assets	Sargent & Lundy	Sargent & Lundy
Operating Characteristic	NREL System Advisory Model (SAM)	NREL System Advisory Model (SAM)	NREL 2021 ATB	NREL 2021 ATB	Company Assets	Company Assets	Sargent & Lundy	Sargent & Lundy
Other Key Assumption								
ELCC / Capacity Credit	Horizons Energy / MISO	Horizons Energy / MISO	Horizons Energy / MISO	Horizons Energy / MISO	MISO	MISO	MISO	MISO
Grid Connection Cost	Sargent & Lundy	Sargent & Lundy	Sargent & Lundy	Sargent & Lundy	Sargent & Lundy	Sargent & Lundy	Sargent & Lundy	Sargent & Lundy
Tax Equity Cost	Sargent & Lundy	Sargent & Lundy	N/A	Sargent & Lundy	N/A	N/A	N/A	N/A

Wind Capital and Operating Costs

Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
$ 1,451	$ 30	$ -

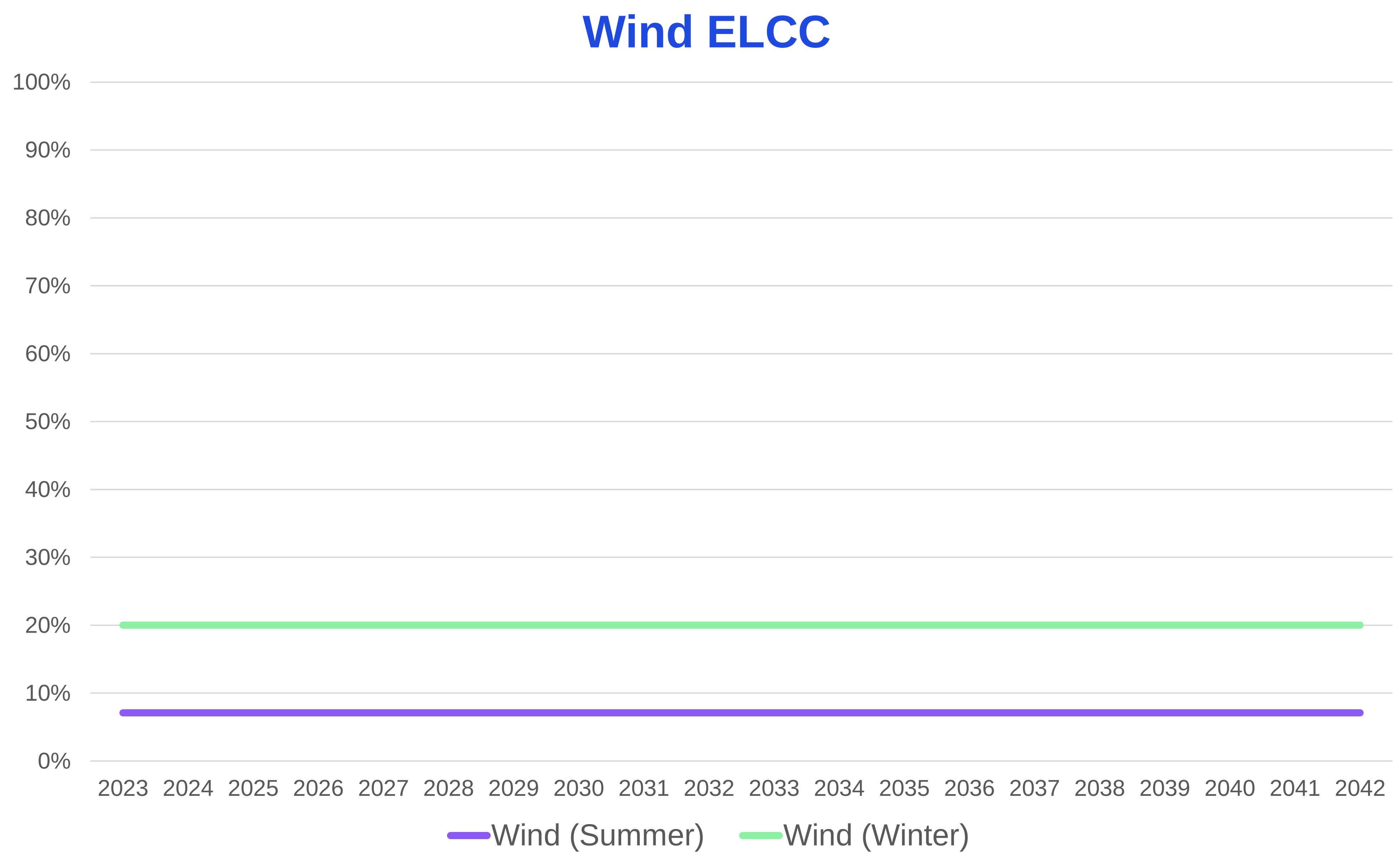


Note: Capital Cost estimates presented here are without federal tax credits. Federal tax credits will be included in modeling based on the IRP scenario assumptions.

Note: Confidential cost forecasts in chart include forecasts from NREL, Wood Mackenzie and BNEF

Wind Parameters

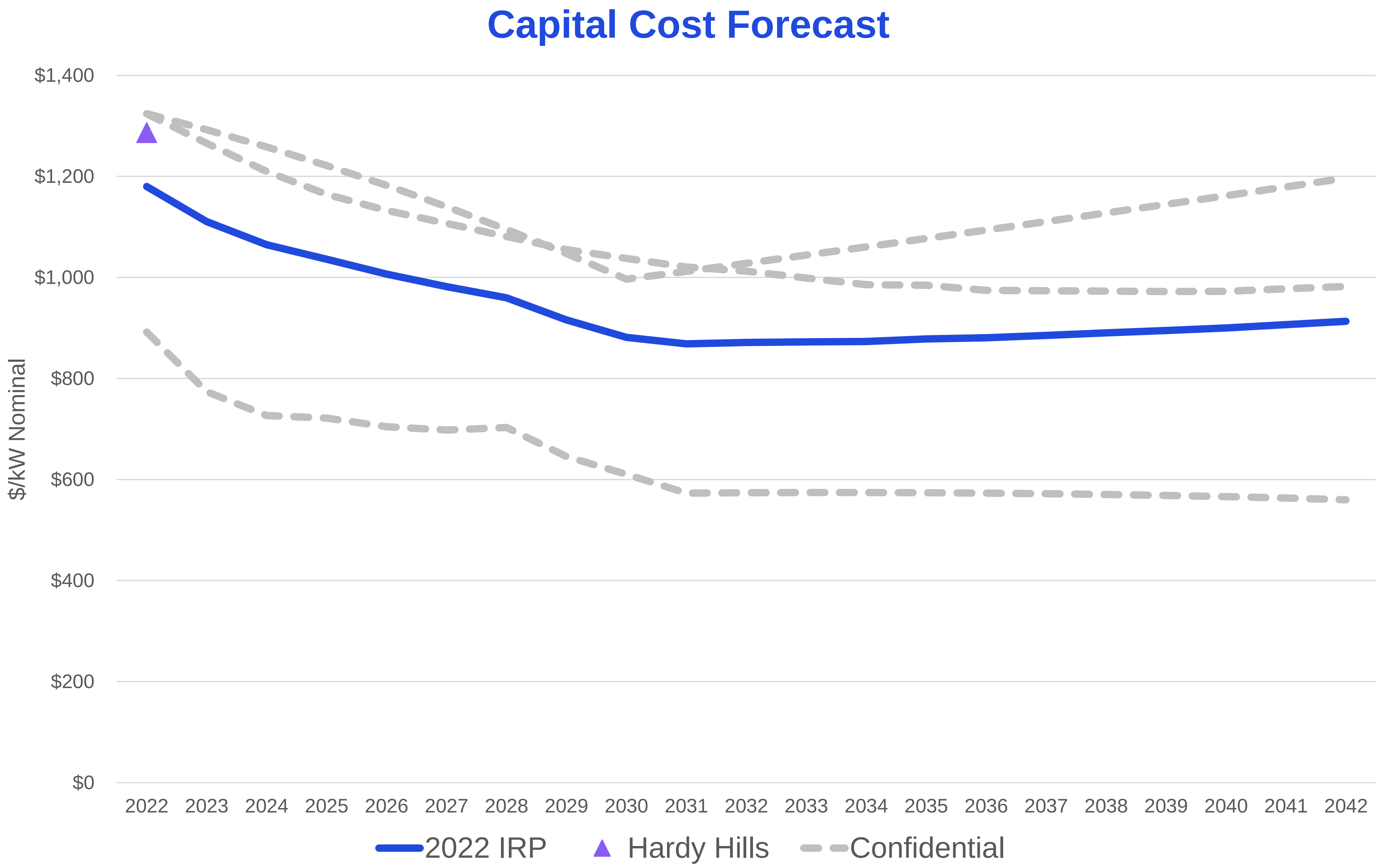
- **Location:** Indiana
- **Annual Capacity Factor:** 33.6 – 40.4%
- **Source Profile:** NREL System Advisory Model (SAM)
- **Project Size:** 50 MW ICAP
- **Useful Life:** 30 years
- **Summer ELCC (2025):** 7.1%; *Source: Horizons Energy*
- **Winter ELCC:** 20%; *Source: MISO RAN*



Indiana

Solar Capital and Operating Costs

Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
$1,111	$12	$0

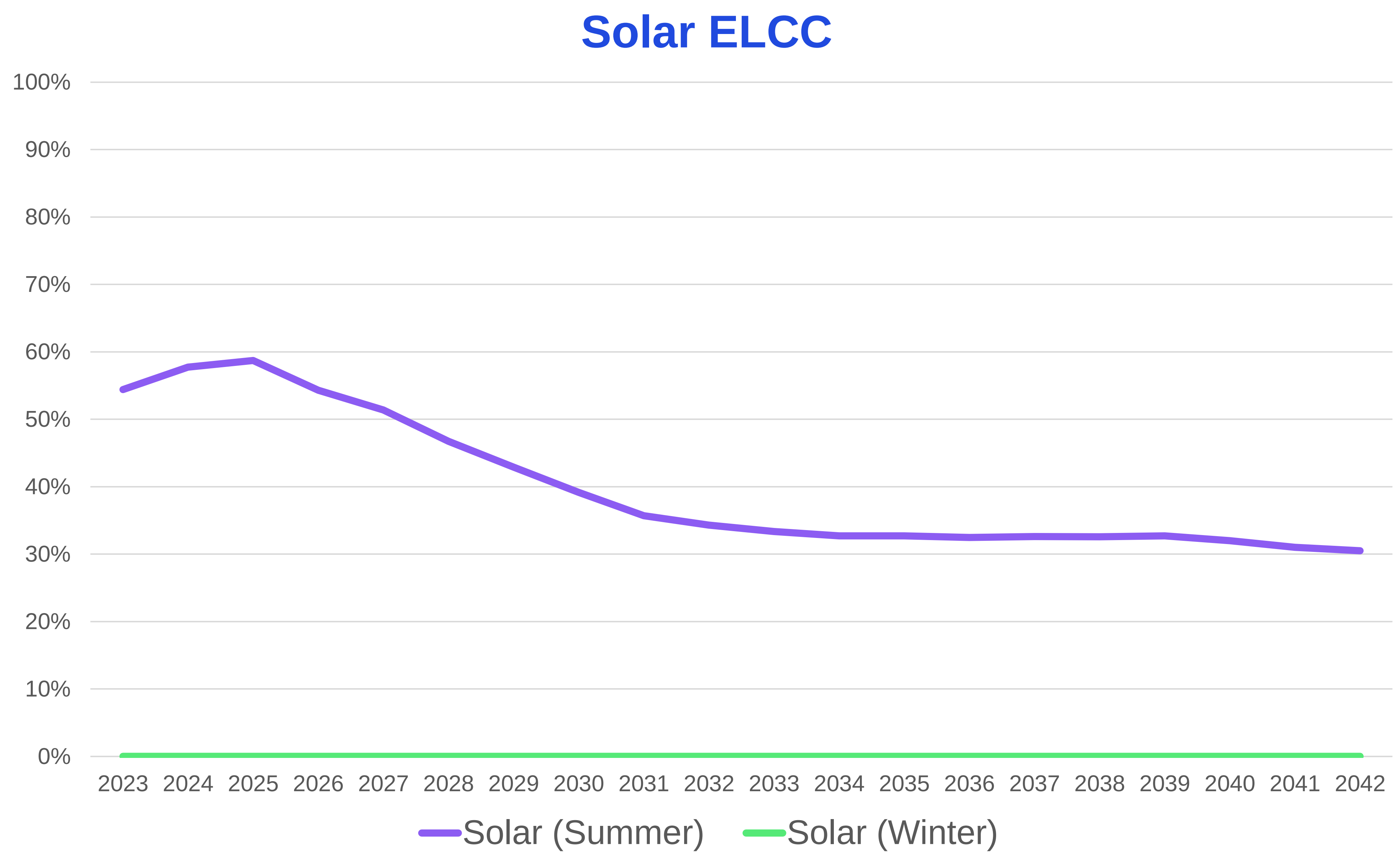


Note: Capital Cost estimates presented here are without federal tax credits. Federal tax credits will be included in modeling based on the IRP scenario assumptions.

Note: Confidential cost forecasts in chart include forecasts from NREL, Wood Mackenzie and BNEF

Solar Parameters

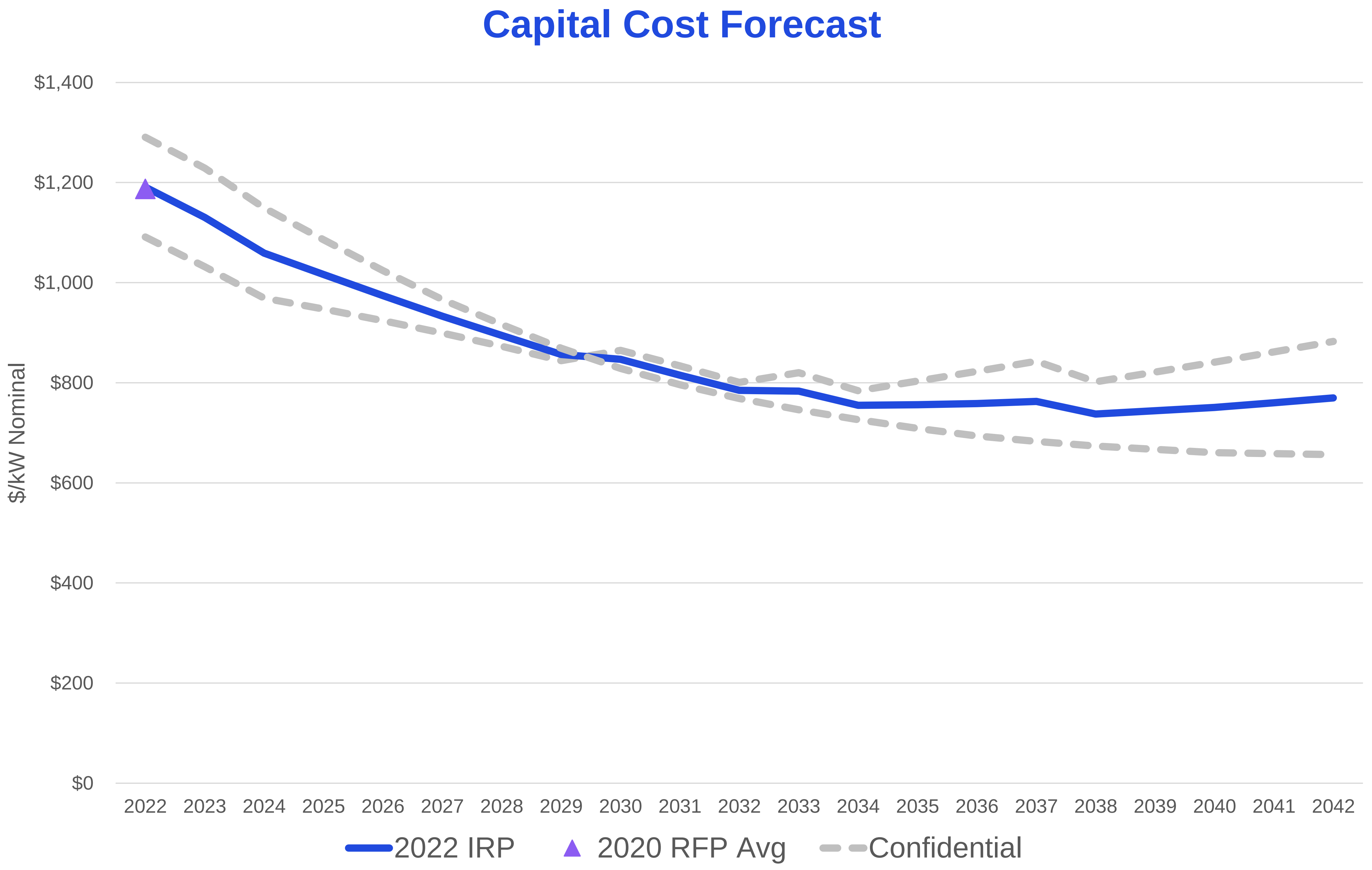
- **Location:** Petersburg, Indiana
- **Annual Capacity Factor:** 24.5%
- **Source Profile:** NREL System Advisory Model (SAM)
- **Project Size:** 25 MW ICAP
- **Useful Life:** 35 years
- **Summer ELCC (2025):** 58.7%; *Source: Horizon Energy*
- **Winter ELCC:** 0%; *Source: MISO RAN*



