NIPSCO
A NiSource Company

2021 NIPSCO Integrated Resource Plan

Stakeholder Advisory Meeting #3

July 13th, 2021
9:00AM-2:00PM CT




NiSource




Parking Lot Safety

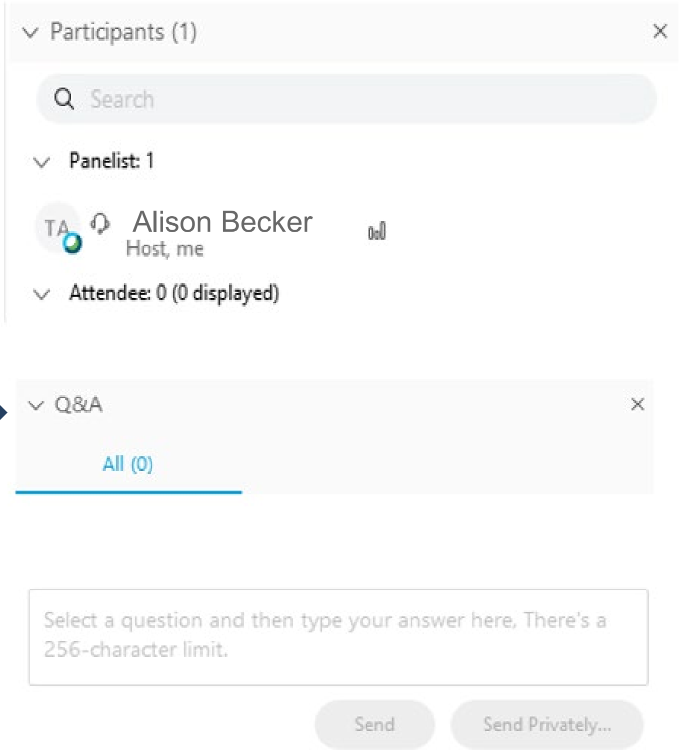
Don't be fooled by slow-moving vehicles: 1 in 5 accidents occur in a parking lot

- Don't become distracted by your cell phone or headphones.
- Be aware of your surroundings. Walk with confidence to buildings and to your car.
- Keep your car locked, even if you are running a quick errand.
- Park near the building in a visible and well-lit area.
- Look twice for pedestrians, bicycles, and other vehicles.
- Drive slowly and obey posted speed limits and signs.
- Stay in lanes and avoid cutting across lots.

Source: Oceaneering

STAKEHOLDER ADVISORY MEETING PROTOCOLS

- Your input and feedback is critical to NIPSCO's Integrated Resource Plan ("IRP") Process
- The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP
- We set aside time at the end of each section to ask questions
- Your candid and ongoing feedback is key:
  - Please ask questions and make comments on the content presented
  - Please provide feedback on the process itself
- While we will mostly utilize the chat feature in WebEx to facilitate comments, we will gladly unmute you if you would like to speak. Please identify yourself by name prior to speaking. This will help keep track of comments and follow up actions
- If you wish to make a presentation during a meeting, please reach out to Alison Becker (abecker@nisource.com)



AGENDA

Time *Central Time	Topic	Speaker
9:00-9:05AM	Webinar Introduction, Safety Moment, Meeting Protocols, Agenda	Alison Becker, Manager Regulatory Policy, NIPSCO
9:05-9:10AM	Welcome	Mike Hooper, President & COO, NIPSCO
9:10-9:30AM	NIPSCO's Public Advisory Process and Updates From Last Meeting	Fred Gomos, Director Strategy & Risk Integration, NiSource
9:30-10:30AM	Developing the Demand Side Management (DSM) Study	Alison Becker, Manager Regulatory Policy, NIPSCO Jeffrey Huber, Managing Director – Energy Efficiency, GDS Pat Augustine, Vice President, CRA
10:30-10:45AM	Break	
10:45-11:15AM	Supply-Side Distributed Energy Resource (DER) Considerations	Pat Augustine, Vice President, CRA
11:15AM-12:00PM	Lunch	
12:00-1:00PM	2021 Request for Proposals (RFP) Results Overview	Andy Campbell, Director Regulatory Support & Planning, NIPSCO Bob Lee, Vice President, CRA
1:00-1:55PM	Incorporating RFP Results Into The IRP	Fred Gomos, Director Strategy & Risk Integration, NiSource Pat Augustine, Vice President, CRA
1:55-2:00PM	Wrap Up & Next Steps	Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

WELCOME

Mike Hooper, President & COO, NIPSCO

WHERE WE ARE IN THE 2021 IRP PROCESS

Appreciate The Stakeholder Engagement

- Thank you for your participation and level of engagement
- Third stakeholder meeting with over 100 participants registered
- 33 unique bidders into our 2021 RFP

Progress on Generation Transition Plan

- 2 wind facilities operational (Jordan Creek and Rosewater) and 1 under construction (IN Crossroads)
- Approval for 11 of the 14 projects we have filed with the Commission

Next Steps for the IRP

- Integrate RFP results into our analysis
- Perform portfolio modeling and evaluate all potential options
- Share directional results in the September Stakeholder meeting and get feedback on that preliminary plan

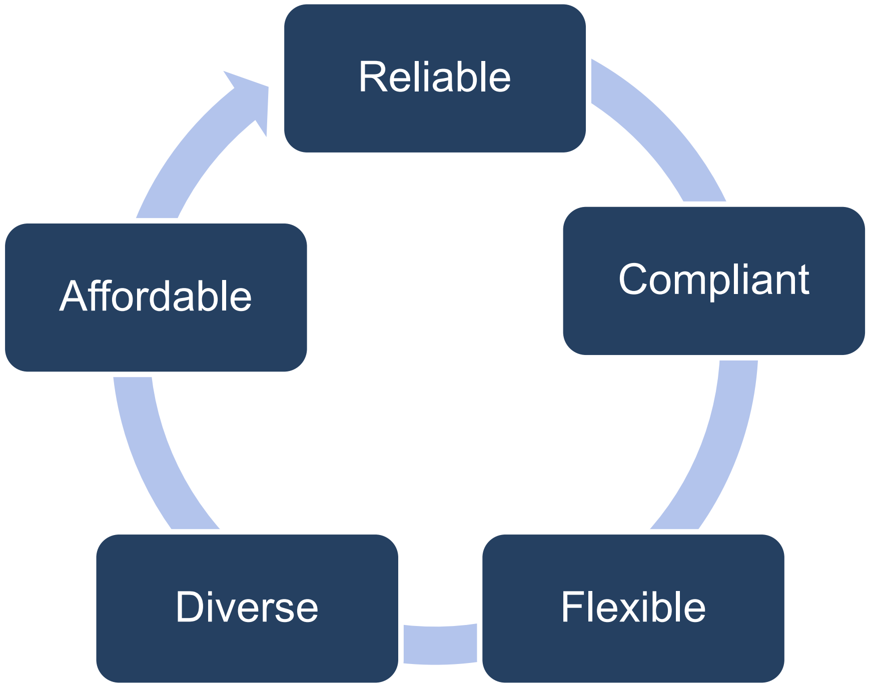
NIPSCO'S PUBLIC ADVISORY PROCESS UPDATES FROM LAST MEETING

Fred Gomos, Director Strategy & Risk Integration, NiSource

Pat Augustine, Vice President, CRA

HOW DOES NIPSCO PLAN FOR THE FUTURE?

- At least every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an IRP – is required of all electric utilities in Indiana
- The IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires Careful Planning and Consideration for:
- NIPSCO's employees
- Environmental regulations
- Changes in the local economy (property tax, supplier spending, employee base)

2021 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 (March)	Meeting 2 (May)	Meeting 3 (July)	Meeting 4 (September)	Meeting 5 (October)
Date	3/19/2021	5/20/2021	7/13/2021	9/21/2021	10/12/2021
Location	Virtual	Virtual	Virtual	Virtual	Virtual
Key Questions	• How has NIPSCO progressed in the 2018 Short Term Action Plan? • What has changed since the 2018 IRP? • How are energy and demand expected change over time? • What is the high level plan for stakeholder communication and feedback for the 2021 IRP?	• How do regulatory developments and initiatives at the MISO level impact NIPSCO's 2021 IRP planning framework? • How has environmental policy changed since 2018? • What scenario themes and stochastics will NIPSCO explore in 2021?	• How are DSM resources considered in the IRP? • How will NIPSCO evaluate potential DER options? • What are the preliminary RFP results?	• What are the preliminary findings from the modeling?	• What is NIPSCO's preferred plan? • What is the short term action plan?
Content	• 2018 Short Term Action Plan Update (Retirements, Replacement projects) • Resource Planning and 2021 Continuous Improvements • Update on Key Inputs/Assumptions (commodity prices, demand forecast) • Scenario Themes – Introduction • 2021 Public Advisory Process	• MISO Regulatory Developments and Initiatives • 2021 Environmental Policy Update • Scenarios and Stochastic Analysis	• DSM Modeling and Methodology • DER Inputs • Preliminary RFP Results	• Existing Fleet Review Modeling Results, Scorecard • Replacement Modeling Results, Scorecard	• Preferred replacement path and logic relative to alternatives • 2021 NIPSCO Short Term Action Plan
Meeting Goals	• Communicate what has changed since the 2018 IRP • Communicate NIPSCO's focus on reliability • Communicate updates to key inputs/assumptions • Communicate the 2021 public advisory process, timing, and input sought from stakeholders	• Common understanding of MISO regulatory updates • Communicate environmental policy considerations • Communicate scenario themes and stochastic analysis approach, along with major input details and assumptions	• Common understanding of DSM modeling methodology • Communicate preliminary RFP results • Explain next steps for portfolio modeling	• Communicate the Existing Fleet Review Portfolios and the Replacement Portfolios • Stakeholder feedback and shared understanding of the modeling and preliminary results. • Review stakeholder modeling and analysis requests	• Communicate NIPSCO's preferred resource plan and short term action plan • Obtain feedback from stakeholders on preferred plan

RESOURCE PLANNING APPROACH

Focus of Today's Meeting

	Activity		Timing
1	Identify key planning questions and themes	✓	Mar
2	Develop market perspectives (planning reference case and scenarios / stochastic inputs)	✓	Mar-May
3	Develop integrated resource strategies for NIPSCO (portfolios)		Jun-Jul
4	Portfolio modeling ▪ Detailed scenario dispatch ▪ Stochastic simulations		Aug-Sep
5	Evaluate trade-offs and produce recommendation		Sep-Oct

3

New resource option parameters

DSM Study

RFP Information

Retirement options and replacement themes (informed by scenarios) → Portfolio Optimization

NIPSCO Portfolios

2 *Scenario Narrative Development*

Integrated gas, coal, carbon forecasts and **MISO market outlook / prices**

Market Modeling Tools (NGF, GPCM, Aurora)

Stochastic Modeling Tools

4

Aurora – **NIPSCO Portfolio** Market Model

Production Cost Dispatch (hourly, chronological)

→ PERFORM

Detailed cost of service and revenue requirements

Scorecard

(2018 Example)

Other analysis

Preferred Retirement Path: 6

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal by 2028 w/ ELG	15% Coal by 2028 w/o ELG	15% Coal in 2023 (Mich. City 2035)	15% Coal in 2023 (Mich. City 2028)	15% Coal by 2023 (Schfr 17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,400 +$4,426 40.3%	$12,911 +$1,937 17.7%	$12,455 +$1,481 13.5%	$12,336 +$1,361 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 - $ - %
Cost Certainty	$15,840 +$4,708 42.3%	$13,158 +$2,026 18.2%	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 - $ - %
Cost Risk	$17,406 +$5,750 49.3%	$14,123 +$2,467 21.2%	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +47%	$0M -%	($23M) (9%)	($31M) (12%)	($65M) (26%)	($74M) (29%)	($74M) (29%)	($94M) (37%)

PROGRESS SINCE LAST MEETING

- **The 2021 RFP was launched after Stakeholder Meeting #2 and closed on June 30th**
  - The RFP team is currently reviewing and organizing bids
  - A preliminary summary will be shared later today
- **NIPSCO portfolio modeling is well underway**
  - Detailed MISO scenario and stochastic inputs (from Stakeholder Meeting #2) have been finalized
  - DSM and DER resource option inputs (to be discussed later today) have been setup
  - RFP tranche development is currently in progress

DEVELOPING THE DEMAND SIDE MANAGEMENT (DSM) STUDY

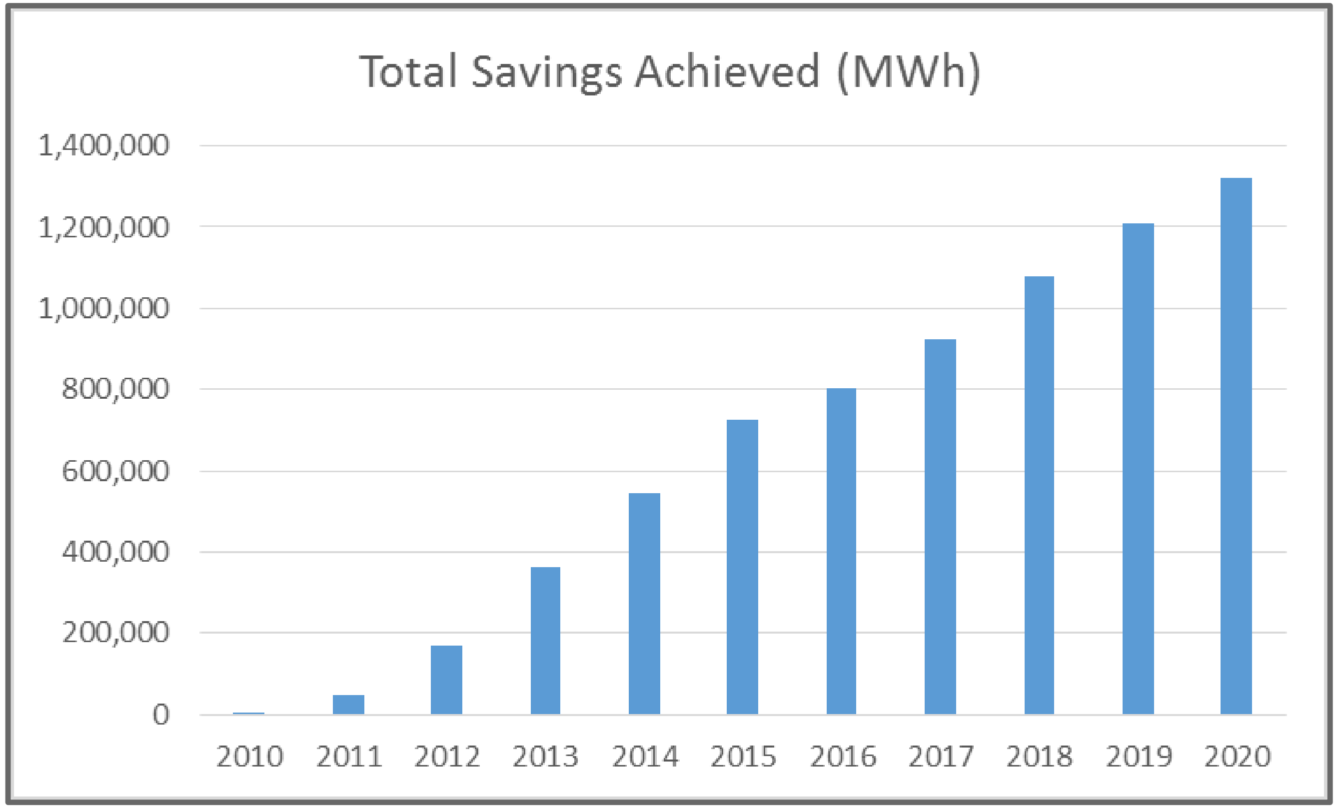
Alison Becker, Manager Regulatory Policy, NIPSCO

Jeffrey Huber, Managing Director – Energy Efficiency, GDS

Pat Augustine, Vice President, CRA

DSM AT NIPSCO – ENERGY EFFICIENCY AND DEMAND RESPONSE

- NIPSCO has had a robust history of actively promoting and implementing energy conservation and efficiency to both its employees and customers since 2010



DSM AT NIPSCO – ENERGY EFFICIENCY AND DEMAND RESPONSE

- NIPSCO actively works with its Oversight Board (“OSB”) to provide direction of both implementation and evaluation of NIPSCO energy efficiency programs
- NIPSCO and the OSB work with a third party administrator, TRC Companies, to offer cost-effective energy efficiency programs for customers
- Although NIPSCO previously offered an air conditioning cycling program, the demand response programs were historically focused on interruptible rate programs with NIPSCO’s largest customers, which now directly participate in the MISO demand response markets as part of the Rate 831 Industrial Customer Service Structure
- NIPSCO is currently seeking approval for the 2022-2023 Gas and Electric energy efficiency programs, and the 2021 IRP will plan for potential continued and new programs starting in 2024 (with a filing scheduled for November 2022)

NIPSCO MARKET POTENTIAL STUDY FOR DSM RESOURCES – ENERGY EFFICIENCY AND DEMAND RESPONSE

- To support the development of the 2021 IRP, the NIPSCO OSB worked with GDS Associates to develop a **market potential study (“MPS”)** to assess the potential level of energy efficiency and demand response savings opportunities and the associated costs
- NIPSCO’s MPS developed residential and commercial & industrial portfolio demand side management market potential and costs over the planning horizon for:
  - Utility-sponsored Energy Efficiency
  - Demand Response
    - Smart Thermostats
    - Direct Load Control
    - Tariff-based dynamic rates and load curtailment potential
- The MPS estimates the **maximum achievable potential (MAP)** and **realistic achievable potential (RAP)** for energy efficiency and demand response for the residential and commercial & industrial customer segments, along with the cost of acquiring the two levels of achievable potential
- The outputs of the MPS analysis will be used as inputs to be incorporated by CRA into the portfolio evaluation phase of the IRP

DEMAND SIDE MANAGEMENT MODELING STEPS

Step 1	Step 2	Step 3
Market Potential Study	Identify “bundles” based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models
• Evaluate detailed energy efficiency and demand response program-level opportunities in NIPSCO service territory • Identify energy efficiency and demand response program impacts and associated costs	• Aggregate detailed measures into bundles of measures at the residential and commercial & industrial segment at the RAP and MAP levels • Produce bundles with detailed energy and demand savings characteristics and costs	• Allow DSM bundles to be selected in optimization analysis, along with other supply-side candidates • Evaluate alternative DSM portfolios (ie, specific bundles or RAP vs. MAP) within the IRP scenario and stochastic analysis process
GDS NIPSCO DSM Team		CRA NIPSCO IRP Team

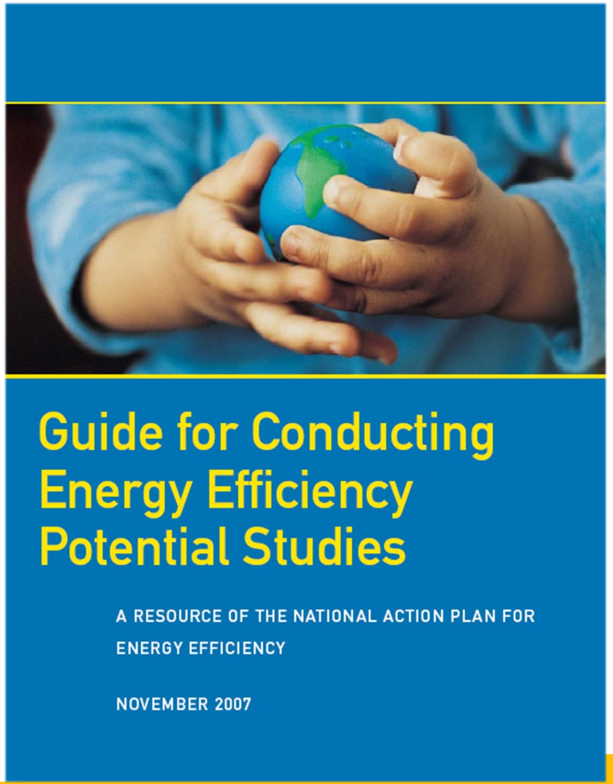
MARKET POTENTIAL STUDY OVERVIEW

WHAT IS A MARKET POTENTIAL STUDY?

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies.

-National Action Plan for Energy Efficiency



TYPES OF POTENTIAL

TECHNICAL POTENTIAL

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

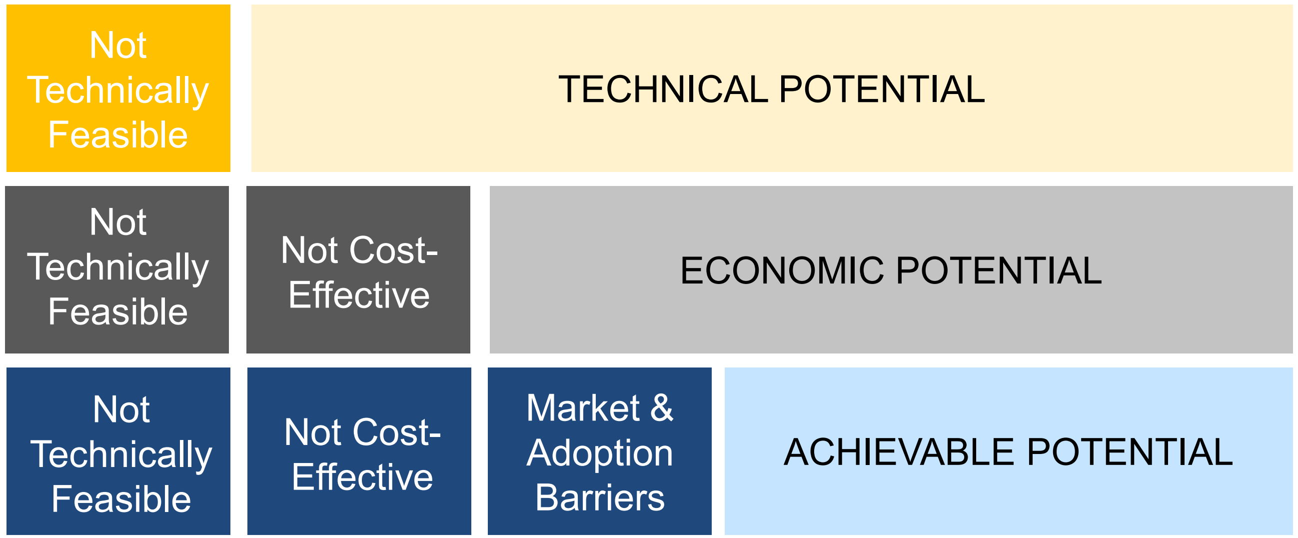
ECONOMIC POTENTIAL

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



Two achievable scenarios

Maximum Achievable Potential (MAP) assumes 100% incentives and more aggressive adoption levels

Realistic Achievable Potential (RAP) assumes incentives that align with current levels

HOW DOES THE MARKET POTENTIAL STUDY INTERACT WITH THE IRP?

