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Attachment 1.1 Non-Technical Summary



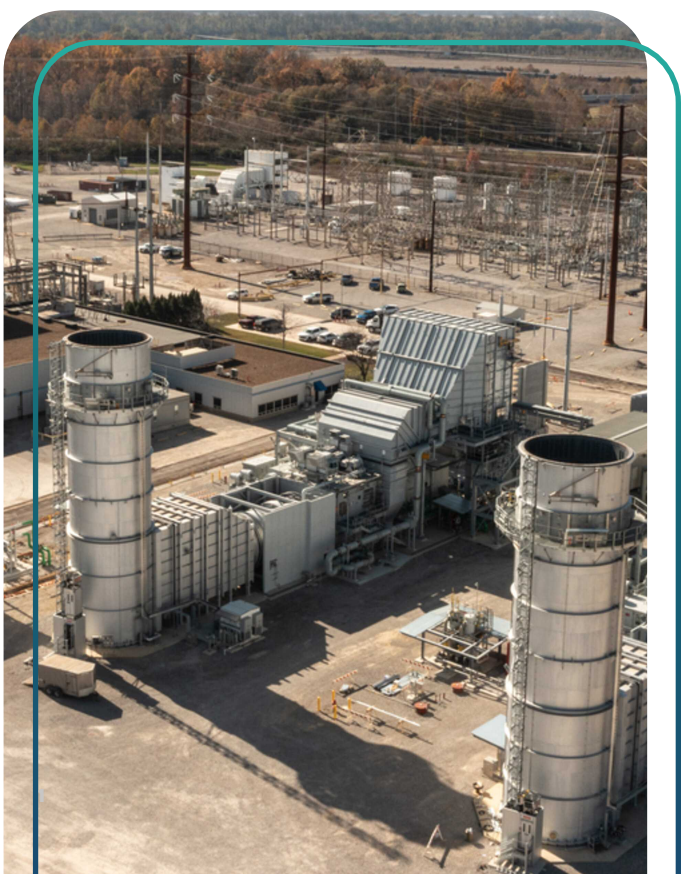
Executive Summary

(Non-Technical Summary)

Introduction

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South's ("CEI South"/"CEIS") 2025 Integrated Resource Plan ("IRP") is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has adhered to the requirements of the Indiana Utility Regulatory Commission ("IURC" or "Commission") and the guidance provided in the Commission's orders related to past Preferred Portfolios described in CEI South's previous IRPs both in the preparation of this IRP and the planning process that preceded the report.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. CEI South's 2022/2023 IRP identified a Preferred Portfolio that included a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with Demand Side Management ("DSM"), wind, and solar resources. CEI South began implementing the 2022/2023 IRP by filing two cases for which CEI South sought and received approval for (1) two signed purchase power agreements ("PPA") for wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project; and (2) approval for the 2025-2027 DSM Plan. Each of these filings were consistent with the 2022/2023 IRP, and as noted below, the IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered their cost relative to what could be acquired in the future, post elimination of Inflation Reduction Act ("IRA") tax incentives for wind and solar resources.



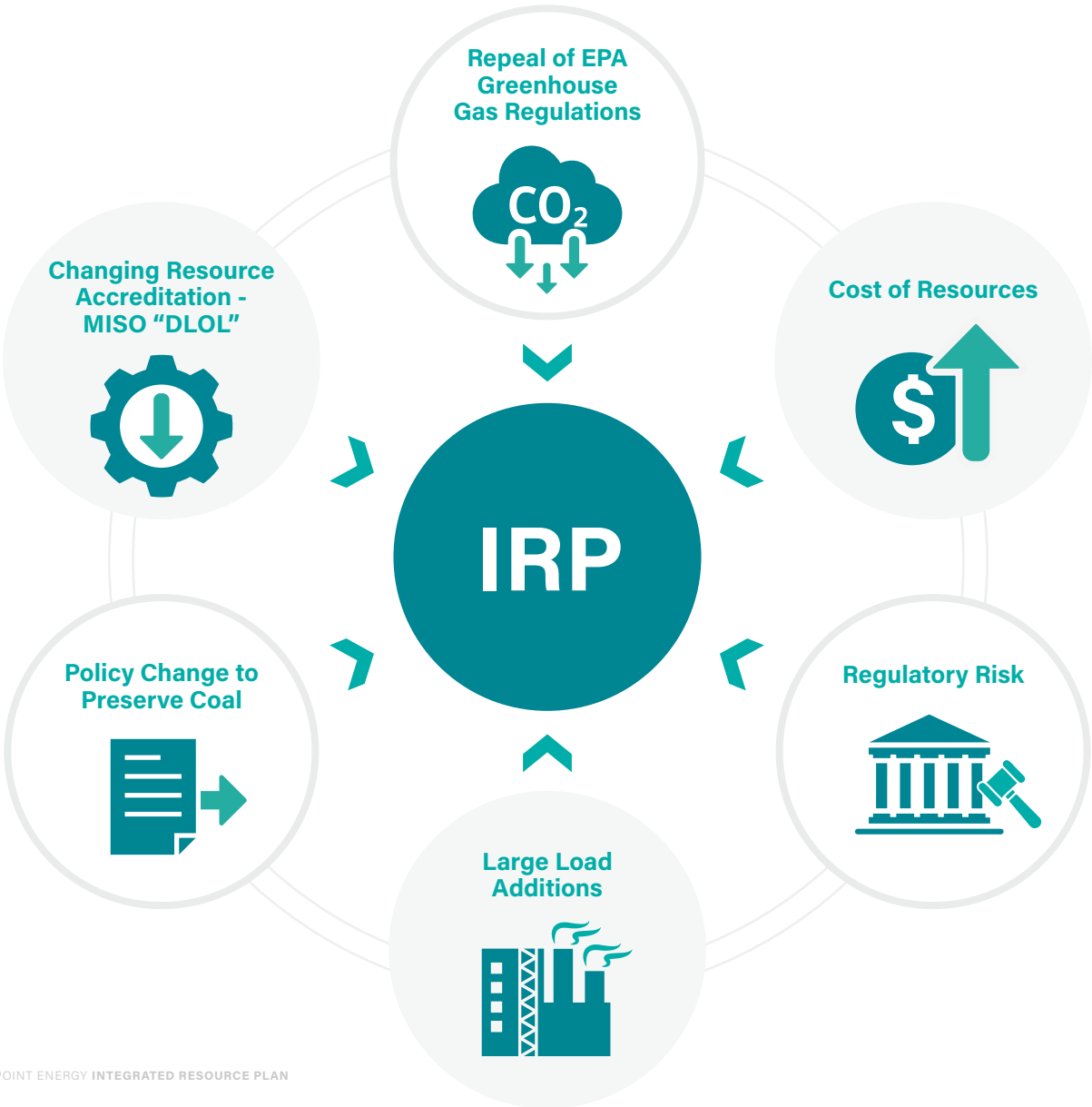
Now in 2025, during this time of unprecedented uncertainty across multiple fronts, the 2025 IRP analysis and its conclusions highlight the prudent decision for CEI South to reevaluate the timing of its generation fleet transition. Amid this time of evolving risk, and following our most recent rate case, there has been feedback from our customers and their advocates to keep bills more affordable. The IRP public meetings allowed us to listen to stakeholders and explain the uncertainty facing the industry.

Therefore, CEI South is reevaluating the timing of its transition to new or upgraded equipment in the near-term with a **focus toward rate stability and system reliability**.



The world looks very different than it did twelve months ago, when this IRP process began. The current pace and amount of change creates a variety of risks that, when weighed together, supports CEI South's decision to reevaluate the generation transition. The figure below summarizes current uncertainties.

Current Uncertainties





In 2023, CEI South filed its first electric base rate case in nearly 14 years. Ultimately, CEI South was approved to recover an additional $80 million from customers to continue to **safely and reliably deliver electricity** to their homes and businesses. While the energy transition CEI South set forth in prior IRPs was more affordable in the long run than continuing to operate its coal units, approximately 80% of the approved rate case increase was related to replacing A.B. Brown coal units 1 & 2 with 191 MW Posey Solar (~$385 million) and 460 MW natural gas combustion turbines (~$287 million). A.B. Brown's aging environmental equipment was required to be updated and replaced at a similar cost by 2024; this fact helps to illustrate the importance of strongly considering near-term affordability within the context of the IRP.

In this dynamic environment, CEI South has remained nimble to allow it to provide affordable and reliable service for its customers. Since the last IRPs were filed, there have been significant challenges in moving forward with key pieces of the last two IRPs' Preferred Portfolios. Several solar projects were terminated due to shifting market dynamics and substantial delays in commercial operation dates—one exceeding four years, with others averaging more than three. These market changes and delays drove project costs beyond the levels approved by the Commission and above what CEI South believed economical for its customers.

As such, the Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025, due to cost increases beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had upward pricing pressure. After years of negotiation and a re-evaluation of this project, CEI South opted, in this IRP, to abandon this project in an effort to avoid additional customer bill impact.

Also, in early 2025, CEI South announced that it paused the plan to convert F.B. Culley 3 to natural gas, to be re-evaluated in this IRP. Within this analysis, CEI South utilized more refined cost estimates and assumptions based on our preparation to convert the unit. This decision to pause the conversion was not taken lightly and was the direct result of near-term affordability concerns raised by the community, along with the current uncertainties listed in the previous figure.

Although the previous IRP projected long-term cost savings, CEI South estimates that implementing all proposed projects as planned would have resulted in a near-term bill increase of approximately $18 per month over the next few years. CEI South also heard some stakeholders express interest in re-evaluating the

decision to convert F.B. Culley 3 within the context of the transparent IRP process, particularly given the near-term uncertainty driven by changes in the Federal and State administrations. CEI South's decision to reevaluate this path forward proved to be prudent. Under today's market conditions, (elimination of future Federal tax incentives for renewables, declining accreditation from MISO for renewables, increased price pressure on resources based on tariffs/ongoing supply chain issues), converting F.B. Culley 3 to natural gas by 2030 with renewables is projected to be the second highest cost portfolio evaluated, 17% higher than the lowest cost portfolio examined and 14% higher than the Preferred Portfolio.

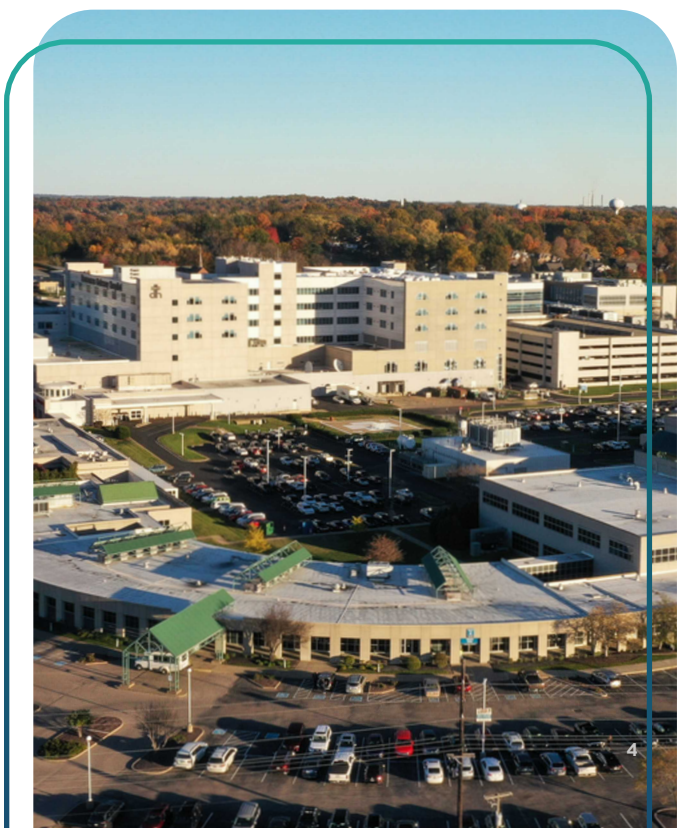
CEI South began its 2025 IRP process in early 2025 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company's exploration included significant input and dialogue with stakeholders. While starting with our 2022/2023 IRP framework as a basis for the 2025 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to, the following:

- expanded sensitivity analysis (distributed solar incentive, large load additions, Demand Response term, etc.);
- increased collaboration with transmission and distribution planning;
- enhanced transmission analysis, unserved energy, capacity risk, etc.;
- inclusion of an expected data release schedule;
- five pillars focused score card with an expanded view of affordability; and
- refreshed IRP layout with enhanced description of analysis and results.

Over the last year, CEI South has participated in active discussions with several large load customers, and there was considerable stakeholder interest in understanding how CEI South would serve a large load addition. In order to maintain maximum flexibility, CEI South responded by including large load sensitivities and adding an alternate reference case to its analysis.

To maintain maximum flexibility and agility in these uncertain times, CEI South has selected both a **Preferred** and an **Alternate Preferred Portfolio**.

The Preferred Portfolio assumes the status quo for our territory. The Alternate Preferred Portfolio was developed should CEI South be in a position to provide power to a large load addition.





The alternate reference case maintains reference case market conditions but includes a potential large load addition that grows by 250 MWs per year, topping out at 1.5 GWs above CEI South's current retail load. This large load profile is indicative of ongoing discussions/ negotiations with prospective customers. Potential large load customers require utilities to be able to serve their needs quickly, or they will take their economic development, supporting jobs and the tax base for the community, elsewhere.

CEI South plays a proactive role in **advancing economic development** across southwestern Indiana. By developing an Alternative Preferred Portfolio, the company enhances its agility **to better serve and support the region's evolving needs**.

With the need to provide reliable, stable, resilient, affordable, and sustainable energy to our customers, both Preferred Portfolios call for the conversion of A.B. Brown natural gas Combustion Turbine ("CT"), units 5 and 6, to an efficient Combined Cycle Gas Turbine ("CCGT"). The Preferred Portfolio provides customers with near and long-term rate stability and pushes this decision out to future IRPs until there is more clarity on the future while the Alternate Preferred Portfolio moves forward with the conversion by 2030. In either case, the decision on F.B. Culley 3's replacement will be decided in a future IRP. Both portfolios include the remaining solar and wind energy resources—secured prior to this IRP—at significantly lower costs compared to future renewable projects that may not benefit from near- to midterm Federal tax incentives. Both portfolios also include battery storage to replace CEI South's smallest and most inefficient coal unit, F.B. Culley 2. This allows time for CEI South to further evaluate the economics of this option relative to purchasing required capacity to maintain reliability. Finally, both include continued investment in energy efficiency and demand response resources.

The company has signed a contract with a demand response ("DR") aggregator for commercial and industrial DR by 2026. CEI South is also nearing the beginning of a pilot which was approved in its recent rate case to explore time-based rates. The Preferred Portfolio includes indicative DR amounts for IRP planning purposes.

Preferred Portfolio

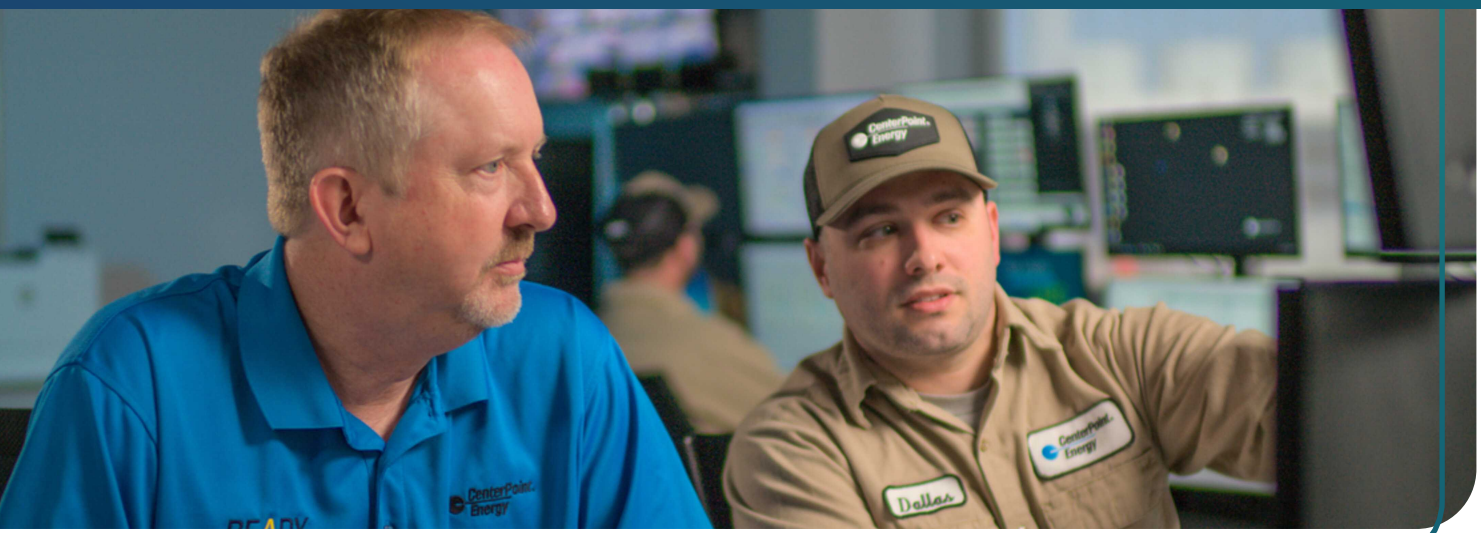


CEI South's Preferred Portfolio takes a more gradual approach to its generation transition, providing time for greater clarity amid today's unprecedented uncertainty. This approach also allows time for transmission system upgrades through CEI South's current TDSIC plan and the MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 projects, which support enhanced reliability and resilience.