*Summer ELCC forecast presented in chart is from the Horizon Custom Reference Case – ELCC forecast will vary by custom scenario

Storage Capital and Operating Costs

Capital Cost ($/kW)		Fixed O&M ($/kW)		Variable O&M ($/MWh)	
$	1,130	$	27	$	-

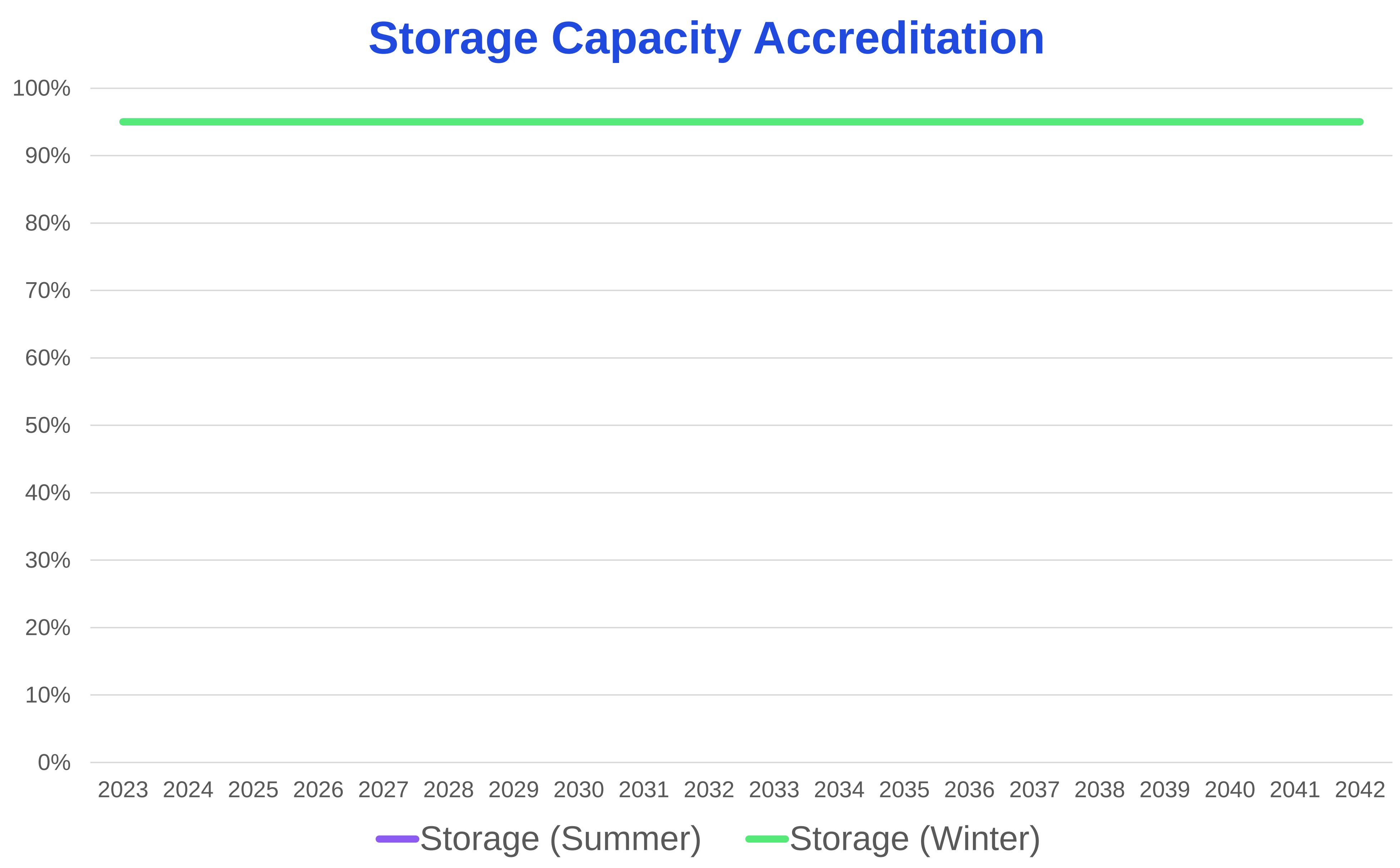


Note: Capital Cost estimates presented here are without federal tax credits. Federal tax credits will be included in modeling based on the IRP scenario assumptions.

Note: Confidential cost forecasts in chart include forecasts from Wood Mackenzie and BNEF

Storage Parameters

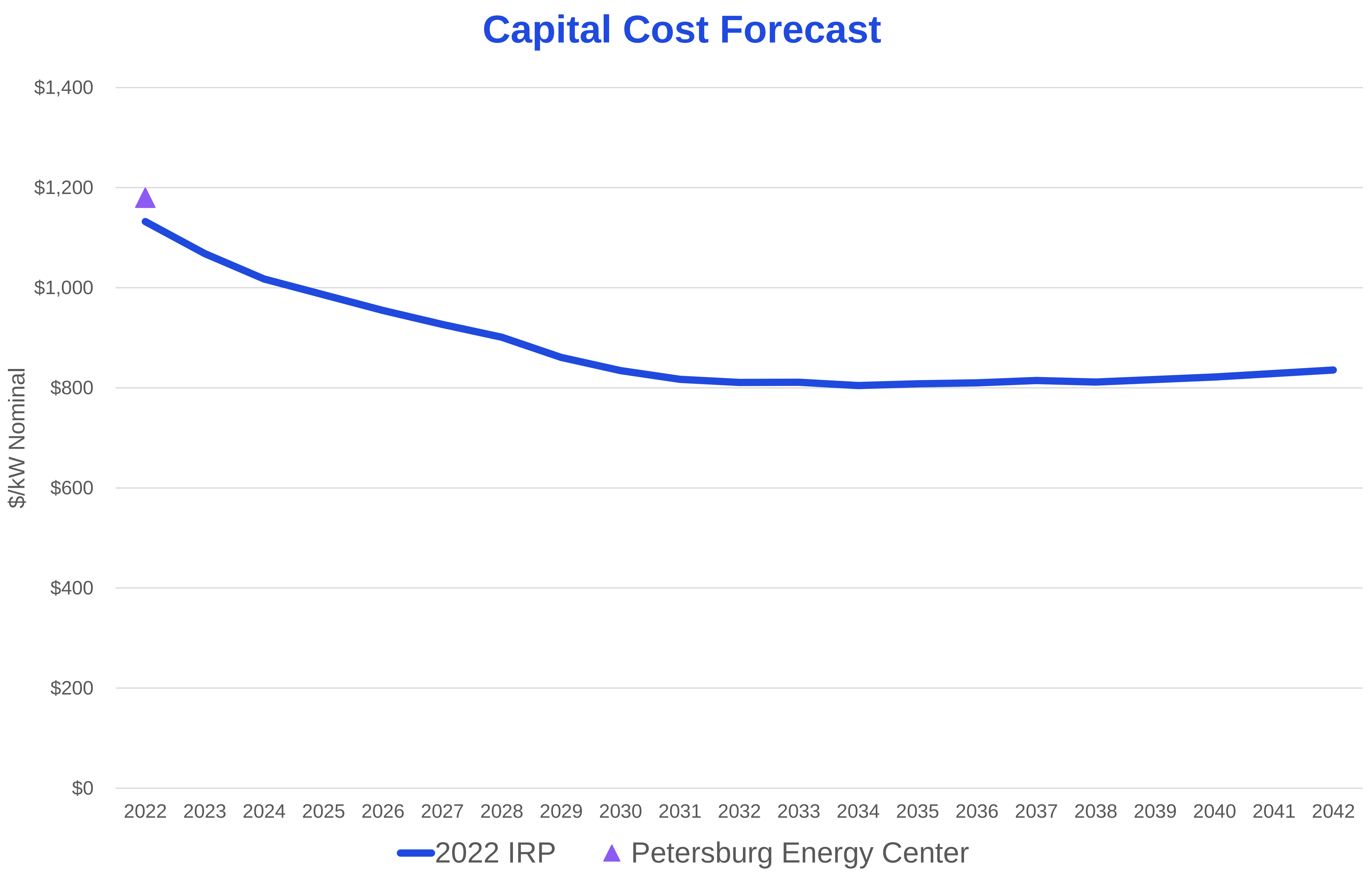
- **Location:** Indianapolis, Indiana
- **Project Size:** 20 MW ICAP | 80 MWh (4-hour)
- **Round Trip Efficiency (RTE):** 85%
- **Useful Life:** 20 years
- **Summer/Winter Capacity Accreditation:** 95% (19 MW)



Note: 6-hour Storage also be modeled and scaled off of the 4-hour Storage assumptions

Solar + Storage Capital and Operating Costs

Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
$1,069	$17	$0



Note: **Capital Cost estimates presented here are without federal tax credits. Federal tax credits will be included in modeling based on the IRP scenario assumptions.**

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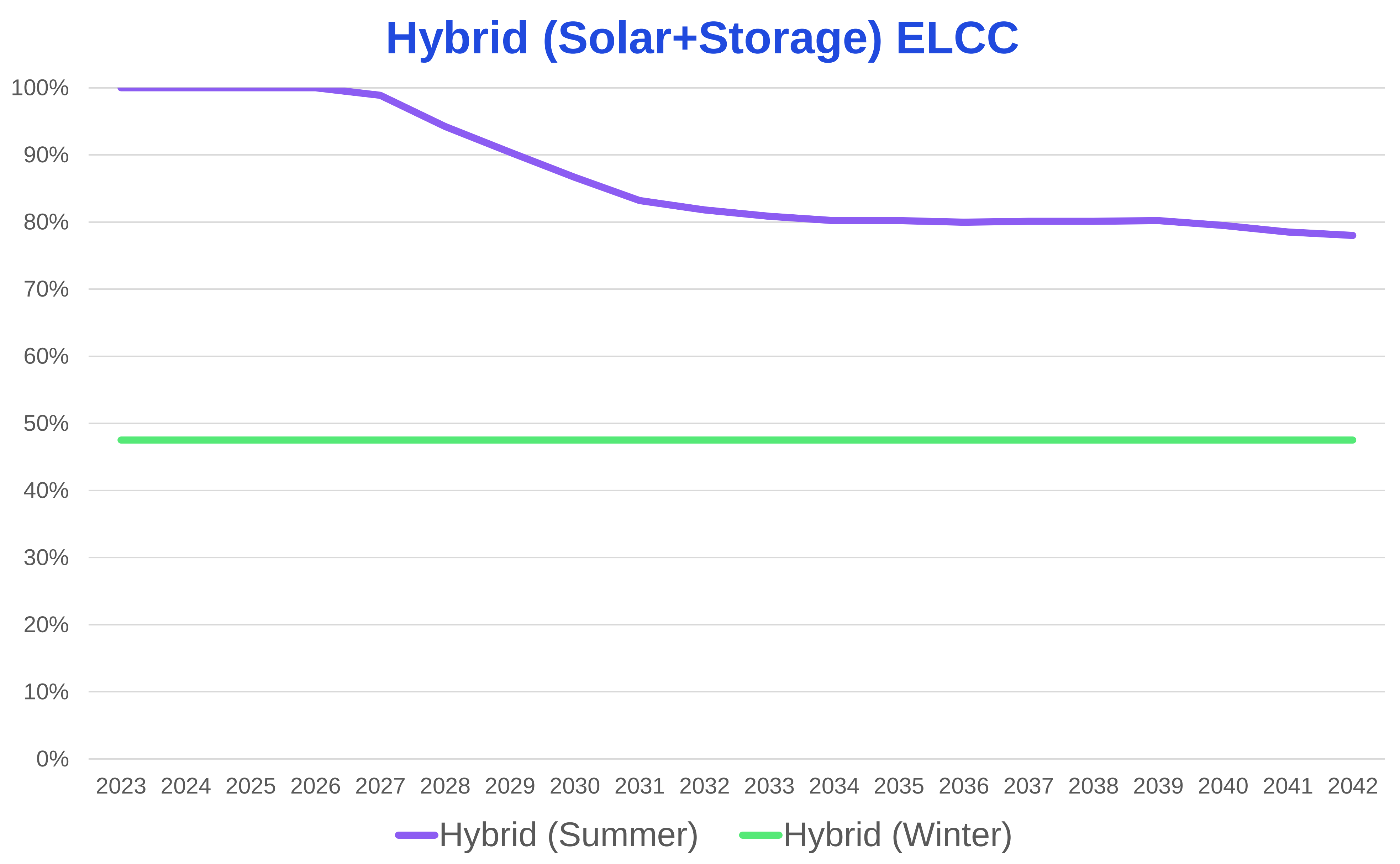
Solar + Storage Parameters

- **Location:** Petersburg, Indiana
- **System:** DC Coupled Solar + Storage System, Storage charges exclusively from the solar array
- **Solar Component:** Identical to stand-alone solar (25 MW ICAP)
- **Storage Component:** 12.5 MW ICAP | 50 MWh
- **Synergies:** 4.3% reduction in capital costs, 2% improvement of RTE
- **Summer ELCC (2025):** 100%
- **Winter ELCC:** 48%