- The MPS represents the starting point for developing inputs for the IRP modeling
- The savings potential from this analysis will be used to create DSM resources and levels to be modeled in the IRP
- DSM selections from the IRP will be used to create NIPSCO's DSM plan for 2024-2026

MARKET RESEARCH OVERVIEW

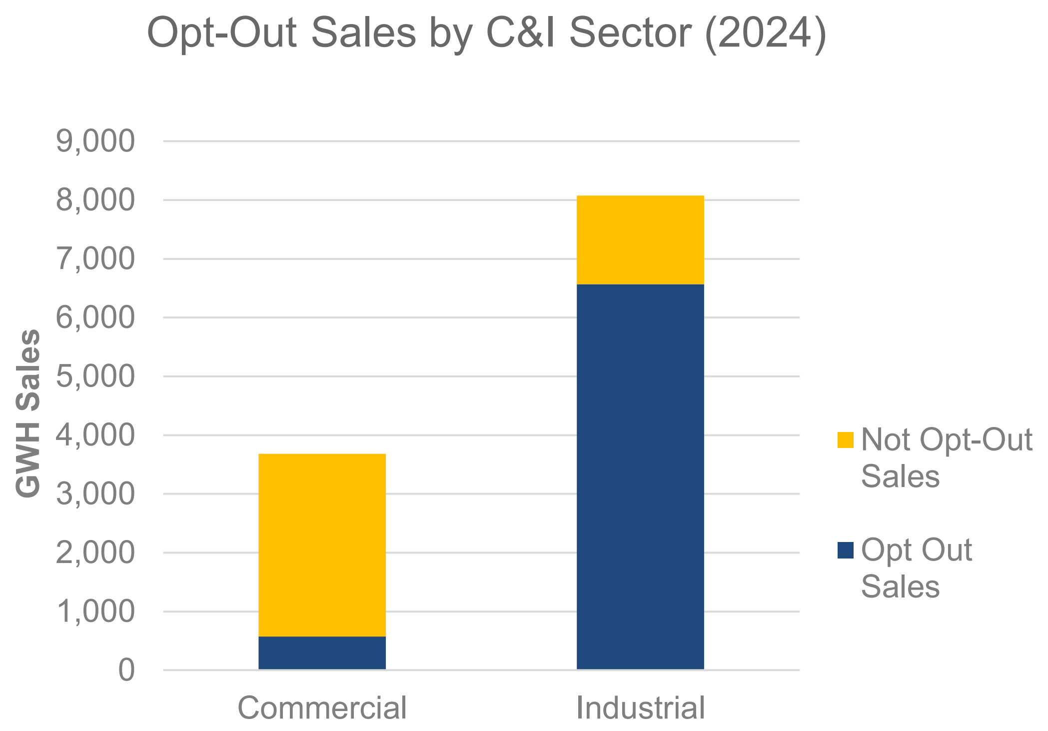
KEY GLOBAL INPUTS AND DATA SOURCES

- NIPSCO Electric Load Forecast*
- Forecasts of Avoided Costs
- Inflation Rate
- Discount Rate
- Planning Reserve Margin
- Line Loss Assumptions
- Energy efficiency and demand response measure costs, kWh and kW savings, useful lives
- Market Characteristic Data*

** To be discussed in more detail*

NIPSCO ELECTRIC LOAD FORECAST

- **NIPSCO's internal sales forecast was modified for use in the MPS**
  - Adjustment removed embedded assumptions about future energy efficiency based on historical DSM performance.
  - MPS also removed sales of current opt-out customers from eligible sales forecast (see graphic to the right)



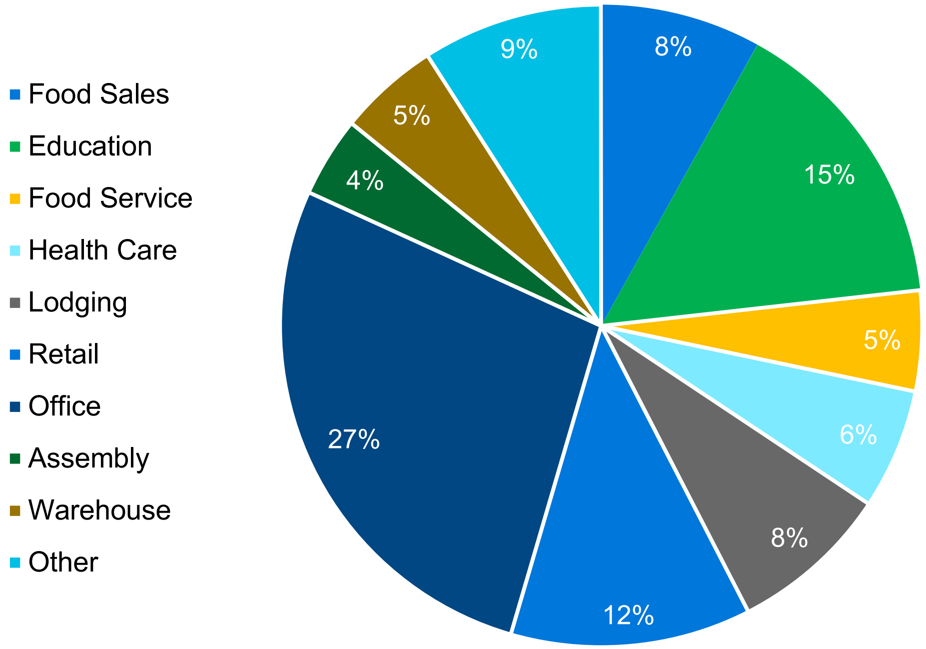
**Note that the industrial load shown here includes some non-firm Rate 831 customers. The non-firm component, however, is not included in NIPSCO's IRP load forecast, since NIPSCO is not obligated to serve that load.*

MARKET CHARACTERISTICS DATA

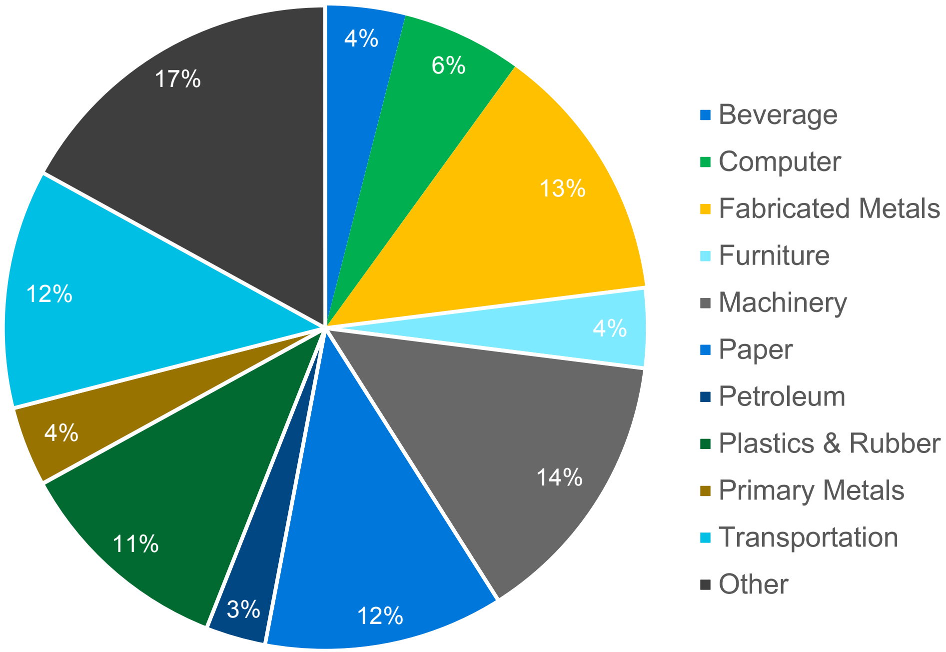
- **To fill in a data gap surrounding equipment characteristics and saturation data, GDS collected primary market research at residential homes and non-residential facilities**
  - Residential sector included both internet/mail surveys, as well as a smaller subset of on-site data collection
  - Commercial sector included on-site survey research
- **Data collection activities also included:**
  - Detailed segmentation of the commercial and industrial sectors from full NIPSCO customer datasets
  - Willingness to participate (WTP) research to inform adoption rates to be used in the assessment of achievable potential

MARKET CHARACTERISTICS DATA

Commercial Sales by Building Type



Industrial Sales by Manufacturing Type



Nonresidential sector analysis uses a top-down approach; understanding sales by building/industry type is a critical component of the top-down approach.

MARKET CHARACTERISTICS DATA

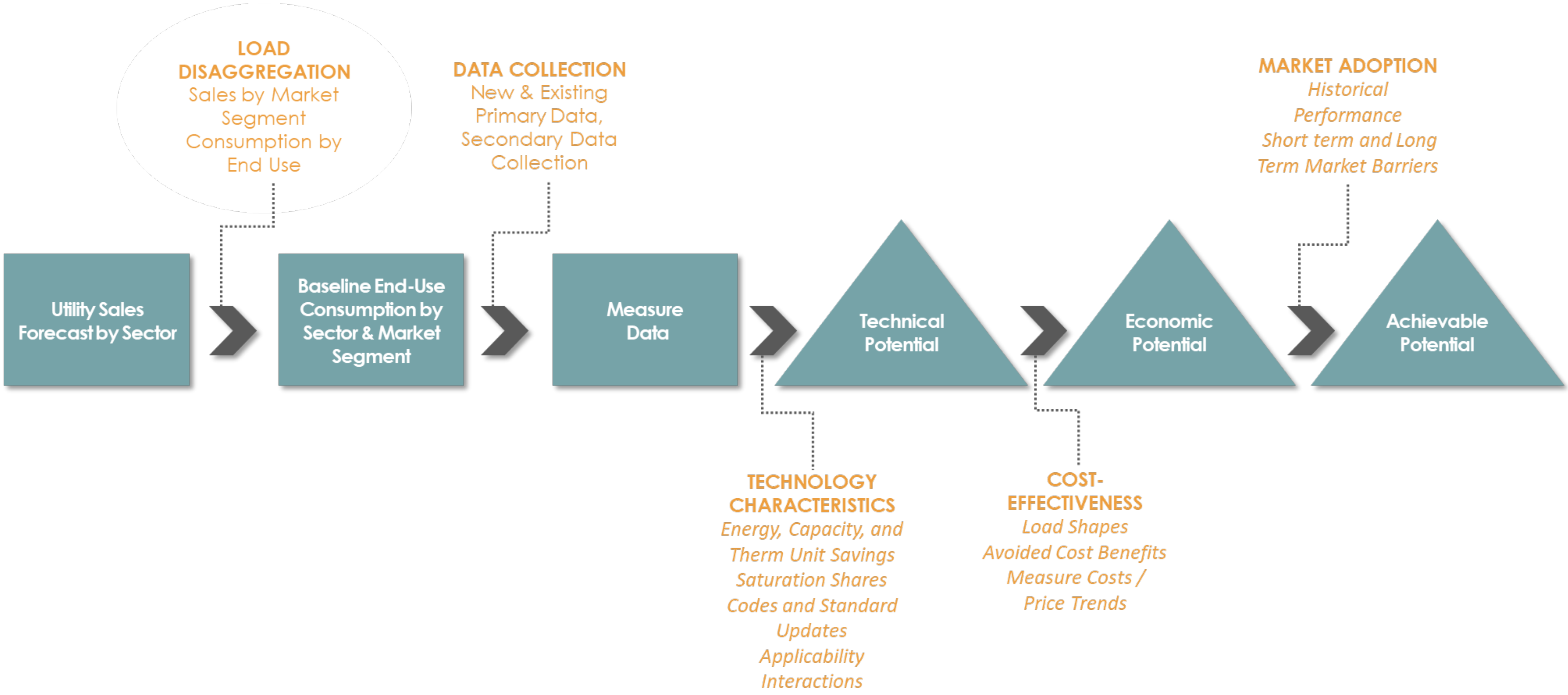
End Use	0% Incentive	25% Incentive	50% Incentive	75% Incentive	100% Incentive
Refrigeration	25.3%	43.2%	78.8%	78.8%	97.5%
Insulation	14.3%	48.3%	72.0%	72.0%	97.8%
HVAC	23.0%	57.3%	76.8%	76.8%	96.7%

Investment Type	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Major Investment	42.8%	58.1%	67.6%	74.6%	81.2%
Minor Investment	41.0%	56.1%	65.7%	73.1%	80.8%

- The Willingness-to-Participate survey is used to inform long-term adoption rate estimates in the achievable potential scenarios.
- Surveys asked residential homeowner and commercial business/property managers their likelihood to participate across various incentive/payback performance levels and end-use/investment types.
- Adoption rates help transition from economic potential (100% adoption) to more achievable levels.
- In addition to WTP estimates (tables on left), the long-term adoption rates included an estimate of program awareness that varied by achievable potential scenario (60%-100%)
  - WTP * Awareness Factor = Long-Term Adoption Rate

ENERGY EFFICIENCY

ENERGY EFFICIENCY METHODOLOGY – STUDY APPROACH

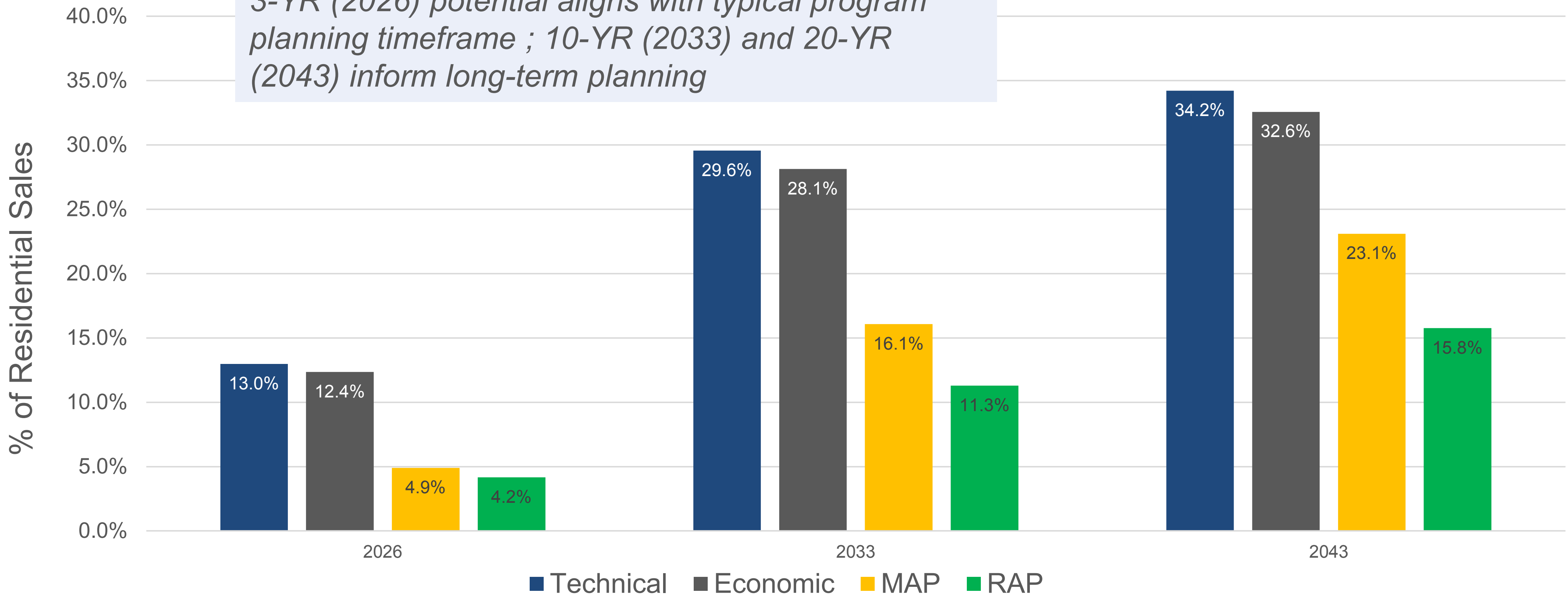


ENERGY EFFICIENCY METHODOLOGY – KEY CONSIDERATIONS

1. Measure list included all current offerings as well as additional emerging measures/technologies
    a. MPS does limit potential from residential general service lightbulbs based on discussions with NIPSCO program administrators and the NIPSCO Oversight Board.
2. Industrial sector potential excluded opt-out customers
3. The Utility Cost Test (UCT) was used to screen measure cost-effectiveness
4. Two achievable scenarios: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP)
5. Estimates of technical, economic, and achievable potential are gross (i.e., not adjusted for free-riders and/or spillover)

ENERGY EFFICIENCY POTENTIAL SUMMARY

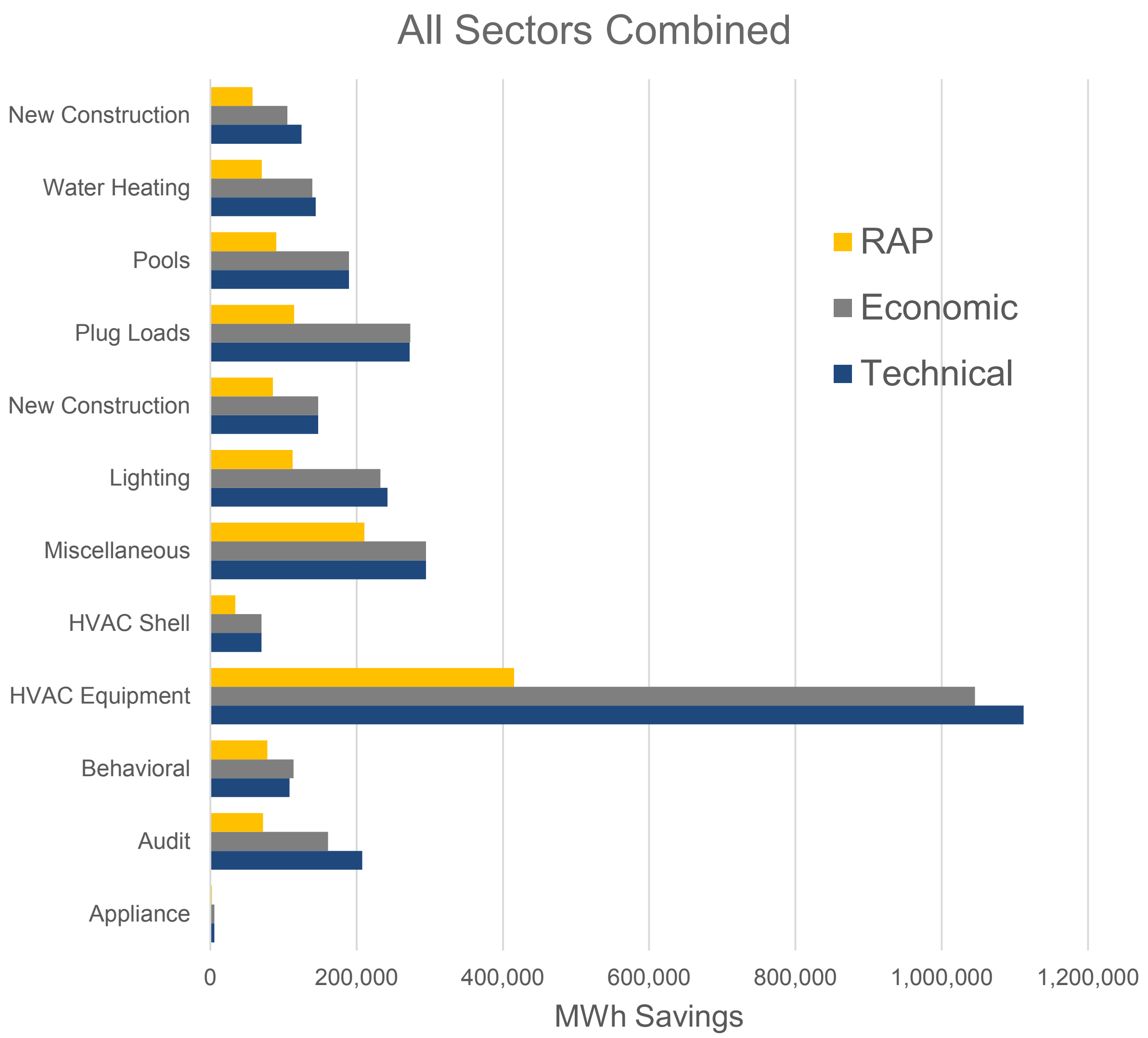
3-YR (2026) potential aligns with typical program planning timeframe ; 10-YR (2033) and 20-YR (2043) inform long-term planning