The Preferred Portfolio provides for **maximum flexibility** to pivot should the future turn out differently than expected.

This is crucial in this current environment, where developers are less willing to share in cost risk which drives generation project costs higher for utility customers, with uncertainty around how much accreditation resources will receive from MISO to meet reliability requirements, or the direction of future greenhouse gas regulations.

In the short term, the plan maintains the F.B. Culley 2 interconnection, with possible 90 MW battery storage reuse and continues the demand side management programs. In the long-term and to be reevaluated in a future IRP, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit in 2034 to replace F.B. Culley 3 by 2035. The plan also calls for 50 MWs of battery storage in 2040 and 2045 to meet its planning reserve margin requirements.



Preferred Portfolio: **How Did We Get Here**

While current modeling suggests that replacement of F.B. Culley 3 coal with conversion of CEI South's two new CTs to a CCGT by 2030 could save customers money in the long run, locking in this option for CEI South's retail customers could increase bills in the near-term, increase risk, and reduce future flexibility. The conversion of these units would cost approximately $1 billion dollars or more and would likely be included in customer rates by 2030, costing customers up to $21 [1] more per month on average in the near term compared to the Preferred Portfolio which delays this decision. Affordability, one of the five pillars, is top of mind for CEI South and its customers following our recent rate case and has also been prominent within IRP stakeholder comments.

By slowing down the generation transition, customers should benefit from rate stability while preserving the flexibility—a critical capability in today's landscape—for CEI South to reevaluate F.B. Culley 3's fate in a future IRP. For example, in its previous IRP, CEI South had planned to convert F.B. Culley 3 to natural gas by 2027 with a continued renewables build out. However, just three years later, shifting external factors—such as reduced MISO accreditation for renewables, increased costs driven by market uncertainty, and diminished federal support following the rollback of key IRA tax incentives—have made this a more costly strategy relative to alternatives (14-17% higher).

Preferred Portfolio: **Overview**

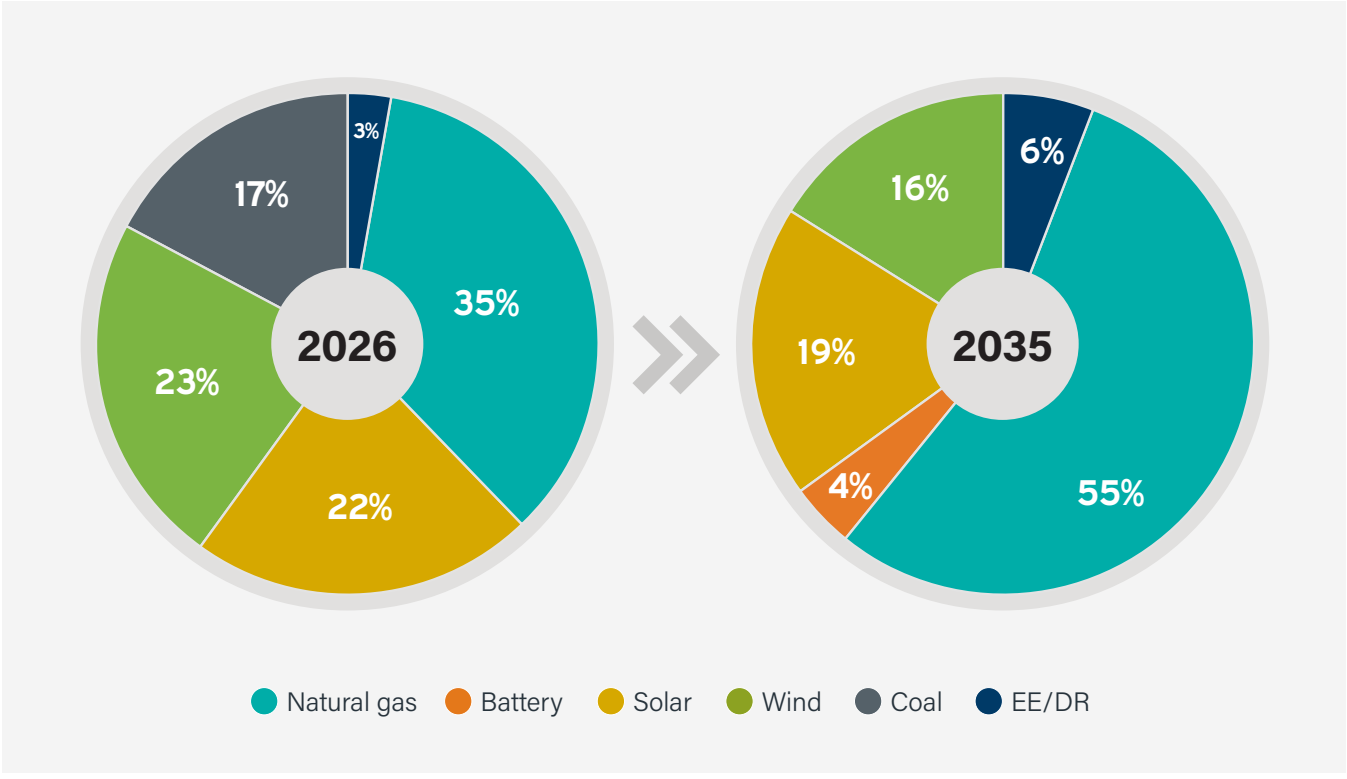
Between now and 2034, the Preferred Portfolio preserves the option to replace F.B. Culley 2 coal plant when it is suspended at the end of 2025 with a 90 MW battery storage unit by the end of 2028. CEI South will conduct another Request for Proposal ("RFP") to determine if the cost of this project has escalated from what was bid in the All-Source RFP and compare the cost to required capacity purchases. Based on the All-Source RFP, the cost of this battery is nearly identical to purchasing an equivalent amount of capacity on the market. Locking in capacity with a battery should help stabilize bills versus purchasing from a volatile capacity market that is expected to see rising prices as MISO's reserve margin continues to decline. It also helps maintain reliability with an on-system resource to help supply stored energy when it is needed most.

The Preferred Portfolio secures cost savings from wind and solar resources identified and acquired through previous IRPs, ahead of the repeal of IRA renewable energy tax incentives under the One Big Beautiful Bill Act ("OBBBA"). It also maintains operational flexibility by allowing F.B. Culley 3 to continue to run on coal, allowing time to reevaluate if conversion to natural gas or earlier retirement makes sense in a future IRP.

[1] *Not including expected offsetting sales revenues*

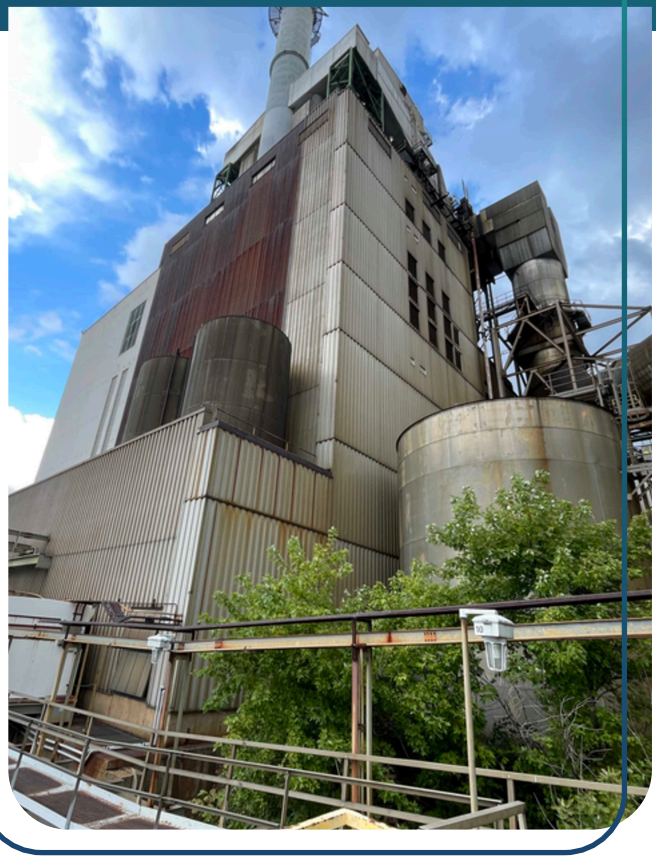
Preferred Portfolio: **Key Considerations**

CEI South's preferred resource plan reduces risk through continued diversification, lowers the cost to serve load over the next 20 years, and provides flexibility to evaluate and respond to future needs through subsequent IRPs.



The Preferred Portfolio has several advantages, including:

1. Among the least cost options, within **3% of the lowest cost portfolio** in the long term.
2. Provides near-term rate stability for **customer affordability** by delaying large capital investment.
3. Provides **affordable**, **reliable energy** with a well-balanced mix of **sustainable energy resources** and continued focus on demand side resources.
4. F.B. Culley 2 battery storage **enables avoidance of certain required capacity purchases**.



5. **Maximizes flexibility** to navigate unprecedented uncertainty; **minimizes risk**.

   - Delaying large capital investment also mitigates cost risk, as we live in very uncertain times. Current uncertainty is driving near-term price increases for various resources. It also helps reduce long-term price risk by allowing more time to better understand the direction of Environmental Protection Agency ("EPA") greenhouse gas regulations. Over the last 16 years environmental regulations have flexed and retracted with each administration. It is possible that in the next administration an aggressive greenhouse gas regulation could materialize which could throttle how much an efficient combined cycle gas unit may run, or a more stringent environmental regulatory requirement is finalized that would significantly increase operating costs for a fossil-fuel fired generation unit.

   - Provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. Maximum flexibility is important as demonstrated by the massive amount of change that has been experienced over the last decade. By proactively canceling high-cost renewable projects and securing affordable wind power purchase agreements, CEI South has taken decisive action to avoid increasing customer expenses. This forward-thinking strategy also strengthens CEI South's position ahead of MISO's upcoming accreditation reforms—reforms that are expected to significantly reduce the reliability value of certain resources, particularly solar. Additionally, pausing the conversion of F.B. Culley 3 and reevaluating under current market conditions preserves future flexibility at a lower near and long-term cost to our customers.

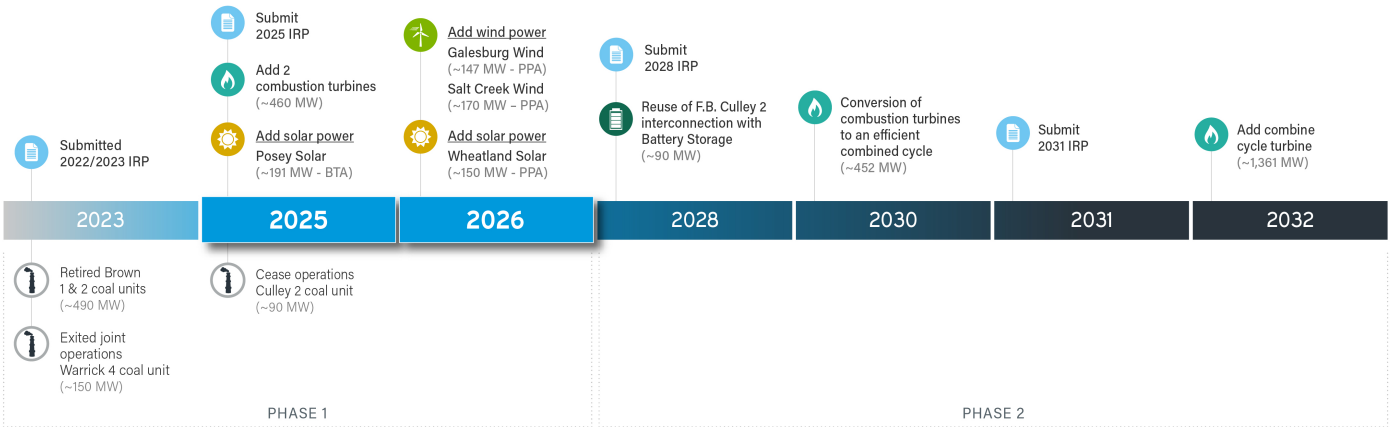
6. **Preserves tax base and jobs in Warrick County.** The replacement of F.B. Culley 2 with a battery storage system provides economic benefit to the community, whereas purchasing this needed capacity from the market does not. It is the equivalent of renting a home vs buying. Allowing F.B. Culley 3 to continue running in the near-term preserves tax base, benefiting the county while it continues to depreciate; it also maintains jobs associated with coal handling. Additionally, the facility uses Indiana-mined coal, preserving mining jobs and supporting the state's economy.

7. Maintains a base load generator on the east side of our system, providing **reliable**, **stable**, and **resilient power**.

   F.B. Culley Unit 3 continues to deliver essential voltage support to our community, providing valuable time for needed transmission expansion and offering flexibility as we await greater clarity on the future of nearby generation facilities that currently play a key role in grid stability.

8. Provides **flexibility** to serve a large load addition, should an **economic development** project materialize (See Alternate Preferred Portfolio).

Alternate Preferred Portfolio



The following Alternate Preferred Portfolio summary includes the process to identify the portfolio as well as an explanation of the planning process, all while focusing on CEI South's operations.

To maintain flexibility and stay nimble for potential economic development opportunities for southwestern Indiana, CEI South chose an **Alternate Preferred Portfolio** for a large load addition.

A large load addition scenario was created, starting at 250 MW and scaling up to 1,500 MWs in the early 2030s. Conversion of the new A.B. Brown CTs to a CCGT and F.B. Culley 2 battery storage become the most affordable options in the near-term to support the ramp. The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028 and continues demand side management programs.

Additionally, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit by 2030, continues F.B. Culley 3 on coal, and builds a large natural gas combined cycle unit by 2032 to support the large load addition. This build out is paired with near-term reliance on the market and aligns with system capabilities.

Alternate Preferred Portfolio: **How Did We Get Here**

Per stakeholder feedback, CEI South evaluated the potential for a large load addition that would scale over time. This scenario complements the multiple large load sensitivities conducted during the IRP and reflects insights gained from CEI South's ongoing conversations over the past several years with prospective customers across a range of industries. Commonly, CEI South is asked to determine how fast the system can be ready to accommodate a potential customer's business plan. Timelines have been compressed from what was considered normal in the past. These requests require CEI South's generation planning team to work closely with its transmission planning team. This scenario incorporates feedback from both teams, along with expert third party consultants to evaluate what is possible.



Alternate Preferred Portfolio: **Overview**

In the alternate reference case, all market conditions remain the same as reference case conditions, but load is increased by 250 MWs per year until the cumulative load reaches 1,500 MWs in the early 2030s. Load evaluations from prospective customers of this size were extremely uncommon for economic development projects in the past but are now approaching routine. CEI South selected the optimized, least cost model results as the Alternate Preferred Portfolio.

By including an Alternate Preferred Portfolio, CEI South is preserving necessary flexibility to quickly pivot, keeping southwestern Indiana competitive for economic development and growth. The Alternate Preferred Portfolio adds tax base and jobs to the community, not only from the prospective customer facility, but also from the infrastructure needed to support it. CEI South's analysis shows that generation near the site of the load is necessary to provide stability and avoid a large transmission outlay.

Alternate Preferred Portfolio: **Key Considerations**

The Alternate Preferred Portfolio:

- Preserves maximum future flexibility, keeping southwestern Indiana competitive for economic development and growth (Speed to market is important for most prospective customers),
- Adds tax base and jobs in our community, which helps all customers thrive,
- Aligns with Federal and State goals,
- Utilizes F.B. Culley 3 until replacement/conversion to natural gas is decided, and
- Adds efficient on-system base load generation for **reliability**, **stability** and **resilience**.

CEI South will continue to have ongoing conversations with prospective customers. At this point, no contract has been signed. As we prepare for this potential, CEI South will continue to evaluate possible timelines and costs necessary to serve. While the Alternate Preferred Portfolio provides a possible path, the resource mix to serve will be heavily influenced by a potential customer's need for low-cost power, along with other criteria important to the prospective customer. As such, CEI South modeled alternatives to aid in these conversations. CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations turn into negotiations/contracts.