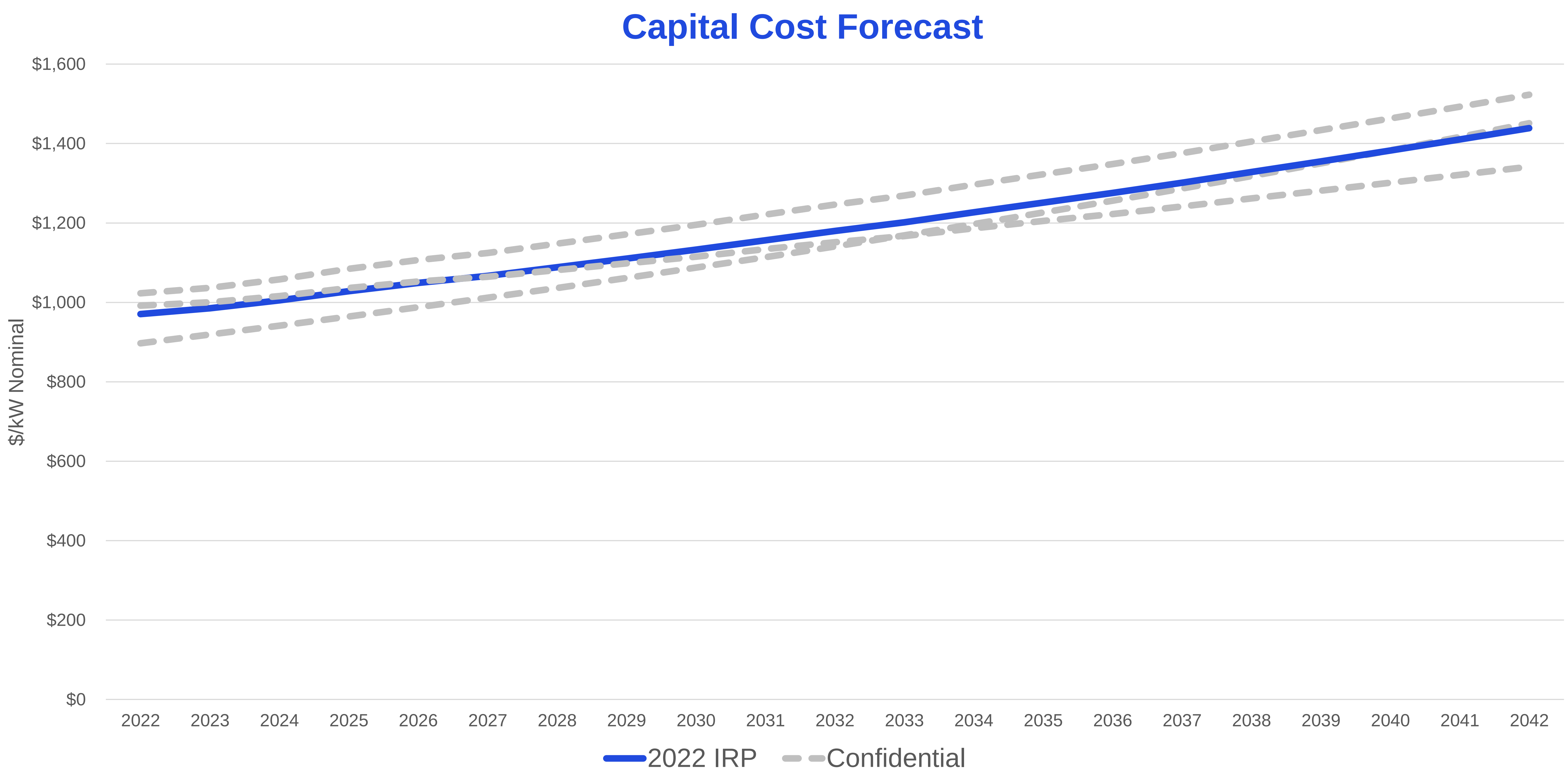


*Summer forecast presented in chart above is from the Horizon Custom Reference Case – forecast will vary by custom scenario

AES Indiana

CCGT Capital and Operating Costs

Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
$1,026	$32	$2



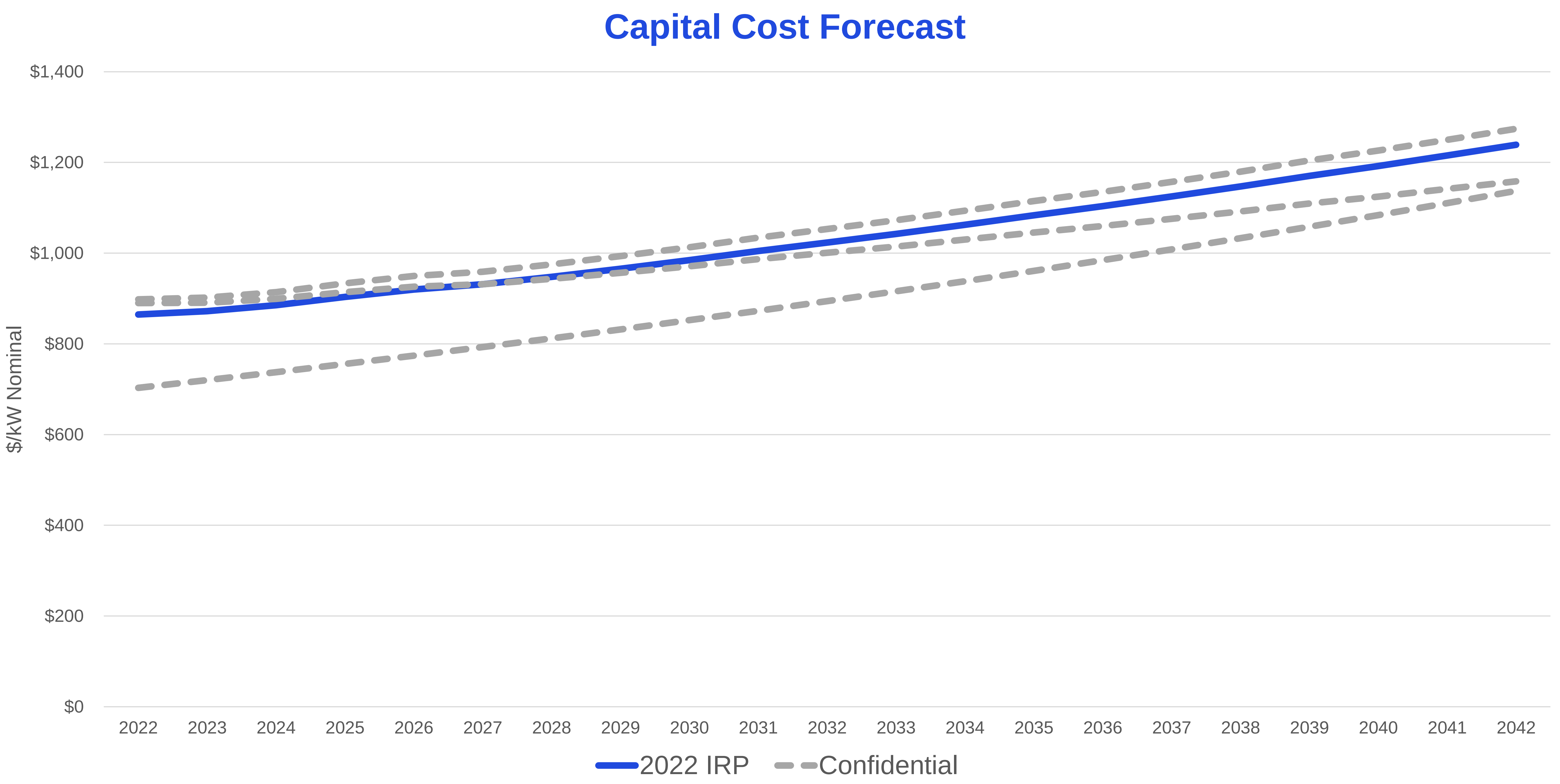
Note: Confidential cost forecasts in chart include forecasts from NREL, Wood Mackenzie and BNEF

CCGT Parameters

- **Project Size:** 325 MW ICAP
- **Heat Rate at Max Economic Load:** 6,700 Btu/kWh
- **Useful Life:** 30 years
- **Summer/Winter Capacity Credit:** 94.2% static

Frame Combustion Turbine Capital and Operating Costs

Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
$872	$30	$1



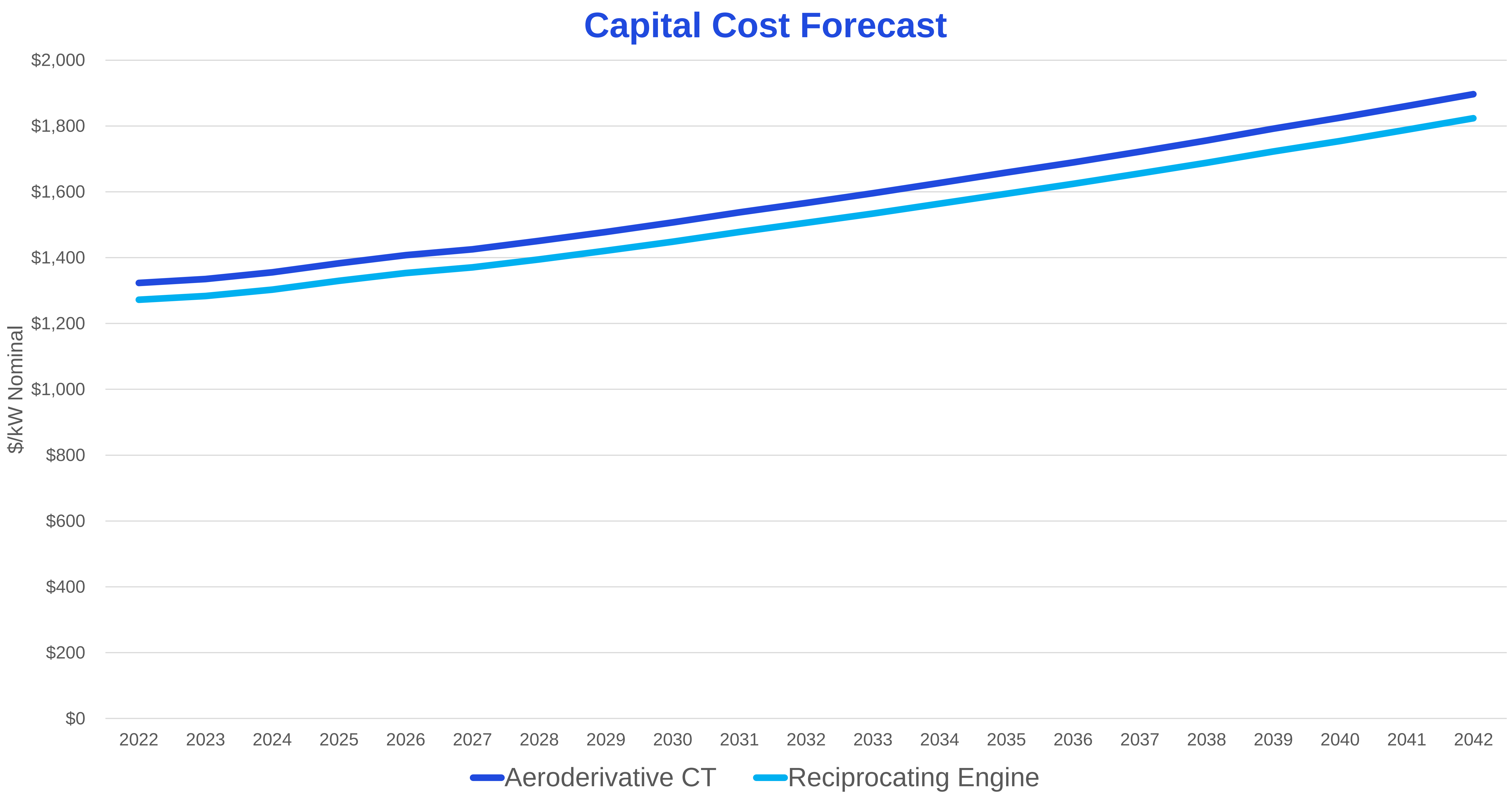
Note: Confidential cost forecasts in chart include forecasts from NREL, Wood Mackenzie and BNEF

Frame Combustion Turbine Parameters

- **Project Size:** 100 MW ICAP
- **Heat Rate at Max Economic Load:** 10,000 Btu/kWh
- **Useful Life:** 20 years
- **Summer/Winter Capacity Credit:** 95.6% static

Aero CT and Recip Engine Capital and Operating Costs

	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
Aero CT	$1,335	$36	$5
Recip	$1,283	$46	$6



Aero CT and Reciprocating Engine Parameters

Aero Combustion Turbine

- **Project Size:** 90 MW ICAP
- **Heat Rate at Max Economic Load:** 8,200 Btu/kWh
- **Useful Life:** 20 years
- **Summer/Winter Capacity Credit:** 95.6% static

Reciprocating Engine

- **Project Size:** 54 MW ICAP
- **Heat Rate at Max Economic Load:** 7,400 Btu/kWh
- **Useful Life:** 20 years
- **Summer/Winter Capacity Credit:** 95.6% static

Petersburg Refuel Capital and Operating Costs

Petersburg Units 3 & 4 Refuel to Natural Gas

→ Low capital cost (~$100/kW)

→ Refueling will require gas infrastructure upgrade not included in capital cost above

Modeling Assumptions

Costs:

→ Capital expenditure estimated based on cost to refuel Harding Street 5, 6, 7

→ Engineering analysis performed to understand the cost for gas infrastructure upgrade

Potential Refueling Benefits

→ Reduces carbon intensity (lower capacity factor and emission rate for ST gas – similar to Harding St)

→ Dispatchable resource that positions AES Indiana well with new MISO seasonal capacity construct

Refuel of Petersburg Units 3 & 4 Parameters

→ **Petersburg Unit 3**

- **Project Size:** 526 MW ICAP
- **Heat Rate at Max Economic Load:** 10,800 Btu/kWh
- **Variable O&M:** < $0.50/MWh
- **Fixed O&M:** 65% reduction from coal Fixed O&M
- **Useful Life:** 20 years
- **Summer/Winter Capacity Credit:** 90.9% static

→ **Petersburg Unit 4**

- **Project Size:** 526 MW ICAP
- **Heat Rate at Max Economic Load:** 10,800 Btu/kWh
- **Variable O&M:** < $0.50/MWh
- **Fixed O&M:** 65% reduction from coal Fixed O&M
- **Useful Life:** 20 years
- **Summer/Winter Capacity Credit:** 94.1% static

IRP Portfolio Matrix Introduction

Erik Miller, Manager, Resource Planning, AES Indiana

Portfolio Matrix: Strategies vs. Scenarios

AES Indiana's Portfolio Matrix considers four generation portfolio Strategies across four Scenarios

Strategies

- AES Indiana's potential future strategies for the generation portfolio.
- Retirement dates, capital expenditures & cost treatments are anticipated and defined for each strategy and included in the planning model.

Scenarios

- Scenarios are views of the future defined by external influences like political outcomes, economics, regulations, etc.
- In the planning model, each scenario will have a unique set of input assumptions that correspond to the external influences defining the scenario.

***Note that AES Indiana will also use stochastics & sensitivities to assess risk around particular variables, e.g. replacement resource costs.**

IRP Strategies

Generation Portfolio Strategies

No Changes to Existing Portfolio	→ Status quo → Units remain in service through useful life of 2042
Petersburg Refuel	→ Petersburg Unit 3 & 4 refueled to Natural Gas in 2025 → Natural gas pipeline already present on site
One Petersburg unit retires early (2026)	→ One unit retired early in 2026 → The other unit remains in service through useful life of 2042 → Replacement capacity starting in 2026
Both Petersburg units retire early (2026 & 2028)	→ One unit retires early in 2026 → The other unit retires early in 2028

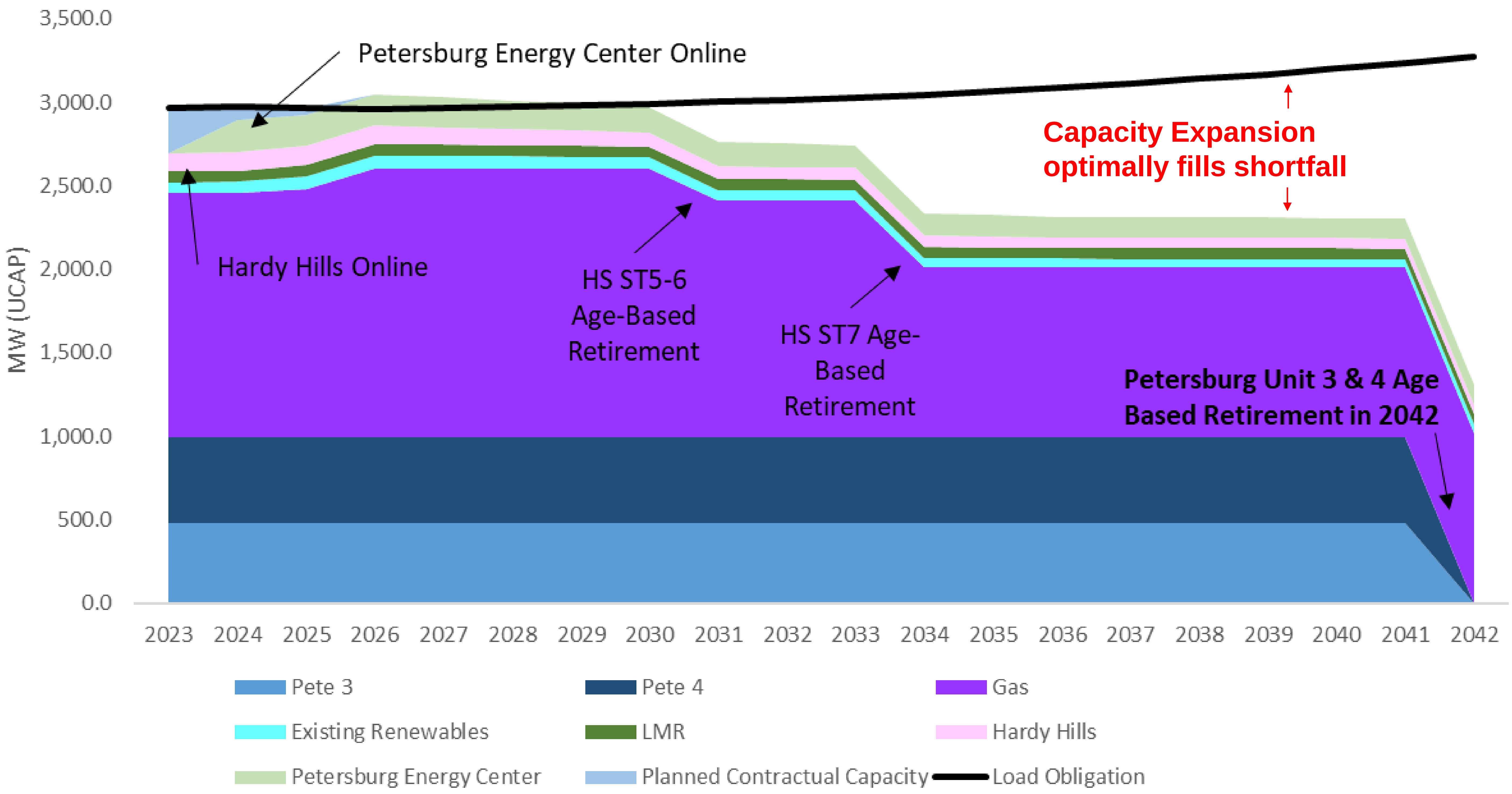
Rationale for Predefined Portfolio Strategies