Results in chart show ***cumulative annual*** savings

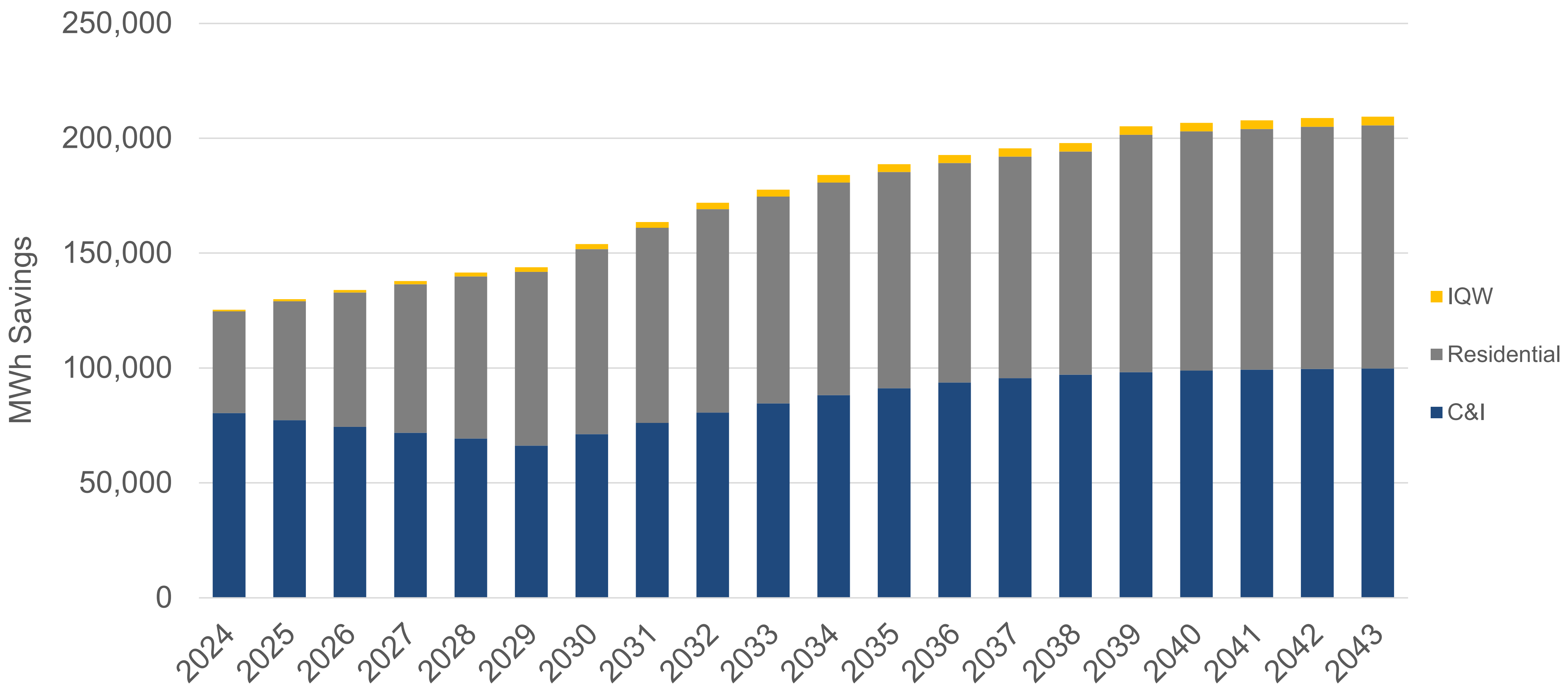
- *Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)*

20-YEAR CUMULATIVE ANNUAL POTENTIAL BY END USE



- There is a large amount of technical and economic potential in the HVAC End Use
  - HVAC includes Heating, Cooling, Ventilation Equipment and Building Shell measures
- Lighting is primary in the C&I sector; there is very limited potential for lighting in the residential sector due to assumptions about general service LED market transformation
- Behavioral savings are slightly higher in economic potential (compared to technical) due to fewer interactive effects

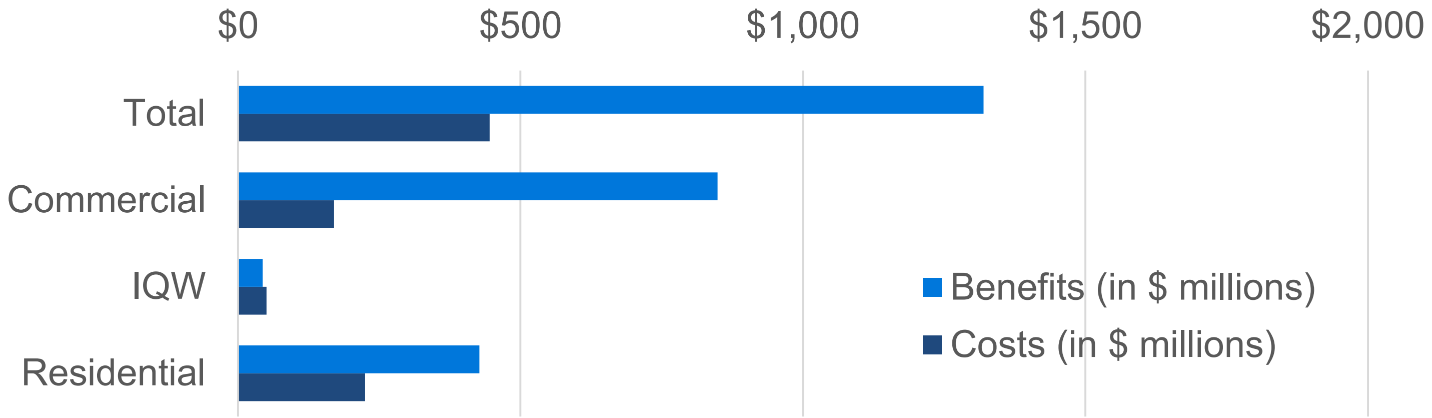
INCREMENTAL RAP BY SECTOR



C&I NPV COSTS AND BENEFITS BY PROGRAM

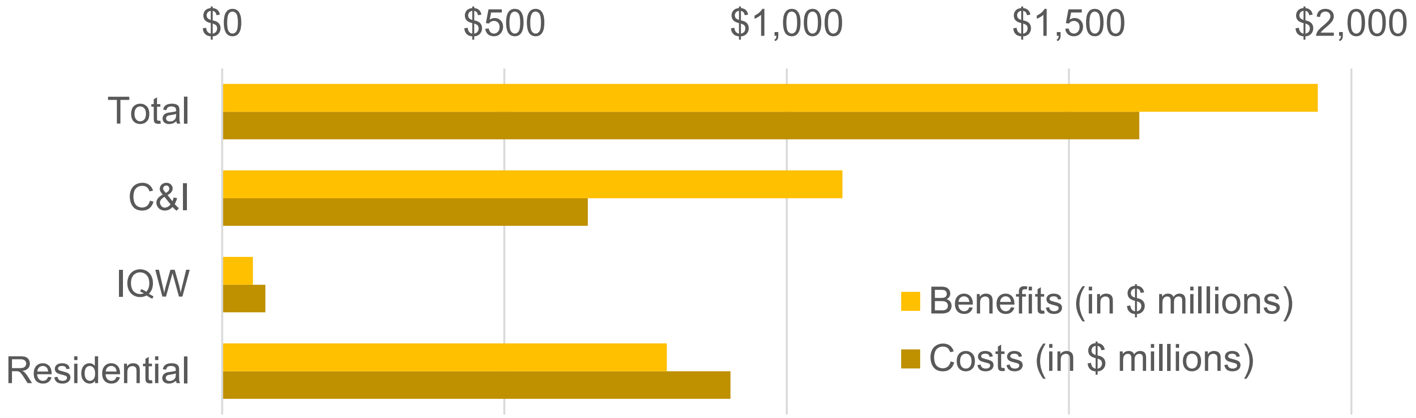
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP



Levelized $/kWh
$0.045
$0.025
$0.212
$0.075

MAP



Levelized $/kWh
$0.116
$0.076
$0.236
$0.174

ALTERNATE AVOIDED COST SCENARIO – ENERGY EFFICIENCY

- GDS analyzed an alternate avoided cost scenario for both energy efficiency and demand response
  - Base avoided cost of generation capacity is based on a natural gas CC unit and totals $164/kW-year in 2024 for G+T+D
  - The alternate avoided cost scenario reduces the total avoided cost to $115/kW-yr in 2024 and is based on a CT (peaking) unit
- The alternate avoided costs led to **slightly reduced potential in the residential sector**
  - 0.11% reduction
- The alternative avoided costs led to **no change in the commercial and industrial sector.**
- ***Energy Efficiency cost-effectiveness is typically dependent on avoided energy costs and less impacted by generation capacity costs.***

DEMAND RESPONSE

HISTORICAL AND CONTEMPLATED PROGRAMS

Prior DR Programs

- **Residential AC cycling:** program suspended in 2015
- **Rate 831 (large industrial customers) interruptible loads:** no longer part of the NIPSCO DR portfolio
  - Prior to the 2018 rate case, NIPSCO offered ~675 MW of Rate 831 interruptible loads to MISO as a load modifying resource (LMR)
  - Since the 2018 rate case, NIPSCO is only required to serve firm load for Rate 831 customers of roughly 167 MW
  - <u>~675 MW Rate 831 interruptible load is not included in this study as DR</u>
- **NIPSCO does not currently have any other DR offerings**

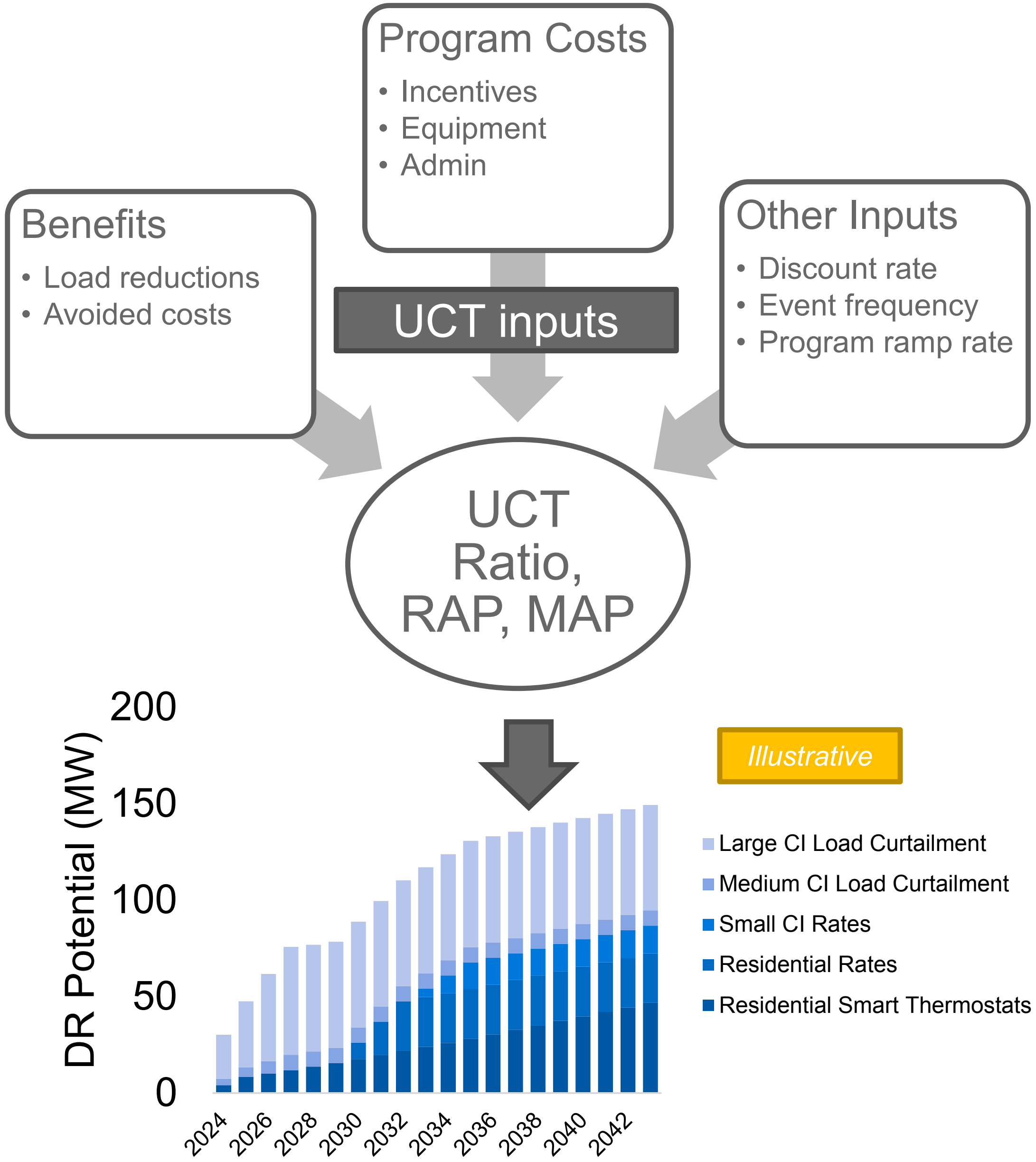
Programs Considered for Study

- **Residential smart (Wi-Fi enabled) thermostats**
  - Allow NIPSCO to control customer AC usage during event windows to reduce loads
  - Designed as add-on to smart thermostat EE rebate measure and uses EE RAP and MAP; also recruit from customers who already have smart thermostats
- **Residential electric water heaters**
  - Devices are controlled via Wi-Fi signal
- **Residential and small C&I dynamic rates**
  - Event-based critical peak pricing program that greatly increases cost of electricity during event hours
  - Enabling AMI assumed to be in place by 2030, but AMI costs are not included in program costs
- **Medium and large C&I load curtailment**
  - Customers earn a payment in exchange for reducing load with day-of notification

METHODOLOGY OVERVIEW

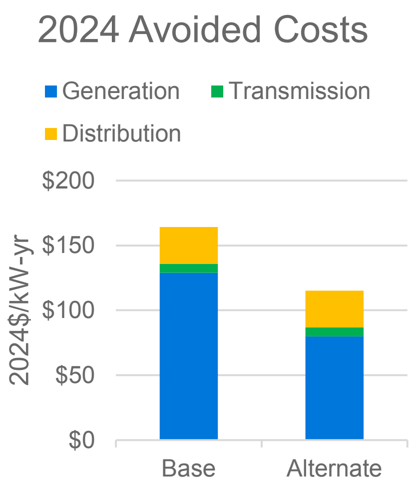
- Programs are evaluated for cost-effectiveness using the Utility Cost Test (UCT)
  - UCT = ratio of NPV benefits to NPV costs per program over 20-year lifespan
  - Only programs with UCT > 1 (benefits exceed costs) are included in RAP and MAP

- MPS contains two DR Potential scenarios:
  1. **RAP (Realistic Achievable Potential):** A “realistic” projection of future cost-effective DR
  2. **MAP (Maximum Achievable Potential):** An “aggressive” projection of future cost-effective DR, achieved by offering more generous incentives or establishing programs as opt-out (default)

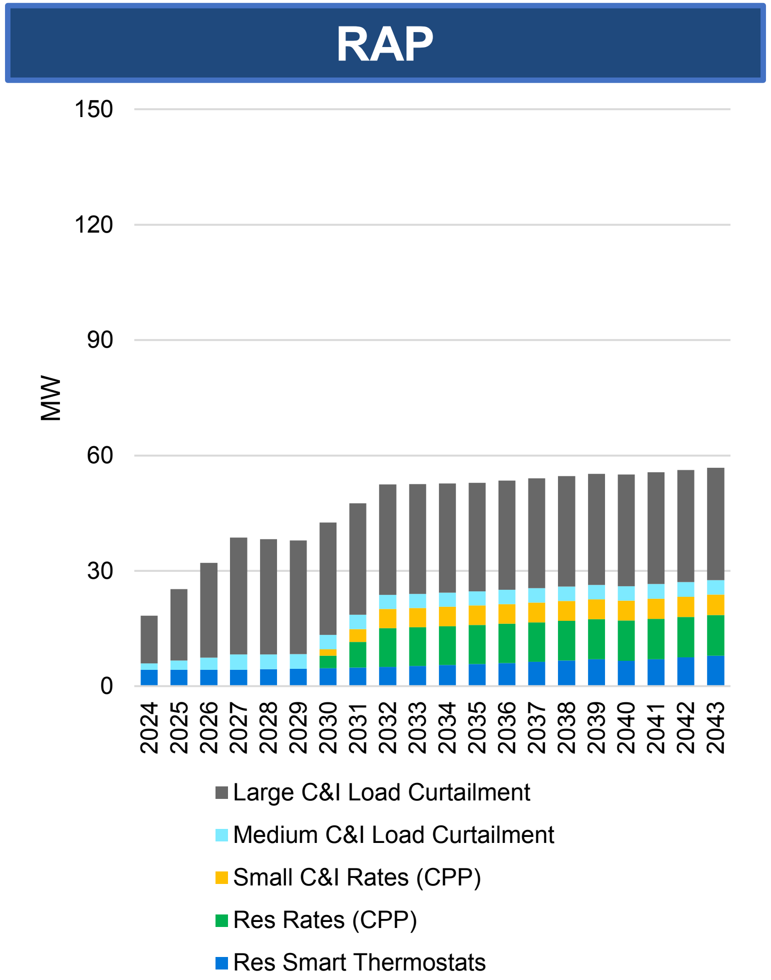


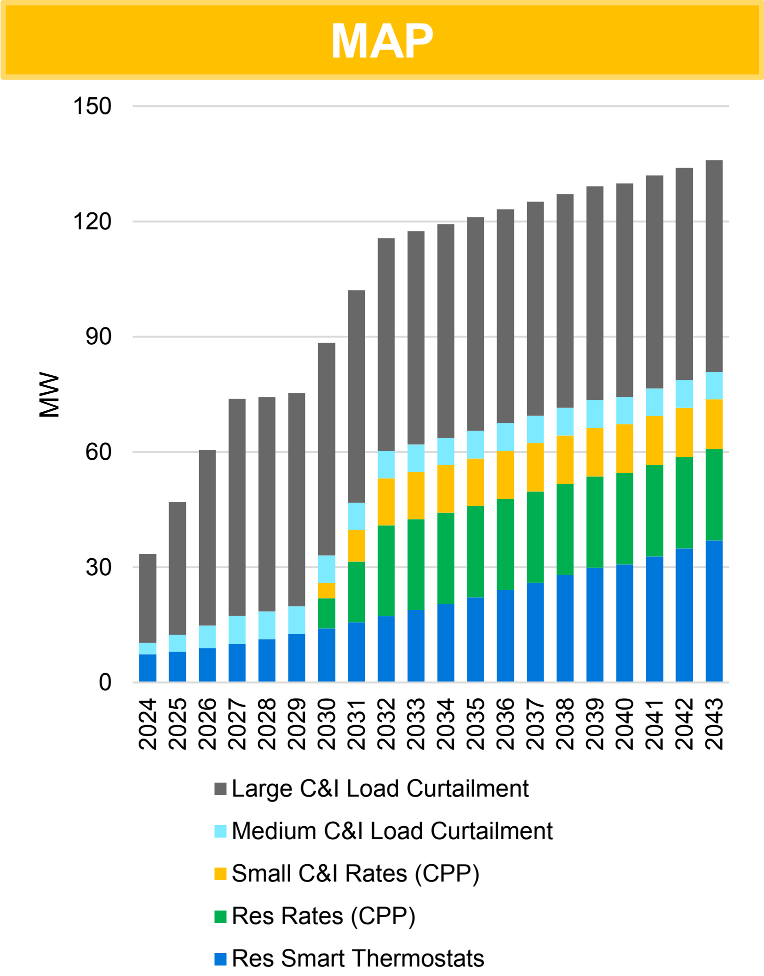
KEY ASSUMPTIONS

- All programs start in 2024 except dynamic rates in 2030 (NIPSCO does not have necessary AMI today)
  - Economic results for dynamic rates programs do not include AMI meter costs
  - All programs incorporate two or three-year ramp-up period
- All reported NPV values are in 2024$
  - Assume a 6.38% nominal discount rate and 2.1% inflation rate
- All impacts are reported in system-level MW
  - Impacts include line losses and customer opt-outs
- The avoided cost of generation capacity is based on a natural gas CC unit and totals $164/kW-year in 2024 for G+T+D
  - The alternate avoided cost scenario reduces the total avoided cost to $115/kW-yr in 2024
- Large C&I customers receive avoided generation and transmission costs only
  - Do not receive avoided distribution costs
- All programs are designed to receive 100% capacity credit under MISO LMR accreditation rules (FERC docket ER20-1846)
  - Programs have a notification times of six hours or less and may be called at least 10 times per year (we assume they are dispatched on average six times per year over a four-hour event)
  - We assume a constant load impact over the duration of the event



BASE CASE: RAP AND MAP TOTAL 57 MW AND 136 MW BY 2043





Program	2043 RAP MW	2043 MAP MW
Residential Smart Thermostats	8	37
Residential Rates (CPP)	11	24
Res Water Heaters[1]	0	0
Small C&I Rates (CPP)	5	13
Medium C&I Load Curtailment	4	7
Large C&I Load Curtailment	29	55
Total	**57**	**136**

Totals may not add up due to rounding

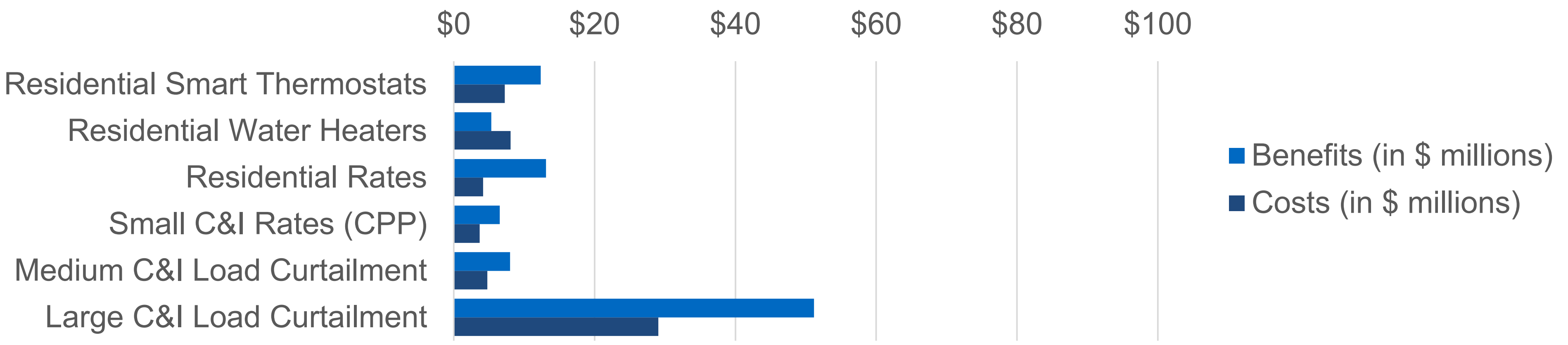
[1] RAP and MAP are zero because program is not cost-effective