CenterPoint Energy Overview

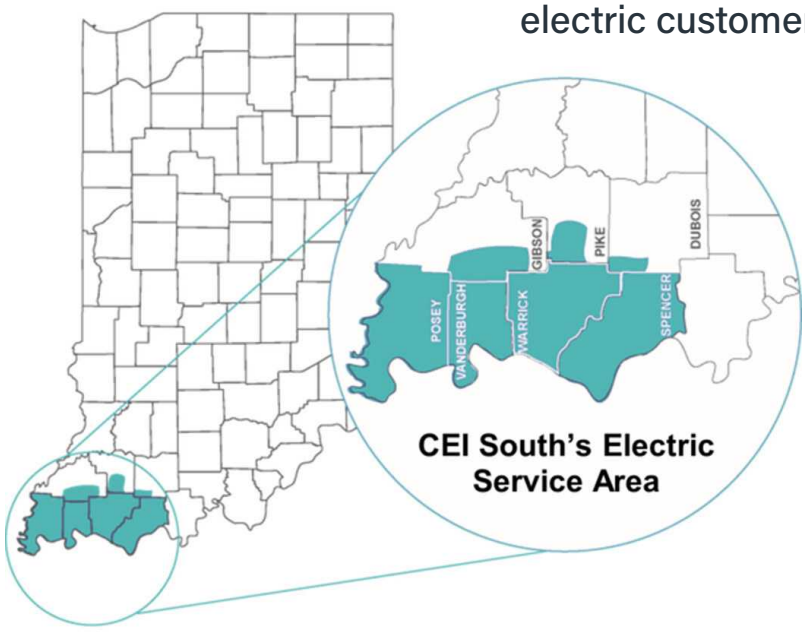
Provides energy delivery services to more than

150,000

electric customers

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in southwestern Indiana. In 2024, approximately 45% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers, and 25% were made to small commercial customers.

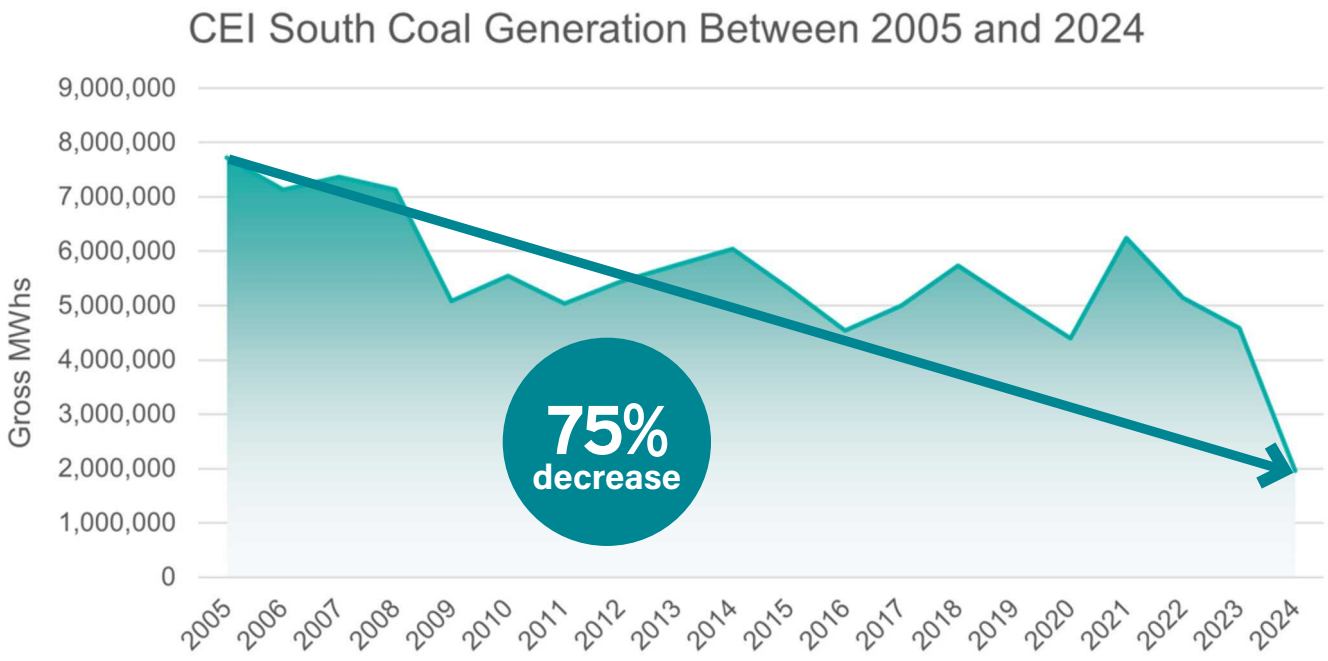
The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.



Unit [2]	Installed capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date/Expiration	Unit Age	Coal Unit Environmental Controls [3]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	230	Gas	2025	N/A	<1	
A.B. Brown 6	230	Gas	2025	N/A	<1	
Blackfoot	3	Renewable Gas	2009	N/A	16	
Fowler Ridge	50	Wind PPA	2010	2029	15	
Benton County	30	Wind PPA	2007	2028	18	
Galesburg	147	Wind PPA	2026	N/A	N/A	
Salt Creek	170	Wind PPA	2026	N/A	N/A	
Troy	50	Solar	2021	N/A	4	
Posey	191	Solar	2025	N/A	<1	
Wheatland	150	Solar PPA	2026	N/A	N/A	
Volkman Rd	2	DG Solar + battery	2018	N/A	7	
Oakhill	2	DG Solar	2018	N/A	7	
Post House	<1	DG Solar	2020	N/A	5	

[2] CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.
[3] Both Coal units are controlled for Sulfur Dioxide ("SO2"), Nitrogen Oxide ("NOx"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO3") and Sulfuric Acid ("H2S04").

CEI South has largely moved away from coal, with the retirement of A.B. Brown units 1 & 2, exiting the joint operating agreement for Warrick 4, and the planned suspension of F.B. Culley 2 at the end of 2025.



These resources have been replaced with a diverse mix of wind, solar, energy efficiency, demand response, and gas resources. The current analysis demonstrates that customers receive a better balance of near-term and long-term affordability and reliability by continuing to evaluate the opportunity to replace CEI South's smallest and least efficient coal unit, F.B. Culley 2, with battery energy storage while deferring a decision on replacement of CEI South's last remaining coal unit that it operates, F.B. Culley 3, to a future IRP.

Integrated Resource Plan

Every three years CEI South submits an IRP to the IURC as required. The IRP describes the analysis process used to evaluate the optimal mix of generation, storage, energy efficiency, and demand response resources (resource portfolio) to meet customers' needs for reliable, resilient, stable, affordable, and environmentally sustainable power ("the five pillars") over the next 20 years. The IRP helps set the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

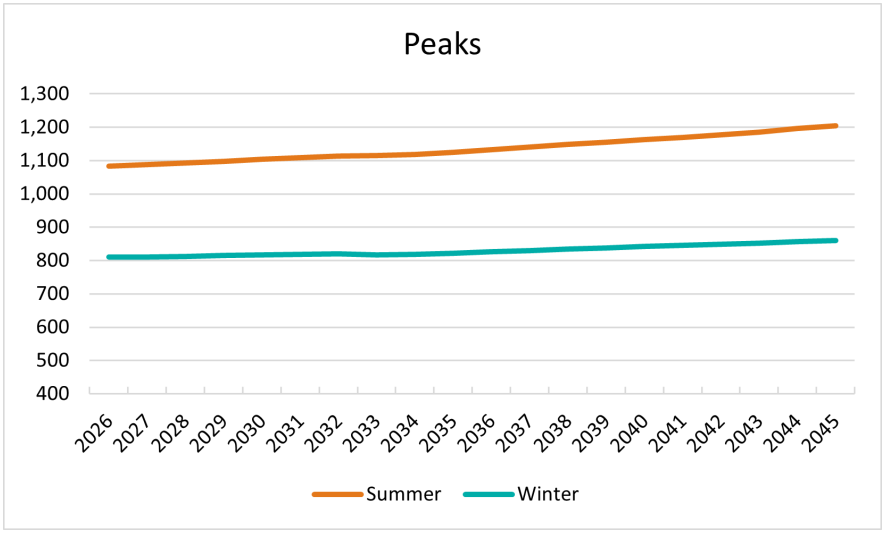
CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, trade associations and environmental advocacy groups. CEI South placed considerable emphasis on the five pillars, rate stability, risk, and resource diversity. The IRP process continues to increase in complexity as MISO continues to implement resource accreditation reforms to maintain reliability of the system that includes increased levels of renewable resources, battery energy storage, and natural gas resources to replace existing coal resources.

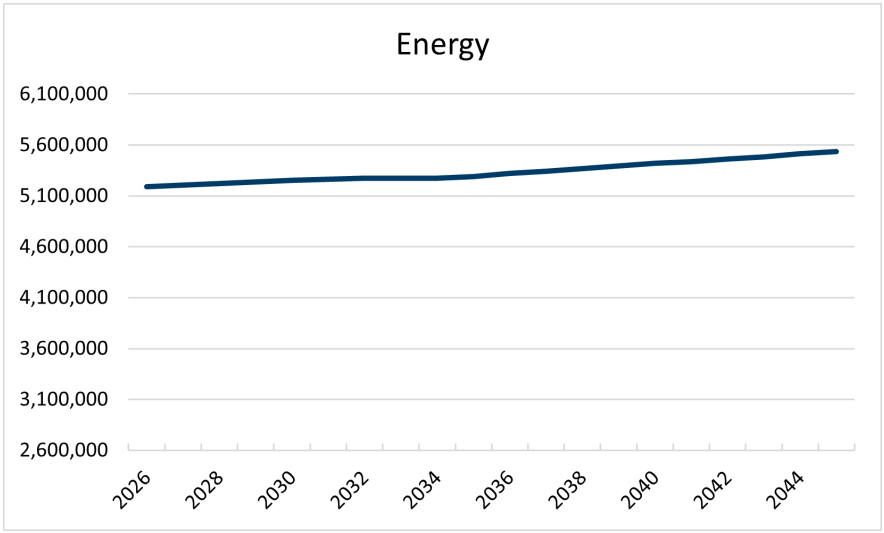
Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Demand is typically measured in Megawatts ("MW"), and energy is typically measured in Megawatt hours ("MWh"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation, demand side (energy efficiency and demand response), and storage resources available to meet expected customers' seasonal peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement ("PRMR") for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO member, CEI South must comply with MISO's evolving rules to maintain reliability.



CEI South must meet customer demand in all hours of the year. This has become more challenging, as the regional resource mix changes towards intermittent (variable) renewable generation. MISO functions as the regional transmission operator for 15 midwestern and southern states, including Indiana (also parts of Canada). MISO evaluates how changes in the future resource mix impact reliability. Recently, they have received FERC approval to update the way resources are accredited to the Direct Loss of Load ("DLOL") methodology beginning in 2028, which is projected to have a substantial impact on solar accreditation in the summer and winter when load is at its highest. CEI South has accounted for this change and worked with stakeholders to develop a reasonable accreditation projection given the best available information. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability.





CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles.

Overall, customer energy and summer peak demand, excluding energy efficiency, are expected to grow by **0.5% per year**. Winter peak demand grows at a slightly slower pace of **0.3% per year**.

Resource Options Considered

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 95 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, bio-mass thermal, demand response, and wind. These project bids provided up-to-date, market-based information to inform the analysis. Additionally, CEI South utilized other information sources for long-term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing F.B. Culley 3 coal unit, conversion of F.B. Culley 3 coal unit to natural gas, various other natural gas resources, conversion of A.B. Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries.

Every IRP is a snapshot in time producing a direction based on the best-known information. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the accelerated sunset of wind and solar tax incentives from the IRA with the passage of OBBBA, the rise of Artificial Intelligence ("AI") data centers and onshoring of industrial manufacturing driving unprecedented load growth, state and federal executive orders to maintain existing resources, continued increased costs for renewables projects, new technologies, and rapid changes in the MISO market to adapt and help enhance reliability.

- Battery storage
- Coal
- Energy efficiency/ Demand response
- Hydro electric
- Natural gas
- Nuclear
- Wind and solar





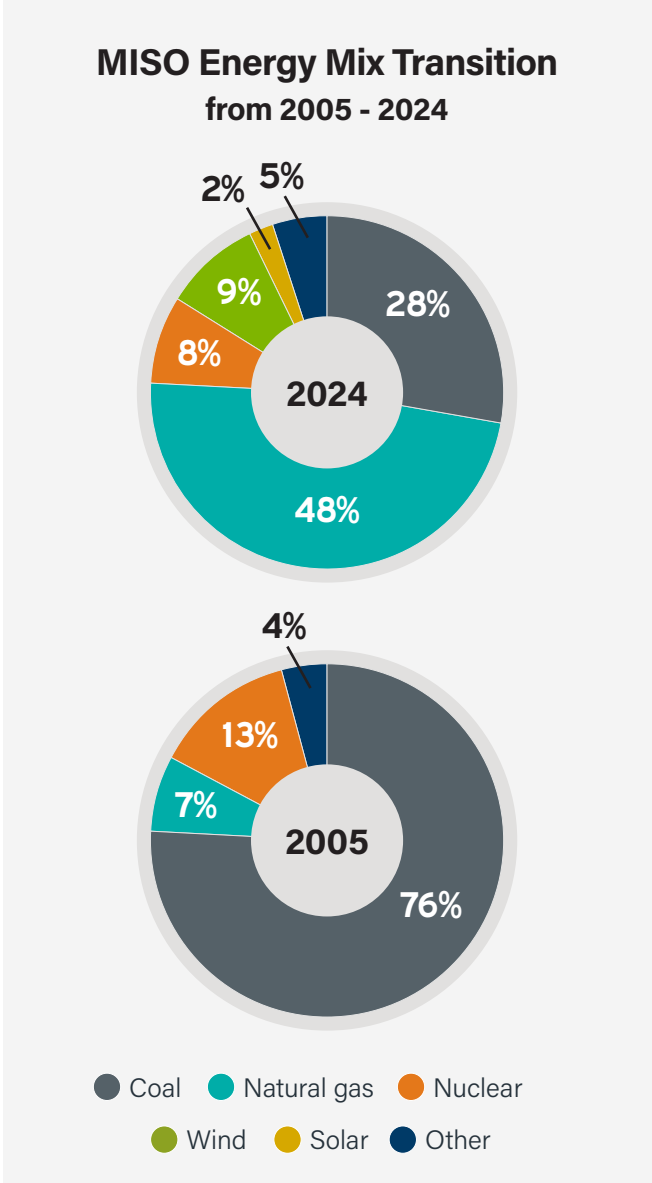


INDUSTRY TRANSITION

The transition to intermittent renewable resources within MISO has continued over the last several years, although at a slower pace. Until the pandemic, renewables costs declined rapidly due to improvements in technology and government incentives. This largely stalled and began an upward climb. Wind and solar resources continue to face increasing price pressure, interconnection delays, and decreasing accreditation from MISO. With the passage of OBBBA, renewable resource tax incentives sunset more quickly than under the IRA placing more pressure on renewable resources.

This comes as load growth to serve data centers supporting AI is projected to ramp very quickly over the next several years. Each data center can use enough energy to power a mid-sized city, and they require power twenty-four hours a day, necessitating dispatchable resources. Additionally, President Trump has made tariffs a core part of his second term. These tariffs are designed to incentivize manufacturing to come back to the United States, thus providing new economic development opportunities, particularly with industries related to national security. For example, his administration has focused on the steel and aluminum industries, which also bring the potential for extremely large loads.

To respond to this challenge, the federal government is working to slash regulations and maintain incentives for baseload (24x7 power) nuclear resources. Additionally, the state of Indiana has responded with incentives for these prospective customers and also with economic development incentives aimed at spurring development in small modular nuclear resources that can provide power intense data centers and large industrial facilities with zero carbon emitting resources, the first of which, in Indiana, is likely to come on-line in the early to mid-2030s.



In the near-term, gas resources are seeing unprecedented demand from utilities to meet increasing near-term load obligations. Installed capacity of wind and solar resources is expected to continue to increase within the MISO footprint, although more slowly than even a few years ago. Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation in 2005, used primarily to meet the needs during peak demand conditions, to approximately 48% of total generation in 2024.[4] Meanwhile, coal has declined but still supplies a little more than a quarter of the energy need within MISO, followed by wind at 9%, nuclear at 8%, and solar at 2%.

[4] *MISO 2024 State of the Market Report, Potomac Economics, June 2025, page 6 https://cdn.misoenergy.org/2021 State of the Market Report625295.pdf https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf*

The move toward renewables and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to consistently compete on short term marginal price with renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with EPA regulations. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has also driven unit retirements.