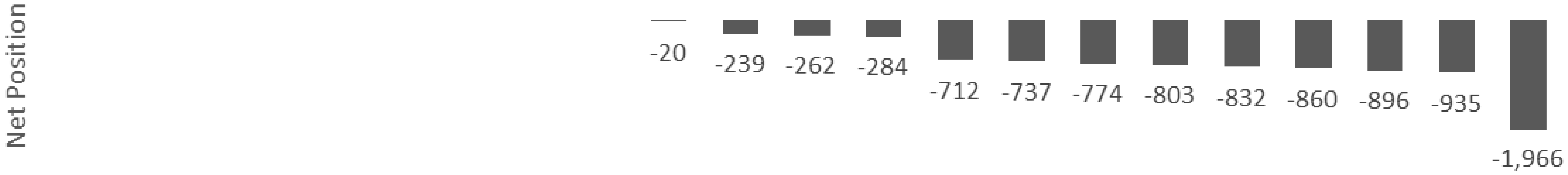
Generation Portfoilo Strategy	Rationale
No Changes to Existing Portfolio	Provides portfolios with coal through 2042 for Scorecard metric comparison & evaluation
Petersburg Refuel	Earliest possible refuel date that provides sufficent lead time to execute the natural gas conversion
One Petersburg Unit Retires Early (2026)	Earliest possible retirement date that provides sufficient lead time to procure capacity
Both Petersburg Units Retire Early (2026 & 2028)	Staggering specific unit retirement dates provides sufficient lead time to procure capacity

Predefined strategies provide for comparison and evaluation of portfolios with the earliest possible exit from coal vs portfolios with coal through the entire planning period.

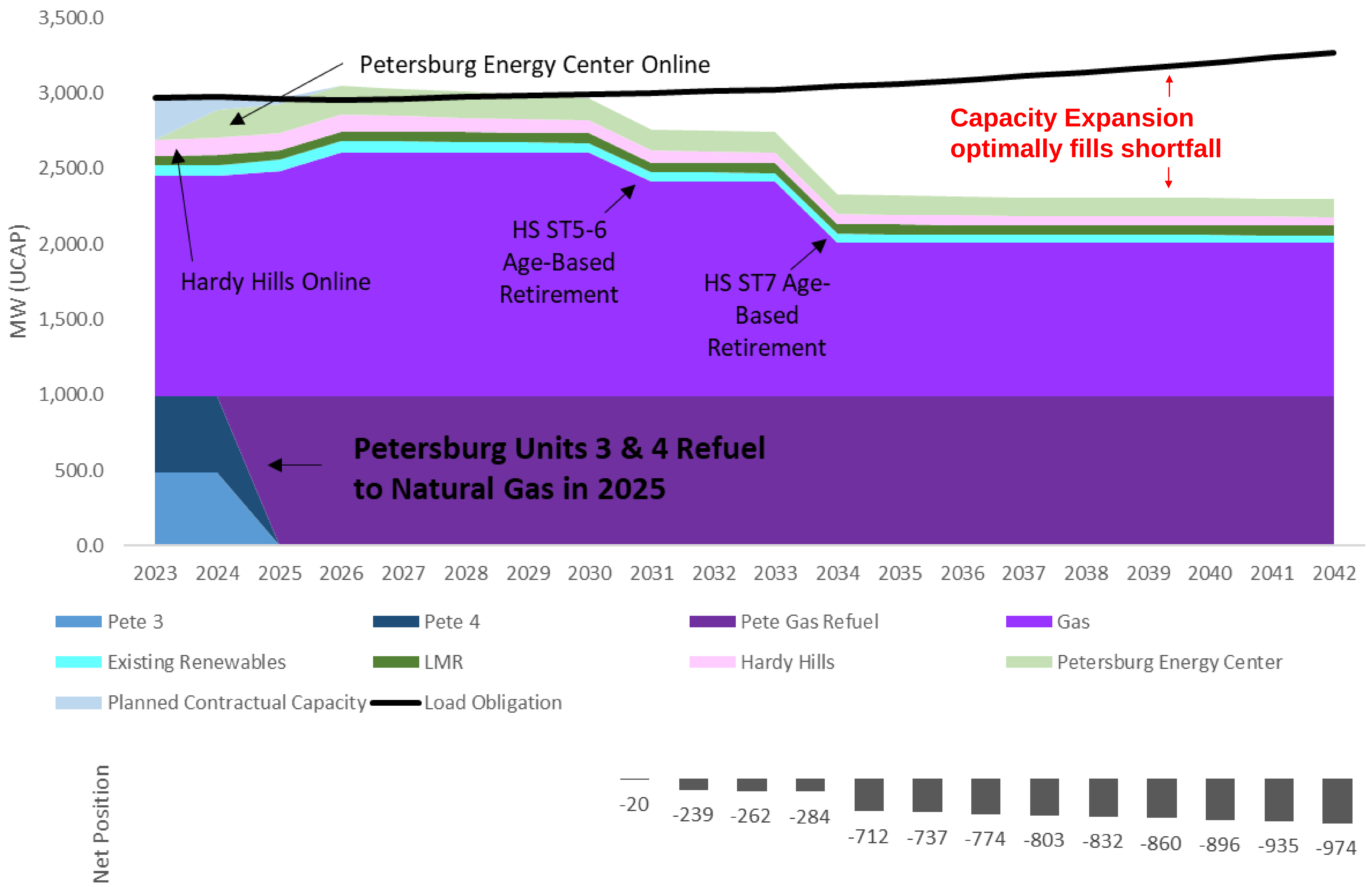
Note: To support decision making, AES Indiana will perform capacity expansion analysis without specified dates that allows the Encompass model to fully optimize retirements and replacements; however, outcomes from this analysis may not be viable and/or reasonable.

Strategy: No Changes to Existing Portfolio





Strategy: Petersburg Refuel in 2025



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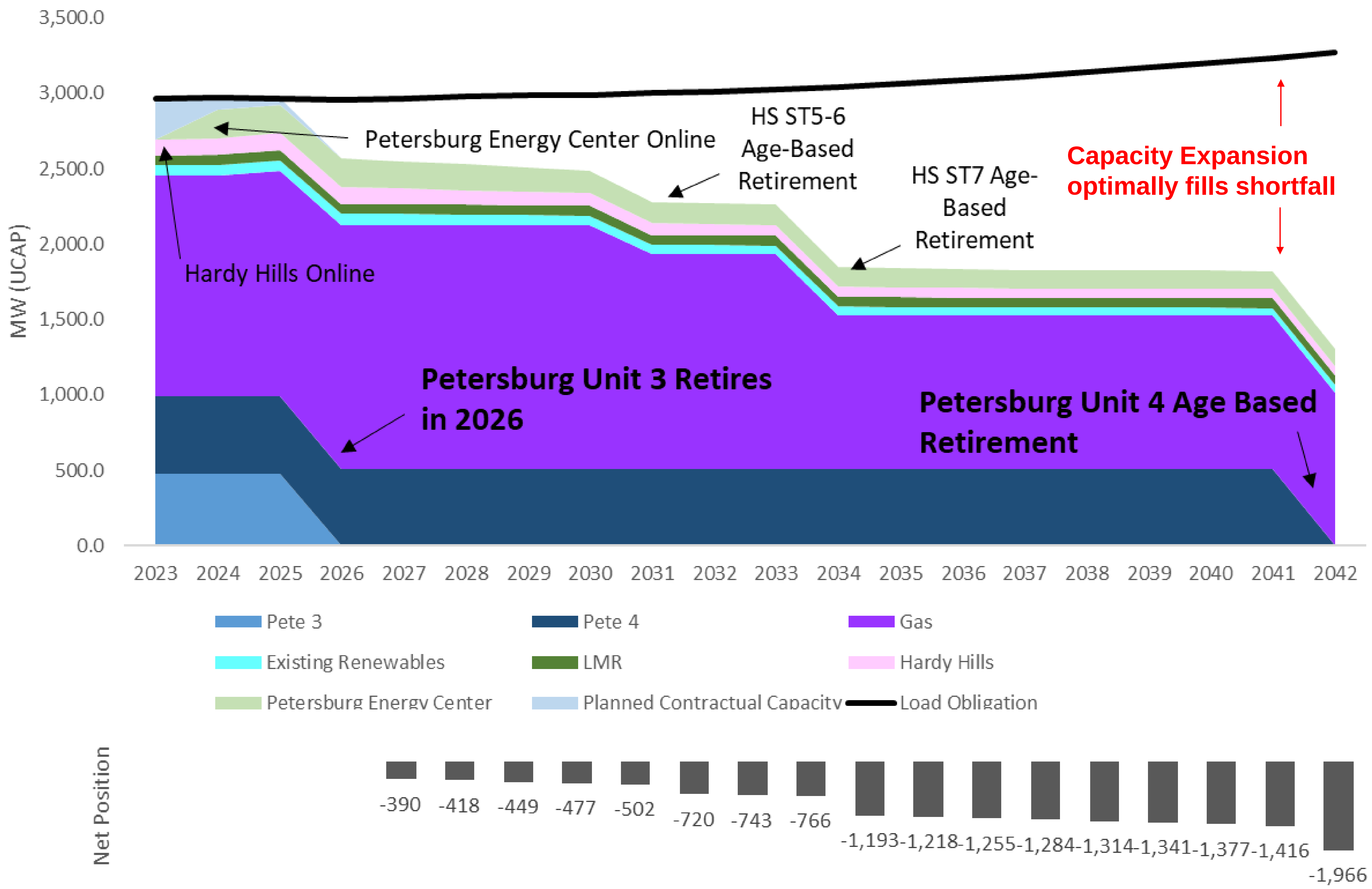
Strategy: One Petersburg Unit Retires



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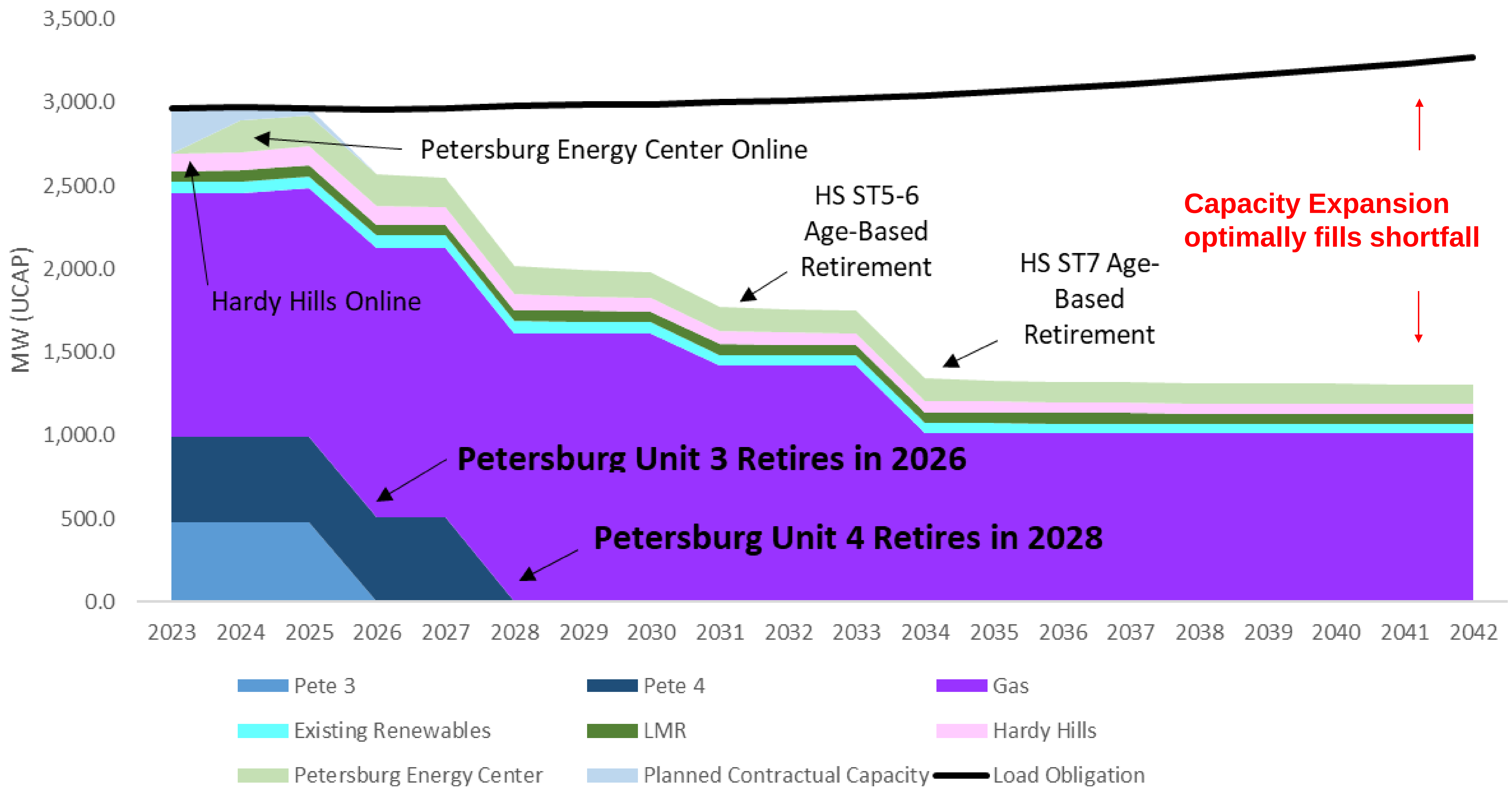
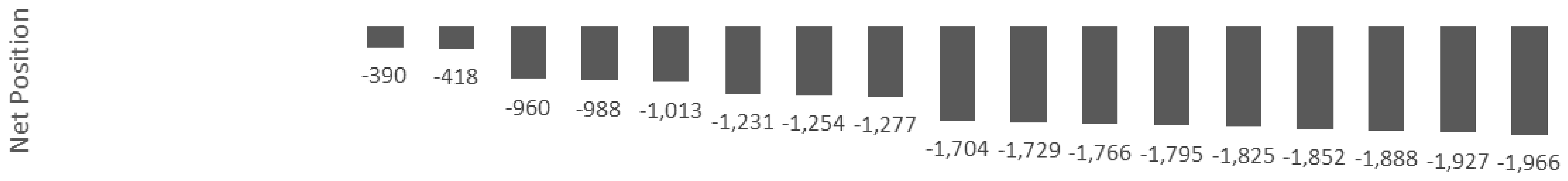
Strategy: Both Petersburg Units Retire





IRP Scenario Framework & Driving Assumptions

IRP Scenarios

AES Indiana will model the four strategies for the generation portfolio across four scenarios:

A. No Environmental Action – “NoEnv”

B. Current Trends (Reference Case) – “Ref”

C. Aggressive Environmental – “AE”

D. Decarbonized Economy – “Decarb”

IRP Commodity Assumptions for the Scenarios

AES Indiana has contracted Horizons Energy to produce custom fundamental commodity forecasts for the four IRP Scenarios – No Environmental Action, Current Trends (Reference Case), Aggressive Environmental and Decarbonized Economy.