- Large C&I load curtailment is the program with highest DR potential
- Rates program start in 2030
- Rate 831 LMRs (~675 MW) are not included in these values

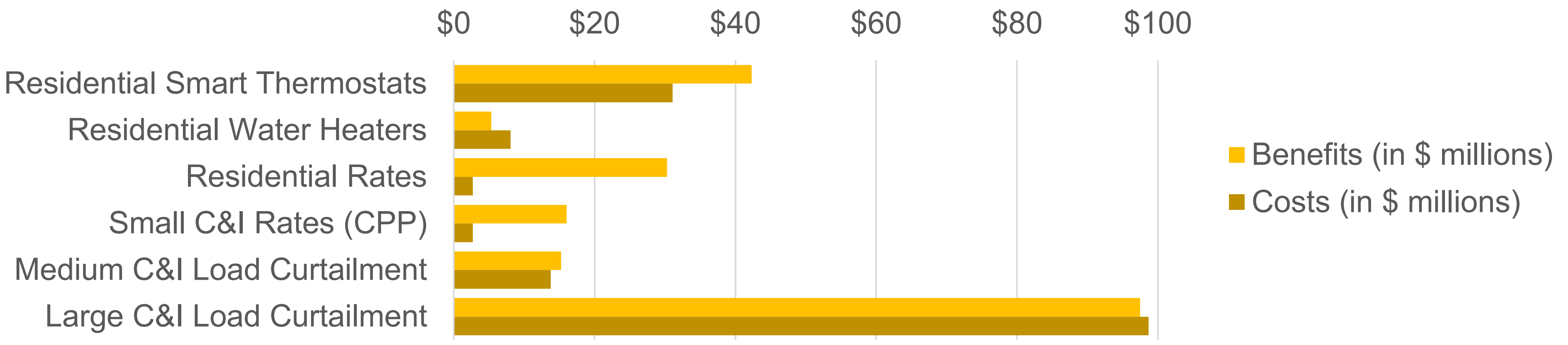
BASE CASE: NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in million 2024$ for the 2024-2043 time period

RAP



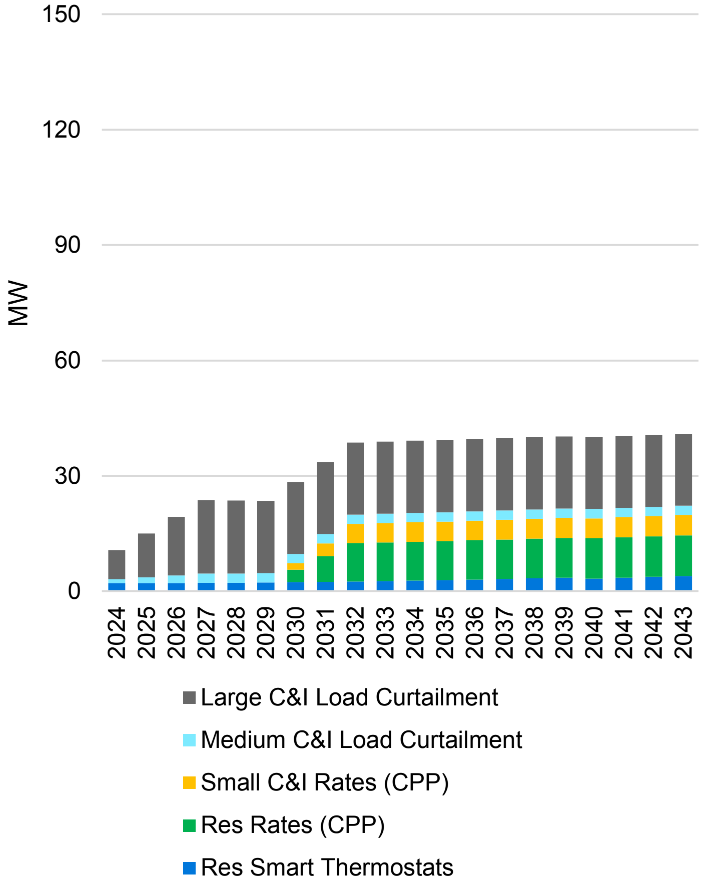
MAP



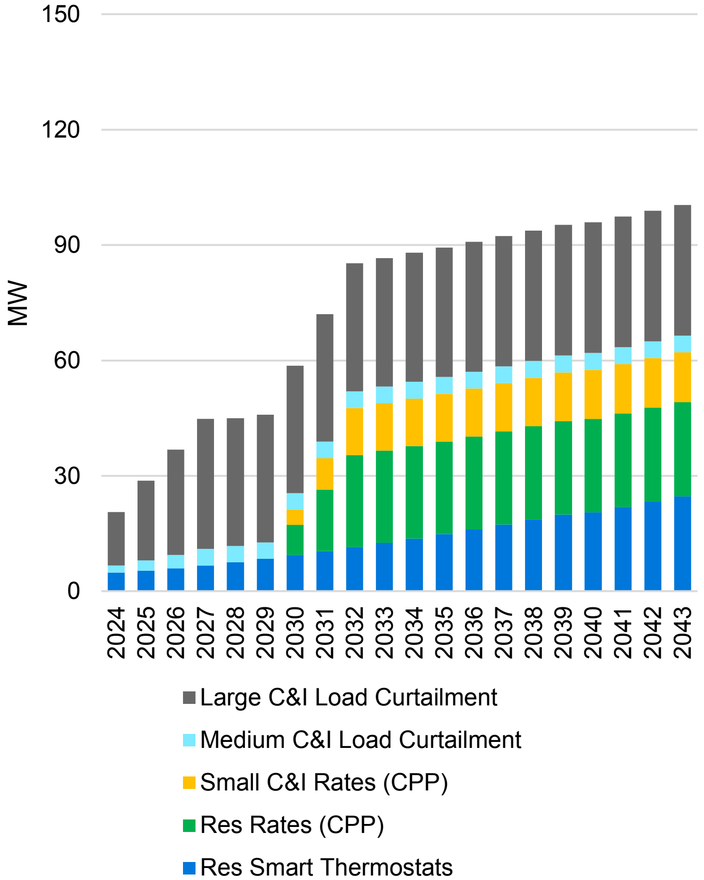
ALTERNATE SCENARIO: RAP AND MAP REACH 41 MW AND 100 MW IN 2043

Alternate avoided cost reduces RAP and MAP by 26% and 28% respectively

RAP



MAP



Program	2043 RAP MW	2043 MAP MW
Residential Smart Thermostats	4 (8)	25 (37)
Residential Rates (CPP)	11 (11)	24 (24)
Res Water Heaters[1]	0 (0)	0 (0)
Small C&I Rates (CPP)	5 (5)	13 (13)
Medium C&I Load Curtailment	2 (4)	4 (7)
Large C&I Load Curtailment	19 (29)	34 (55)
Total	**41 (57)**	**100 (136)**

Totals may not add up due to rounding

[1] RAP and MAP are zero because program is not cost-effective

Results from base case shown in parentheses

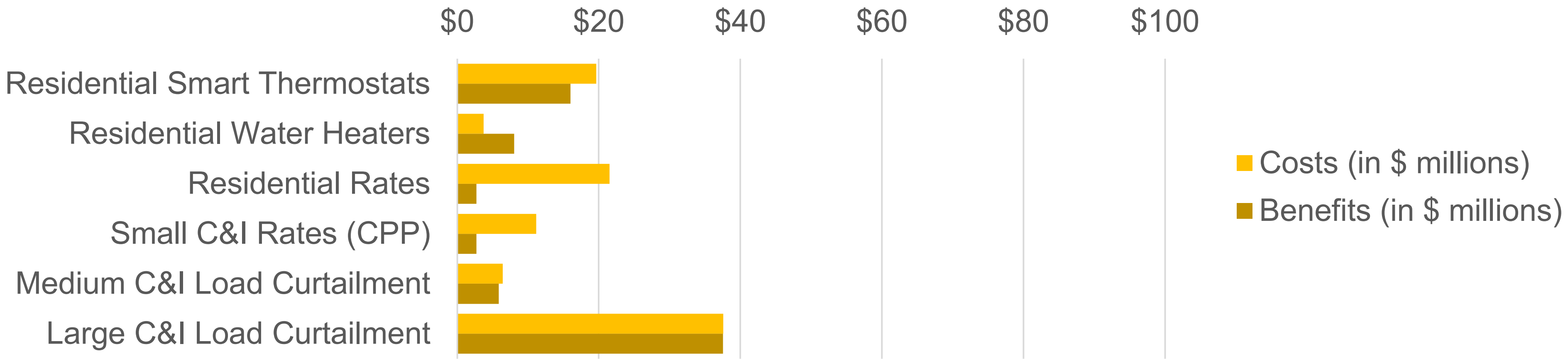
- Large C&I load curtailment is program with higher DR potential
- Rates program start in 2030
- Rate 831 LMRs (~675 MW) are not included in these values

ALTERNATE SCENARIO: NPV COSTS AND BENEFITS BY PROGRAM

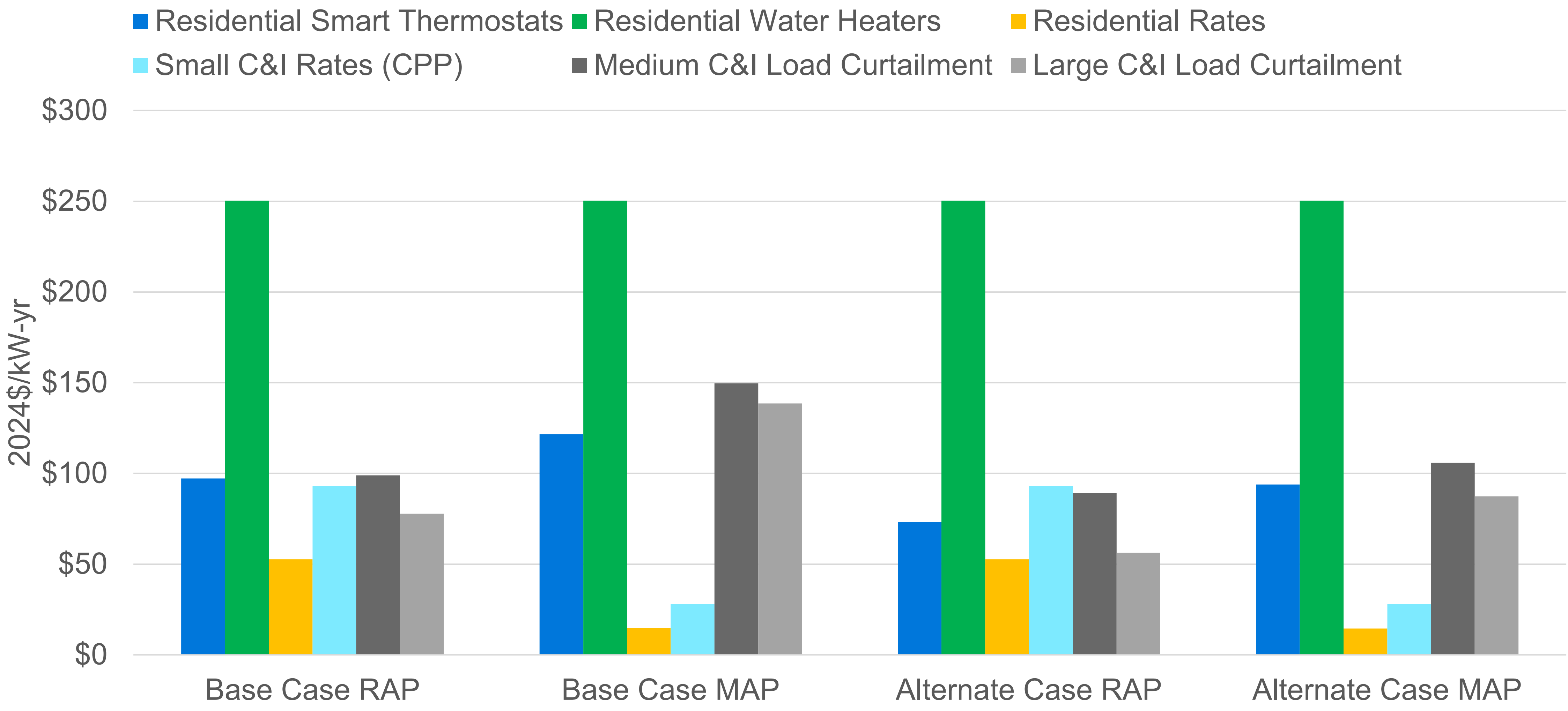
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP

MAP



LEVELIZED COSTS BY SCENARIO



Residential and Small C&I Rates have lower costs in MAP scenarios because program is designed as default with no incentive, whereas RAP is designed as opt-in with incentive

EE/DR MODELING IN IRP

MARKET POTENTIAL STUDY SAVINGS AND DSM INPUTS FOR IRP

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

- NIPSCO will model DSM impacts (EE & DR) based on the results from the 2021 Market Potential Study
- EE and DR estimates for IRP modeling are aggregated at the sector level:
  - Both MAP and RAP levels
  - Both the base and alternate avoided cost scenarios
  - Three vintage blocks: 2024-2029, 2030-2035 and 2036-2041 (2022 and 2023 DSM levels are informed by the current approved DSM Plan)

MARKET POTENTIAL STUDY SAVINGS AND DSM INPUTS FOR IRP

Energy Efficiency

- RAP and MAP Potential Savings were provided for input into the IRP with the following adjustments:
  - Income Qualified Program savings are constrained to align with current program budgets *(held constant in real dollars)*
  - Due to concerns about overall residential program costs, residential inputs were split into two tiers for IRP modeling.
  - DSM Inputs are based on net savings (not gross)
  - Each sector bundle has its own 8,760 shape based on measure mix

Demand Response

- RAP and MAP were provided for three categories – Rates, Residential, and C&I – for base case and alternate scenario
- DR resources will be modeled as supply, with peak capacity contribution plus limited energy duration availability

DSM BUNDLE EVALUATION IN IRP PORTFOLIO MODELING

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

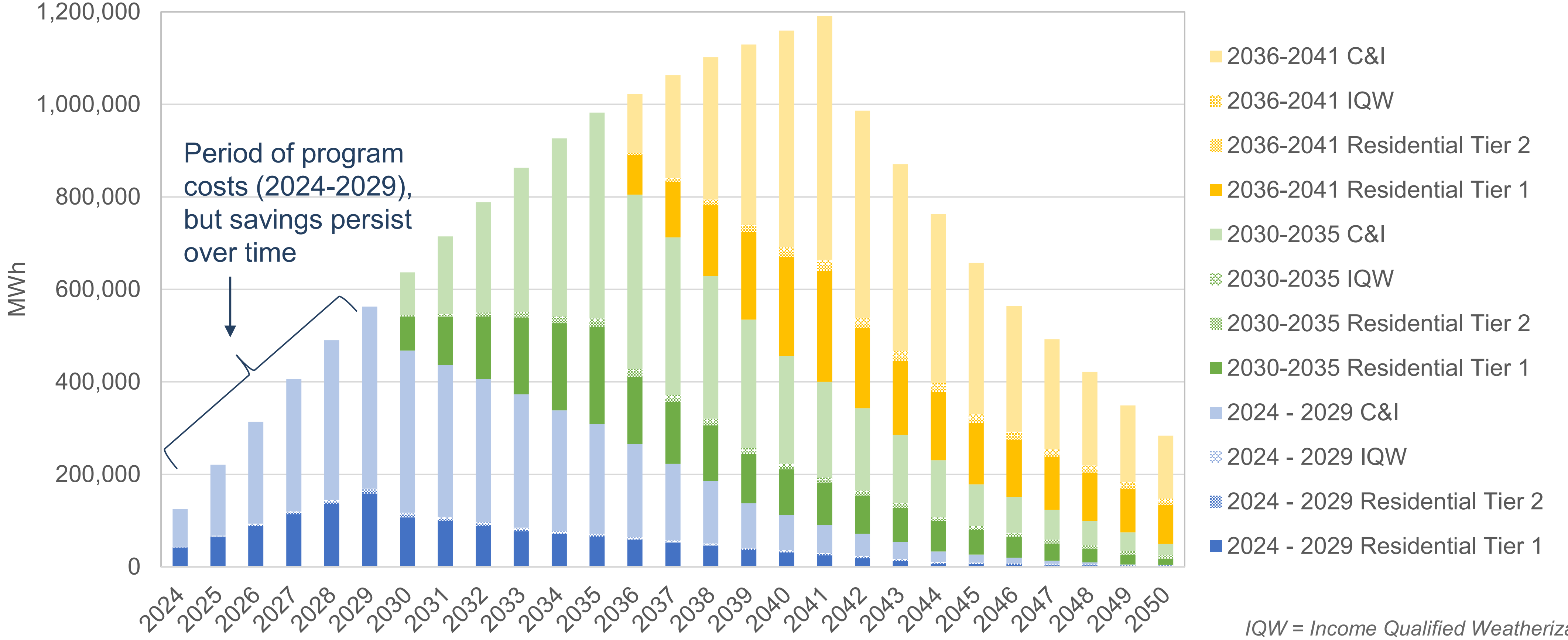
- NIPSCO and CRA will be incorporating the DSM bundles into the portfolio development process, which will allow for portfolio selection from several resource options:
  - EE and DR bundles
  - DER resources, beyond customer-owned DERs that impact the load forecast (to be discussed later)
  - RFP supply resources (to be discussed later)

- As NIPSCO conducts the portfolio analysis, specific DSM evaluation will likely occur beyond the portfolio optimization process:
  - Assessment of the impact of various bundles if not selected through optimization
  - Assessment of the differences in the RAP vs. MAP portfolios or different avoided costs for DR

ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

- DSM bundling approach allows for a representation of potential program duration over time, with differentiation across customer type and costs
- Annual costs and savings (inclusive of marginal line losses) are incorporated