While coal has been declining, it remains an important source of power for our grid, particularly as this capacity-rich resource has seen an uptick in market capacity revenues. Additionally, President Trump has written executive orders aimed at supporting the coal industry in an attempt to preserve remaining plants. With these market changes, coupled with increasing costs for renewable and gas resources, we are more likely to see some coal units remain online longer than they otherwise would have.



CHANGING MARKET RULES TO HELP ENSURE RELIABILITY

MISO recognizes the major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have overproduction (more energy produced than is needed at the time) and other periods will have low-to-no renewable energy production, requiring dispatchable resources to meet real-time demand for power. MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future.

Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing mix of resources, there is an increased importance of ensuring that adequate attributes are available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained, MISO implemented a seasonal resource adequacy construct beginning with the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand. As part of the seasonal construct, thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("EFORd") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources continues to be challenged as MISO received approval to further revise the accreditation approach in 2028 with the introduction of DLOL methodology. The move to DLOL is expected to most affect renewable resources, particularly solar. For example, solar resources were expected to provide about 25% or more of their total installed capacity to cover MISO's reliability requirement. This is expected to drop over time to approximately 5% or below in the summer, CEI South's tightest season. The practical effect is that more capacity will be needed when fully implemented.

Also, MISO continues to study how demand response resources will be accredited. To date, these reforms have provided more certainty that demand response will be there when called upon; however, there is a much higher bar than in the recent past for industrial customers to participate with annual testing and required faster response times to remain a participant in these programs. MISO reforms will continue as reserve margins continue to tighten and increasingly include intermittent renewable resources that make it more difficult to maintain acceptable voltage and thermal limits on the grid than traditional, dispatchable resources.

CEI South has accounted for these changes by incorporating the seasonal construct and DLOL accreditation approach into the Encompass model, and the portfolios in this analysis provide sufficient resources to meet its MISO obligations in all four seasons with limited capacity purchases. Additionally, CEI South analyzed the thermal limits of equipment along with the voltage and reactive power needs of the system for various portfolio options and identified mitigations.

BATTERY STORAGE AND TRANSMISSION RESOURCES

To support greater reliance on intermittent renewable resources, utilities are increasingly considering the opportunity to add battery storage to resource portfolios to help provide availability and flexibility. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature. In fact, 2024 All-Source RFP bids for battery storage to replace F.B. Culley 2 as a potential CEI South resource were cost effective for the first time.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining the reliability of the transmission system. CEI South has experience operating a 1 MW battery designed to capture energy from an adjacent solar project. This pilot project has provided information that will be helpful in moving forward with a much larger project. The 90 MW battery will be available to discharge energy for four hours and will be available for energy arbitrage and meeting peak load conditions.

Uncertainty/Risk

As demonstrated over the past few years, the future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the preferred resource portfolio mix of generation and demand side resources to serve customer energy needs over a wide range of possible future states. CEI South worked with 1898 & Co. to perform two sets of modeling to contribute to the risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes. Additionally, the risk analysis included sensitivities and qualitative judgement.

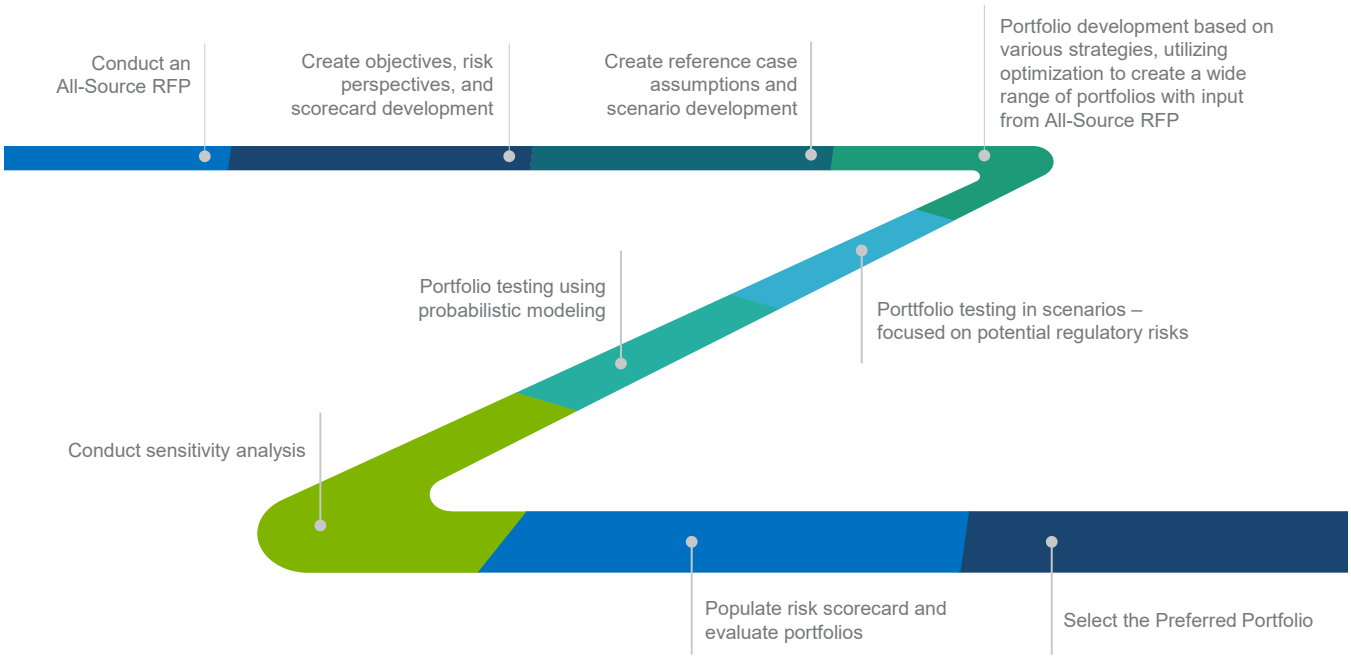


Analysis

CEI South's analysis included a step-by-step process to identify the Preferred Portfolio. The graphic below summarizes the major steps which included the following:

1. Conducted an **All-Source RFP** to better understand resource cost and availability.
2. Worked with stakeholders to develop a **scorecard** as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Worked with stakeholders to develop a wide range of **future states**, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Worked with stakeholders to develop a wide range of **portfolios** for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Conducted a **risk analysis,** including deterministic and probabilistic modeling with sensitivity analysis.
6. Utilized the **quantitative scorecard measures** and **judgment** to select the Preferred Portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).

Analysis Process



Stakeholder Process

As in the last IRP, each of the last three stakeholder meetings began with stakeholder feedback. CEI South reviewed requests/comments from the prior stakeholder meeting and provided feedback. Suggestions were taken, and in instances where suggestions were not acted upon, CEI South explained why not. Notes for each meeting were included in question-and-answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (IRP@CenterPointEnergy.com) and with phone calls/meetings in between each public stakeholder meeting by request.

While maintaining the virtual option to participate, CEI South thought it was important to continue face-to-face meetings. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to southwestern Indiana or did not wish to participate in person. Dates and topics covered are listed below.

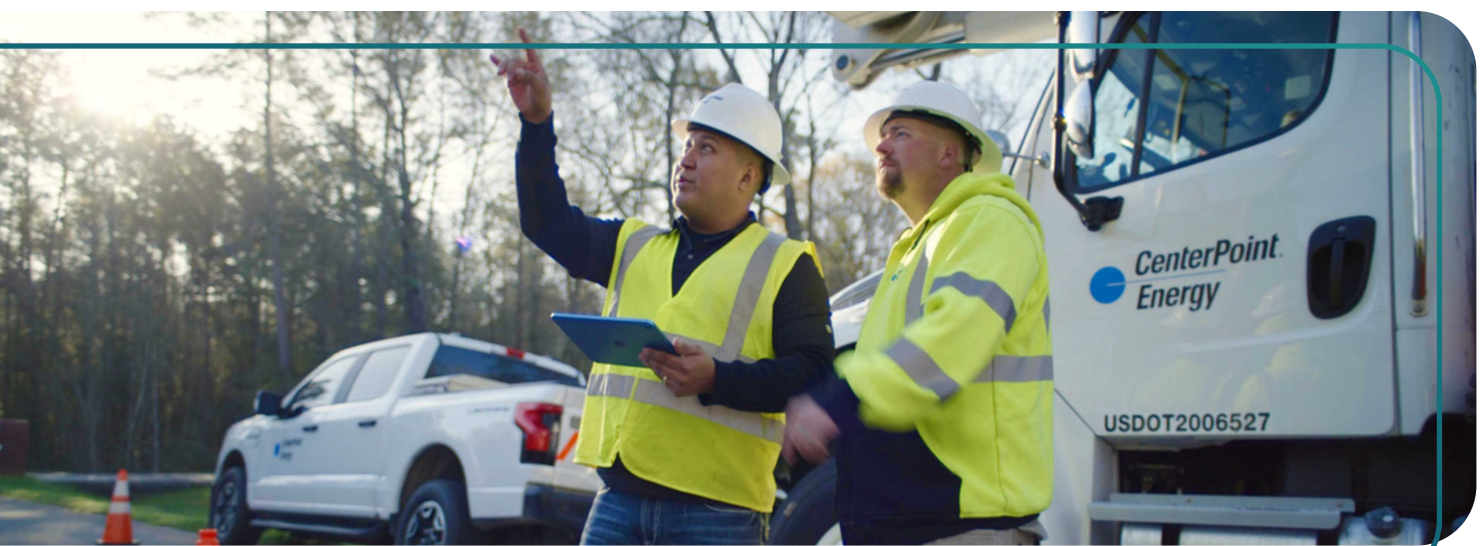
CEI South held a series of technical meetings with stakeholder groups willing to sign a Non-Disclosure Agreement ("NDA") and participate in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. These meetings, along with a data release schedule, helped keep technical stakeholders informed throughout the process and provided an opportunity to engage with CEI South in a way that is not always possible during public stakeholder meetings.

CEI South also incorporated feedback from the Director's report on its previous IRP, along with insights from the annual Contemporary Issues Conference hosted by the IURC. The 2025 Conference topics proved especially timely - highlighting considerations for large load coordination and planning. Discussions underscored the importance of flexibility and preparation to account for the impacts of large load within our planning process. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.



Based on this stakeholder engagement, CEI South made fundamental changes to the analysis in real-time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the Preferred Portfolio were updated through this process. CEI South held meetings with interested stakeholders willing to sign an NDA ahead of and in between public stakeholder meetings. This, along with providing modeling inputs, helped to allow for a more productive dialogue throughout the process. CEI South appreciates the time and attention provided by each group that participated in this process.

CEI South utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios, including the addition of a possible future, the alternate high regulatory scenario. CEI South updated the scorecard to measure risks in each of the five pillars (Affordability, Environmental Sustainability, Reliability, Resiliency, Stability) with a separate section for other market risks. Per the Director's report, CEI South added the 5th percentile of Net Present Value Revenue Requirements ("NPVRR"). CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding an affordability metric (electric energy burden) that illustrated the 5-10 year incremental impact to energy burden (incremental residential bill impact in 2030 and 2035 divided by Vanderburgh County median household income). This measure highlights near to mid-term price pressure that customers may face for each portfolio. Additionally, CEI South added measures for Dynamic VAR Support ("MVAR") and Short Circuit Ratio ("SCR") from its updated transmission reliability analysis. CEI South also added SOx and NOx emissions and capacity sales/purchases to the scorecard. Adjustments were also made to modeling inputs and assumptions based on direct stakeholder feedback. The following table shows key stakeholder requests made during the process and CEI South's response.



Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scorecard	Under the Environmental Sustainability Objective: Remove CO_2 intensity, keep CO2-e tons	CEI South believes that there is value in keeping CO_2 intensity, as well as CO_2-e metrics. CO_2 intensity allows the reader to compare CO_2 levels across scenarios.
Scorecard	Include metrics for SOx and NOx	CEI South has added metrics that includes combined tons of SOx and NOx.
Scorecard	Under the Affordability Objective: consider adding an energy burden calculation	CEI South proposes to add electric energy burden, defined as the 5-Year [5] residential rate impact as of July 1, 2025 divided by the Vanderburgh County Median Household Income.
Resource Options	Are the Demand Response proposals subject to discussion/change with Demand Side Management (DSM) Oversight Board	CEI South continues to discuss Demand Response with members of the DSM Oversight Board
Resource Options	Is CEI South considering what the resource mix could be if a resource incentive (updated EDG rate) is included in the IRP?	CEI South is conducting a sensitivity considering a $500 per kW incentive for Distributed Generation solar resource.
Load Forecast	Provide a breakout of peaks by customer class	See graph in 3/19/2025 Stakeholder meeting notes posted at www.centerpointenergy.com/irp
Load Forecast	Why is CEI South using historical rather than forecast temperature, e.g., Purdue University temperature forecast?	CEI South used a linear projection of temperature based on historical data; it is not significantly different from the Purdue University study for the IRP period.
Load Forecast	Requested CEI South to revisit the estimated 12,000 miles for EVs used in the forecast	Itron EV assumption for reference forecast. The 12,000 miles per year for EVs was revised to 9,500 miles per year. This revision is noted in the 5/14/2025 Stakeholder meeting slides

[5] *CEI South ultimately added a 5 and 10 year incremental energy burden per stakeholder request.*

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Load Forecast	Does the EV charging profile used for CEI South's load forecast account for remote work at home?	The NREL tool, EVI-Pro, documentation does not specifically state any assumptions regarding work from home. The "EVHome" charging profile on slide 61 of the 3/19/2025 stakeholder slides includes some level of charging between 11am-2pm. (slides posted at www.centerpointenergy.com/irp)
Load Forecast	Does CenterPoint have plans to electrify its fleet?	CenterPoint does have plans to electrify its fleet - please see the following link https://sustainability.centerpointenergy.com/energy-transition-goals/fleet/
Commodity Inputs	Does the natural gas forecast assume increased drilling under the current administration?	At this time, CEI South is uncertain how the current administration's policies will affect natural gas prices. Our vendors consider multiple factors when developing commodity forecasts. Utilizing a consensus forecast is an approach CEI South has taken in previous IRPs. These various perspectives allow us to capture the diversity in opinions for future market prices.
Generation Timeline	Regarding Salt Creek Wind, is this project going to service CenterPoint customers or just provide power to the MISO grid as accredited power? If it's going to be service to CenterPoint customers, what kind of transmission loss are you expecting since the power is coming from Iowa?	Please see Witness Swanson's public testimony in Cause No. 46218.
Objectives & Draft Measures	Will the electric energy burden separate electrically heated homes from gas heated homes, or will those be combined in the aggregate?	We'll look at both the customers with electrically heated homes and the customers with gas heated homes. However, either view will show the same relative difference among portfolios.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scenarios	Suggest adding an option where load stays at base. In this scenario, generation capital costs could still be high.	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Scenarios	When looking between high regulatory and alternative high regulatory, can you potentially do the same with low regulatory (an alternative low regulatory with low load)?	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Supply-Side Resource	Can CEIS incorporate real coal price offers made to CenterPoint. The uncertainty variable is not the mining cost as much as the demand.	Due to the confidential and competitive nature of CEIS's contractual coal price this was discussed during the 8/20/2025 Tech to Tech meeting
Supply-Side Resource	How many bids did CEIS receive for storage?	There were 17 standalone storage bids. The 2024 All-Source RFP results were shared during the 3/19/2025 Stakeholder meeting. The presentation is available here: CenterPointEnergy.com/IRP.
Supply-Side Resource	Is CEIS accounting for all costs and benefits, including considerations such as health costs? Will these other benefits be incorporated into the IRP?	Health costs are captured within EPA regulations that are included in the applicable scenarios.
Supply-Side Resource	Has CEIS considered the water pressure nuclear option, such as the Westinghouse AP1000?	The general nuclear option included in the Tech Assessment is representative of a variety of future nuclear options. If you have information regarding technology performance or costs that you would like to see in the model, please email IRP@CenterPointEnergy.com