- Horizons Energy is modeling AES Indiana's environmental policy and fuel price assumptions associated with each scenario to produce scenario-specific fundamental forecasts for the MISO system.

- Horizons Energy uses the EnCompass model for capacity expansion of the MISO System in producing the custom fundamental forecasts.

- Fundamental Curve modeling results include:
  - ATC, On-Peak and Off-Peak Power Prices
  - Capacity Prices

- **The No Environmental Action, Current Trends (Reference Case), Aggressive Environmental and Decarbonized Economy custom fundamental forecasts are currently in production with Horizons Energy.**

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Scenario “NoEnv”: No Environmental Action

Driving Assumptions							
Scenario	Load	EV	PV	Power	Gas	Coal	CO2
No Environmental Action	Low	Low	Low	TBD	Low	Base	None

Scenario Narrative

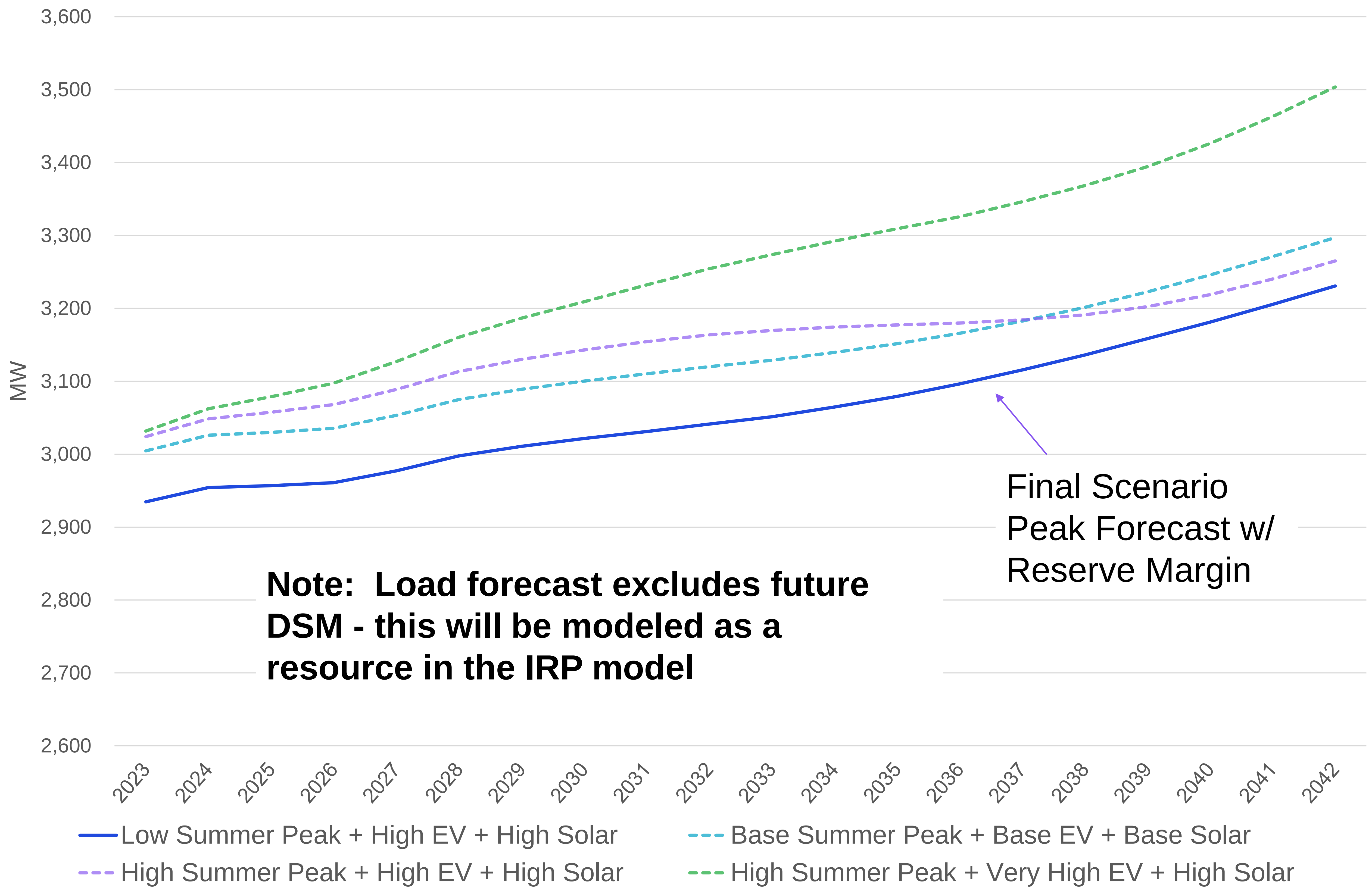
- → Future defined by relaxed environmental regulations, expanded fracking and low demand with low electrification.
- → Inflation persists driving low GDP & customer growth.
- → Continued coal operation combined with expanded gas production result in low gas prices.

Scenario "NoEnv": No Environmental Action – Load Assumptions

Load Forecast:
Low Case
Driven by Moody's Economics S3:
Alternative Scenario 3 – Downside – 90th Percentile

Electric Vehicle Forecast:
Low Case
EV market share of 12% in 2042

Distributed Solar Forecast:
Low Case
Market adoption of 6% in 2042



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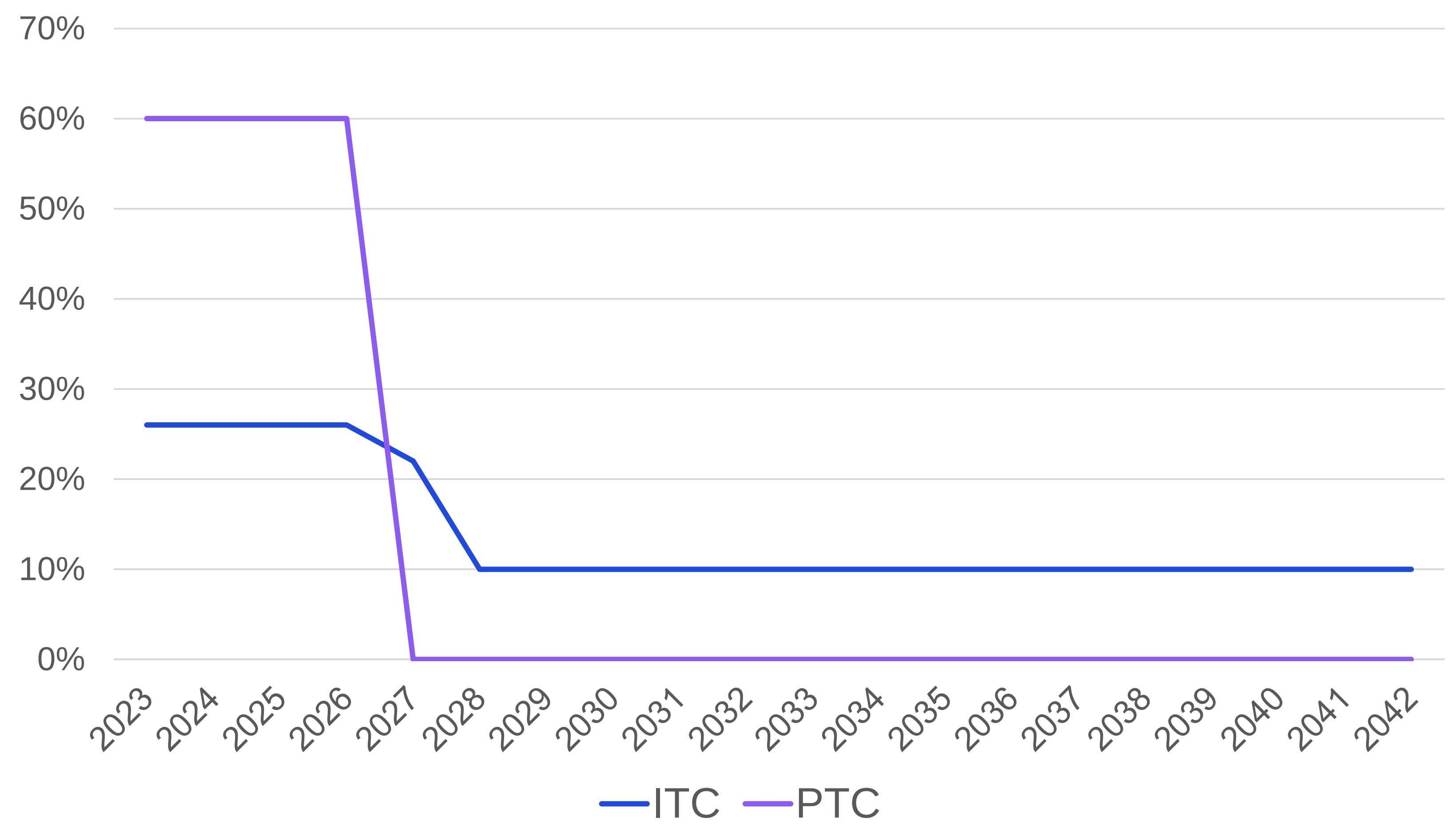
Scenario “NoEnv”: No Environmental Action – Environmental Policy Assumptions

ITC: No subsidy extension; Current tax subsidy schedule – declines to 10% by 2028 and remains at 10% through analysis period

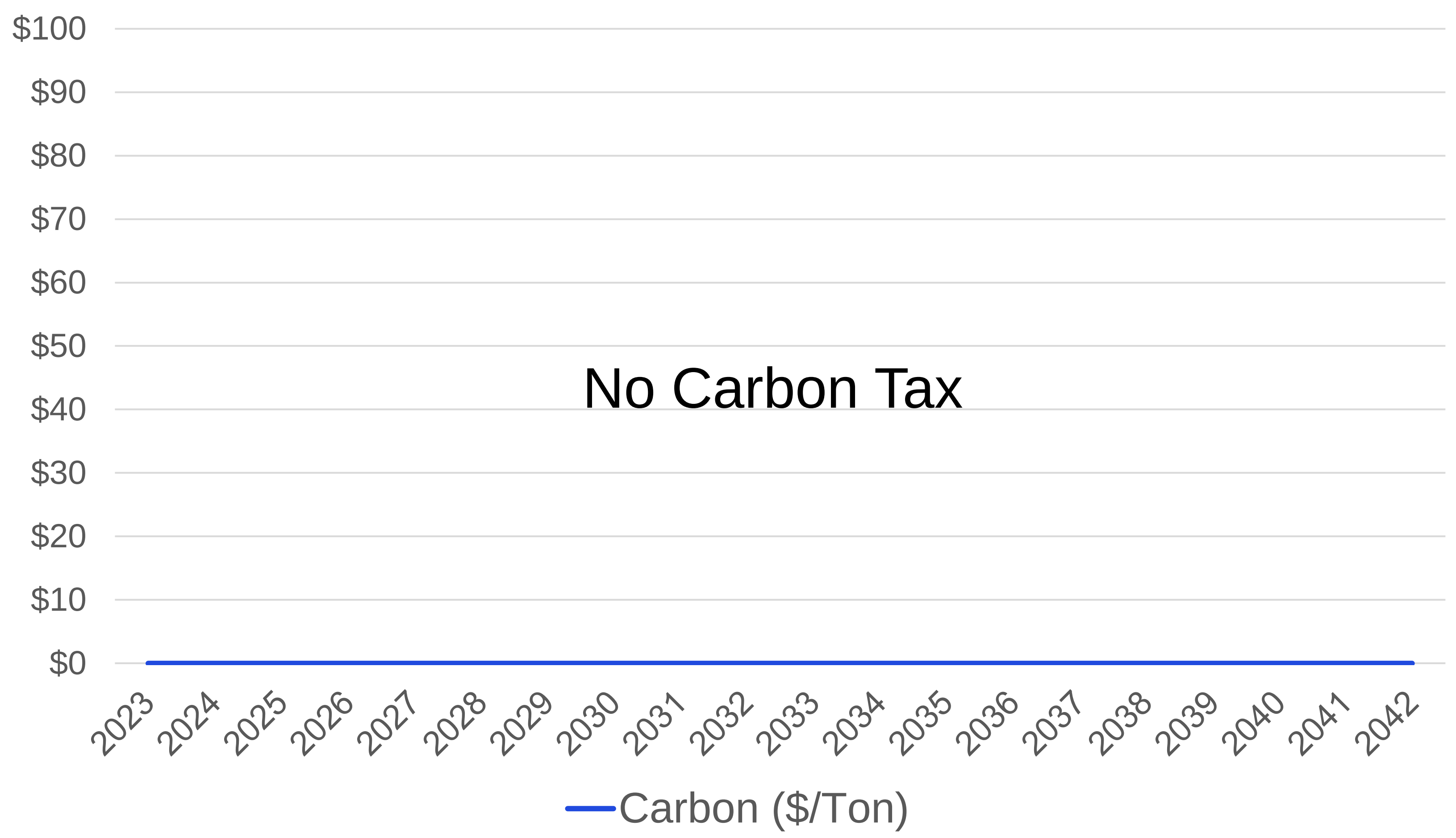
PTC: No subsidy extension; Current tax subsidy schedule – safe harbor period expires in 2027

Carbon: None

Additional Coal-fired Production Costs: None



*Years correspond to years projects first produce energy



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Scenario "Ref": Current Trends (Reference Case)

Driving Assumptions							
Scenario	Load	EV	PV	Power	Gas	Coal	CO2
Current Trends	Base	Base	Base	TBD	Base	Base	Low

Scenario Narrative

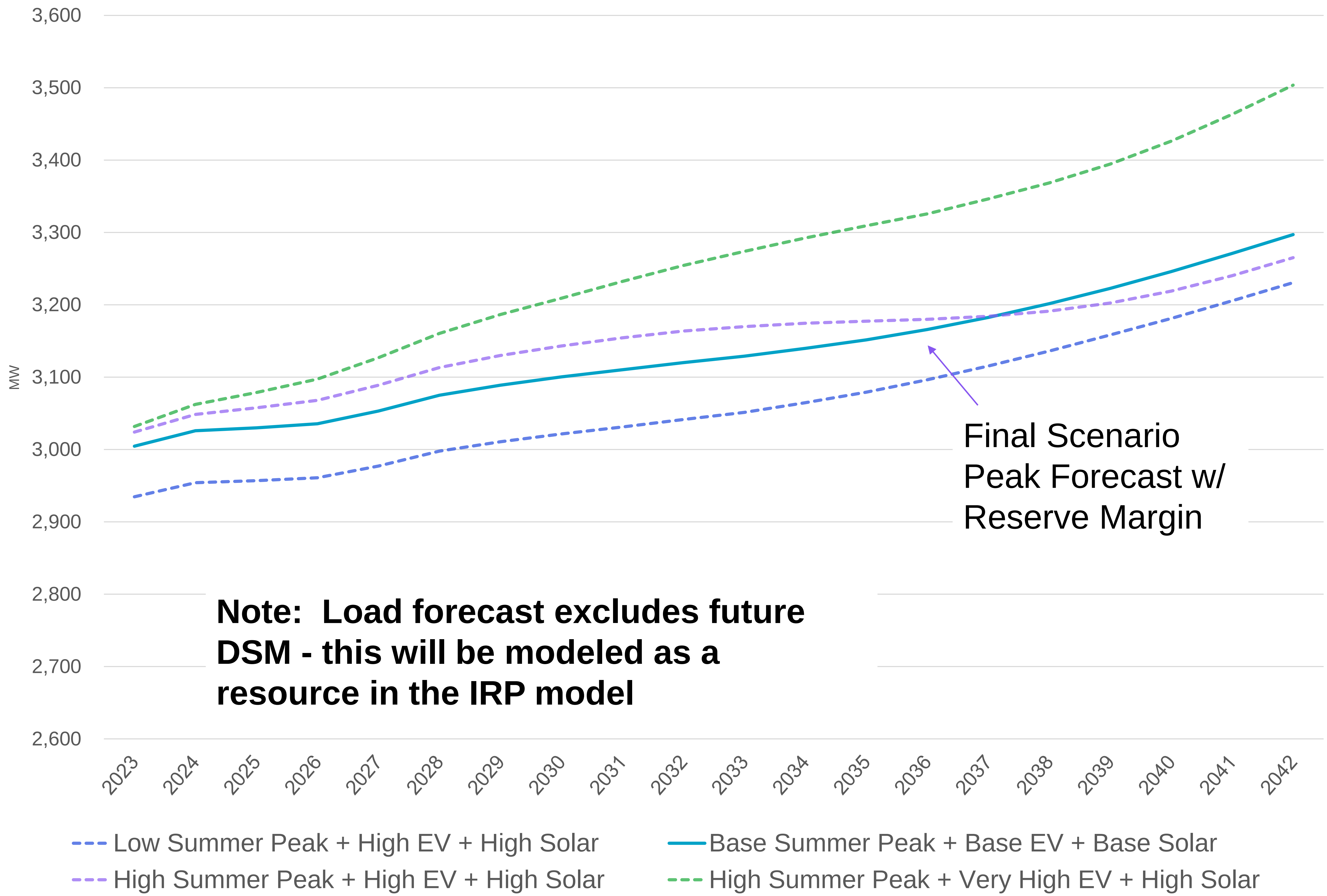
- Congressional gridlock persists with stalled progress on passing sweeping environmental legislation.
- The ITC and PTC given single year extensions for the next five years.
- Assumes modest price for carbon starting at $6.49/ton in the late 2020s.