Total MWh Savings - RAP

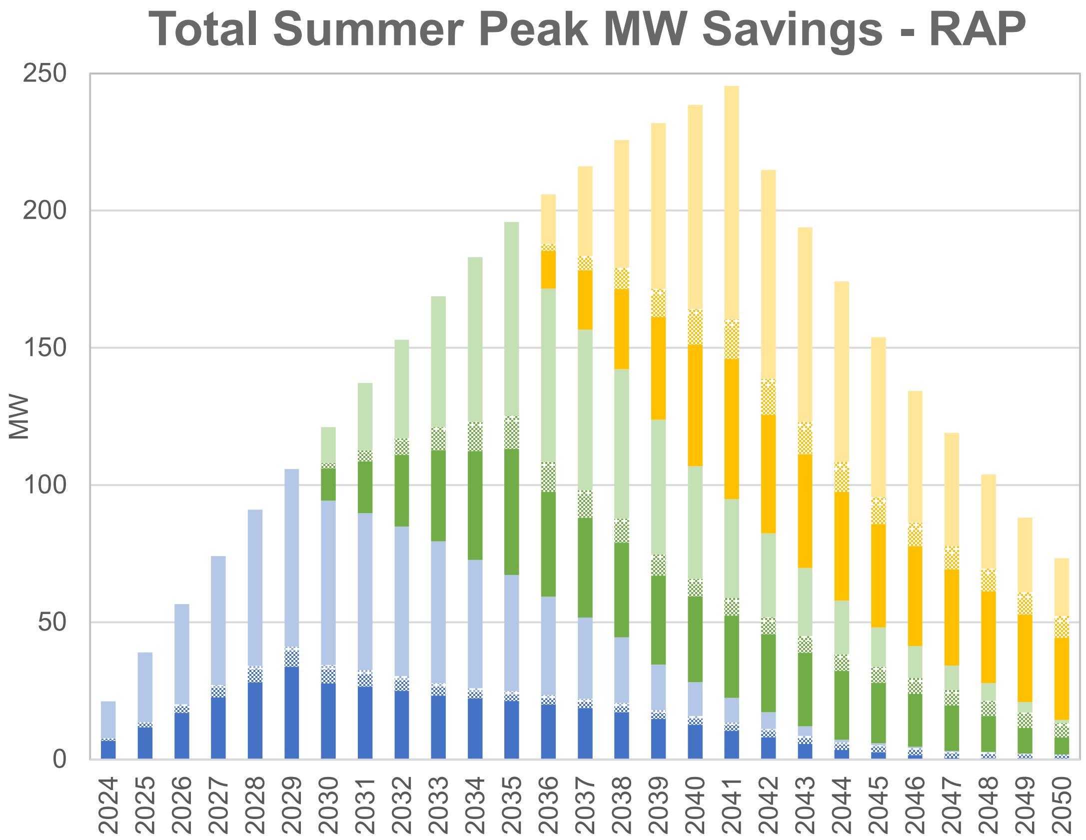


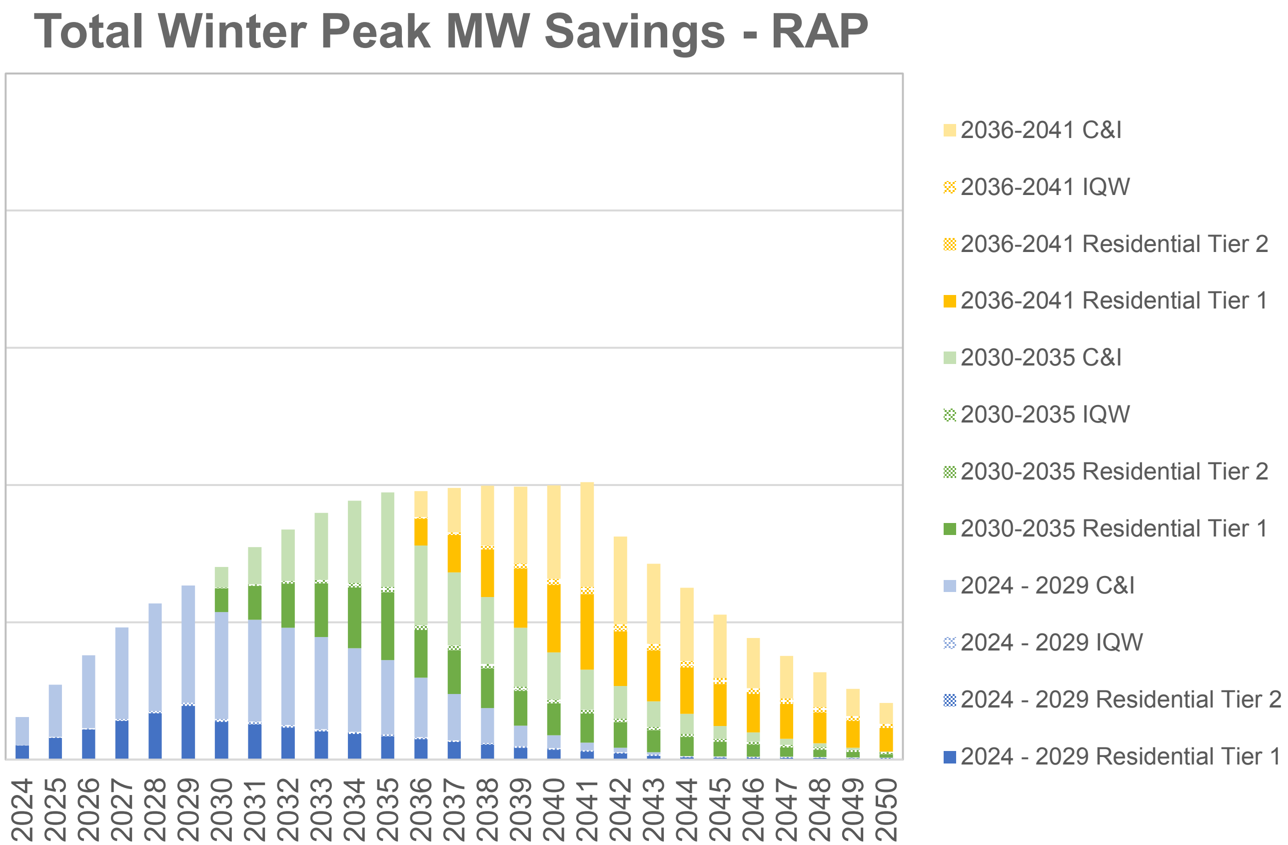
Bundle	Levelized Cost ($/MWh)
2036-2041 C&I	29
2036-2041 IQW	138
2036-2041 Residential Tier 2	253
2036-2041 Residential Tier 1	65
2030-2035 C&I	28
2030-2035 IQW	140
2030-2035 Residential Tier 2	244
2030-2035 Residential Tier 1	60
2024 - 2029 C&I	25
2024 - 2029 IQW	146
2024 - 2029 Residential Tier 2	231
2024 - 2029 Residential Tier 1	53

IQW = Income Qualified Weatherization

ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

- Peak program impact is captured for the summer and winter seasons

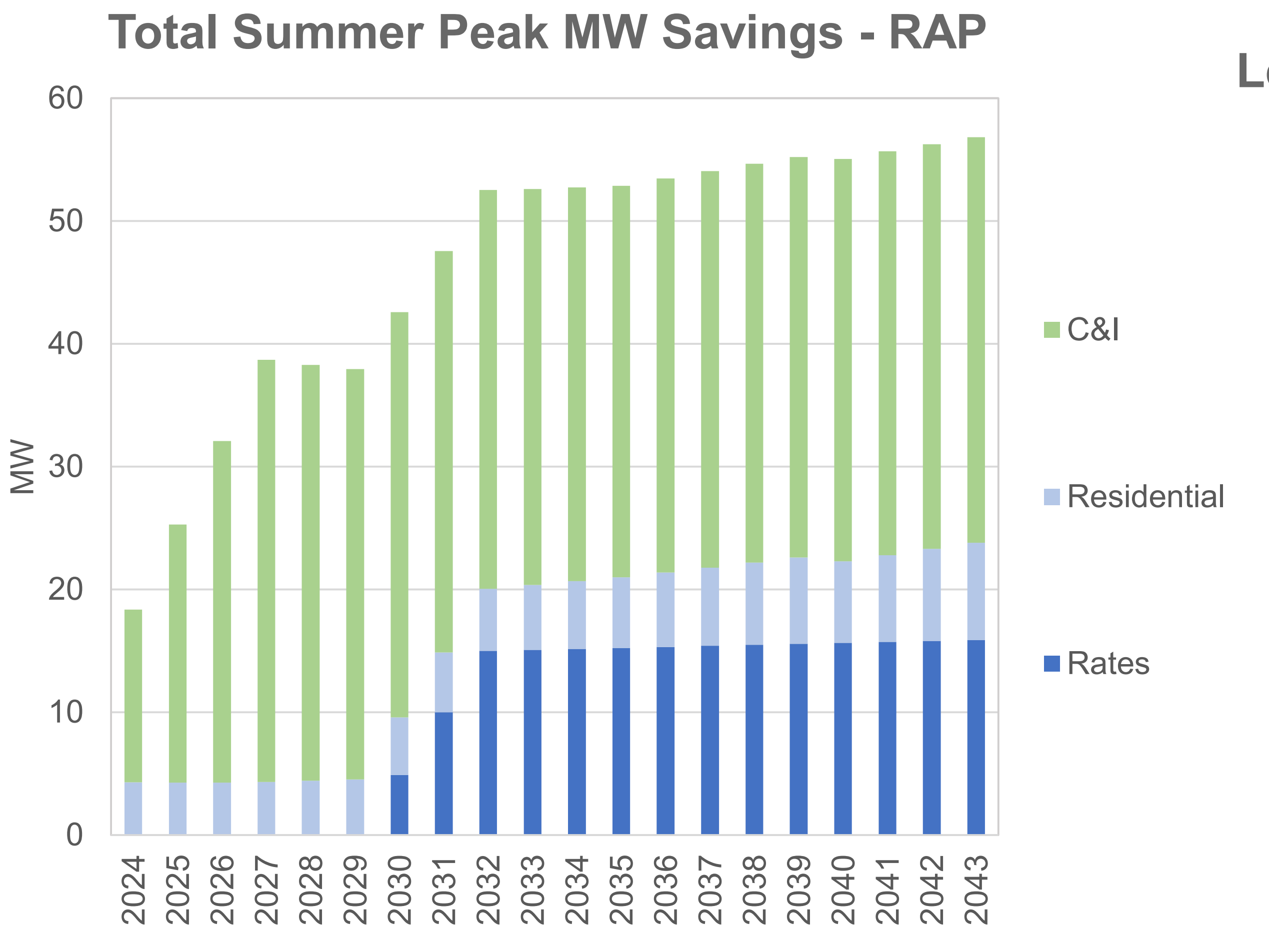


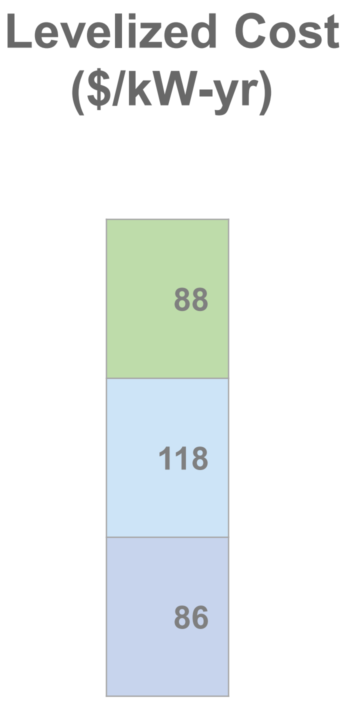


IQW = Income Qualified Weatherization

DEMAND RESPONSE BUNDLES FOR IRP MODELING

- Demand response (DR) programs are being evaluated in three total bundles for rates, Residential, and C&I customers
- DR programs provide summer peak savings, but minimal winter peak and energy value to the portfolio





BREAK

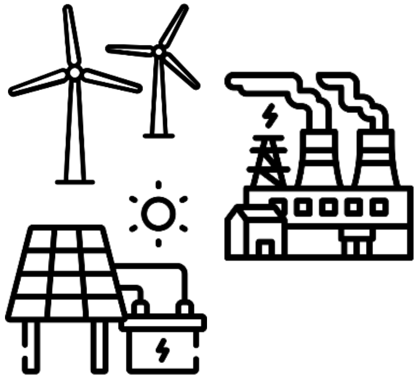
SUPPLY-SIDE DISTRIBUTED ENERGY RESOURCE (DER) CONSIDERATIONS

Pat Augustine, Vice President, CRA

GENERATION PLANNING IS EVOLVING

- IRP has historically been centered on Generation Planning, although NIPSCO has integrated relevant T&D considerations in prior IRPs
- Technology and regulatory change is motivating a closer connection across all planning segments

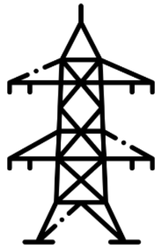
Generation Planning



- Planned generator retirements (ie, Schahfer or Michigan City upgrade requirements)
- New generator upgrades (ie, interconnection costs for RFP projects)

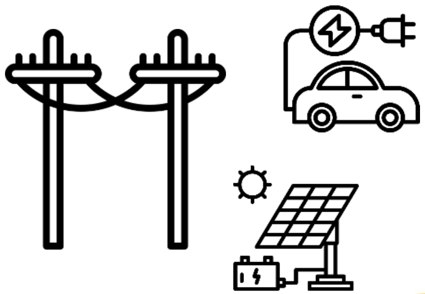
- Load forecasting enhancements (ie, customer-owned DERs, EVs)
- Other distribution planning considerations (ie, generation, advanced metering for DSM)

Transmission Planning



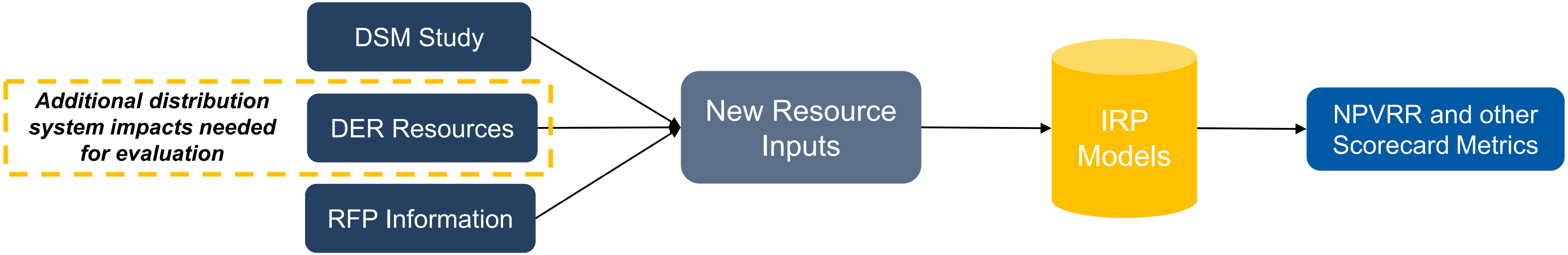
- Regional transmission vs. distribution solutions

Distribution Planning



INTEGRATING DER OPTIONS INTO NIPSCO'S 2021 IRP

- **Why evaluate DER?**
  - Technology costs for solar and storage have declined, making distributed options cost-competitive
  - Regulatory developments like FERC Order 2222 (See Stakeholder Meeting #2 slides) will establish new market structures for integration
- **How is NIPSCO evaluating DER in the 2021 IRP?**
  1. NIPSCO's **load forecast** incorporates a range of customer-owed DERs across scenarios (See Stakeholder Meeting #1 and Stakeholder Meeting #2 slides)
  2. Additional **supply-side** DER options (inclusive of distribution system impacts) will be evaluated against other resources



CONSIDERATIONS FOR DER RESOURCE MODELING IN THE IRP

	Utility-scale	DER
Costs	• Significant cost data and transparency from RFP bids	• Generally a cost premium to utility-scale, but may depend on specific project
T&D Impacts	• Transmission interconnection costs are incorporated in analysis	• Lowered line losses through T&D system • Strategic siting can defer upgrades on the D system
Storage duration	• ISO rules generally pointing towards 4-hour storage for capacity credit	• Storage duration *can* be shorter and optimized around utility system peaks
Peak planning and pairing with solar	• Higher solar to storage ratios generally preferred, given primary focus on summer peak needs and overall energy value	• Peak requirements may be location/circuit-specific, and lower solar to storage ratios often preferred for capacity value
Ancillary services	• Clear access to wholesale A/S markets	• Current participation options are sometimes unclear, but market rules evolution (i.e. FERC Order 2222) requires tracking

EVALUATION OF DEFERRED DISTRIBUTION INVESTMENT OPPORTUNITIES

- NIPSCO's distribution planning team has assessed *near-term* *(within the next 5 years)* system upgrade requirements across the distribution system, with an eye towards how strategically sited generation alternatives could defer substation and other distribution system investment
- NIPSCO identified several locations on the system that will require capacity improvement investments in the next five years and assessed the following* for each location:
  - Estimated distribution upgrade project cost
  - Potential battery storage and paired solar+storage additions that could defer the distribution upgrade, with consideration given for the availability of nearby land to site capacity
  - Estimated years of deferral of the distribution upgrade project that could be achieved with the generation addition
- Based on each location's deferred upgrade cost, potential capacity addition, and estimated investment deferral, an NPV of **deferred investment on a $/kW basis was developed for each location**

**Note that all estimates are based on planning-level information to support IRP analysis. Potential future project execution would require further engineering diligence.*

DER BUNDLES FOR IRP MODELING

- NIPSCO and CRA categorized the projects identified by the distribution planning team into High, Medium, and Low bundles of deferred distribution investment costs
- These resource options will be available for selection and analysis in the portfolio assessment phase:
  - *Near-term opportunities only*, to defer required distribution system investments currently identified
  - Distribution-level cost premiums to be assessed relative to larger scale projects
  - NPV of deferred distribution investment will be effectively subtracted from capital cost of the resource options

Deferral Cost Bundle	Resource	Battery Storage MW	Solar MW	Range of Potential NPV of Deferred Investment ($/kW)
High	Solar + Battery	7.0	2.7	**700 – 900**
Mid	Solar + Battery	7.0	9.1	**200 – 300**
Low	Solar + Battery	2.0	2.7	**10 – 100**

← *Indicative ranges, subject to change for actual projects*

- The IRP will aim to identify the *types of DER projects and characteristics of candidate locations* that may be attractive, with additional project-specific evaluation required in the future
- NIPSCO intends to continue assessing DER options in more detail in future IRPs as integrated planning advancements are made and as MISO makes its filings in response to FERC Order 2222 (See Stakeholder Meeting #2 slides for more information)

LUNCH

2021 RFP RESULTS OVERVIEW

Andy Campbell, Director Regulatory Support & Planning, NIPSCO
Bob Lee, Vice President, CRA

Northern Indiana Public Service Company LLC

2021 Request for Proposals
for Power Supply Generation Facilities
and/or Purchase Power Agreements

Stakeholder Advisory Meeting
July 13, 2021

CRA International

NIPSCO

CRA Charles River Associates

NIPSCO 2021 RFP

Participating Bidders

NIPSCO

CRA Charles River Associates

- Development Partners
- Invenergy
- lightsource bp
- bp
- Hartree®
- HOOSIER SOLAR
- MITSUBISHI POWER
- Origis Energy®
- APEX CLEAN ENERGY
- TENASKA®
- GLIDEPATH®
- Capital Dynamics TRULY INVESTED.
- ST. JOSEPH energy center
- bp
- Blue Steel Energy, LLC
- SIGC SOUTHERN ILLINOIS GENERATION COMPANY
- CORDELIO POWER
- RANGER POWER
- Ørsted
- edp renewables
- EASTERN GENERATION LLC
- ENERGY VAULT Enabling a Renewable World
- ORION RENEWABLE ENERGY GROUP LLC
- nationalgrid renewables
- Primary Energy®
- ibV energypartners an ib vogt company
- Swift Energy Storage Holdings, LLC
- Clēnera
- NEXTera ENERGY
- INDECK®
- eDF renewables
- HALLADOR ENERGY COMPANY
- GALE HEAD DEVELOPMENT
- BRIGHTNIGHT
- REDEUX

NIPSCO 2021 RFP

Overview of Proposals Received

- **2021 RFP generated a tremendous amount of bidder interest**
- **182 total proposals were received across a range of deal structures**
- **78 individual projects across five states with ~15 GW (ICAP) represented**
  - Many of the proposals offer variations on pricing structure and term length
  - Several instances of renewables paired with storage
  - Majority of the projects are in various stages of development

Preliminary

Count of Proposals by Technology and Deal Structure

Technology	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
Asset Sale	1	2	6	4	-	-	-	13
PPA	15	20	8	10	7	2	4	66
Both	37	60	-	2	-	-	4	103
Total	53	82	14	16	7	2	8	182
Locations	IN, IL, KY	IN, IL, KY, WI	IN, WI	IN, IL, KY	IN, IL, MO	IN	MISO	

NIPSCO 2021 RFP

Overview of Projects Received

Project MW ICAP by State and Technology

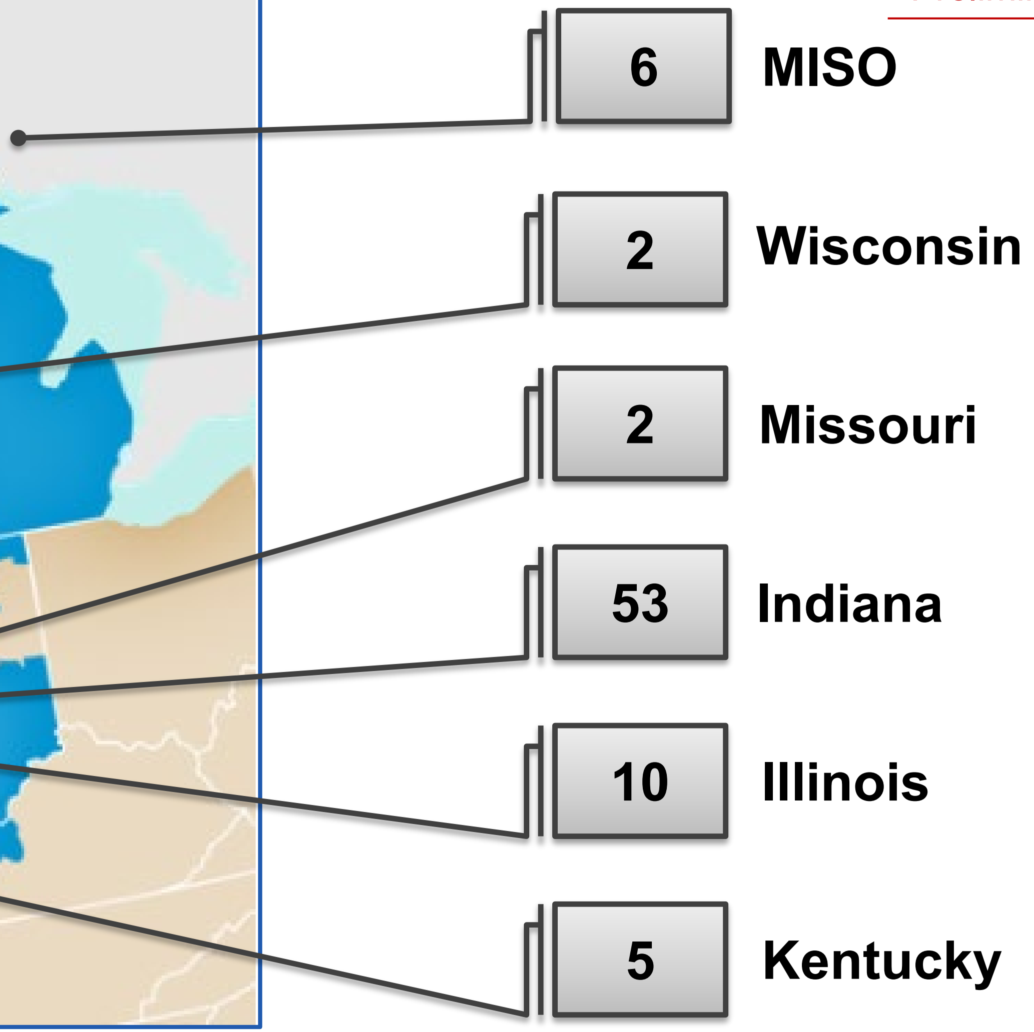
Preliminary

State	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
Illinois	150	473	-	1,074	465	-	-	2,162
Indiana	3,413	3,141	1,169	2,522	200	213	-	10,658
Kentucky	100	431	-	650	-	-	-	1,181
Missouri	-	-	-	-	670	-	-	670
MISO	-	-	-	-	-	-	100	100
Wisconsin	-	200	100	-	-	-	-	300
Total	3,663	4,245	1,269	4,246	1,335	213	100	15,071

NIPSCO 2021 RFP

Distribution of Projects Received

Preliminary



Note: Blue area represents MISO territory

NIPSCO 2021 RFP

PPA Overview

NIPSCO | CRA Charles River Associates

Proposal MW ICAP by PPA Term Length (PPA or Both) and Technology

Preliminary

Duration	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
10 Years	125	-	-	300	-	-	100	525
12 Years	125	-	-	-	-	-	-	125
15 Years	4,303	2,374	450	1,430	1,035	-	-	9,592
20 Years	4,055	7,056	400	2,716	500	213	-	14,940
25 Years	400	4,832	213	-	-	-	-	5,445
30 Years	400	1,000	-	136	-	-	-	1,536
Total	9,408	15,262	1,063	4,582	1,535	213	100	32,163