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
MPS	For the battery storage program, without large enough penetration of batteries, it's hard for benefits to outweigh the costs. Could we look at a battery storage equipment incentive?	We performed cost-effectiveness screening using a range of incentives and adoption rates. In all scenarios the Utility Cost Test ratio was less than 1, which is not cost-effective. Results are included in today's (9/11/2025) Stakeholder meeting.
MPS	For EVs, are customers bringing their own device for the charger? Would customers have to use specific technology to participate?	We are assuming that the customer would supply their own charger, and CenterPoint would provide an incentive to join the program, as well as an annual participation incentive. A managed charging program would require some sort of network connection, which could include Wi-Fi, cellular, or a wired connection. A specific technology would not be required, as control could happen through the charger or telematics through the EVs
MPS	Some DR measures like batteries and water heaters can be used for other grid services (ancillary services, resilience) – how are these benefits being considered in developing levelized costs and/or accounted for in the IRP? Is it possible to treat these like T&D benefits and reduce from the cost side?	When performing cost-effectiveness screening, the benefits include the avoided energy, capacity, and T&D. Resilience and ancillary services have not been a benefit of Demand Response captured in the IRP analysis.
Model Inputs	Is CEIS going to include Scope 3 emissions?	Scope 3 emissions are outside the scope of the IRP as it's related to emissions of the end-user and separate from electricity generation.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Model Inputs	Since CEIS is considering nuclear, does CEIS want to run a stochastic process for uranium?	We are currently using publicly available data sources for uranium pricing forecasts. Uranium pricing is not expected to be a major differentiator in the portfolio risk assessment when compared with other cost drivers. Given this, we do not anticipate that running a stochastic process for uranium will materially change the outcomes of the analysis.
Model Inputs	Is CEIS planning to use the MISO published 2025/2026 indicative DLOL results for the solar and wind accreditation assumptions?	We have revised the accreditation values to interpolate between the first season of DLOL and 2035. Providing a smoother shift in accreditation. Revised Solar and Wind capacity accreditation forecasts are included in the 9/11/2025 presentation's Appendix.
Model Inputs	Recommendation to analyze two DER resource portfolios, Distributed Capacity Procurement (DCP) and Virtual Power Plants (VPPs) in CEI South's 2025 IRP	CEI South's evaluated demand response programs that align with the intent of both DCP and VPP programs as well as a DG Solar incentive during the IRP process. Updates on the evaluations are included in today's (9/11/2025) Stakeholder meeting.
Modeling	Scenario Portfolios – Explain why manual modifications applied to scenario portfolios to align with the Reference Case load	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Scenario Portfolios – Request to re-run the capacity expansion simulation instead of the production cost simulation	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Modeling	Scenario Portfolios – Request to share documentation illustrating manual modifications made to the scenario portfolios	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Build Limits – Request for CEI South to consider running scenarios with relaxed limits	CEI South ran a simulation and chose to relax limits to allow more resources to be selected within the capacity expansion model.
Modeling	Consider a study with FB Culley 3 retiring in 2030	Given the unprecedented amount of uncertainty at this time and future transmission upgrades that will help with system reliability and resilience, it would not be prudent to consider retirement prior to 2031/2032, as is being considered within this IRP.
Affordability Measure	Request for energy burden calculation	CEI South will make the energy burden workpaper available to technical stakeholders with a signed NDA.
Rates	Request to provide guidance on bill itemization	Please see the CenterPoint website, where is shows an explanation of the bills. https://www.centerpointenergy.com/en-us/residential/customer-service/resource-hub/understanding-your-bill?sa=in

Meeting materials for each meeting can be found at **CenterPointEnergy.com/IRP** and in Technical Appendix Attachment 4.2 Stakeholder Materials.

Next Steps

CEI South's flexible plan provides two paths forward, depending on what the future holds. If a large load customer agreement is not made prior to the next IRP in 2028, CEI South will move forward with the Preferred Portfolio. With this path, there are a few items that must be done in the short-term action plan.

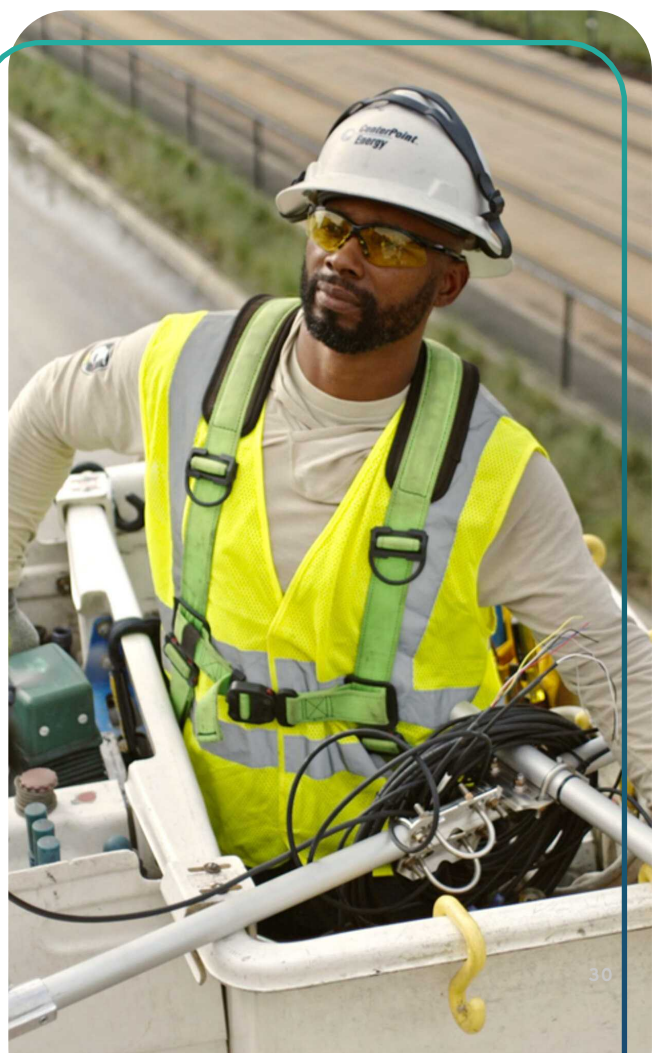
First, CEI South will continue to implement the generation transition that was identified in prior IRPs. CEI South is currently pursuing three renewable projects that are scheduled to be online in 2026: 147 MW Galesburg Wind (approved PPA), 150 MW Wheatland Solar (approved PPA), and 170 MW Salt Creek Wind (approved PPA). These projects will continue to diversify CEI South's generation mix.

Secondly, CEI South will conduct two RFPs to determine current pricing for capacity and battery storage for replacement of F.B. Culley 2 interconnection in the next three years. Having run past its useful life, F.B. Culley unit 2 (coal) is slated for suspension at the end of this year. FERC rules allow for replacement of the interconnection within 3 years of suspension. CEI South will continue to evaluate the proper path forward with consideration for Indiana's five pillars. Should CEI South choose to reutilize the interconnection, it will seek approval in a Certificate of Public Convenience and Necessity ("CPCN") before the IURC and modify its Attachment Y with MISO to an Attachment X.

Third, CEI South will file for a DSM plan, consistent with the results of the Preferred Portfolio.

Finally, CEI South will continue to engage with economic development opportunities to help strengthen southwestern Indiana. Should a large load addition materialize, CEI South would diligently work to implement its Alternate Preferred Portfolio that would potentially require multiple CPCNs and approval of a contract with the IURC. These filings will be consistent with the Preferred Portfolio paths. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the Preferred Portfolio.

CEI South's plan must be flexible, as several items are not certain at this time, including but not limited to: MISO DLOL, EPA greenhouse gas regulations, cost of resources, policy change, the potential for large load additions, and regulatory risk.



Attachment 2.1 2024 All-Source Request for Proposal & Report

1898 & CO.
PART OF BURNS McDONNELL

ALL-SOURCE REQUEST FOR PROPOSAL

CenterPoint Energy

CENTERPOINT ENERGY INDIANA SOUTH

Issued August 15, 2024

NOI, NDA, and Application Due August 28, 2024

Proposal Due October 8, 2024

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List of Abbreviations

Abbreviation	Term/Phrase/Name
1898 & Co.	1898 & Co., part of Burns & McDonnell
CenterPoint	CenterPoint Energy Indiana South
COD	Commercial Operating Date
CSP	Curtailment Service Providers
DA	Definitive Agreement
DIR	Dispatchable Intermittent Resource
DR	Demand Response
EPC	Engineering, Procurement, and Construction
GI	Generation Interconnection
GIA	Generator Interconnection Agreement
ICAP	Installed Capacity
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
LCOE	Levelized Cost of Energy
LMR	Load Modifying Resource
LRZ	Local Resource Zone
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-Hour
NCF	Net Capacity Factor
NDA	Non-Disclosure Agreement
NRIS	Network Resource Interconnection Service
OVEC	Ohio Valley Electric Corporation
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
RFP	Request for Proposal

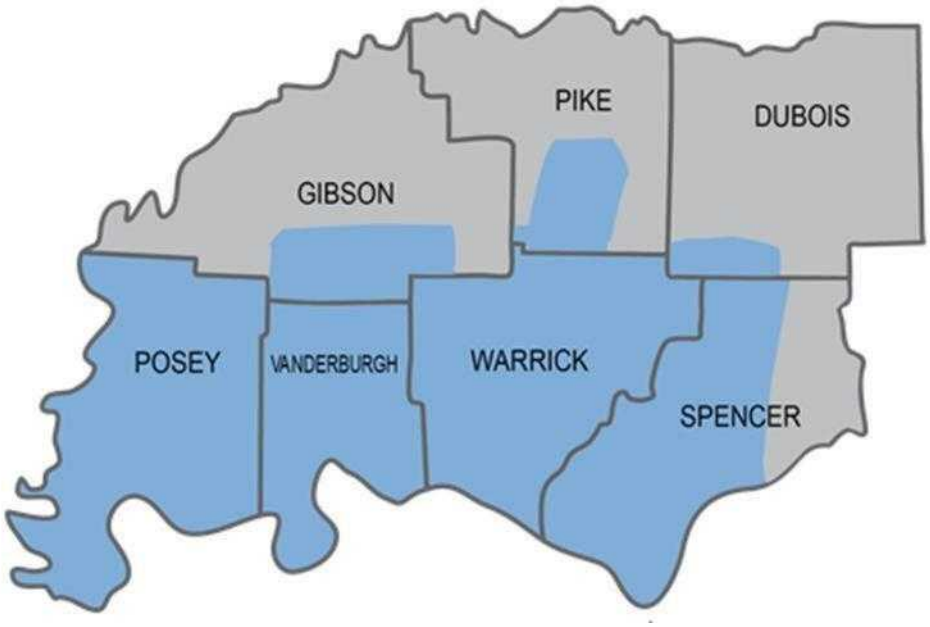
1.0 RFP Overview

1.1 Introduction

CenterPoint Energy Indiana South (CenterPoint) is a subsidiary of CenterPoint Energy, headquartered in Houston, Texas. CenterPoint provides energy delivery services to approximately 150,000 electric customers located in southwestern Indiana. CenterPoint also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market.

CenterPoint's electric customers are currently served by a mixed portfolio, including 360 megawatts (MW) of coal-fired generation, up to 160 MW of gas-fired generation and 54 MWs of solar coupled with 1 MW of storage. The portfolio also contains 3 MW from landfill gas to an electric project and purchases from the Ohio Valley Electric Corporation (OVEC) of up to 32 MW, wind purchases of up to 80 MW, and purchases from the Midcontinent Independent System Operator (MISO) power pool as needed to meet CenterPoint's load requirements.

Figure 1: CenterPoint Electric Service Area



1.2 Purpose

CenterPoint has issued this all-source Request for Proposals (RFP) seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. For asset purchases and power purchase agreements (PPAs), the capacity is desired to be fully accredited prior to March 1, 2028; however, earlier delivery of projects and capacity products is encouraged. CenterPoint is required to submit an updated Integrated Resource Plan (2025 IRP) to the Indiana Utility Regulatory Commission (IURC) by November 1, 2025, which will evaluate existing resources and identify the preferred resource options to meet capacity and energy requirements. Information on CenterPoint IRPs can be found at https://midwest.centerpointenergy.com/irp. Only resources capable of firm deliverability to MISO Local Resource Zone (LRZ) 6 will be considered.

CenterPoint prefers Proposals for resources that are directly interconnected to CenterPoint's system or Proposals that reflect all the costs and characteristics of the resource necessary for energy to be financially settled or delivered to CenterPoint's load node (SIGE.SIGW). All potential agreements are subject to IURC and the CenterPoint Board of Director's approval and are not effective until such approval is final.

All Proposals must be submitted via the All-Source Request for Proposal website (http://CenterPoint2024ASRFP.rfpmanager.biz/) no later than the Proposal Submittal Due Date shown in Section 2.3. CenterPoint reserves the right in its sole discretion to modify this schedule for any reason.

In connection with this RFP, CenterPoint has retained the services of an independent third-party consultant, 1898 & Co., a division of Burns & McDonnell, to help manage the RFP process and work with CenterPoint to perform the quantitative and qualitative evaluations of all Proposals. However, CenterPoint will make final decisions (subject to IURC review, as applicable) at its sole discretion.

All Respondents will directly interface with 1898 & Co. for all communications, including questions, RFP clarification issues, and Proposal submission. All questions related to this RFP should be submitted via the RFP Website. If for any reason there are technical issues with bid or question submittal, the following email address can be contacted: CenterPointRFP@1898andco.com.

CenterPoint has concluded that it is in the best interest of its customers to seek resources that qualify as MISO internal resources (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS). However, as described in the RFP requirements below, Proposals for resources located outside of MISO and which can show firm deliverability to MISO LRZ 6 may still qualify for consideration under this RFP. CenterPoint is issuing this all-source RFP for supply-side and demand-side capacity resources to identify viable resources available to CenterPoint in the marketplace to meet the needs of its customers. Depending upon further evaluation of aging resources and subject to IRP results, the exact capacity need of CenterPoint has not yet been identified. The 2025 IRP will evaluate a wide number of potential resource portfolio combinations that will include a variety of new resource additions as CenterPoint continues their fleet transition. Therefore, Respondents are encouraged to offer multiple projects and/or resource blocks depending on their availability.

CenterPoint is seeking to provide reliable power supply resources for its customers. This RFP is issued to either acquire or contract for:

- Existing or planned utility-scale solar, wind, and storage (standalone or paired) resources described further in Section 4.0;
- Existing or planned thermal resources described further in Section 5.0;
- LMR/DR products described further in Section 6.0; or
- New projects utilizing the FB Culley 2 interconnection described further in Section 8.0.

Accordingly, you are invited to submit a written, binding Proposal in accordance with the requirements described in this RFP and subject to the following dates. See Section 2.3 for additional information about milestone dates.

Table 1: RFP Milestone Dates

Milestone	Date
Issue RFP	Thursday, August 15, 2024
Notice of Intent with Application Documents Due	Wednesday, August 28, 2024
Proposals Due	Tuesday, October 8, 2024

2.0 Information and Schedule

2.1 Information Provided to Potential Respondents

This RFP and all its Appendices are available on the RFP website (http://CenterPoint2024ASRFP.rfpmanager.biz/). Interested parties are expected to be able to download this RFP with its required forms and complete the forms in Microsoft Word, Microsoft Excel, [1] and/or PDF format. Respondents should upload and submit properly completed forms by the specified due date to the RFP website. 1898 & Co. will accept only Proposals that are complete. Proposals that are nonconforming, not complete, mailed, or hand-delivered may be deemed ineligible and may not be considered for further evaluation. By submitting a Proposal in response to this RFP, the Respondent certifies that it has not divulged, discussed, or compared any commercial terms of its Proposal with any other party (including any other Respondent and/or prospective Respondent), and has not colluded whatsoever with any other party.

2.2 Information on the RFP Website

The information on the RFP website (http://CenterPoint2024ASRFP.rfpmanager.biz/) contains the following:

- This RFP and associated appendices
- Frequently asked questions and answers about this RFP
- Updates on this RFP process and other relevant information

Phone calls and verbal conversations with Respondents regarding this RFP are not permitted before the Proposal Submittal Due Date. All Respondents will directly interface with 1898 & Co. through the RFP website and email for all communications regarding this resource request. Proposals will be opened in private by 1898 & Co. on a confidential basis, but written questions will not be considered confidential. Individual questions submitted on the website before the submittal due date will be answered and responses will be posted on the website or sent back via email to the Respondent as soon as practical. Responses to select questions may be placed on the RFP website for the benefit of all Respondents, with any identifying information redacted from the question.

Proposals will be reviewed by 1898 & Co. for completeness, and offers that do not include the information requirements of this RFP may be notified by 1898 & Co. and allowed five business days to conform. After Proposals are submitted, 1898 & Co. will review, and both quantitatively and qualitatively evaluate all conforming Proposals. Respondents may be contacted for additional data or clarifications during the evaluation process by 1898 & Co. Any Respondents contacted for further clarifications may or may not be invited to begin further negotiations of terms and details of the offers.

2.3 Schedule

CenterPoint has retained 1898 & Co. to act as an independent third-party consultant to assist with this RFP. All Respondents will directly interface with 1898 & Co. for all communications, including questions, RFP clarification issues, and Proposal submission. All questions should be submitted to the website, and as required, additional correspondence concerning this RFP should be sent via email to CenterPointRFP@1898andco.com.

[1] Microsoft Excel Format is required for the submission of Appendix D.

The schedule below provides the timeline for conducting this resource solicitation. CenterPoint reserves the right to modify this schedule in its sole discretion.