Scenario "Ref": Current Trends – Load Assumptions

Load Forecast:
Base Case with base Moody's economic assumptions

Electric Vehicle Forecast:
Base Case
EV market share of 22% in 2042

Distributed Solar Forecast:
Base Case
Market adoption of 15% in 2042



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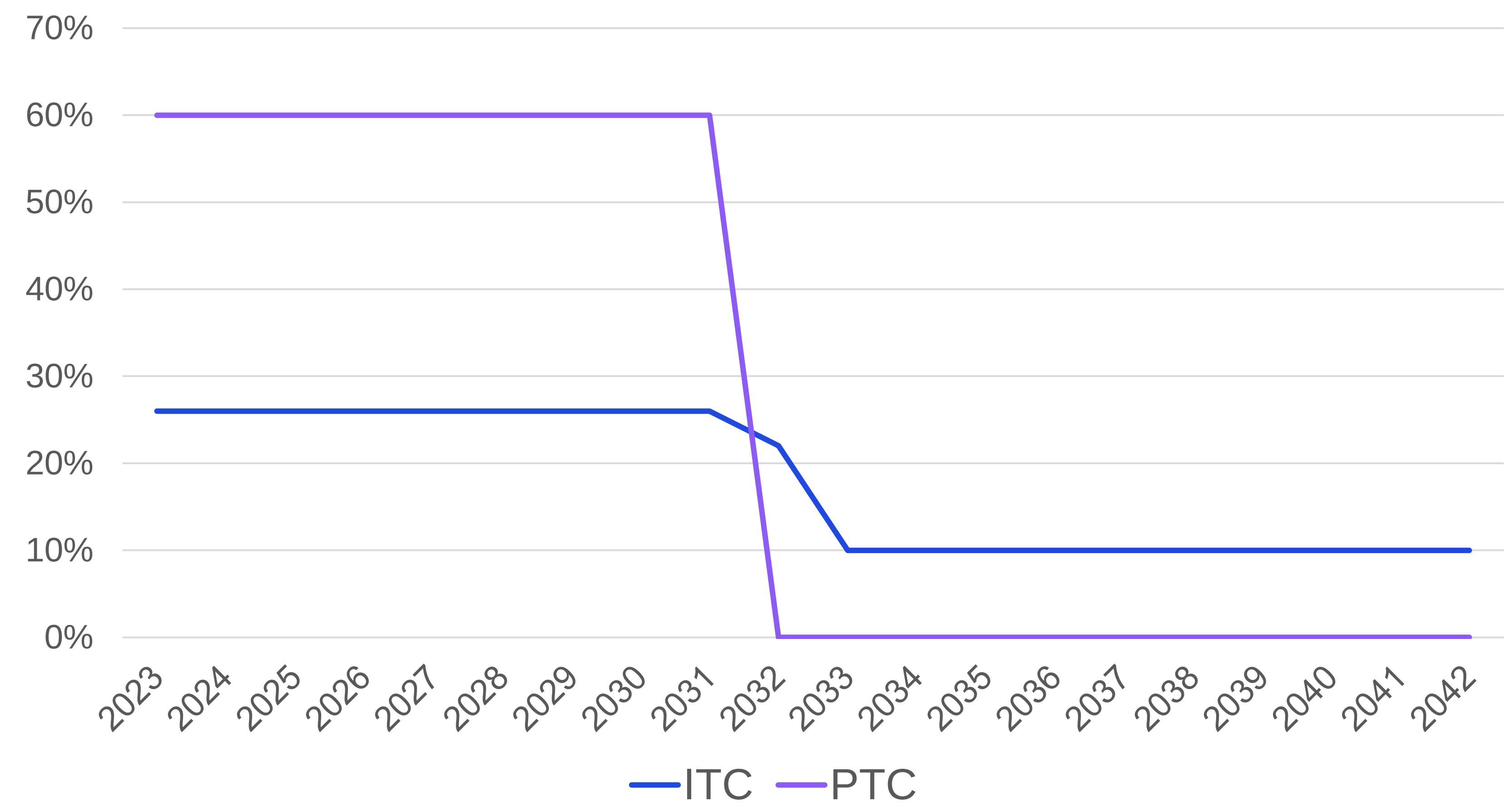
Scenario "Ref": Current Trends – Environmental Policy Assumptions

ITC: Five-year extension – declines to 10% by 2032 and remains at 10% through analysis period

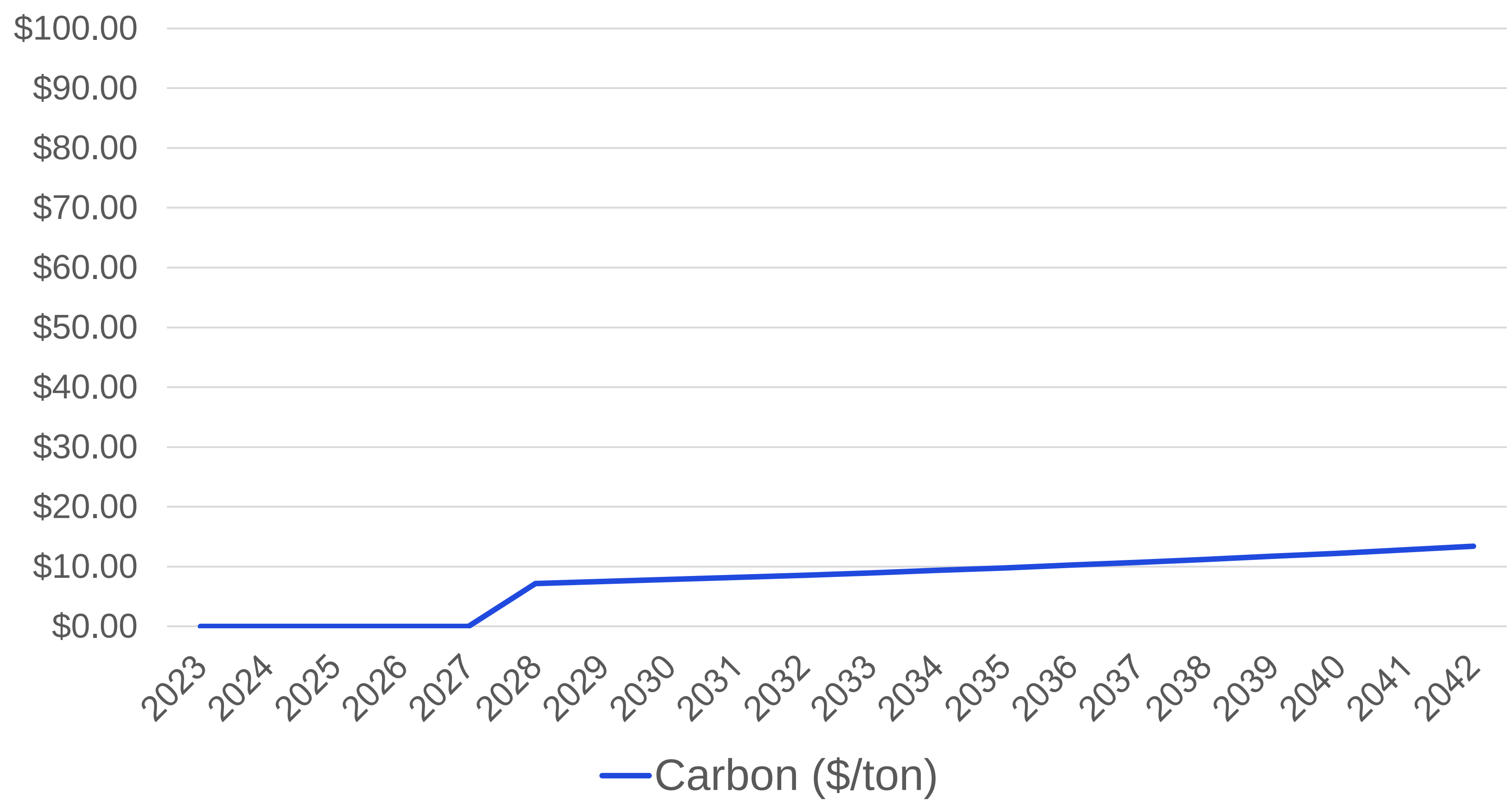
PTC: Five-year extension – safe harbor period expires in 2032

Carbon: Carbon set at $6.49/ton starting in 2028 and escalating at 2.5% through planning period; Carbon price consistent with 1/3 the value of the Social Cost of Carbon as calculated by the U.S. Govt Interagency Working Group on Social Cost of Greenhouse Gases

Additional Coal-fired Production Costs: None



*Years correspond to years projects first produce energy



https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

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Scenario “AE”: Aggressive Environmental

Driving Assumptions							
Scenario	Load	EV	PV	Power	Gas	Coal	CO2
Aggressive Environmental	High	High	High	TBD	High	Base	High

Scenario Narrative

- Congress passes environmental legislation that includes carbon tax starting in 2035.
- ITC and PTC extensions are consistent with Build Back Better.
- Includes high demand scenario with high electric vehicle and solar forecasts
- Near term transition from coal to natural gas results in high gas prices.

Scenario “AE”: Aggressive Environmental – Load Assumptions

Load Forecast:

High Case driven by Moody’s S1: Alternative Scenario 1 – Upside – 10th Percentile

Electric Vehicle Forecast:

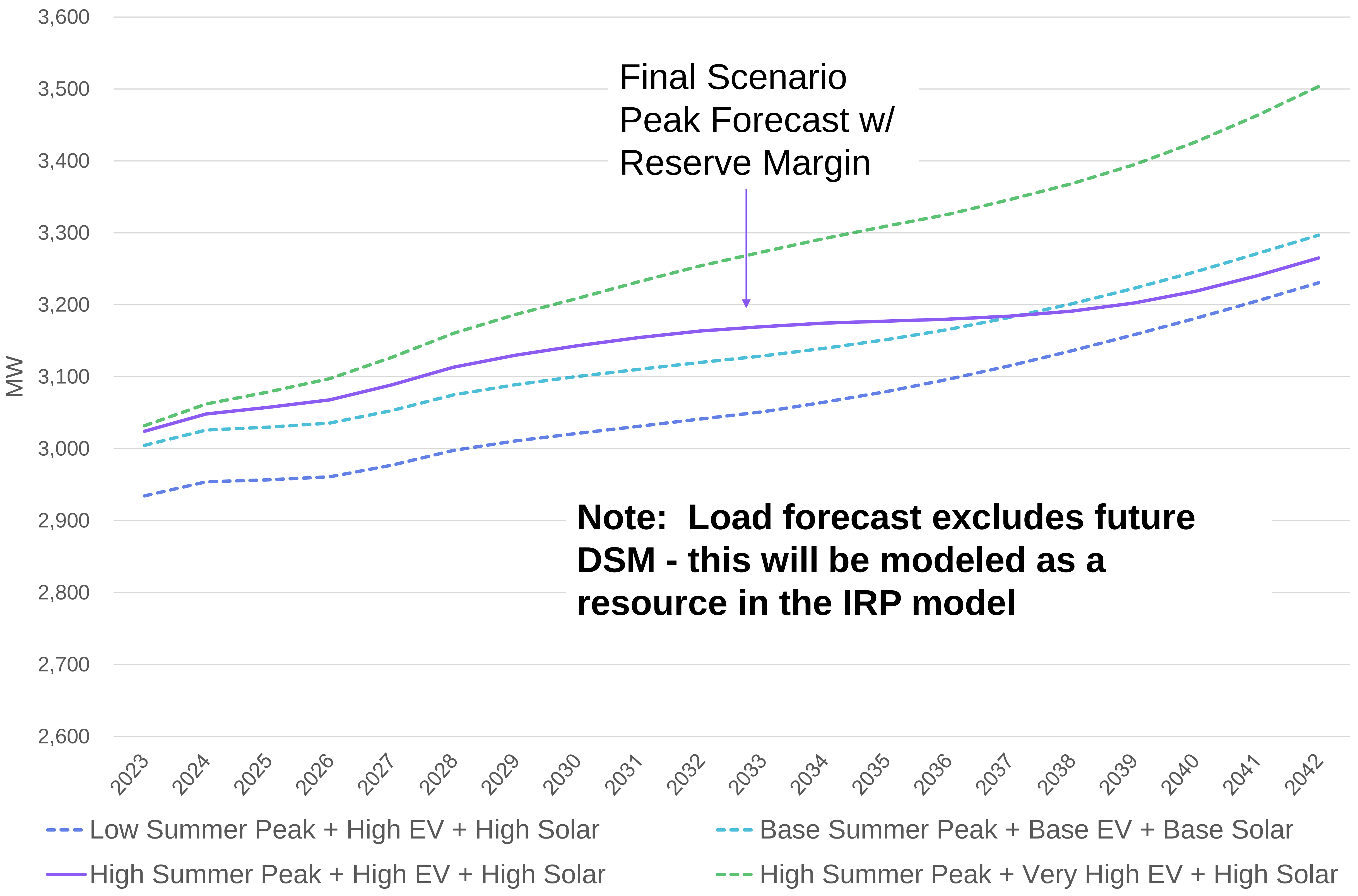
High Case

EV market share of 44% in 2042

Distributed Solar Forecast:

High Case

Market adoption of 29% in 2042



Scenario “AE”: Aggressive Environmental – Environmental Policy Assumptions

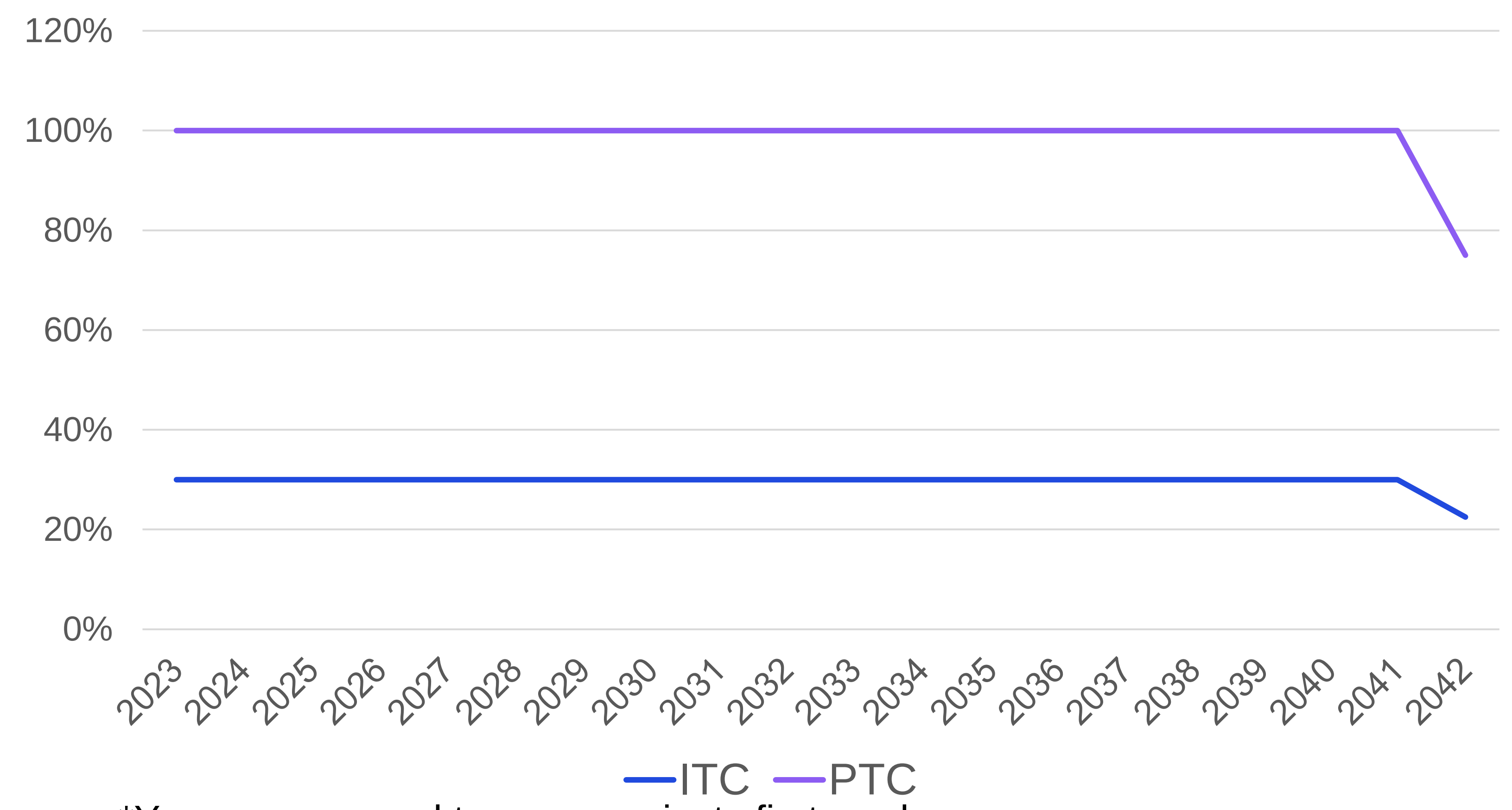
ITC: Ten-year extension – declines to 10% by 2042 and remains at 10% through analysis period

PTC: Ten-year extension – safe harbor period expires in 2042

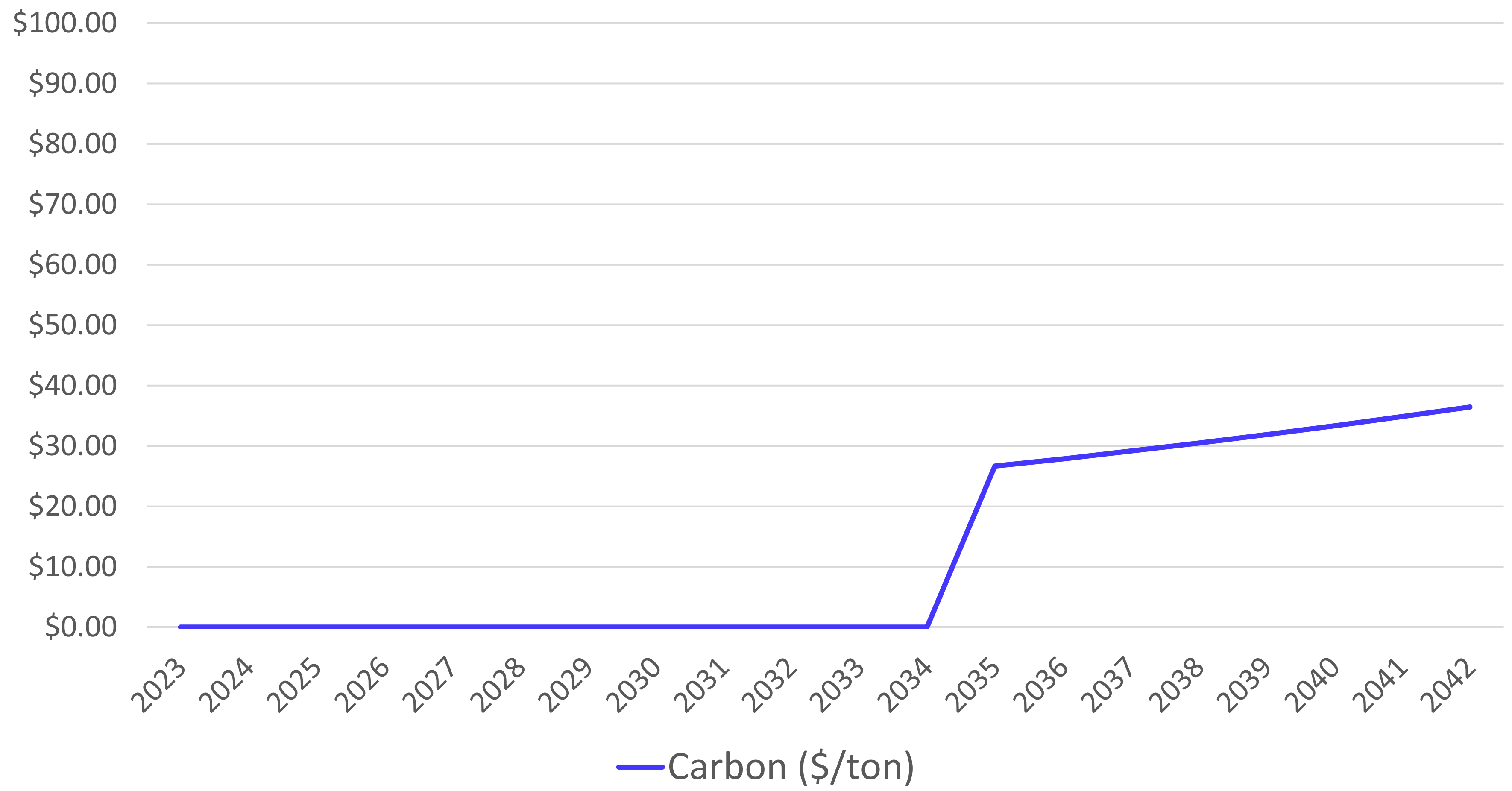
Carbon: Carbon set at $26.64/ton starting in 2035 and escalating at 5% through planning period; Carbon price consistent with the whole value of the Social Cost of Carbon as calculated by the U.S. Govt Interagency Working Group on Social Cost of Greenhouse Gases.

Additional Coal-fired Production Costs:

1 Additional cost for coal ash disposal   2 High Ozone Season NOx price forecast



*Years correspond to years projects first produce energy



https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Scenario “Decarb”: Decarbonized Economy

Driving Assumptions							
Scenario	Load	EV	PV	Power	Gas	Coal	CO2
Decarbonized Economy	High	Very High	High	TBD	Base	Base	None*

*Carbon targets will be modeled through a National Renewable Portfolio Standard

Scenario Narrative

- Congress passes aggressive decarbonization mandate on power sector with explicit renewable energy targets.
- High ITC/PTC runs through planning horizon.
- Carbon targets achieved through a Renewable Portfolio Standard that targets Net Zero; not a market mechanism like a carbon tax or cap and trade.
- High load driven by electrification
- Base gas prices driven by low demand due to reduced gas generation.

Scenario “Decarb”: Decarbonized Economy – Load Assumptions

Load Forecast:

High Case driven by Moody’s S1: Alternative Scenario 1 – Upside – 10th Percentile

Electric Vehicle Forecast:

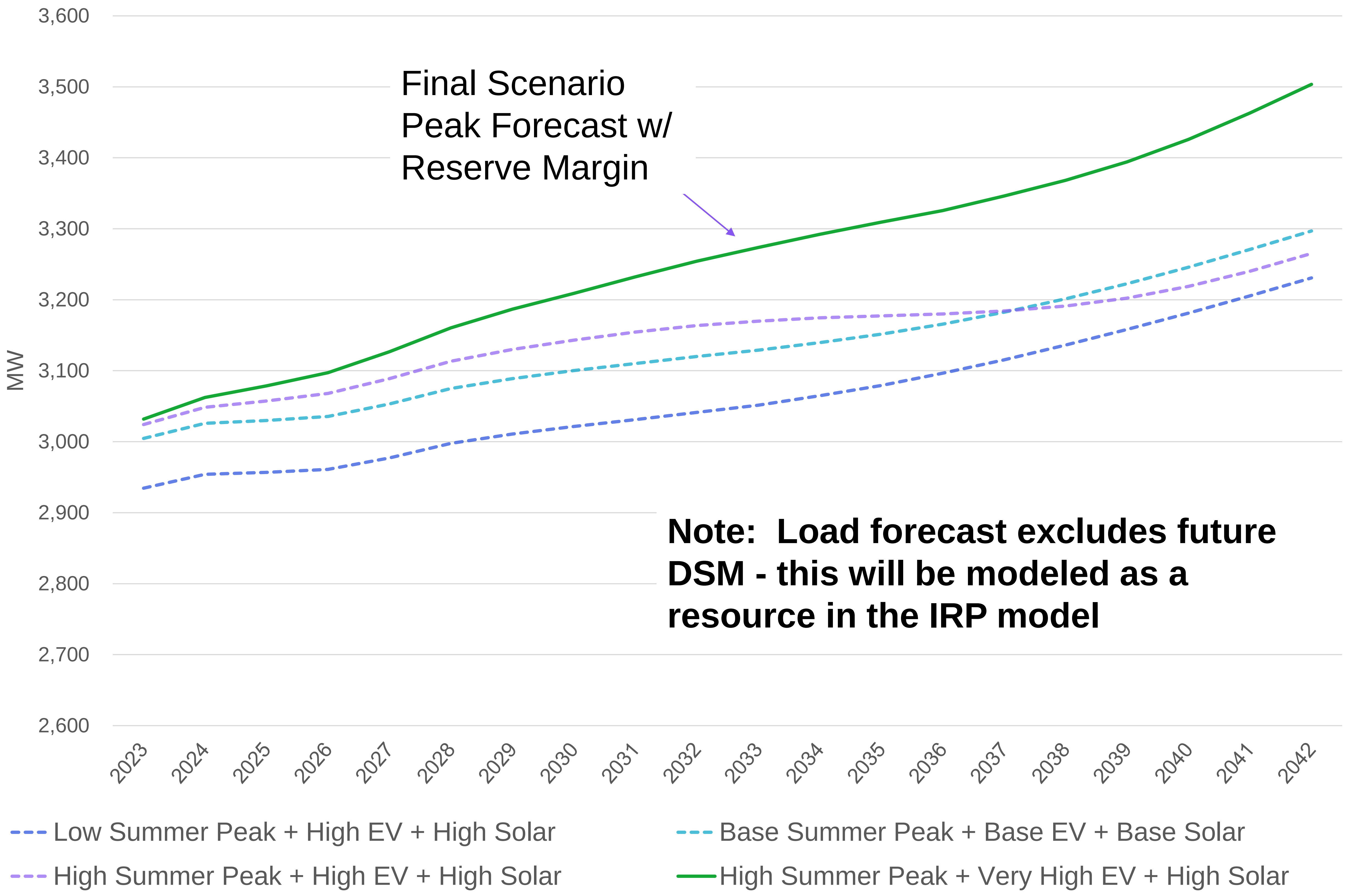
Very High Case

EV market share of 85% in 2042

Distributed Solar Forecast:

High Case

Market adoption of 29% in 2042



Note: Load forecast excludes future DSM - this will be modeled as a resource in the IRP model

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Scenario “Decarb”: Decarbonized Economy – Environmental Policy Assumptions