NIPSCO 2021 RFP

Storage Overview

- NIPSCO received bids for storage both as standalone projects and integrated with solar facilities
- MW totals for “Solar + Storage” reflect the solar capacity only but the storage component adds value and functionality to the integrated facility

Preliminary

Storage Project MW ICAP by Type	
Storage Integrated with Solar	1,763
Standalone Storage	1,269

- Integrated options for solar exist in several locations within MISO but like standalone options are concentrated within the target LRZ6 region

Storage Project MW ICAP by State and Type

State	Storage Integrated with Solar	Standalone Storage
Illinois	235	-
Indiana	1,238	1,169
Kentucky	190	-
Missouri	-	-
MISO	-	-
Wisconsin	100	100
Total	1,763	1,269

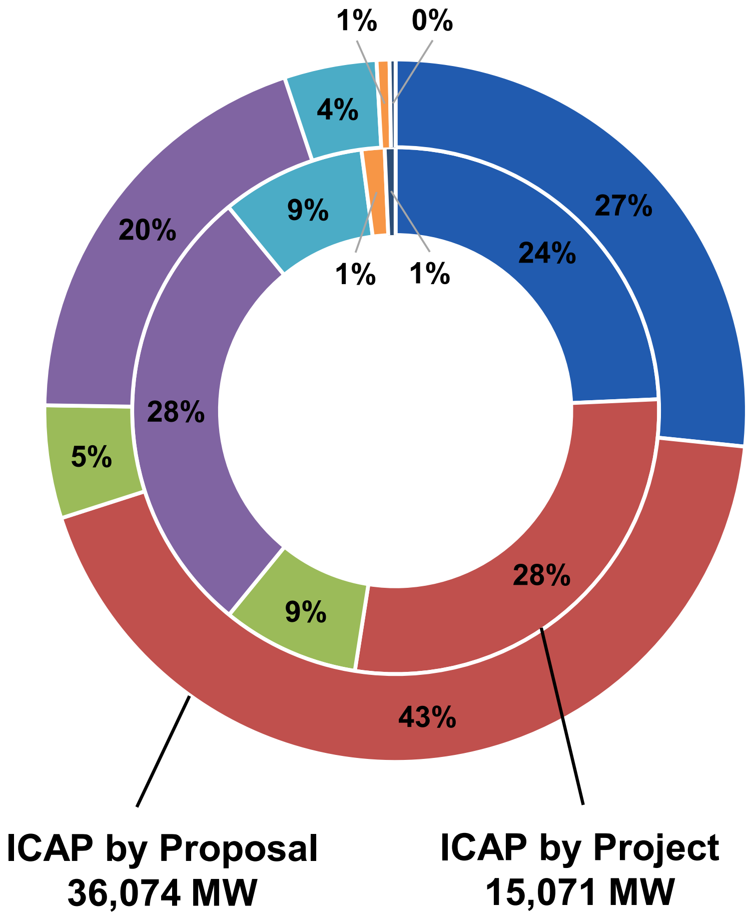
NIPSCO 2021 RFP

Allocation of Proposals and Projects by Technology

Allocation by Technology (MW ICAP)

Preliminary

Technology	ICAP by Project		ICAP by Proposal	
	MW	%	MW	%
Solar	3,663	24%	9,608	27%
Solar + Storage	4,245	28%	15,661	43%
Storage	1,269	9%	1,875	5%
Thermal	4,246	28%	7,082	20%
Wind	1,335	9%	1,535	4%
Hydrogen Enabled	213	1%	213	1%
Other	100	1%	100	0%
Total	15,071	100%	36,074	100%



NIPSCO 2021 RFP

Summary of Pricing

Average Weighted Pricing by Technology & Deal Structure

Preliminary

Technology	Asset Sale		Power Purchase Agreement			Comments
	$/kW	Count	PPA $/MWh	$/kW-Mo	Count	
Solar	$1,467	38	$41.31	-	52	Many projects were bid as both PPA and Asset Sales as well as several PPA structures
Solar + Storage	$1,719	62	$42.77	$3.86	80	Typical PPA structure for integrated solar and storage includes both a fixed and variable component
Storage	$965	6	-	$12.93	8	
Thermal	$1,075	6	$0.36	$7.95	12	Thermal bids also typically would include pass through costs for startup and fuel
Wind	-	-	$39.63	-	7	
Hydrogen Enabled	-	-	-		2	Hydrogen pricing not reported due to limited bid count and fundamental differences in the bids received
Other	-	4	$21.83	$2.81	8	Other includes a range of structures that may or may not include both energy and capacity

- Average bid prices shown for ‘Asset Sale’ represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport competition between technologies; Separate short-listed assets are created for each RFP event

NIPSCO 2021 RFP

Next Steps in RFP Evaluation Process

- **Tuesday, July 6, 2021:** Start of Bid Evaluation Period (currently in progress)
- **Friday, August 20, 2021:** Bid Evaluation Period Completed (tentative)
- **August 2021 – July 2022:** Definitive Agreements Signed with Bidders (tentative)

- Bid evaluation considers both cost and non-cost factors
  - Asset Cost - levelized cost of energy (“LCOE”) or levelized cost of capacity (“LCOC”)
  - Facility Reliability and Deliverability
  - Development Risk
  - Asset Specific Benefit and Risk Factors

- Representative cost and performance characteristics by technology were developed based on RFP bids and provided to the IRP team for portfolio optimization modeling
- IRP to determine the preferred portfolio for execution

INCORPORATING RFP RESULTS INTO THE IRP

Fred Gomos, Director Strategy & Risk Integration, NiSource
Pat Augustine, Vice President, CRA

HOW DO THE RFP RESULTS INFORM THE IRP ANALYSIS?

The responses to the all-source RFP provide insight into the supply and pricing of alternatives available to NIPSCO and are fed into the existing fleet and replacement analysis

- **Existing Fleet Analysis**
  - RFP results provide known and visible replacement costs and volumes
  - Representative project groups/tranches will be constructed from RFP results, assembled by technology and ownership, for use in the IRP analysis
  - Existing fleet analysis will be run using the representative RFP projects as selected by the optimization model
- **Replacement Analysis**
  - RFP results provide visibility into executable alternatives for NIPSCO
  - Replacement analysis will be run using the representative project groups/tranches

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

WHY ORGANIZE BIDS INTO REPRESENTATIVE GROUPS OR TRANCHES?

- The IRP is intended to select the best resource mix and future portfolio concept, and *not* select specific assets or projects
  - While highly informed by current and actionable RFP data, the IRP is meant to develop a planning-level recommended resource strategy
  - Asset-specific selection requires an additional level of diligence (full assessment of development risk, locational considerations such as congestion risk, transmission system impacts, etc)
- The IRP is a highly transparent and public process that requires sharing of major inputs
  - There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data
- The IRP modeling is complex, and resource grouping improves the efficiency of the process
  - Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set improves the efficiency of setup and run time

IRP ANALYSIS: TRANCHE DEVELOPMENT AND ASSESSMENT

A three-step process to incorporate RFP data and run the IRP models

1 Tranche Development

Additional screening focus in 2021 to inform tranche development

Screen Bids

- High-level bid review by RFP team to confirm compliance w/ requirements and overall viability

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Oper. characteristics
- Aggregated cost and operational information compiled in Aurora

2 Portfolio Optimization

Select Portfolios

- Based on portfolio concepts (retirement / replacement), capacity need, and other constraints, identify which tranches (or portions of tranches) are selected for the portfolio through Aurora optimization

Confirm Reasonableness

- Confirm that optimization model is selecting feasible block sizes and options based on resource-specific data

3 Portfolio Modeling

Refine Portfolio Details

- Adjust model setup as necessary to cover full range of retirement and replacement options

Analyze Portfolios

- Evaluate each portfolio across range of scenarios and stochastic inputs
- Report portfolio costs and other metrics to support scorecard development

TRANCHE DEVELOPMENT

2018 IRP Example

- **Bids will be aggregated and similar resources combined into representative tranches**
  - Bids sorted by bid type (PPA or asset sale), technology type, duration, online year, and cost
  - Price and operational characteristics for the tranche are calculated using weighted average of individual bids within the tranche
  - Certain tranches may contain only one bid, if the bid had unique characteristics that make it difficult to aggregate

PPA Solar Tranche Example

Bid Name	Bid Type	ICAP (MW)*	Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	2023	20	$27.xx	-
			...			
Bid 9	Solar	275	2023	20	$32.00	24%
Bid 10	Solar	100	2023	20	$34.00	24%
Bid 11	Solar	75	2023	20	$34.00	23%
Bid 12	Solar	25	2023	20	$35.00	24%
Bid 13	Solar	500	2023	25	$35.00	25%
			...			
Bid 26	Solar	-	2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	2023	23	$33.93	24.2%

*Capacity and bid prices are rounded to the nearest 25 MW and dollar respectively to preserve confidentiality.

INFORMATION WILL BE USED IN THE IRP TO DEVELOP NIPSCO'S PREFERRED PORTFOLIO

- The IRP is designed to select **the preferred resource/technology mix** and will **not identify specific projects**

	Existing Fleet Analysis	Replacement Analysis
Core Questions	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?* *Is the portfolio flexible and adaptable to address changes in market rules and energy policy?*	*What are the replacement resource portfolio options?* *How do different replacement themes compare with regard to cost, risk, environmental sustainability, and reliability?*
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

SETTING THE CONTEXT FOR ASSESSING RELIABILITY IN THE IRP

Previous Reliability Assessments

- In the 2018 IRP, NIPSCO began including reliability risk metric in the scorecard used to evaluate the performance of various resource portfolios

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

- As part of the 2020 Portfolio Analysis to support NIPSCO renewable filings, the reliability criteria were further expanded to consider operational flexibility

2020 Portfolio Analysis

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 34 year NPV of revenue requirement (Base scenario deterministic results)
Long term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: MW weighted duration of generation commitments
Capital Requirement	• Estimated amount of capital investment required by portfolio • Metric: 2020 -2023 capital needs
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 UCAP MW sourced from non-gas resources)
Environmental	• Carbon intensity of portfolio / Total carbon emissions • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Operational Flexibility	• The ability of the portfolio to be controlled in manner to respond to changes in load (dispatchable) • Metric: % of 2025 Controllable MW in gen. portfolio

2021 IRP Approach

1 Ensure consistency with MISO rules evolution

- Seasonal resource adequacy
- Future effective load carrying capability (ELCC) accounting

2 Expand Uncertainty Analysis

- Incorporation of renewable output uncertainty
- Broadening risk analysis to incorporate granular views of tail risk

3 Incorporate New Metrics

- Incorporating new scorecard metrics informed by stochastic analysis and capabilities of portfolio resources

CORE ECONOMIC MODELING CAN CAPTURE ELEMENTS OF RELIABILITY

- Many elements of reliability will be incorporated in the core portfolio analysis and will ultimately contribute to the cost and risk metrics used in the scorecard

Focus of NIPSCO's IRP (Resource Adequacy, Energy Adequacy) — *NIPSCO coordinates with MISO* (Operating Reliability)

	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
Forward Planning Horizon:	Year-ahead	Day-ahead	Real-time or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including with stochastic risk	Ancillary services analysis (regulation, reserves), with sub-hourly granularity

ECONOMIC ANALYSIS OF REAL-TIME MARKET DYNAMICS + ANCILLARY SERVICES

- CRA's Energy Storage Operations (ESOP) model is an optimization program that estimates the value of storage and other flexible resources in the **real-time and ancillary services (A/S) markets**, offering an estimate of **the incremental value** such resources offer beyond what can be estimated in the day-ahead hourly production cost framework of Aurora
- NIPSCO and CRA will assess the economic value of candidate resource types (based on RFP bids) in the ESOP model for incorporation in the full portfolio revenue requirement analysis in Aurora and the PERFORM financial tool

Category	Aurora Portfolio Tool	ESOP
Market Coverage	Day-ahead energy	Real-time arbitrage plus A/S (frequency regulation and spinning reserves)
Time Granularity	Hourly, chronological	5-minute intervals, chronological
Time Horizon	20 years	Sample years (ie, 2025, 2030, 2035, 2040)
Pricing Inputs	MISO-wide fundamental analysis feed NIPSCO-specific portfolio dispatch	Historical data drives real-time and A/S pricing; specific asset types dispatched against price
Asset Parameters Used	Hourly ramp rate, storage cycle and depth of dispatch limits, storage efficiency	Sub-hourly ramp rate, storage cycle and depth of discharge limits, storage efficiency
Outputs	Portfolio-wide cost of service	Incremental real-time and A/S value for specific asset type

ECONOMIC ANALYSIS ALONE DO NOT CAPTURE THE FULL VALUE OF RESOURCES

- NIPSCO participates in the Midcontinent Independent System Operator (MISO) in a variety of roles with various compliance standards and responsibilities
- These responsibilities and standards are met in part by existing resources

Role	Definition
Energy, Capacity, and Ancillary Services Market Participant	Offers resources into markets and procures services on behalf of load to ensure adequate provision of energy, capacity, and ancillary services to support system reliability
Transmission Owner (TO)	Owns and maintains transmission facilities
Transmission Operator (TOP)	Responsible for the reliability of its local transmission system, and that operates or directs the operations of the transmission facilities

- As a TOP, NIPSCO is required to comply with a variety of NERC standards, particularly those that govern the reliable operation of the Bulk Electric System
  - For example, EOP-005-3 governs system restoration from Black Start Resources. Part of NIPSCO's compliance plan relies on resources that currently exist within the portfolio and the NIPSCO TOP area
- Any resource decisions (retirement or replacement) will need to consider the implications for NIPSCO's ability to comply with NERC and MISO standards and procedures now and into future

An expanded scoring criteria can account for these additional considerations

RELIABILITY ASSESSMENT PROCESS OVERVIEW

1 Define Initial Assessment Criteria	2 Obtain Stakeholder Feedback	3 Engage 3rd Party Reviewer	4 Incorporate into IRP Analysis Scorecard(s)
Collaborated with NIPSCO transmission planning and system operations group to develop initial framework and criteria	We will seek feedback from interested stakeholders who want to learn more about the assessment criteria and provide input and feedback	Engage a qualified 3rd party expert to review the assessment criteria, develop the scoring methodology and score and rank the various resource technologies under consideration	Engage a qualified 3rd party expert to review the assessment criteria, develop the scoring methodology and score and rank the various resource technologies under consideration
✓	**July**	**August**	**September**

INITIAL RELIABILITY ASSESSMENT CRITERIA

Preliminary

	Criteria	Description	Rationale	Normal Operation	Potential to Capture in Economic Analysis (Normal Op)	Islanded Operation (Black-out Restoration)	NERC Standard IEEE Standard
1	Blackstart	Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency and voltage control	In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system	N/A	N/A	✓	EOP-005-3
2	Energy Duration	Resource is able to meet energy and capacity duration requirements. In emergency conditions, resource is able to supply full or near full output continuously for up to a week or more independent of the electric system, except for auxiliary load needs	NIPSCO must have long duration resources for emergency procedures and must assess economic value risk for energy duration attributes over time	Various durations provide different value	✓ Hourly dispatch, capacity value, A/S value	✓	EOP-005-3
3	Dispatchability and Automatic Generation Control	The unit will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system	MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures	✓	✓ Regulation A/S value	✓	BAL-001-2
4	Operational Flexibility and Frequency Support	Ability to provide an inertial energy reservoir or a sink to stabilize the system. The resource can adjust its output to provide frequency support or stabilization. The resource must have the capability of ranging from 0.85 lagging to 0.95 leading power factor	MISO provides market construct under normal conditions, but NIPSCO must have the ability to maintain operation during under-frequency conditions in emergencies	✓	✓ Regulation A/S value	✓	MOD-025 Attach. 1 BAL-003-2
5	VAR Support	The resource can be used to deliver VARs out onto the system or absorb excess VARs and so can be used to control system voltage under steady-state and dynamic/transient conditions. The resource can provide dynamic reactive capability (VARS) even when not producing energy. The resource must have Automatic voltage regulation (AVR) capability	NIPSCO must retain resources on the transmission system to provide this attribute in accordance with NERC and IEEE Standards	✓	X	✓	VAR-001-5 VAR-002-4.1 IEEE 1453 - 2004
6	Geographic Location Relative to Load	The resource will be located in NIPSCO's footprint (electric/Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV or 345kV facilities and is not restricted by fuel infrastructure. The resource can be interconnected at 138kV or 345kV	MISO requires locational capacity resources and runs an LMP market to provide locational energy signals; under emergency restoration procedures, a blackstart plan reliant on external resources would create a significant compliance risk	Location drives some energy and capacity value	✓ LRZ6 for capacity; project-specific congestion as needed	✓	

INTEGRATING SCORING INTO THE IRP ANALYSIS

1. Gain stakeholder feedback
2. Engage a qualified third party to develop scoring methodology utilizing the metrics identified for individual technologies and in aggregate on a portfolio level and score and rank various generation resource technologies bid into the RFP across these metrics
3. Show preliminary scoring in the September Public Stakeholder meeting

WRAP UP & NEXT STEPS

Erin Whitehead, Vice President Regulatory & Major Accounts, NIPSCO

NEXT STEPS

Portfolio Modeling (July – September)

- IRP analysis will incorporate results of the RFP

Stakeholder Process

- Next Public Stakeholder Advisory Meeting #4 is scheduled for September 21st
- Reach out to Alison Becker (abecker@nisource.com) for 1x1 meetings

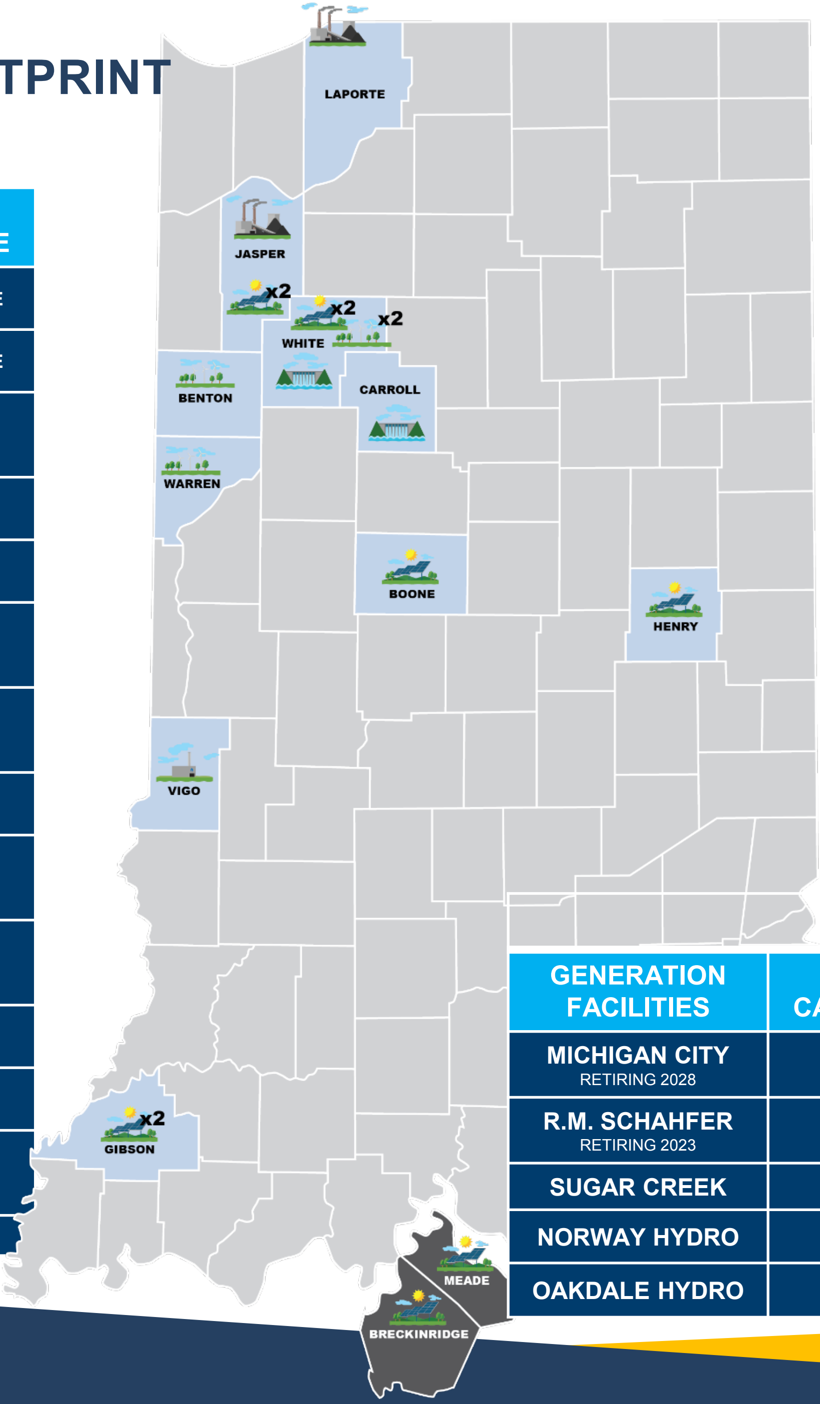
Stakeholder engagement is a critical part of the IRP process

APPENDIX

2023 ANTICIPATED GENERATION FOOTPRINT

New Generation Facilities

PROJECT	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102MW	WHITE	COMPLETE
JORDAN CREEK WIND	400MW	BENTON WARREN	COMPLETE
INDIANA CROSSROADS WIND	300MW	WHITE	2021
DUNNS BRIDGE SOLAR I	265MW	JASPER	2022
BRICKYARD SOLAR	200MW	BOONE	2022
GREENSBORO SOLAR	100MW +30MW BATTERY	HENRY	2022
INDIANA CROSSROADS SOLAR	200MW	WHITE	2022
GREEN RIVER SOLAR	200MW	BRECKINRIDGE & MEADE (KENTUCKY)	2023
DUNNS BRIDGE SOLAR II	435MW +75MW BATTERY	JASPER	2023
CAVALRY SOLAR	200MW +60MW BATTERY	WHITE	2023
GIBSON SOLAR	280MW	GIBSON	2023
FAIRBANKS SOLAR	250MW	SULLIVAN	2023
INDIANA CROSSROADS II WIND	204MW	WHITE	2023
ELLIOT SOLAR	200MW	GIBSON	2023