Table 2: RFP Schedule

Step	Date
RFP Issued	Thursday, August 15, 2024
Notice of Intent, NDA, and Respondent Application Due	5:00 p.m. CDT, Wednesday, August 28, 2024
Pre-Bid Meeting	3:00 p.m. CDT, Monday, September 9, 2024
Proposal Submittal Due Date	5:00 p.m. CDT, Tuesday, October 8, 2024
Initial Proposal Review and Evaluation Period	Wednesday, October 9, 2024 – Monday, November 4, 2024
Proposal Evaluation Completion Target and Short List to CenterPoint	Tuesday, November 5, 2024
Due Diligence and Negotiations Period	Q4 2024

3.0 RFP General Requirements

Proposals must meet the general minimum eligibility requirements described below. 1898 & Co. will screen all Proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration as part of this RFP process. Respondents should refer to the Proposal Checklist in Appendix E for high-level guidance on Proposal requirements.

For a Proposal to be eligible under this RFP, it must:

- Offer MISO LRZ 6 zonal resource credits (e.g., NRIS transmission service or other fully deliverable resource).
- Have an existing MISO Generator Interconnection Agreement (GIA), be in the MISO generator interconnection queue, or provide justification for how the resource is able to meet CenterPoint's timing needs absent current queue position. CenterPoint will consider Proposals that aim to reuse existing interconnection rights for retiring generation facilities, including the FB Culley 2 site option detailed in Section 8.0.

CenterPoint prefers the project to be in service and operational prior to 3/1/2028.

3.1 General Requirements for General Facility Proposals

Respondents should provide sufficient detail to fully evaluate the “all-in” physical, electrical, and economic attributes of any Proposal. In all cases, Respondents shall describe the expected useful life of all facilities included in their Proposals. If a facility does not have black start capability installed but could be made black start capable, Proposals should indicate the estimated costs to construct and operate and include the estimated construction timeline. Respondents shall provide their best estimate of interconnection costs and/or other costs to deliver energy into MISO to a single point of interconnection or other energy settlement node.

3.1.1 Name and Location

Respondents shall state the name of the generating facility, the county where the generating facility is located, the owner of the facility, and the commercial pricing node associated with the facility, if applicable. The facility must be qualified to receive Zonal Resource Credits for Zone 6 consistent with MISO’s Module E Planning Resource Auction. Should the facility not be qualified in Zone 6, Respondents shall detail in their Proposals the means by which Zonal Resource Credits will be delivered/fulfilled in Zone 6.

3.1.2 Capacity Characteristics

Respondents shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and, for existing facilities, the awarded seasonal accredited capacity of the generation facility for the last five MISO planning years, as applicable. Respondents shall specifically identify any known derates affecting the facility.

3.1.2.1 Interconnection, Capacity Availability and Deliverability

Respondents must identify the specific point(s) of interconnection. CenterPoint has a preference for the type of transmission service to be NRIS, but will consider other Proposals as long as capacity is fully deliverable and accreditable. Proposals for facilities without existing firm deliverability should include cost estimates including transmission and/or interconnection studies associated with securing such deliverability. The GIA or most recent available Definitive Planning Phase (DPP) Study results should be included if applicable.

If available, the Proposal should also include nodal economic analyses (at COD, 2030, and 2035) showing expected unit economic metrics (including congestion impacts on energy production and cost to deliver) for the project at the proposed delivery point(s), or other relevant interconnection studies and analyses.

CenterPoint reserves the right to reject any Proposal that does not include the full cost of any known or potential interconnection costs or network upgrades that may be required to provide firm deliverability to MISO LRZ 6 and/or that does not include interconnection, reliability, and/or economic analyses supporting interconnection and transmission requirements. Such materials should include a technical description and estimated costs of network upgrades from studies completed or underway.

CenterPoint will consider Proposals that plan to re-use existing injection rights under an interconnection agreement currently occupied by a retiring generating facility. Respondents can submit Proposals that utilize CenterPoint's FB Culley 2 interconnection agreement for up to 90MW; more details on the FB Culley 2 site are in Section 8.0. Qualifying Proposals shall include a discussion of the required MISO studies, project ownership, and timing of commercial operation under the existing interconnection agreement, as applicable. Respondents shall include an estimate of the costs required to build gen-tie lines connecting a project to the point of interconnection and shall not assume that existing transmission lines or other utility easements will be available to host the gen-tie circuit.

3.1.3 Technical and Economic Detail

3.1.3.1 Generation Technology

Respondents shall describe the generation technology of the facility, including the make, model, and name of the supplier of all major equipment. All Proposals to sell a generation facility to CenterPoint must utilize an existing, proven technology, with demonstrated reliable generation performance that is capable of sustained, predictable operation.

3.1.3.2 Dispatch, Emissions, and Performance Characteristics

Dispatch, emissions and performance characteristics will vary between different types of generation facilities, but shall be provided by Respondents as applicable including but not limited to load levels, ramp rates, heat rates, fuel consumption, expected energy production based on actual or typical weather, operating limitations, etc. Please refer to Sections 4.0, 5.0, and 6.0 of this document for additional resource-specific requirements.

Regarding any major current and/or historical operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g., original equipment manufacturer (OEM) design, material condition of the facility, environmental permits, etc.). To the extent that expected performance deviates from observed performance, the Respondent shall provide the basis for the assumption.

3.1.3.3 Operating Costs and Taxes

Respondents proposing new generation facilities must provide reasonable estimates for all of the following requested details associated with plant costs, fixed and variable operations costs, expected upgrades and service timing, and taxes.

Respondents shall provide a detailed breakout of the generation facility's estimated and actual annual fixed costs for the following categories: labor, benefits, materials, and all others for the past five years. Respondents shall provide a breakdown of the number of people employed at the facility, including permanent and contracted employees, and whether those employees are organized under any labor agreement.

If fixed or variable costs for the generation facility are expected to change in the foreseeable future (e.g., following planned upgrades, etc.), the Respondent should provide both the new expected cost(s) and the year(s) in which the costs are expected to change.

Respondents shall also describe any state, local, and property taxes and tax abatements associated with the generation facility.

3.1.4 Operating Considerations

3.1.4.1 Operating Data

Respondents proposing new or planned generating facilities shall include reasonable estimates for all of the following requested operating data points. Proposals shall include the manufacturer or developer quoted expected performance and, if available, historical performance of similar facilities in MISO.

For an existing generation facility, Respondents shall provide historical operating data consisting of:

- The commercial operation date (COD) of the facility
- The annual run-time hours (per unit, if applicable)
- The annual operating cycles per year (per unit, if applicable)
- The annual facility capacity and availability factors
- The equivalent forced outage rate demand (EFORd)

The above annual data may be limited to the most recent five years. The EFORd should correspond to the unforced capacity (UCAP) amounts awarded for the last five MISO Planning Years. Respondents shall provide a breakdown of EFORd by failure mode or North American Electric Reliability Corporation/Generating Availability Data System category. Respondents shall provide a description of the major contributors to the generation facility EFORd. If there are particular costs associated with maintaining the EFORd of a generation facility, those must be provided. Generating facilities considered a Dispatchable Intermittent Resource (DIR) in MISO shall provide historical curtailments over the most recent years. New facilities shall put forth a best effort forecast of curtailments by MISO.

For an existing generation facility, Respondents shall provide details on any current generation facility equipment issues and concerns, including any operation outside recommended parameters established by OEM, compromised equipment, etc. Respondents shall provide historical information on such issues and concerns, how they were resolved, and the associated costs for the past 10 years or since the beginning of operation.

Respondents shall provide the following maintenance history for the past 10 years or since the beginning of operation: (i) dates of last full unit inspection and findings based on OEM recommendations; and (ii) outstanding OEM recommendations remaining to be implemented, including the cost and outage duration for any major maintenance requirements expected over the coming ten years. Respondents shall provide the annual reports for major planned and forced outages over the past five years.

3.1.4.2 Operating Plan

Proposals should include a summary of the operating plan for the generation facility. Such plan should include software management system(s) and personnel roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements. Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

3.1.5 Environmental Considerations

New and existing resources must be in compliance with all applicable environmental rules and regulations. To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances in any form (emissions credits, offsets, financial credits, etc.), related to the power being purchased, should be conveyed to CenterPoint. Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability and shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

3.1.6 Permitting

The generation facility must have all relevant environmental, site-use and all other ministerial and discretionary permits necessary for construction and/or operation and maintenance. Existing facilities without such permits may be disqualified from consideration at CenterPoint's sole discretion. Respondents shall provide a description of all permits currently in place for the construction and/or operation and maintenance of the facility and must state whether there are any provisions that would prohibit the assignment of such permits and/or any consents required for the assignment of such permits.

3.1.7 Financial Considerations

3.1.7.1 Acquisition Price/Capital Expenditures

Respondents shall submit an acquisition price with their Proposal, representing their best and final price, consisting of a single fixed price that is inclusive of all monetary consideration for the generation facility including, but not limited to, costs associated with interconnection, engineering studies, siting, permitting, acquisition, construction, ancillary facilities, working inventory, and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Different transaction structures may warrant a schedule of payments as described below, but the acquisition price should represent the total all-in purchase amount required to close the transaction and achieve complete commercial operation of the generating facility. Respondents must provide details regarding any liabilities that CenterPoint might assume as a buyer of a generation facility.

3.1.7.2 Other Contractual Commitments

Respondents shall provide a description, including detailed cost information, of any other contracts that are necessary to operate the generating facility, including, but not limited to, long-term service agreements, state union labor contracts and/or technical support contracts, agreements related to capacity and/or energy sales from the facility and any capacity offers submitted to any independent system operator/regional transmission organization related to the generation facility that, if accepted, would be binding on CenterPoint as a result of an acquisition. Respondents must also state whether there are any provisions that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract, including transfer or cancellation fees.

3.1.8 Legal Considerations

3.1.8.1 Legal Proceedings, Liabilities & Risk

The Proposal shall include a summary of all material actions, suits, claims or proceedings (threatened or pending) against Respondent, its guarantor (if applicable) or involving the generation facility or the site as of the Proposal due date, including existing liabilities whether or not publicly disclosed, including but not limited to those related to employment and labor laws, environmental laws, or contractual disputes for the development, construction, maintenance, fueling, or operation of the facility.

3.1.8.2 Material Contingencies

Proposals that have material contingencies, such as for financing, may not be considered.

3.1.9 Other

All Proposals for new generation facilities must have a well-defined and credible development plan for Respondent to complete the development, construction, and commissioning of the facility on its proposed development timeline. Respondents submitting Proposals for new or planned facilities should review the Development Risk evaluation metric and be sure to discuss key development milestones in their Proposal.

Quality Proposals should provide information to assess the following:

- (Key contractual arrangements) Roles and responsibilities of the companies involved in the design, development, procurement, and construction of the facility. Information about key contributors including the status of contractual relationship with each key contributor, key contractual assurances, guarantees, warranties or commitments supporting the Proposal, (e.g., executed EPC contract), and any past experience of Respondent working with each key contributor.
- (EPC) Description of status of major equipment procurement, as well as processes for engineering, procurement, and construction bids and awards.
- (Site control) Description of the facility site and Respondent's rights (i.e., whether owned, leased, under option) to such site. Please indicate whether additional land rights are necessary for the development, construction, and/or operation of the facility.
- (Schedule) Discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including whether there are contract commitments from contractors supporting the proposed schedule. The Respondent should be prepared to document and commit to a proposed development schedule, which should include a COD.
- (Financing) Discussion of the financing arrangements secured or expected to be secured by the Respondent, including an overview of the sources of funds, and level of commitment from debt, equity,

or other investors; Respondent's or guarantors' senior unsecured debt and/or corporate issuer ratings documentation from Moody's and Standard & Poor's showing the name of the rating agency, the type of rating, and the rating of the Respondent or guarantor.

- (Permits and zoning) Discussion on permitting, including a list of all required permits, permitting status of each, and key risks to securing necessary future permit approvals. Respondents should provide all applicable zoning requirement language for the project location (e.g., county, city, township, etc.) and describe current status of project zoning.
- (Interconnection) Description of status in MISO queue process and presentation of documents described in Section 3.1.2.1.

Respondents shall assume for the purposes of Proposal pricing that development schedule, budget, permits and approval risk will be their sole responsibility.

3.2 Eligible Transaction Structures

The following are eligible project transaction structures as part of this RFP. Resource-specific requirements and attributes are provided further down in Sections 4.0 - 6.0 pertaining to specific types of resources. Term sheets containing additional key assumptions for particular contract- and resource-type combinations have been developed and are included in the appendices.

3.2.1 Power Purchase Agreement (PPA)

CenterPoint will consider meeting some or all of its resource requirements through short, medium and/or long-term PPAs. CenterPoint will only consider PPAs that have a term of five years or greater.

3.2.1.1 Price

Respondents shall submit an annual power purchase price ($ and/or $/MWh as applicable) consisting of a payment that is inclusive of all monetary consideration for the capacity, energy, RECs, and, if applicable, ancillary facilities and contractual arrangements related to the generation facility. The contract price shall include all costs of interconnection, including possible MISO and affected system network upgrade costs, and transmission owner interconnection facility and substation upgrade costs. Respondents must provide a flat pricing option (i.e. fixed price for the term of the contract) with each Proposal, and may also include optional escalating pricing options for CenterPoint's consideration.

3.2.1.2 Energy Settlement Location

As described further in the evaluation section below, CenterPoint has a preference for Proposals that include all costs to have energy financially settled or directly delivered to CenterPoint's load node (SIGE.SIGW). However, CenterPoint will consider pricing options for Proposals that settle at the facility's point of interconnection (busbar) or Indiana Hub.

3.2.2 Asset Purchase

CenterPoint will accept Proposals for new, planned, or existing generation facilities that are complete and operational in advance of the expected acquisition date, including build-transfer structures. CenterPoint will only consider offers for facilities that have an estimated remaining useful life of five (5) or more years from acquisition date.

3.2.2.1 Location

CenterPoint has a preference for projects located near its load. However, CenterPoint will accept Proposals for new or planned generation facilities that will be complete and operational in advance of the expected acquisition date. A project will be defined as complete and commercially operable if, and only if, it includes all facilities necessary to generate and deliver energy into MISO to at least one single point of interconnection within MISO.

3.2.2.2 Tax Credits

Respondents shall state the qualifications of the project for any applicable tax credits and provide relevant documentation. This documentation should include discussion on IRA tax credit eligibility data, including domestic content, prevailing wage and apprenticeship, energy communities, and other tax credit assumptions. Respondents should provide a discussion of the method for acquiring tax incentives through safe harbor or other methods and attest whether safe harbored equipment is specifically dedicated to the project, if applicable.

3.2.2.3 Tax Abatements

Respondents shall include a discussion of any tax abatements acquired by the project. Respondents should provide all terms, conditions, and relevant documentation related to tax abatements.

3.2.3 Renewable Project in Development

CenterPoint has a preference for Asset Purchase Proposals as described above in Section 3.2.2. However, CenterPoint will accept Asset Purchase Proposals for Generating Facilities in which ownership transfer of the project occurs prior to project completion; however, such Proposals must provide a definite path to completion. Proposals for Projects in Development must include pricing for completion of the project following transfer of ownership and must otherwise adhere to the Proposal requirements specified in Section 3.2.2 and elsewhere in this document including the Term Sheets provided in Appendices F, G and H. Appendices F and G contemplate asset transfer at completion; however, Proposals with a pre-completion transaction structure shall provide the same protections and commitments contemplated in the Term Sheets. Deviations shall be detailed in the Proposal narrative. Proposals must include discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including commitments from contractors supporting the proposed schedule. The Respondent shall document and commit to a proposed development schedule up to and including commercial operation.

3.2.4 Demand-Side Contracts

CenterPoint will consider LMR and DR resources from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of CenterPoint as described in Section 6.0 below. Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. CenterPoint will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

3.3 Respondent Pre-Qualification: Notice of Intent and Non-Disclosure Agreement

Respondents to this RFP are required to fill out and sign pre-qualification documents in their present form -- Appendix A: Notice of Intent to Respond, Appendix B: Non-Disclosure Agreement (NDA), and Appendix C: Pre-Qualification Application. Respondents shall submit the signed forms to the RFP website (http://CenterPoint2024ASRFP.rfpmanager.biz/) by 5:00 p.m. CDT on August 28, 2024. Respondents may download the forms from the RFP website. After submission of the pre-qualification documents, Respondents will be provided with the applicable pro forma PPA and Build Transfer Agreements (the "Pro Forma Agreements").

3.4 Multiple Proposals

Respondents may submit up to three Proposals (Projects) at no cost in response to this RFP. Respondents submitting more than three separate responses will incur a Proposal Evaluation Fee for each additional Proposal (Project) submitted. The non-refundable fee for evaluating each additional Proposal (Project) is $5,000. This sum will serve to defray evaluation costs. Respondents can find instructions for paying fees for their Proposal(s) on the RFP website (http://CenterPoint2024ASRFP.rfpmanager.biz/).