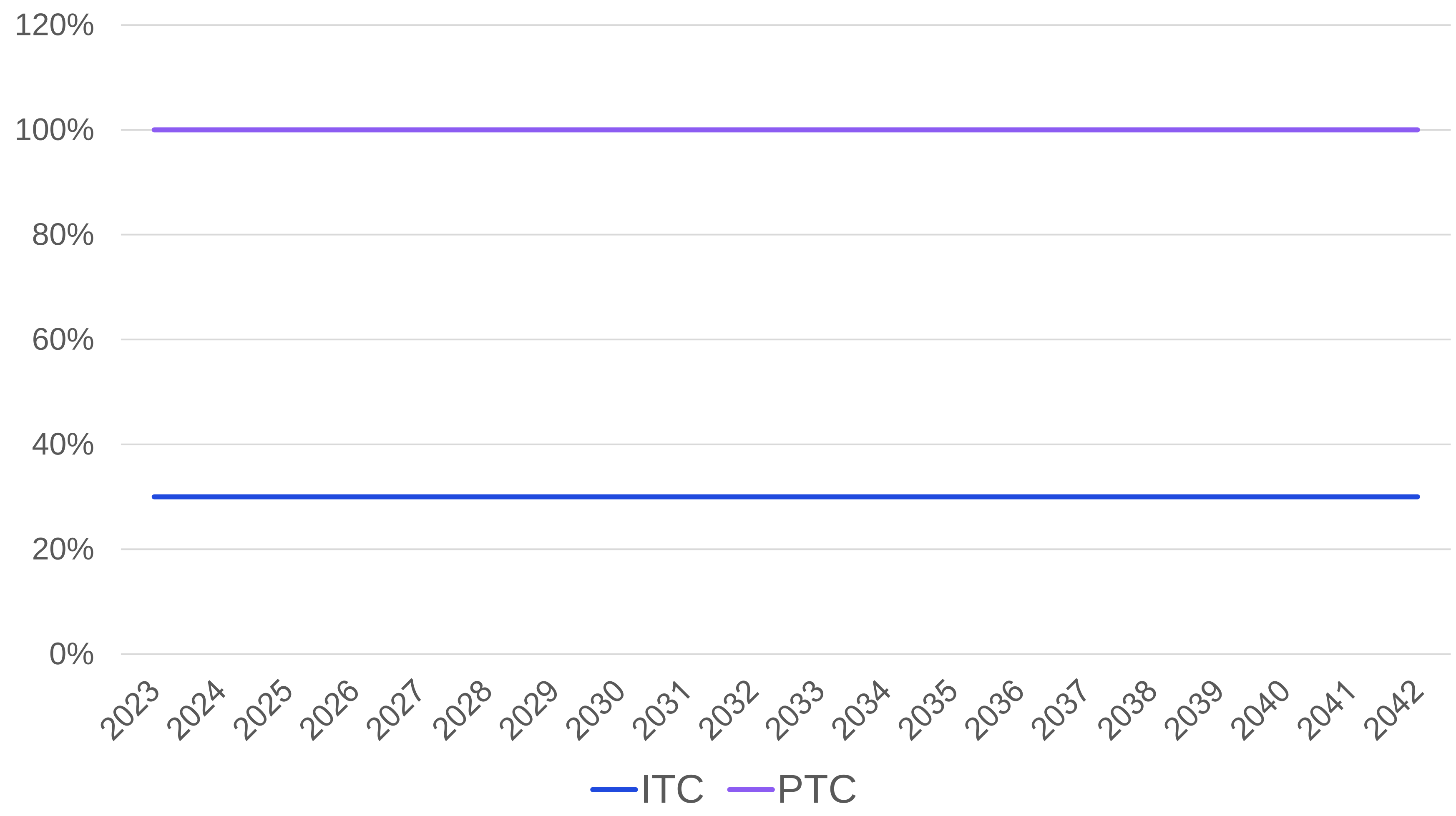
ITC: 30% throughout the planning period

PTC: 100% through entire period

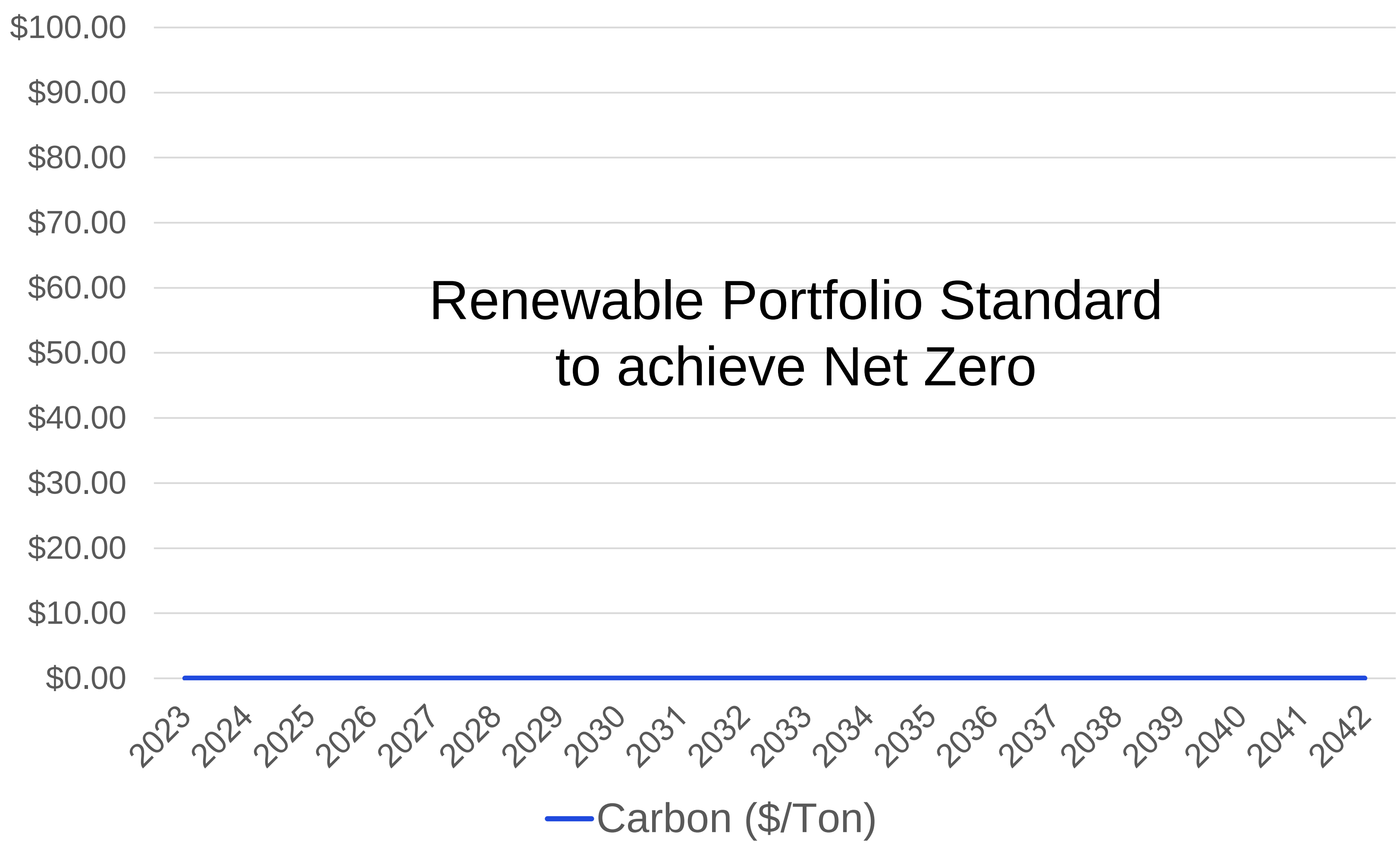
Carbon: No price on Carbon; Renewable Portfolio Standard similar to Clean Energy Performance Program (CEPP)

Additional Coal-fired Production Costs:

1. Additional cost for coal ash disposal
2. High Ozone Season NOx price forecast



*Years correspond to years projects first produce energy



Summary of Scenario Driving Assumptions

Scenario	Load	EV	Dist Solar	Power	Gas	Coal	CO2
No Environmental Action – “No Env”	Low	Low	Low	TBD	Low	Base	None
Current Trends (Reference Case) – “Ref”	Base	Base	Base	TBD	Base	Base	Low
Aggressive Environmental – “AE”	High	High	High	TBD	High	Base	High
Decarbonized Economy – “Decarb”	High	Very High	High	TBD	Base	Base	None*

*Carbon targets will be modeled through a National Renewable Portfolio Standard

Final IRP Portfolio Matrix

Final Portfolio Matrix

Combining Strategies and Scenarios results in the Portfolio Matrix or framework for IRP evaluation:

		Scenarios			
		No Environmental Action	**Current Trends (Reference Case)**	**Aggressive Environmental**	**Decarbonized Economy**
Generation Strategies	**No Early Retirement**	No Retire/NoEnv	No Retire/Ref	No Retire/AE	No Retire/Decarb
	Pete Refuel to 100% Gas (est. 2025)	Refuel/NoEnv	Refuel/Ref	Refuel/AE	Refuel/Decarb
	One Pete Unit Retires (2026)	One Unit/NoEnv	One Unit/Ref	One Unit/AE	One Unit/Decarb
	Both Pete Units Retire (2026 & 2028)	Both Units/NoEnv	Both Units/Ref	Both Units/AE	Both Units/Decarb

- The 16 portfolios defined above will be evaluated using a Scorecard that includes cost, environmental, reliability & risk metrics.
- A Preferred Resource Portfolio will be selected using this rigorous Scorecard evaluation process.

Risk Analysis: Sensitivities & Stochastic

Risk Analysis

→ Key variable sensitivities

- AES Indiana will model sensitivities for key variables to understand how the PVRR may change in a future where the variable looks very different from the IRP assumption, e.g. renewable capital cost sensitivity.

→ Portfolio sensitivities

- AES Indiana will model environmental policy sensitivities on the optimized capacity expansion results from the Current Trends (Reference Case) to understand how the PVRR may change in a very different policy future.
- The results will help to answer the question – “How would the optimized Reference Case perform in a very different policy future, e.g. Reference Case in a Decarbonized Economy future?”

→ Stochastic Analysis

- AES Indiana will run a stochastic analysis on fuel prices, energy prices and load in order to understand the risk to PVRR in the Reference Case from these key IRP variables.

Further detail regarding the Risk Analysis will be presented in Public Advisory Meeting #3.

Final Q&A and Next Steps

Public Advisory Meeting

Public Advisory Meeting #1	Public Advisory Meeting #2	Public Advisory Meeting #3	Public Advisory Meeting #4	Public Advisory Meeting #5
Jan. 24, 2022	**April 12, 2022**	**June 2022**	**August 2022**	**October 2022**

- All meetings will be available for attendance via Teams. Meetings in 2022 may also occur in-person.
- A Technical Meeting will be held the week preceding each Public Advisory Meeting for stakeholders with nondisclosure agreements. Tech Meeting topics will focus on those anticipated at the next Public Advisory Meeting.
- Meeting materials can be accessed at ***www.aesindiana.com/integrated-resource-plan.***

Thank You

APPENDIX

IRP Acronyms

Note: A glossary of acronyms with definitions is available at https://www.aesindiana.com/integrated-resource-plan.

IRP Acronyms

- ACEE: The American Council for an Energy-Efficient Economy
- AMI: Advanced Metering Infrastructure
- BESS: Battery Energy Storage System
- BNEF: Bloomberg New Energy Finance
- BTA: Build-Transfer Agreement
- BTU: British Thermal Unit
- C&I: Commercial and Industrial
- CAA: Clean Air Act
- CAGR: Compound Annual Growth Rate
- CCGT: Combined Cycle Gas Turbines
- CCS: Carbon Dioxide Capture and Storage
- CDD: Cooling Degree Day
- COD: Commercial Operation Date
- CONE: Cost of New Entry
- CP: Coincident Peak
- CPCN: Certificate of Public Convenience and Necessity
- CT: Combustion Turbine
- CVR: Conservation Voltage Reduction
- DER: Distributed Energy Resource
- DG: Distributed Generation
- DGPV: Distributed Generation Photovoltaic System
- DLC: Direct Load Control
- DOE: U.S. Department of Energy
- DR: Demand Response
- DRR: Demand Response Resource
- DSM: Demand-Side Management
- DSP: Distribution System Planning
- EE: Energy Efficiency
- EFORd: Equivalent Forced Outage Rate Demand
- EIA: Energy Information Administration
- ELCC: Effective Load Carrying Capability
- EM&V: Evaluation Measurement and Verification
- EV: Electric Vehicle
- GDP: Gross Domestic Product
- GT: Gas Turbine
- HDD: Heating Degree Day
- HVAC: Heating, Ventilation, and Air Conditioning
- IAC: Indiana Administrative Code
- IC: Indiana Code
- ICAP: Installed Capacity
- ICE: Internal Combustion Engine
- IRP: Integrated Resource Plan
- ITC: Investment Tax Credit
- IURC: Indiana Regulatory Commission
- kW: Kilowatt
- kWh: Kilowatt-Hour
- LED: Light Emitting Diode
- LMR: Load Modifying Resource
- LNBL: Lawrence Berkeley National Laboratory
- Max Gen: Maximum Generation Emergency Warning
- MAP: Maximum Achievable Potential
- MIP: Mixed Integer Programming
- MISO: Midcontinent Independent System Operator
- MPS: Market Potential Study
- MW: Megawatt
- NDA: Nondisclosure Agreement
- NOX: Nitrogen Oxides
- NPV: Net Present Value
- NREL: National Renewable Energy Laboratory
- NTG: Net to Gross
- PPA: Power Purchase Agreement
- PRA: Planning Resource Auction
- PTC: Renewable Electricity Production Tax Credit
- PRMR: Planning Reserve Margin Requirement
- PV: Photovoltaic
- PVRR: Present Value Revenue Requirement
- PY: Planning Year
- RA: Resource Adequacy
- RAN: Resource Availability and Need
- RAP: Realistic Achievable Potential
- REC: Renewable Energy Credit
- REP: Renewable Energy Production
- RFP: Request for Proposals
- RIIA: MISO's Renewable Integration Impact Assessment
- SAC: MISO's Seasonal Accredited Capacity
- SCR: Selective Catalytic Reduction System
- SMR: Small Modular Reactors
- ST: Steam Turbine
- SUFG: State Utility Forecasting Group
- TRM: Technical Resource Manual
- UCT: Utility Cost Test
- UCAP: Unforced Capacity
- WTP: Willingness to Participate
- XEFORd: Equivalent Forced Outage Rate Demand excluding causes of outages that are outside management control

Replacement Resource Cost Assumptions Summary Table (of all parameters by tech type)

	Wind	Solar	Storage	Solar + Storage	CCGT	Frame CT	Aero CT	Reciprocating Engine
Fuel type:	Wind	Solar	Battery	Solar + Battery	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Unsubsidized Capital Cost ($/kWac):	$1,451	$1,111	$1,310	$1,126	$1,026	$872	$1,335	$1,283
*Subsidized Capital Cost ($/kWac):	$1,002	$803	N/A	$882	N/A	N/A	N/A	N/A
Fixed O&M ($/kW-yr):	$37	$21	$36	$25	$32	$30	$36	$46
Variable O&M ($/MWh):	$0	$0	$0	$0	$2	$1	$5	$6
Grid Connection Cost ($/kWac):	$26	$54	$59	$54	$30	$30	$30	$30
**Tax Equity Cost ($/kWac):	$59	$59	N/A	$59	N/A	N/A	N/A	N/A
Size (POI MW):	50	25	20 MW | 80 MWh	25 MW POI, 32.5 MWdc Solar, 12.5 MW | 50 MWh Battery	325	100	90	54
Asset Useful Life (years):	30	35	20	31	30	20	20	20
Capacity Factor:	33.6-40.4%	24.5%	N/A	20.0%	Varies	Varies	Varies	Varies
Summer ELCC (2025):	7%	59%	96%	100%	94%	96%	96%	96%
Summer Capacity Credit (2025):	4	15	19	25	306	96	86	52
Heat Rate at Max Econ Load (Btu/kWh):	N/A	N/A	N/A	N/A	6,700	10,000	8,200	7,400
Ramp Rate (MW/min):	N/A	N/A	N/A	N/A	20	12	43	37
WACC:	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Estimated LCOE (2022$/MWh):	$30	$38	$113	$53	$44	$120	$69	$61

*Includes 26% ITC for solar and $15/MWh PTC for wind consistent with the Current Trends Scenario
**Cost only considered when resource is subsidized
***Storage LCOS assumes one full discharge per day; Dispatchable resources LCOE calculations highly dependent on capacity factor

DSM Market Potential Study

APPENDIX SLIDES

Demand Response Assumptions – Residential Load Reduction

Program	Residential Load Reduction Per Participant
DLC Central AC Switch	0.972 kW
DLC Central AC Thermostat	0.846 kW
DLC Smart Appliances	0.072 kW
DLC Water Heaters	0.4 kW Summer, 0.8 kW Winter
DLC Electric Space Heaters	1 kW
DLC Electric Vehicle Chargers	0.63 kW
Battery Energy Storage	3 kW
Time of Use Rate with Enabling Technology	8% of CP billing demand
Time of Use Rate without Enabling Technology	5.2% of CP billing demand
Behavior DR	12.9% of CP billing demand

Demand Response Assumptions – Non-Residential Load Reduction

Program	Non-Residential Load Reduction Per Participant
DLC Central AC Switch	1.103 kW
DLC Central AC Thermostat	0.96 kW
DLC Water Heaters	0.6 kW Summer, 1.2 kW Winter
DLC Electric Space Heaters	1.5 kW
DLC Lighting	8.9% of CP billing demand
Curtail Agreements	5% of CP billing demand for day ahead, 3% day of
Demand Bidding	7% of CP billing demand
Capacity Bidding	19.5% of CP billing demand
Time of Use Rate with Enabling Technology	3.8% of CP billing demand
Time of Use Rate without Enabling Technology	2% of CP billing demand

Demand Response Assumptions – Residential Costs

Program	Equipment & Installation Cost	Incentive Cost
DLC Central AC One-Way Communicating Switch	$220	$20/participant/year
DLC Central AC Two-Way Communicating Switch	$245	$20/participant/year
DLC Central AC Thermostat	$300	$20/participant/year
DLC Smart Appliances	$245	$20/participant/year
DLC Water Heaters	$300	$20/participant/year
DLC Electric Space Heaters	$0; assumed must be participating in DLC AC program	$20/participant/year
DLC Electric Vehicle Chargers	$0; assumed must have Level 2 charger	$50/participant/year
Battery Energy Storage	$12,385	$0
Time of Use Rate with Enabling Technology	$300	$0
Time of Use Rate without Enabling Technology	$0	$0
Behavior DR	$0	$0.75/kWh

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Demand Response Assumptions – Non-Residential Costs

Program	Equipment & Installation Cost	Incentive Cost
DLC Central AC One-Way Communicating Switch	$220	$30/participant/year
DLC Central AC Two-Way Communicating Switch	$245	$30/participant/year
DLC Central AC Thermostat	$300	$30/participant/year
DLC Water Heaters	$300	$30/participant/year
DLC Electric Space Heaters	$0; assumed must be participating in DLC AC program	$30/participant/year
DLC Lighting	$1,900	
Curtail Agreements	$0	Starts at $87/kW-yr for MAP and $47/kW-yr for RAP; increases by 2% per year
Demand Bidding	$0	$0.5/kWh-yr
Capacity Bidding	$0	$8.50/kW-yr
Time of Use Rate with Enabling Technology	$300	$0
Time of Use Rate without Enabling Technology	$0	$0
Ice Energy Storage Rate	$55,000	$0

Demand Response Assumptions – Adoption Rates

Residential Adoption Rates

Program	MAP	RAP
DLC Central AC (Switch and Thermostat Total)	71%	41%
DLC Smart Appliances	31%	20%
DLC Water Heaters	65%	35%
DLC Electric Space Heaters	20%	15%
DLC Electric Vehicle Chargers	72%	27%
Battery Energy Storage	10%	5%
Time of Use Rate (with and without Enabling Technology total)	64%	46%
Behavior DR	93%	21%

Non-Residential Adoption Rates

Program	MAP	RAP
DLC Central AC (Switch and Thermostat Total)	14%	3%
DLC Water Heaters	16%	7%
DLC Electric Space Heaters	14%	3%
DLC Lighting	14%	3%
Demand Bidding	8%	1%
Capacity Bidding	21%	3%
Time of Use Rate (with and without Enabling Technology total)	74%	13%
Ice Energy Storage Rate	81%	16%