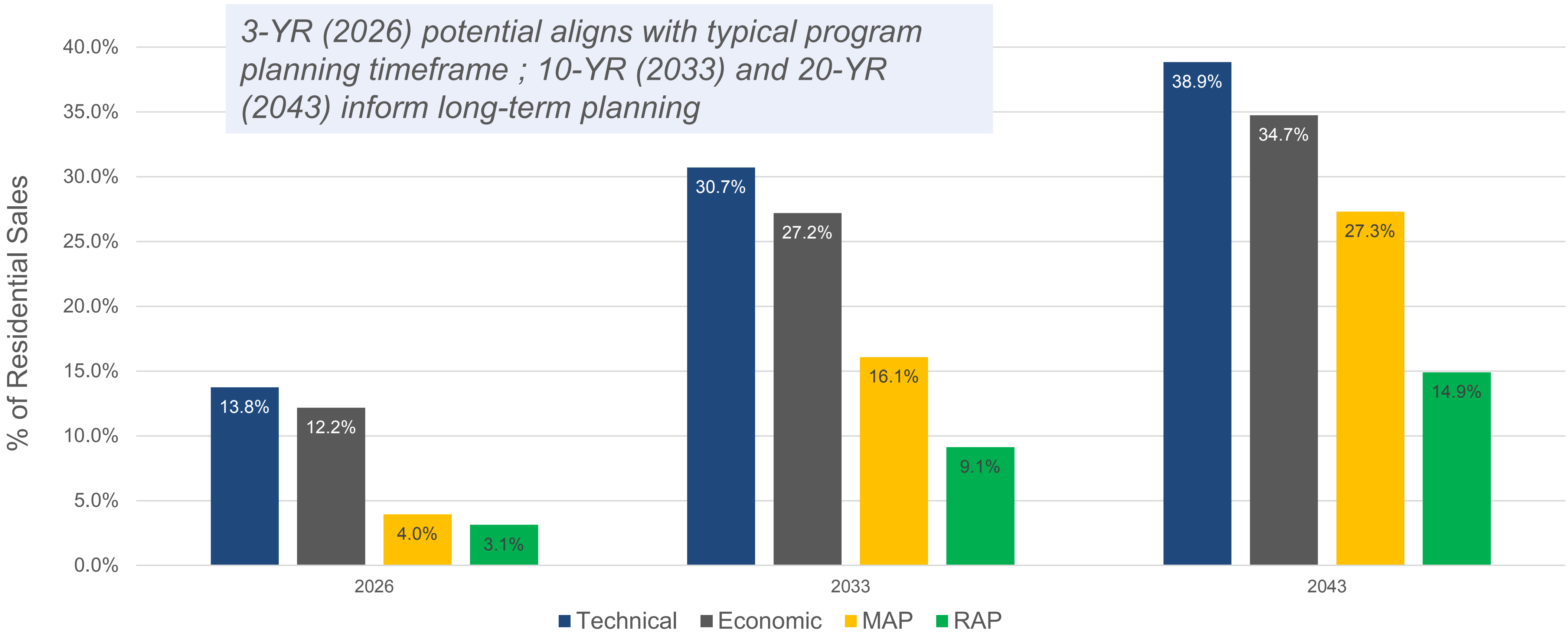


- Planned renewable resources expected to add 3,330MW installed capacity
- Additional $5 billion capital investments, much of which stays in the Indiana economy
- Generation transition plan generates more than $4 billion in cost-savings for our customers with industry-leading emissions reductions

Current Facilities

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	469MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2023	1,780MW	COAL	JASPER
SUGAR CREEK	535MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2MW	WATER	WHITE
OAKDALE HYDRO	9.2MW	WATER	CARROLL

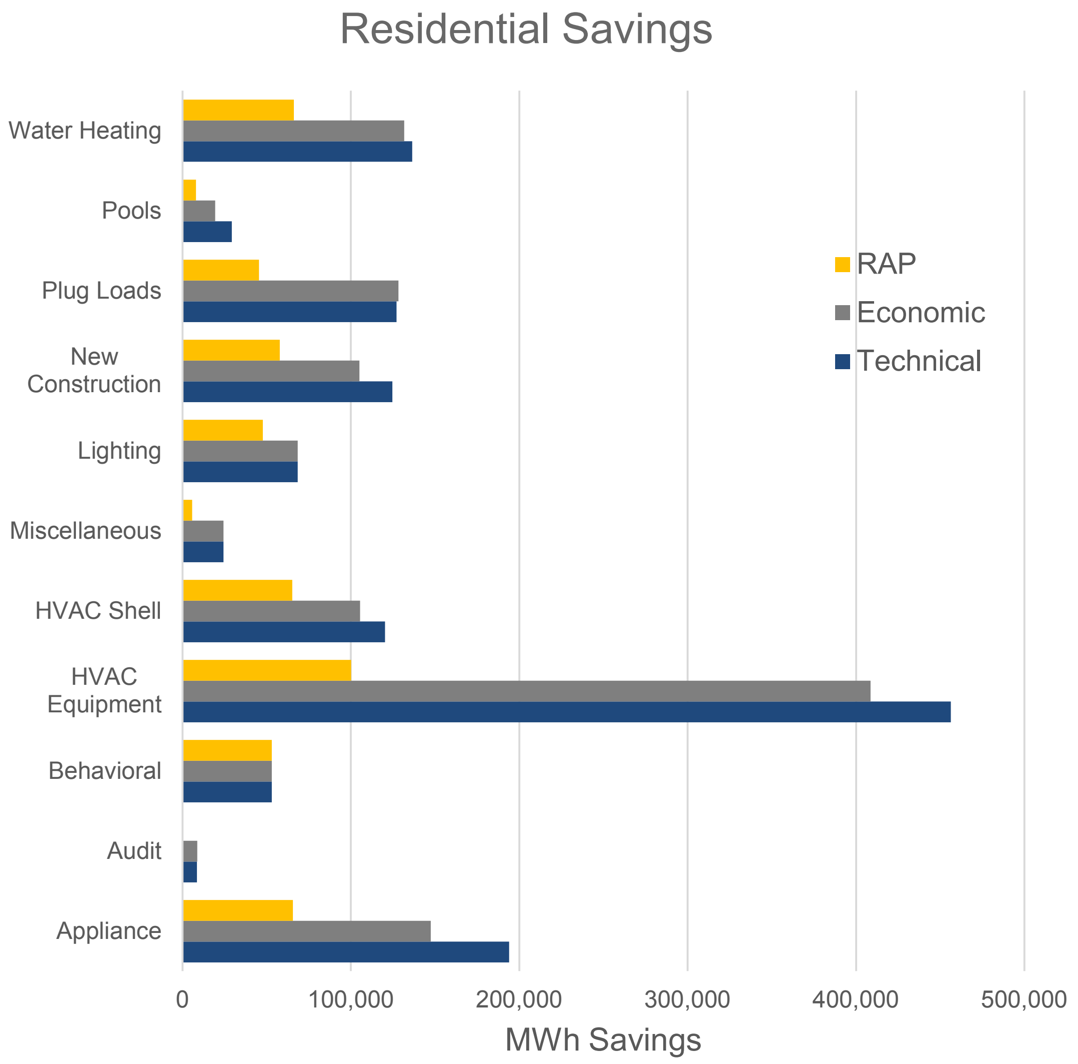
RESIDENTIAL ENERGY EFFICIENCY POTENTIAL SUMMARY



Results in chart show ***cumulative annual*** savings

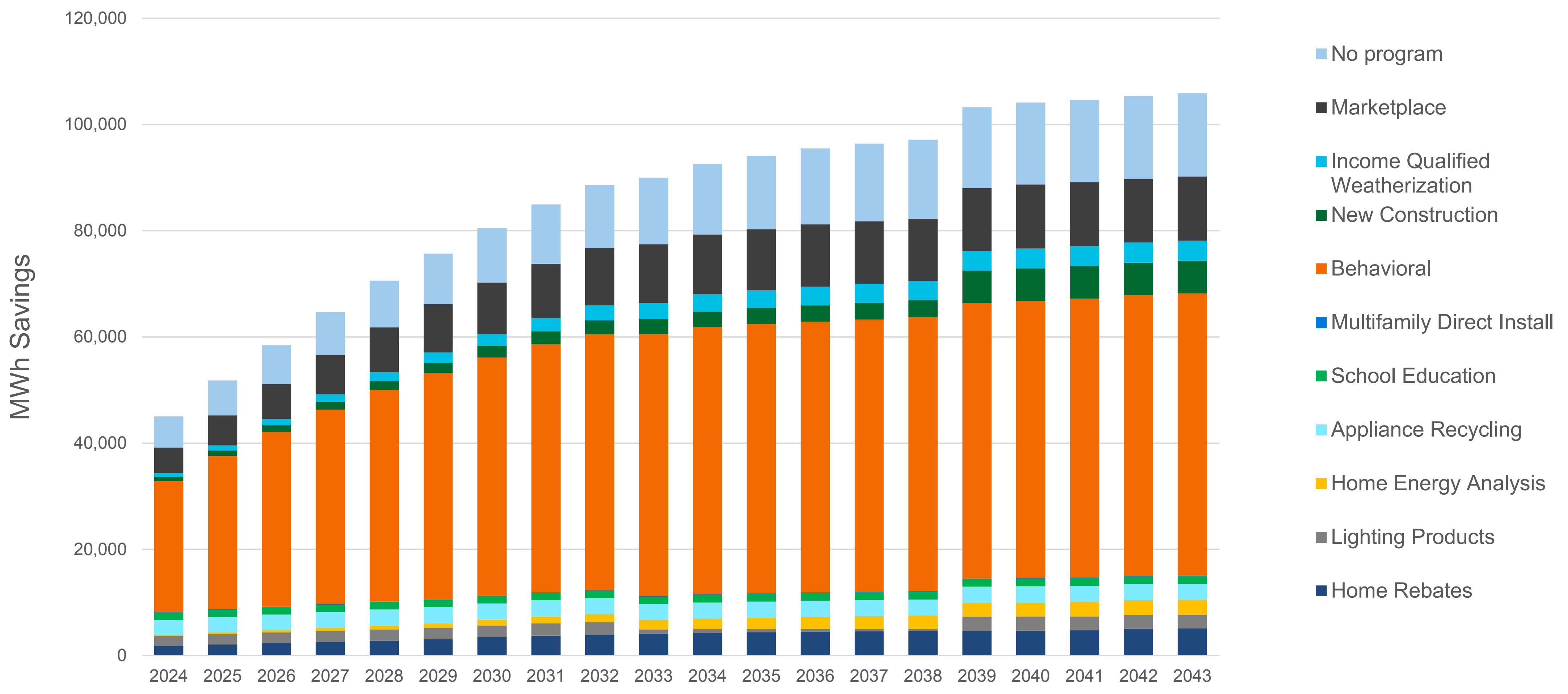
- *Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)*

20-YEAR CUMULATIVE ANNUAL RESIDENTIAL POTENTIAL BY END-USE



- Large amount of technical and economic potential in the HVAC Shell and HVAC Equipment end uses
- Balanced contribution by HVAC Equipment / Shell, New Construction, Water Heating and Appliances in the RAP level

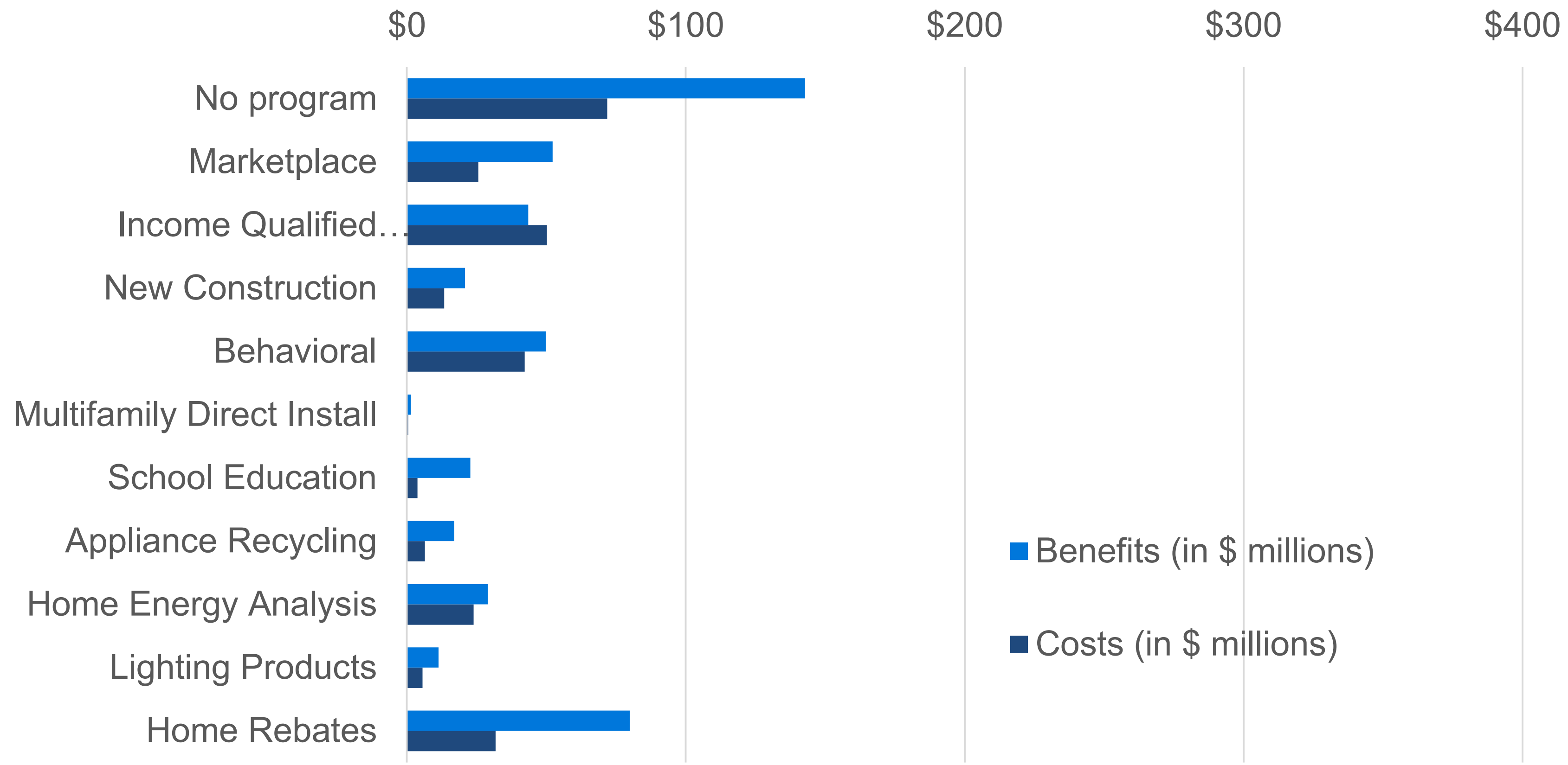
RESIDENTIAL INCREMENTAL RAP BY PROGRAM TYPE



RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

RAP

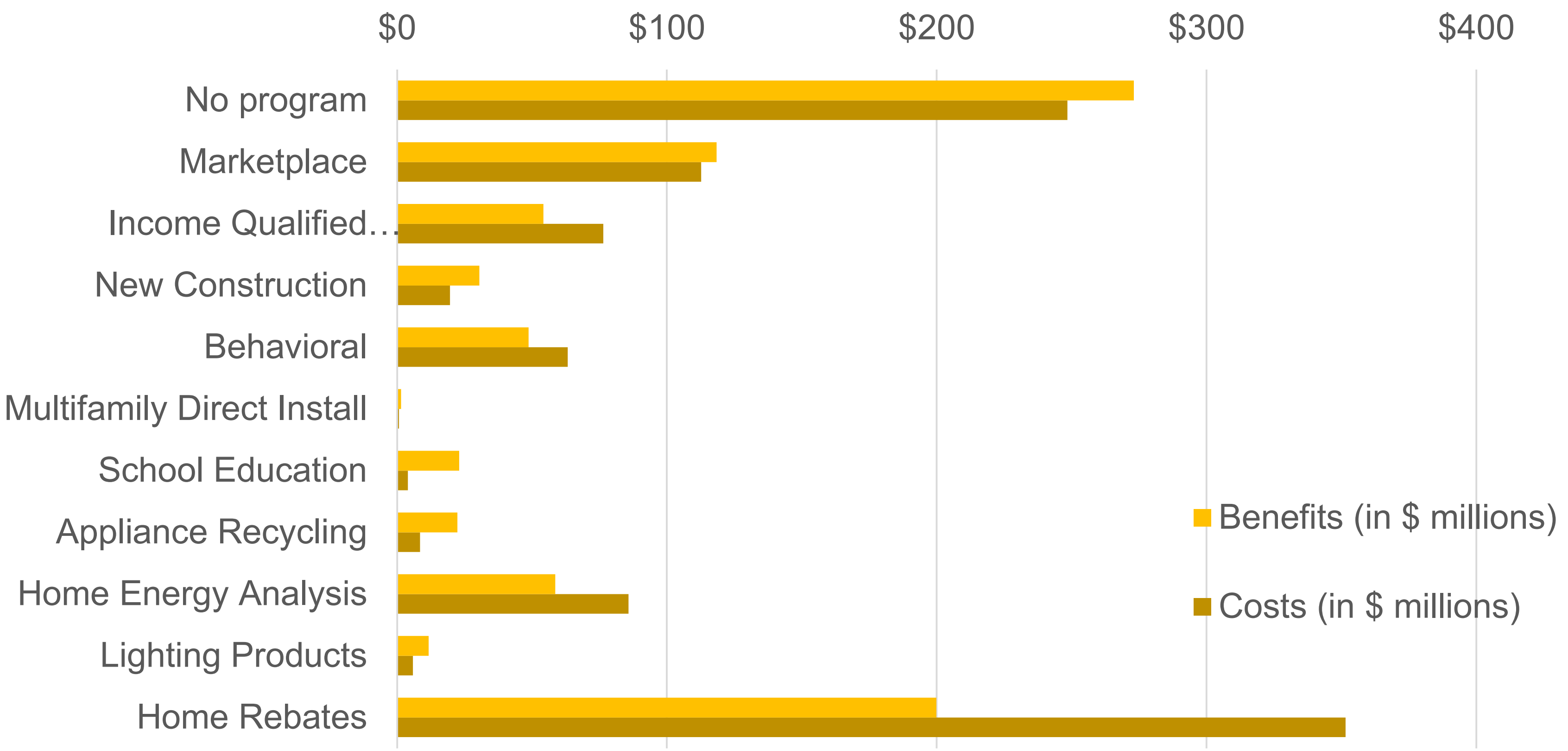


Levelized $/kWh
$0.07
$0.16
$0.21
$0.08
$0.08
$0.04
$0.03
$0.03
$0.17
$0.03
$0.13

RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

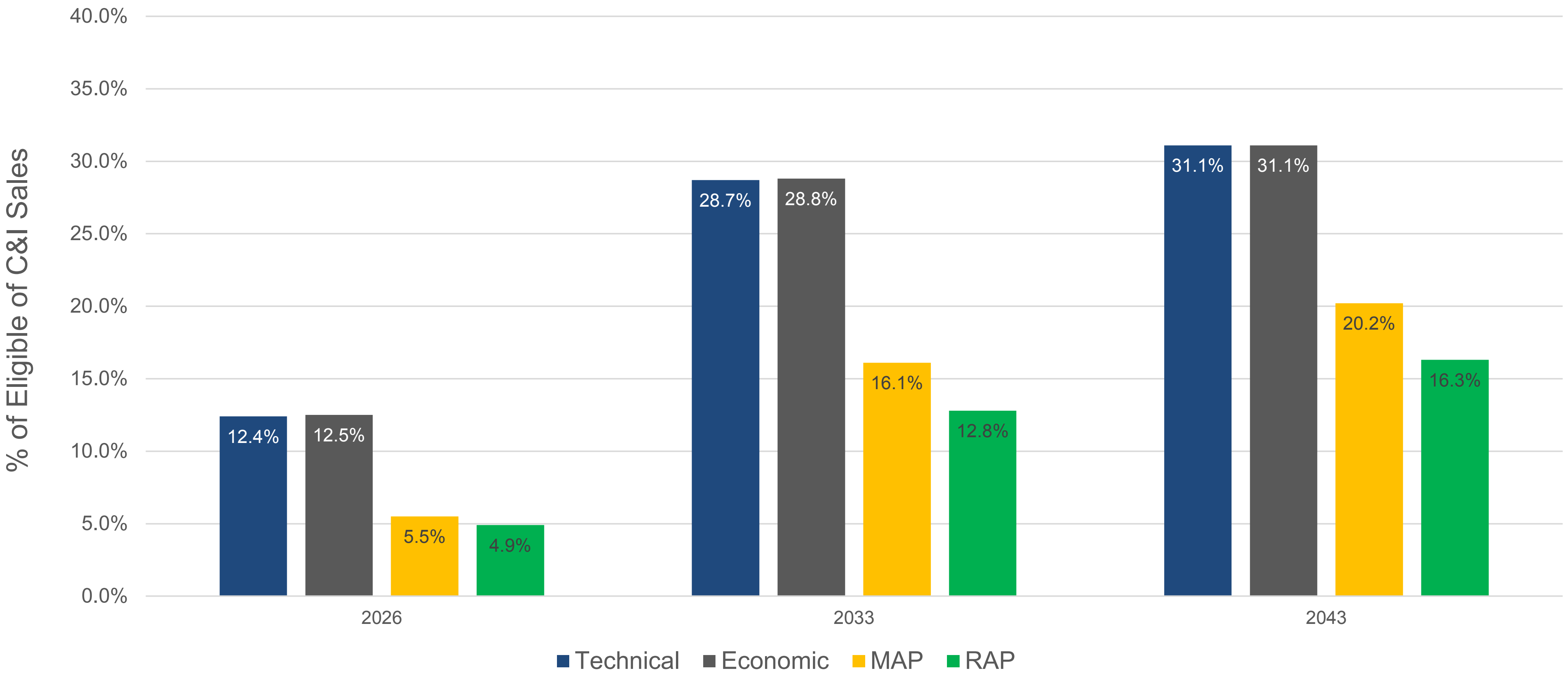
All values shown are 20-year net present values (NPV) in 2024$ for the 2024-2043 time period