CenterPoint encourages Respondents to offer their Projects in a variety of ways and each Project offered with multiple options will be considered as a single Proposal. For example, Projects that are offered under multiple transaction structures (e.g., PPA or Asset Purchase) will count as one Proposal as it relates to the evaluation fee. Projects that offer various PPA term lengths and/or energy settlement locations (Project busbar, CenterPoint's load node, or Indiana Hub) will also be considered as one Proposal. In addition, Projects that are proposed both as standalone generating assets (e.g., solar) and also paired with storage will be considered as one Proposal as it relates to the fee. CenterPoint and 1898 & Co. will have sole discretion to determine whether a submission is deemed a single Proposal or multiple Proposals.

3.5 Proposal Pricing and Duration

Respondents shall make best efforts to offer Proposals with firm pricing not subject to any revisions during the evaluation, short-list selection and IRP process. As such, **pricing shall reflect the transaction price under current conditions (i.e. steel and other commodities, major equipment costs, tariffs and other duties, shipping costs, labor costs, availability of tax benefits, etc.).** For example, only current, active solar module tariffs in effect at the time of Proposal submission should be included and any potential future tariffs that may be levied should not be included in pricing. Likewise, Proposal pricing shall assume EPC costs such as material and labor as observed today, and shall not make assumptions as to the increase or decrease of costs at some future time.

Respondents shall provide cost assumptions in Appendix D and may provide further detailed justification for cost assumptions in the Proposal narrative. Proposals that base pricing on assumptions out of line with current conditions may be disqualified. All pricing should be provided in Appendix D in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. CenterPoint is not obligated to provide an opportunity in the evaluation schedule for Respondents to refresh or update their pricing before the final selection(s) are made (if any).

3.6 Acknowledgement of RFP Terms and Conditions

The submission of a Proposal shall constitute Respondent's acknowledgment and acceptance of all the terms, conditions, and requirements of this RFP.

3.7 RFP Response Summary Information

All Proposals must include a table of contents and provide concise and complete information on the additional topics described below, organized as follows:

3.7.1 Executive Summary

Please provide the following table in the Proposal as part of the executive summary in the form of a cover letter. The summary table of all proposed projects will be used to ensure all projects are accounted for and the required documents have been submitted. In addition to the information in the table, please provide the primary contact's name, email, and phone number. The Executive Summary must be signed by an officer of the Respondent who is duly authorized to commit the firm to carry out the proposed transaction should CenterPoint accept the Proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

Executive Summary Table

Bid #	Project Name	Project Location	Technology Type	ICAP Size (MW)	Contract Start Date/ Project In-Service Date	Contract Type (PPA, Purchase, Other)	Year 1 PPA Price ($/MWh)	Purchase Price ($)
1								
2								
…								

3.7.2 Respondent's Information and Experience

Please include information on the Respondent's corporate structure (including identification of any parent companies), the project's financing plan, the Respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of Respondent attesting to its accuracy, a copy of Respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of Respondent's relevant experience. Please describe any current litigation or environmental fines involving the Respondent within the last five years, including but not limited to, any litigation, settlements of litigation or fines, that could potentially affect the facility or its operation. Please identify all bankruptcy or insolvency proceedings relating to the Respondent in any way. Please describe any litigation the Respondent or its parent company have been a party to in the last six years related to PPAs, asset purchases, or other transactions similar to those solicited in this RFP. All financial statements, annual reports and other large documents may be referenced via a website address.

Generating Facility Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale power generation facilities.

4.0 Proposals Including Renewables & Battery Storage

4.1 Additional Requirements – Renewable and Storage Resources

Proposals for renewable and storage resources such as wind, solar, standalone storage, or storage paired with solar or other renewable projects (Renewable Resources) will be considered when submitted in response to this RFP. This section of the RFP provides additional requirements applicable to Proposals that include one or more renewable or storage resource(s). In addition, please see applicable Term Sheets (additional key pricing assumptions) in Appendices F, G and H.

4.2 Wind Energy Proposals

CenterPoint is seeking Proposals for wind energy projects with an installed capacity (ICAP) of 50 MWac or greater but will consider Proposals for projects of any size. In addition to the general requirements provided in Section 3.0, the following additional requirements apply to any Proposal that includes a wind project:

- Major Component Data: The Proposal shall provide details on major components (such as turbines, blades, transformers, circuit breakers, switchgear, all protection and control systems, etc.) including manufacturer, country-of-origin, individual turbine ratings, rotor diameter and hub height.
- Location: CenterPoint has a preference for wind projects located in MISO Zone 6 as well as MISO Zone 4 and MISO Zone 5 but will also consider Proposals for projects located elsewhere. Proposals for facilities without existing firm deliverability to MISO LRZ 6 shall include cost estimates and transmission studies associated with securing such deliverability.
- Site control and layout: Proposals for wind projects shall include discussion of the project turbine layout and status of land acquisition required to site the layout. Respondents shall include a discussion of any nearby land features or facilities imposing land-use constraints including, but not limited to, wetlands, airports and other FAA facilities, zoning restrictions, etc.
- Permits and zoning: Respondents shall include a discussion of permitting status for the project including zoning status and restrictions such as setbacks, tip height limits, etc.
- Expected performance: Proposals shall include P50 expected annual production in MWh or NCF. Respondents shall provide the wind data or describe the data set used to estimate production.
- Price: Any Asset Purchase Proposal must clearly state the purchase price for the wind asset and indicate the intended disposition of Production Tax Credits or Investment Tax Credits. PPA Proposals must include the applicable contract price. Either proposal must include Respondent’s comments on the applicable term sheet and should include Respondent’s comments on the applicable Pro Forma Agreement. CenterPoint shall evaluate such comments holistically as part of its evaluation of all Proposals. Proposals may also include an option to purchase the assets and shall clearly state the terms of such purchase option.
- To the extent RECs are included in a Proposal, they must be registered with the Midwest Renewable Energy Tracking System (M-RETS).

4.3 Solar Energy Proposals

CenterPoint is seeking Proposals for solar energy projects with an installed capacity (ICAP) of 50 MWac or greater but will consider Proposals for projects of any size. In addition to the general requirements provided in Section 3.0, the following additional requirements will apply to any Proposal that includes a solar energy project:

- Major Component Data: The Proposal shall provide details on major components (such as solar panels, racking, inverters, transformers, circuit breakers, switchgear, all protection and control systems, etc.) including manufacturer, country-of-origin, individual panel ratings, and whether the panels will be fixed or tracking. The Proposal shall also include information on the inverters to be included in the project, including the manufacturer, size of individual inverters, and the type/configuration of the inverter system.
- Location: CenterPoint has a preference for solar projects located in MISO Zone 6 but will also consider Proposals for projects located elsewhere. Proposals for facilities without existing firm deliverability to MISO LRZ 6 shall include cost estimates and transmission studies associated with securing such deliverability.
- Site control and layout: Proposals for solar projects shall include discussion of the project panel/array layout(s) and status of land acquisition required to site the layout. Respondents shall include a discussion of any nearby land features or facilities imposing land-use constraints including, but not limited to, wetlands, zoning restrictions, etc. Respondents shall also include a description of civil work that will be required to prepare the land for solar installation as well as the contiguity of the land parcels used for the project. If possible, Proposals should include layout drawings and schematics for the project.
- Permits and zoning: Respondents shall include a discussion of permitting status for the project including zoning status and restrictions such as setbacks, vegetation screening requirements, etc.
- Expected performance: Proposals shall include P50 expected annual production in MWh or NCF. Respondents shall provide the solar data or describe the data set used to estimate production.
- Price: Any Asset Purchase Proposal must clearly state the purchase price for the solar asset and indicate the intended disposition of Production Tax Credits or Investment Tax Credits. PPA Proposals must include the applicable contract price. Either proposal must include Respondent's comments on the applicable term sheet and should include Respondent's comments on the applicable Pro Forma Agreement. CenterPoint shall evaluate such comments holistically as part of its evaluation of all Proposals. Proposals may also include an option to purchase the assets and shall clearly state the terms of such purchase option.
- To the extent RECs are included in a Proposal, they must be registered with the Midwest Renewable Energy Tracking System (M-RETS).

4.4 Energy Storage Proposals

CenterPoint is seeking Proposals for energy storage projects with an installed capacity (ICAP) of 25 MW or greater and a minimum duration of 4 hours; however, Proposals for storage projects of any size will be considered. In addition to the general requirements provided in Section 3.0, the following additional requirements will apply to any Proposal that includes stand-alone storage or storage paired with other renewable technologies (e.g., solar + storage):

- Major Component Data: The Proposal shall provide details on major components (such as cells/modules, inverter, BMS, container system, climate control, fire protection, transformers, circuit breakers, switchgear, and control systems, etc.) including manufacturer, country-of-origin, etc.
- Location: CenterPoint has a preference for storage projects located in MISO Zone 6 but will also consider Proposals for projects located elsewhere. Proposals for facilities without existing firm deliverability to MISO LRZ 6 shall include cost estimates and transmission studies associated with securing such deliverability.
- Expected performance: Proposals shall include the system efficiency (i.e. roundtrip efficiency), overbuild, annual augmentation, maximum/warranty daily and annual cycles, etc. Proposals should include a description of the control strategy and dispatch control ownership.
- Price: Any Asset Purchase Proposal must clearly state all terms and obligations of the parties associated with the proposed transaction, including the disposition of Investment Tax Credits if applicable.
    - For purposes of incorporating the effect of tax benefits in Proposal pricing, Respondents shall apply tax law currently in effect at the time of Proposal submission and clearly state which tax assumptions are used. Respondents may optionally provide a discussion on the pricing impacts of possible future scenarios; however, a Proposal may be disqualified if it does not at a minimum provide pricing applying only current laws.

4.5 Evaluation Methodology

The following tables summarize the criteria that will be used to evaluate renewable and battery storage resource Proposals. Further definitions of each criterion and how criteria will be evaluated are outlined in Section 7.0.

Table 3: Renewables Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (20%)	100	Proportionately from 0 (awarded to highest LCOE in group) to 100 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[2] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	Points awarded equally to 4 milestones. • Max points for completed GIA & cost cap • 75 points for DPP Phase 3 & offered cost cap • 50 points for DPP Phase 2 & offered cost cap • 25 points for DPP Phase 1 & offered cost cap • 0 points otherwise
Project Risk Factor (20%)	100	• Credit and Financial Plan – 20 points awarded proportional to CenterPoint internal score from 0-10 • Development Experience – 20 points awarded proportional to MW in service, max of 1,500 • Site Control – 20 points proportional from 0%-100% of site control verified by provided documents • Permits – 20 points for Proposals showing all permits needed for construction/operation • Zoning – 20 points for Proposals showing completed zoning requirements
Agreement to Terms (20%)	100	• Max points awarded for no material changes (redlines) and affirmative statement of acceptance • 75 points awarded for 1 to 4 material changes (redlines) • 50 points awarded for 5 to 7 material changes (redlines) • 0 points awarded for more than 7 material changes (redlines)

[2] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory.

Table 4: Storage Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[3] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	Points awarded equally to 4 milestones. • Max points for completed GIA & cost cap • 75 points for DPP Phase 3 & offered cost cap • 50 points for DPP Phase 2 & offered cost cap • 25 points for DPP Phase 1 & offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CenterPoint internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Site Control – 30 points proportional from 0%-100% of site control verified by provided documents • Permits – 30 points for Proposals showing all permits needed for construction/operation • Zoning – 30 points for Proposals showing completed zoning requirements

[3] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory.

5.0 Proposals Including Thermal Resources

5.1 Additional Requirements – Thermal Resources

Proposals for thermal generating resources such as coal, natural gas, hydrogen or nuclear units will be considered when submitted in response to this RFP. This section of the RFP provides additional requirements applicable to Proposals that include one or more thermal resource(s).

5.2 Dispatch, Emissions, and Performance Characteristics for Thermal Resources

Respondents shall provide the dispatch and emissions characteristics of the generation facility in Appendix D, including, but not limited to:

- Minimum load level
- Maximum load level
- Ramp rates (up and down)
- Number of gas turbines that can be started simultaneously (if applicable)
- Heat rate curve for typical operations, including the minimum load and full load heat rates
  - If applicable, Respondent shall also provide heat rate curves for summer and winter seasons
- Fuel consumption and heat rate during startup, including startup time and the total number of hours annually the facility can be assumed to be in startup mode
- Fuel consumption and heat rate when the facility is being shut down, including how long shutdown takes and the total number of hours annually the facility can be assumed to be in shutdown mode
- An estimation of the total number of hours annually that the facility operates at full load
- Capability reductions as a result of ambient temperature increases
- Supplemental firing capability, including black start capability, and any operating limitations caused by such factors of design
- Emissions rates in units of lb/MWh at relevant dispatch levels (startup, minimum, mid and full loading) and seasons (summer, winter, shoulder) for nitrogen oxides (NOX), sulfur dioxide (SO2), carbon dioxide (CO2), volatile organic compounds (VOC), particulate matter (PM) and carbon monoxide (CO)
- Any other operational limitations that reduce unit availability or reduce a unit's ability to dispatch or regulate

5.3 Operating Considerations

In addition to the instructions provided above in Section 3.0, Respondents shall provide the following data specific to thermal resources.

5.3.1 Operating Data

Respondents shall provide details on any current generation facility equipment issues and concerns, including the potential drivers and recommended mitigation procedures for the issues and/or concerns. These may include, but are not limited to, any operation of the turbine, generator, or boiler outside recommended parameters established by OEM, compromised turbine or compressor blades, etc. Respondents shall provide a list of any redundant equipment that is currently bypassed or out of service, and the related reason. Respondents shall also provide historical information on such issues and concerns that have arisen, how they were resolved, and the associated costs for the last ten years of operation, or for the commercial life of the generation facility, whichever is lesser.

5.3.2 Fuel Supply

Proposals shall describe, to the extent possible, fuel sourcing strategy, including from where their fuel is sourced. Respondents shall provide a description, including detailed cost information, contract duration, and material contract terms (including whether fuel contracts are take or pay, minimum volume requirements, price reopeners, assignability or termination provisions) of all fuel purchase, storage, and transport agreements related to the generation facility Proposal. Cost of fuel commodities shall be provided separately from the cost of fuel transportation. Respondents also must list any provisions or other considerations that would prohibit or impair the assignment and/or affect the performance obligations of either party under the respective contract(s). Respondents shall describe fuel purchase and transport to the generation facility, as well as any existing or known potential operational restrictions or impediments on such fuel purchase and transportation. Respondents also are required to provide a description of the existing fuel supply (and storage) infrastructure serving the generation facility, including the infrastructure for the delivery of secondary fuel for dual-fuel resources. However, CenterPoint, through this RFP, is exploring the potential purchase of generation facilities, and it is CenterPoint's sole discretion whether to assume any contract or contracts associated with the proposed generation facility related to fuel commodities and/or fuel transportation.

Proposals shall describe the generation facility's ability to access a reliable fuel supply that would support operation for any hour throughout the year, including the plant's onsite fuel storage and dual-fuel capabilities, if applicable. Proposals for gas generators shall indicate whether the facility is dual-fuel capable and Proposals should include an indication of the days of onsite fuel storage available. Gas generators without dual fuel capability shall provide information on the costs required to make the facility dual fuel capable to the extent that such cost estimates are available. Natural gas fired facilities shall have firm gas transportation contracts in place for the amount of gas capacity necessary to fulfill the amount of UCAP being bid. Proposals that do not include firm gas supply may be disqualified.

5.4 Environmental Considerations

In addition to the instructions provided above Respondents shall provide the following data specific to thermal resources.

5.4.1 Emissions and Waste Disposal Compliance

To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to CenterPoint. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to SO2, NOX, Mercury (Hg), and CO2. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer or PPA seller.

For Asset Purchase Proposals, the Seller will retain all pre-closing environmental liabilities and obligations as well as all known future environmental liabilities and obligations, in each case associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all other post-closing environmental liabilities and obligations. For purposes of facility design, Seller should assume that the unit will be required to meet the proposed New Source Performance Standards for Greenhouse Gases (40 Code of Federal Regulations (CFR) part 60, subpart TTTT).

5.4.2 Water Supply

Respondents shall provide a detailed description of the water supply, including but not limited to, contract term, water usage, and cost of water for the generation facility. Respondents shall also provide the status of the facility's National Pollutant Discharge Elimination System (NPDES) permits, including, but not limited to, permit conditions, permit violations reported over the last five years, the timing of next permit renewal, and any other known concerns.

If applicable, Respondents shall provide a summary of the facility's water chemistry program, including key systems and suppliers, and its performance in the most recent year.