MAP

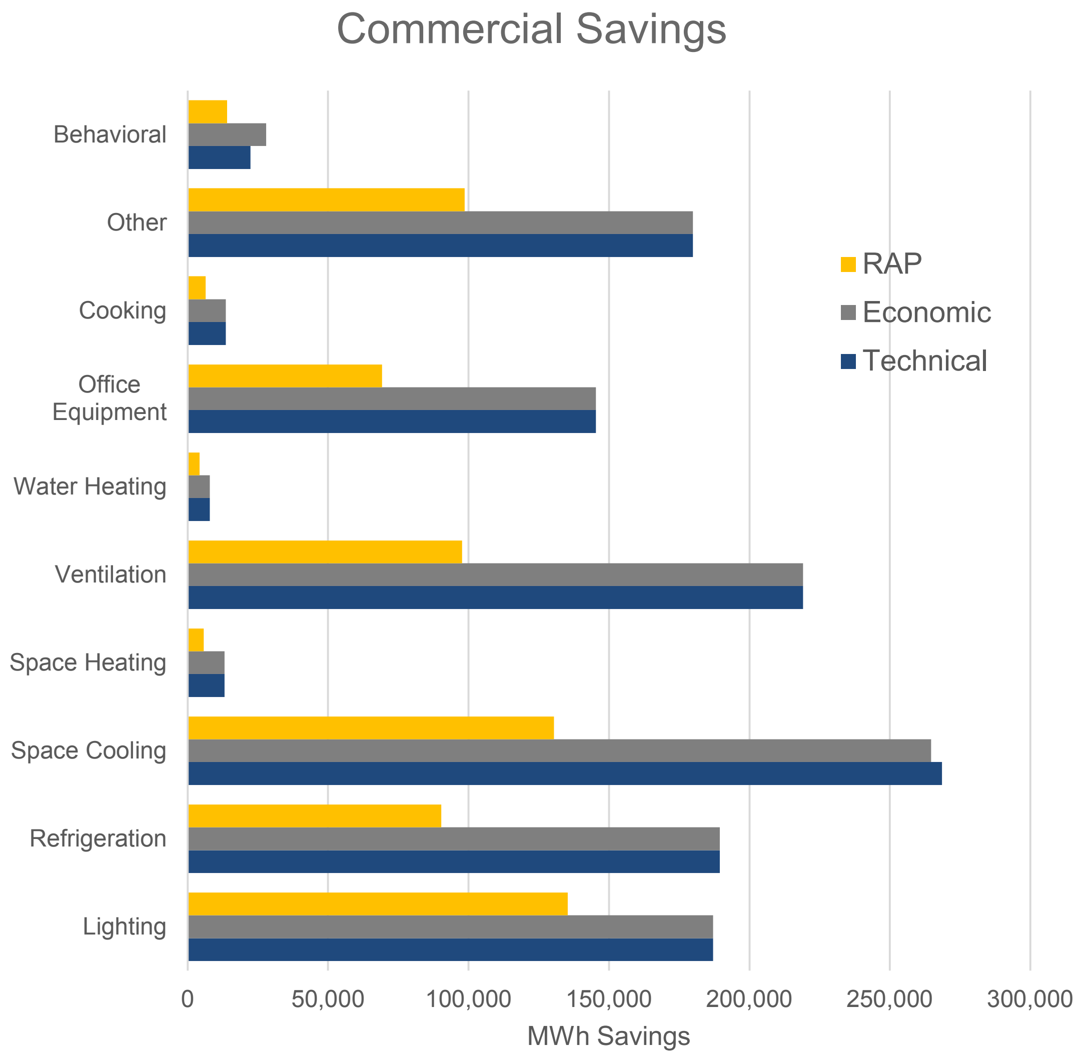


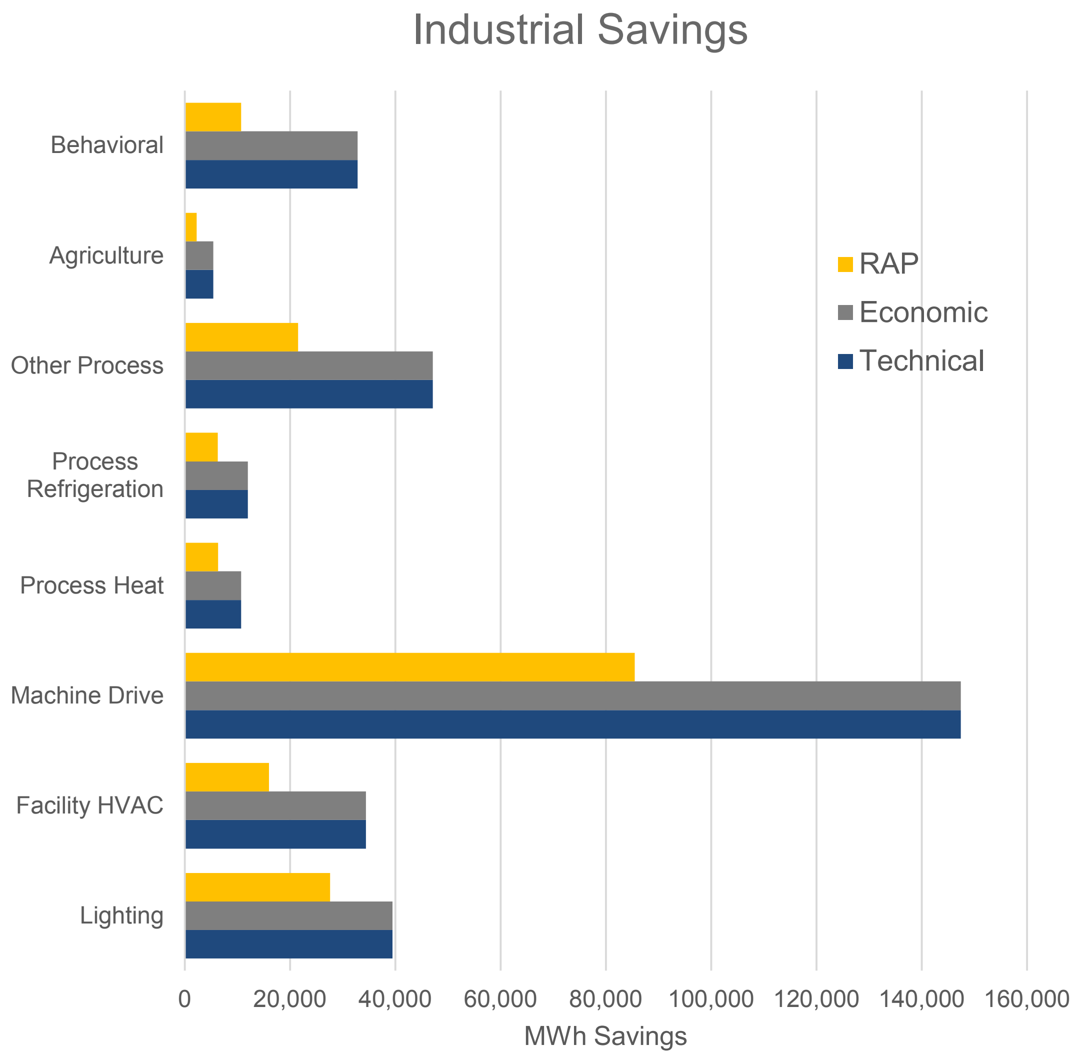
Levelized $/kWh
$0.13
$0.12
$0.24
$0.08
$0.13
$0.07
$0.03
$0.03
$0.28
$0.04
$0.53

C&I ENERGY EFFICIENCY POTENTIAL SUMMARY

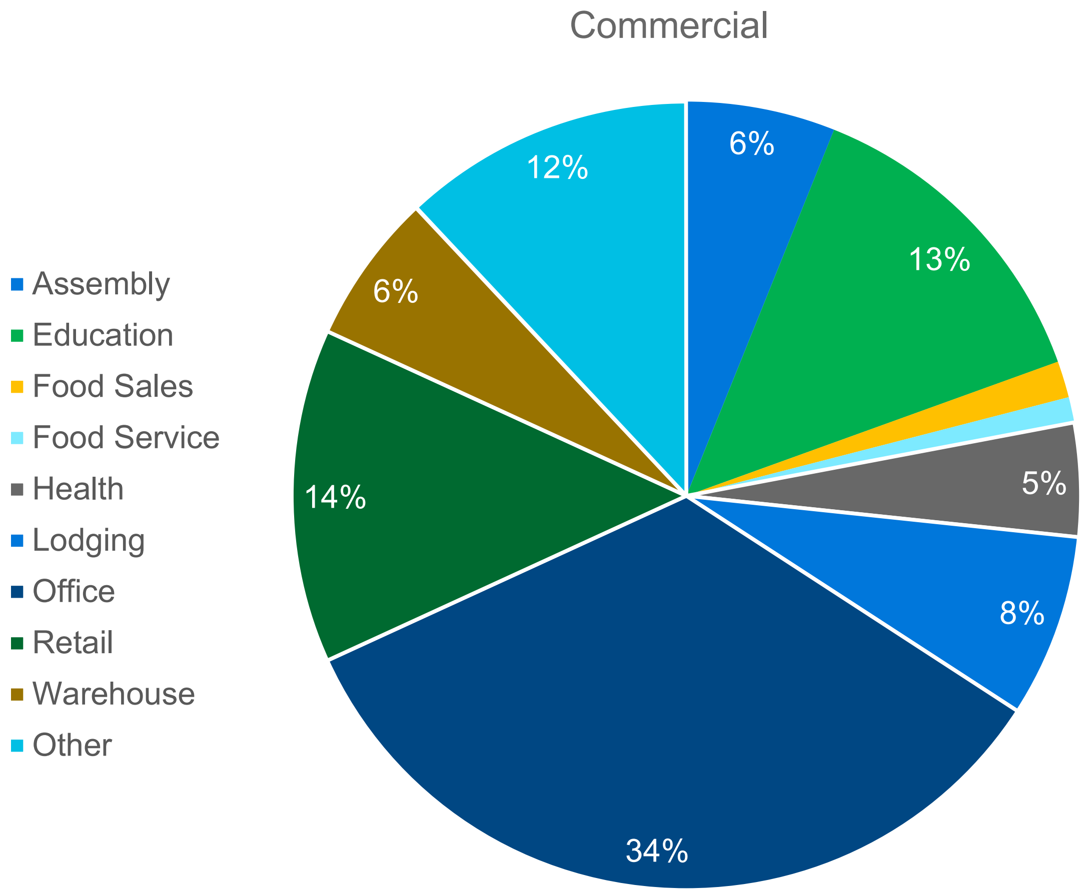


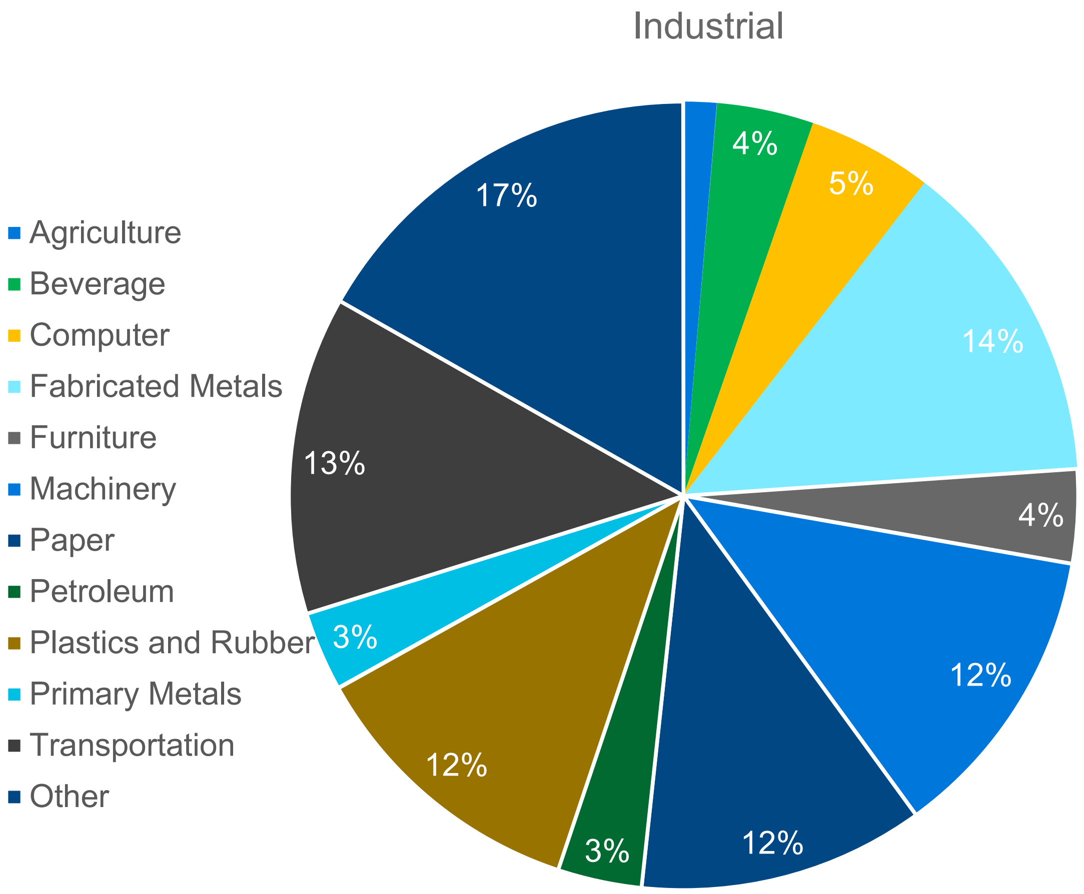
20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY END-USE





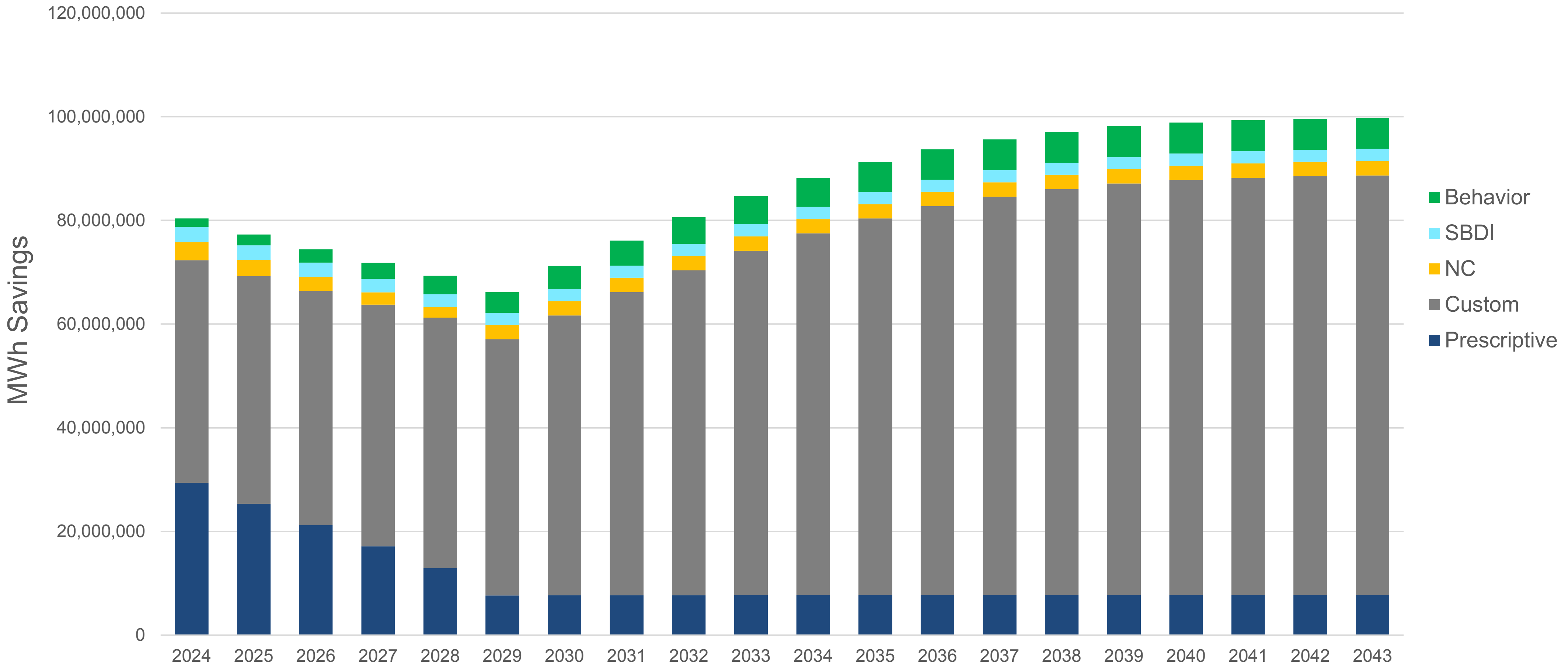
20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY BUILDING/INDUSTRY TYPE





Data labels for building/industry types with less than 3% of savings were removed for presentation purposes.

C&I INCREMENTAL RAP BY PROGRAM TYPE



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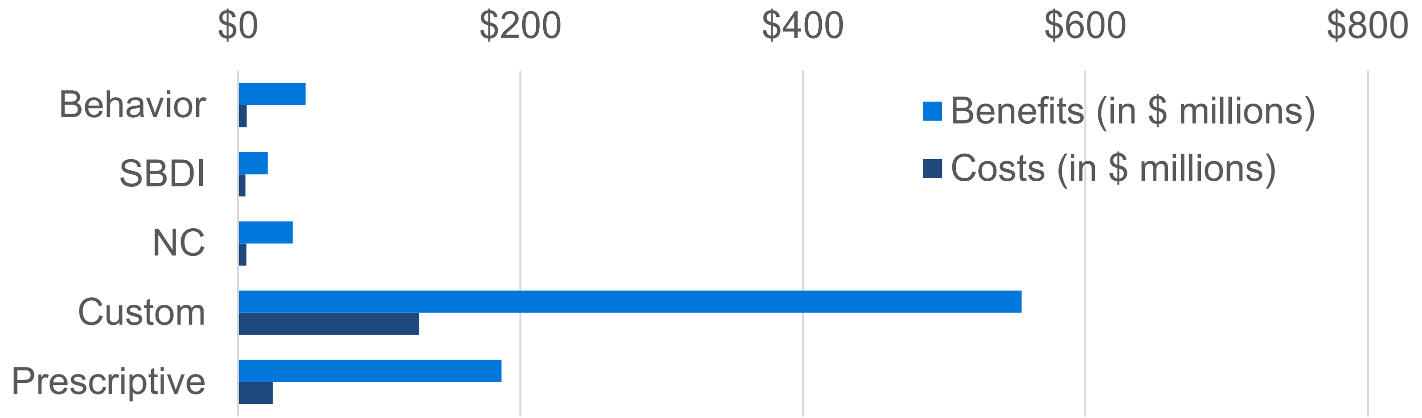

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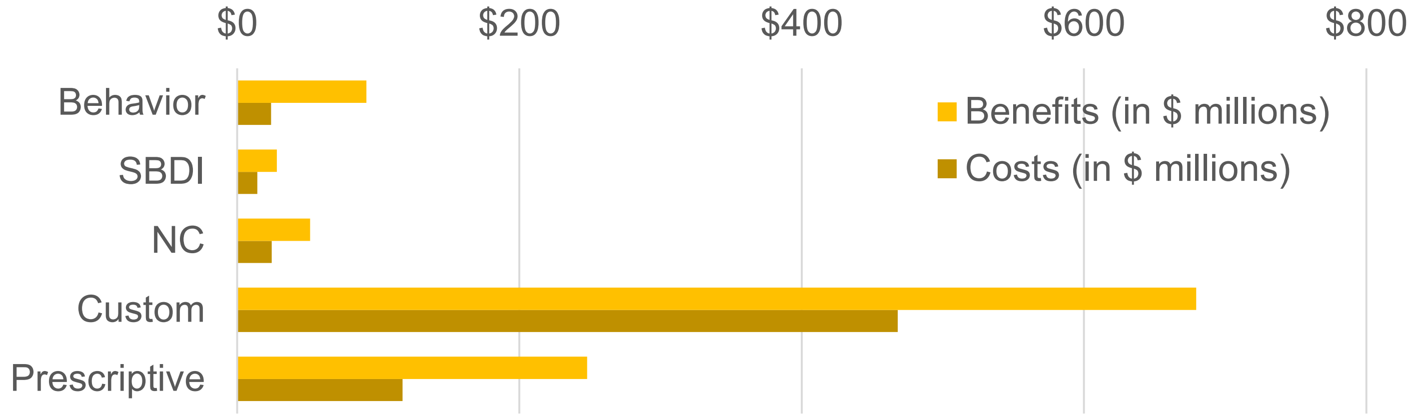
$0.03
$0.02
$0.03
$0.02

MAP



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$0.06
$0.06
$0.08
$0.07

PREVIOUS RELIABILITY ASSESSMENTS

2018 Retirement Scorecard	
Criteria	**Description**
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