5.4.3 Permits

As stated above, the generation facility must have all relevant environmental and other permits necessary for operation and maintenance. Respondents shall provide a description of all permits currently in place for the operation and maintenance of the facility (e.g., Spill Prevention Containment and Control plans, Title IV and Title V permits of the Clean Air Act, Cap and Trade Permits, NPDES permits, Water Withdrawal, and Pollution Incident Prevention Plan, etc.).

Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability.

Respondents shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

5.5 Evaluation Methodology

The following table summarizes the criteria that will be used to evaluate thermal resource Proposals. Further definitions of each criterion and how criteria will be evaluated are outlined in Section 7.0.

Table 5: Thermal Facility Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[4] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	Points awarded equally to 4 milestones. • Max points for completed GIA & cost cap including interconnection agreement re-use • 75 points for DPP Phase 3 & offered cost cap • 50 points for DPP Phase 2 & offered cost cap • 25 points for DPP Phase 1 & offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CenterPoint internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Fuel Risk – 15 points • Operational Control – 15 points • Site Control – 30 points proportional from 0%-100% of site control verified by provided documents • Permits – 15 points for Proposals showing all permits needed for construction/operation • Zoning – 15 points for Proposals showing completed zoning requirements

[4] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory.

6.0 Proposals Including Load Modifying Resources/Demand Resources

LMRs/DRs are demand-side resources and behind the meter generation not typically modeled or measured as part of MISO's operations but used during capacity shortages to help meet the energy balance. CenterPoint will consider LMRs/DRs from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of CenterPoint as described in Sections 6.1 and 6.3. In addition, for LMRs/DRs located within Indiana, Respondent must identify how the Proposal conforms with any requirements of the local utility and state law in order to offer resources for capacity accreditation within the MISO market under Module E Capacity Tracking.

Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. CenterPoint will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

6.1 Product Definition

To be eligible for participation in this RFP, the LMR/DR offered by a supplier must:

- Meet LMR/DR Requirements for participation in MISO as a demand-side resource, including any future changes to MISO's requirements for LMRs/DRs for the term of the Proposal
- Meet the additional performance requirements described in Section 6.3
- For capacity accreditation, the Proposal must be sourced from locations entirely within MISO LRZ 6
- Use an existing, proven technology that has demonstrated reliable demand reduction, which may include use of Behind the Meter Generation (as defined by MISO)
- Reduce load by a predetermined amount when notified by CenterPoint of a Curtailment Event without further direction or communication by or from CenterPoint.

6.2 Purchase Agreement

If selected, the LMR/DRs supplier and CenterPoint will negotiate a mutually acceptable agreement to govern any commercial relationship established by the parties. With respect to a Proposal from a CSP, CenterPoint will not be responsible for making payments to, communicating with, or managing the relationship or performance of any customer within an aggregation, and the CSP shall be solely responsible for the same in all respects. To mitigate risk, CenterPoint will require the LMR/DR supplier to provide collateral upon execution of a LMR/DR Proposal. CenterPoint reserves the right to determine the form of that collateral requirement for a winning Proposal.

6.3 Curtailment Events: Notification and Performance Requirements

LMRs/DRs must meet notification and performance requirements applicable to a Curtailment Event, as defined and described herein and comply with MISO current and future testing requirements. A Curtailment Event shall be initiated by either CenterPoint or MISO as described further in Section 6.3.1.

6.3.1 Notification, Performance, and Test Requirements

Curtailment Events initiated by MISO: For Curtailment Events initiated by MISO, LMR/DR suppliers shall agree to and be capable of meeting, throughout the entire term of the Proposal, all notification and performance requirements applicable to Capacity Performance demand resources. The supplier shall comply with all MISO Module E Capacity Tracking measurement and verification requirements.

Curtailment Events initiated by CenterPoint: Suppliers shall also agree to and be capable of meeting the following additional notification and performance requirements applicable to Curtailment Events initiated solely by CenterPoint:

- Suppliers shall curtail Actual Measured Load by the designated load amount within the proposed notification time specified in the Proposal.
- Notification of a Curtailment Event initiated solely by CenterPoint will consist of an electronic message issued by CenterPoint to a device or devices such as telephone, facsimile, or email, selected and provided by the supplier and approved by CenterPoint. Two-way information capability shall be incorporated by CenterPoint and the supplier in order to provide confirmation of receipt of notification messages. CenterPoint will provide the supplier a notification of when Curtailment Events have ended. Operation, maintenance, and functionality of communication devices for receipt of notifications selected by the supplier shall be the sole responsibility of the supplier, and receipt of notifications set out in this paragraph shall be the sole responsibility of the supplier.
- During the entire period of a Curtailment Event initiated by CenterPoint, the supplier's Actual Measured Load must curtail by at least the designated load amount . A supplier's Actual Measured Load shall be determined by integrating the megawatts used over every clock hour (hour-ending).

6.3.2 Remedies for Non-Performance

A supplier whose Actual Measured Load does not curtail by the designated load amount will be subject to performance penalties which may include, but not be limited to, refunding to CenterPoint monthly payments under the agreement.

A supplier shall be responsible for and shall indemnify CenterPoint for, any non-performance penalties, costs, charges, or other amounts assessed by MISO and incurred by CenterPoint as a result of non-performance attributable to the supplier's LMR/DR, including but not limited to any Capacity Resource Deficiency Charges, Non-Performance Charges, or similar charges or penalties under the MISO agreements. In no event shall the penalties listed above for non-performance during a Curtailment Event be less than the sum of any MISO non-performance penalties, costs, charges, or other amounts incurred by CenterPoint as a result of non-performance attributable to the supplier's LMR/DR and the Curtailment Event charge.

6.4 Proposal Requirements

6.4.1 Acquisition Price

Suppliers shall submit an acquisition price consisting of a single fixed amount denominated in units of dollars per megawatt-day ($/MW-day), which is to apply for the term of the Proposal. If a Proposal is accepted, the supplier will be compensated in an amount equal to the monthly Curtailable Load times the Acquisition Price. The Proposal shall include all monetary consideration for the LMR/DR offered. Suppliers must submit their best and final price with their Proposal.

Should CenterPoint execute an agreement with a Respondent, the contract price between CenterPoint and the Respondent will be the Acquisition Price submitted in its respective Proposal through this RFP process.

6.4.2 Product Description

A Proposal shall include a description of the individual LMR/DR customer(s) and expected load drop values (kW), equipment, and technology that will be deployed and make available any other information required by MISO to meet its registration process, and for CSPs, plans for recruiting, engaging, and maintaining Program Participants.

Proposals should discuss the experience, qualifications, and financial strength of the supplier and other key contributors including the specific number of months the supplier has been providing LMR/DR services in MISO. Responses should indicate whether the supplier has ever been assessed a performance penalty in association with the resource and if so, when any penalties were assessed. For CSPs, Proposals should describe well-defined roles and responsibilities of the supplier and its participants. The supplier should describe successful protocols, if any, they have employed in the MISO LRZ 6 or other MISO zones for dispatching their LMR/DR.

While the product definition requires a load reduction upon notification by CenterPoint or MISO of a Curtailment Event, there is a preference for resources that can provide a more rapid response and/or ramp up or down in response to specific control signals. Respondents are urged to detail the full, demonstrated capability of the proposed resource in accordance with the evaluation criteria included in Section 7.0.

For planned LMRs/DRs, the supplier must fully describe specific plans detailing what equipment or technology it will deploy and/or utilize to support its operations. For CSPs, Proposals must describe supplier's processes for aggregating participants, how the supplier intends to recruit and engage participants including but not limited to providing a standard contract between the CSP and participant, and/or provide lists of participants. The Proposal also must describe curtailment systems and procedures, budgeting for and structure of dispute resolution, and plans for communicating with participants in connection with a curtailment period.

6.4.3 Technical Requirements

CenterPoint shall acquire all rights, titles, and interests in the LMR/DR including all the potential capacity and energy revenues. Suppliers must agree to cooperate with CenterPoint in providing information needed to meet all MISO LMR/DR information requirements.

The supplier will assume all responsibilities and liabilities associated with providing LMRs/DRs. Accordingly, Proposals offering LMRs/DRs must include acknowledgment and agreement that the supplier is responsible for the following non-exhaustive list of activities and obligations:

- Managing load reductions, including all notices, communications, controls, equipment, or other processes required
- If the supplier is a CSP, determining the number of participants, in its aggregation, the number of interruptible hours per customer, and the size of each participant's load reduction
- If the supplier is a CSP, paying any participants according to the CSP's agreement with those participants. Such agreements shall be independent of CenterPoint's agreement with the CSP and must hold CenterPoint harmless for any direct or indirect obligations or liability associated with the program
- Paying penalties assessed due to the non-performance of the LMR/DR

The agreement shall reflect that it will be the supplier's responsibility to reimburse CenterPoint for any penalties, fees, or charges resulting from non-performance of its LMR/DR, including replacement capacity to maintain CenterPoint's Planning Reserve Margin (PRM) requirement, and the supplier's obligation to indemnify and hold CenterPoint harmless against any claim arising from such non-performance. In the case of a supplier who is a CSP, the agreement will additionally set forth CSP's responsibility to reimburse CenterPoint for any penalties, fees, or charges resulting from non-performance of any CSP participant, and CSP's obligation to indemnify and hold CenterPoint harmless against any claim arising from such CSP participants' non-performance.

6.5 Evaluation Methodology

The following evaluation criteria will be used to evaluate Proposals including other LMR/DRs. Since there is a wide range of potential products which could be offered within this category, adjustments may be made on scoring criteria to accurately compare bids within categories to each other. Further definitions of each criterion and how criteria will be evaluated are outlined in Section 7.0.

Table 6: Demand-Side Contracts Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
Cost Evaluation (40%)	200	Scaled proportional to the cost of similar Proposals.
Historical Performance (20%)	100	Awarded based on time in-service and absence of a non-performance penalty.
Response Time (20%)	100	Awarded based on response time to specific control signals.
Project Risk Factor (20%)	100	Allocated based on material risk of reduced deliverability.

6.6 Contract Execution

CenterPoint does not, by this RFP, obligate itself to purchase any LMR/DR, or to execute an agreement with any Respondent who submits an offer to sell a LMR/DR to CenterPoint. CenterPoint may, in its discretion, reject any or all Proposals to sell a LMR/DR to CenterPoint, as such are described in this RFP.

Selection of a Proposal as a finalist shall not be construed as a commitment by CenterPoint to execute an agreement. Execution of any agreement is contingent upon CenterPoint receiving all required regulatory approvals and completion of such due diligence as CenterPoint in its sole discretion determines is reasonable to confirm the qualifications and performance of a given LMR/DR. During the period between when 1898 & Co. makes its recommendation(s) to CenterPoint, and the date of execution of the agreement, CenterPoint may conduct additional due diligence on the Proposal.

7.0 Proposal Evaluation and Contract Negotiations

7.1 Initial Proposal Review

An initial review of the Proposals will be performed by 1898 & Co. Proposals will be reviewed for completeness. Proposals that do not include all of the required information as described herein may be deemed ineligible and may not be considered for further evaluation. If it appears that certain information has inadvertently been omitted from a Proposal, 1898 & Co. may, but is not obligated to, contact the Respondent to obtain the missing information, per Section 2.2. These communications will be initiated via email (CenterPointRFP@1898andco.com).

Each complete Proposal will be evaluated by quantitative and qualitative factors. The evaluation criteria outlined in this section are intended to relatively compare each Proposal to analogous submissions and will be the starting guidelines for the evaluation. If needed, the scoring may be adjusted to provide distinction between Proposals. This evaluation will be used to determine which projects are most capable of providing CenterPoint customers with a safe, reliable, and affordable power supply. Project scoring will be used to narrow the field down to a short list.

7.2 Evaluation Criteria - Generation Facility

1898 & Co. will quantitatively and qualitatively evaluate all conforming generation facility Proposals' ability to meet power supply needs. During this evaluation process, 1898 & Co. may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations.

Table 7: Renewables Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (20%)	100	Proportionately from 0 (awarded to highest LCOE in group) to 100 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[5] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	Points awarded equally to 4 milestones. • Max points for completed GIA & cost cap • 75 points for DPP Phase 3 & offered cost cap • 50 points for DPP Phase 2 & offered cost cap • 25 points for DPP Phase 1 & offered cost cap • 0 points otherwise
Project Risk Factor (20%)	100	• Credit and Financial Plan – 20 points awarded proportional to CenterPoint internal score from 0-10 • Development Experience – 20 points awarded proportional to MW in service, max of 1,500 • Site Control – 20 points proportional from 0%-100% of site control verified by provided documents • Permits – 20 points for Proposals showing all permits needed for construction/operation • Zoning – 20 points for Proposals showing completed zoning requirements
Agreement to Terms (20%)	100	• Max points awarded for no material changes (redlines) and affirmative statement of acceptance • 75 points awarded for 1 to 4 material changes (redlines) • 50 points awarded for 5 to 7 material changes (redlines) • 0 points awarded for more than 7 material changes (redlines)

[5] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory.

Table 8: Storage Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (20%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[6] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	Points awarded equally to 4 milestones. • Max points for completed GIA & cost cap • 75 points for DPP Phase 3 & offered cost cap • 50 points for DPP Phase 2 & offered cost cap • 25 points for DPP Phase 1 & offered cost cap • 0 points otherwise
Project Risk Factor (20%)	150	• Credit and Financial Plan – 30 points awarded proportional to CenterPoint internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Site Control – 30 points proportional from 0%-100% of site control verified by provided documents • Permits – 30 points for Proposals showing all permits needed for construction/operation • Zoning – 30 points for Proposals showing completed zoning requirements

[6] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory.

Table 9: Thermal Facility Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[7] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	Points awarded equally to 4 milestones. • Max points for completed GIA & cost cap including interconnection agreement re-use • 75 points for DPP Phase 3 & offered cost cap • 50 points for DPP Phase 2 & offered cost cap • 25 points for DPP Phase 1 & offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CenterPoint internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Fuel Risk – 15 points • Operational Control – 15 points • Site Control – 30 points proportional from 0%-100% of site control verified by provided documents • Permits – 15 points for Proposals showing all permits needed for construction/operation • Zoning – 15 points for Proposals showing completed zoning requirements

[7] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory.

7.2.1 Levelized Cost of Energy – 100 Points for Renewables / 150 Points for Thermal and Storage

The initial evaluation will be primarily based on a comparison of each Proposal's Levelized Cost of Energy (LCOE). A LCOE allows for Proposals within asset classes, which have different sizes, pricing, operating characteristics, ownership structures, etc. to be evaluated and compared to each other on an equivalent economic basis. The LCOE analysis will incorporate all costs associated with an asset purchase or PPA. These costs will include the applicable purchase or PPA cost, fixed costs, and variable operating expenses across standard technology respective operating parameters. The levelized value of these costs over this time period are then divided by the energy produced by the respective Proposal.

CenterPoint specific assumptions used in this analysis will be in accordance with CenterPoint's 2025/2026 IRP assumptions, including but not limited to

- Discount rate
- Capital recovery factor
- Escalation pro
- Fixed operations and maintenance expenses
- Variable operations and maintenance expense

The LCOE evaluation is a screening level economic evaluation which will determine the cost of energy provided by each Proposal relative to similar technology types. Proposals within an evaluation class with the lowest LCOE will receive full scoring for this metric. Points awarded to higher cost Proposals will be scaled inversely proportional with the highest cost Proposal receiving 0 points for this metric.

The rules for performing the LCOE analysis will be determined by 1898 & Co. and CenterPoint in advance of the receipt and review of any Proposals. However, as part of the process of evaluating Proposals, cases may arise where, in order to adequately project asset costs or to facilitate a comparison between qualified Proposals, the rules related to the LCOE analysis may require review and/or adjustment. To the extent that any additions or adjustments are required, such additions or adjustments will be made solely by 1898 & Co. In such cases, any and all rules will be applied consistently across all Respondents.

While performing LCOE analyses of Proposals, 1898 & Co. may request additional or clarifying information from a given Respondent regarding resource performance, operating costs, or other factors that influence the LCOE calculation for a given resource. This evaluation may also include grid congestion analysis. Requests for additional information may be required to ensure that all qualified Proposals are fairly and consistently evaluated. Consistent with Section 2.2, in such cases, Respondents will be required to respond within five business days of receipt of such request. 1898 & Co. will not consider unsolicited updates from Respondents related to the cost of any power supply resource.

Please note, the total points allocated for the LCOE scoring category differ slightly between renewables and storage and thermal resources. The total possible points for renewable bids are 100 points with thermal and storage bids having 150 possible points.

7.2.2 Energy Settlement Location – 100 Points

CenterPoint has a preference for Proposals that include all costs to have energy financially settled or directly delivered to CenterPoint's load node (SIGE.SIGW). Proposals that settle at SIGE.SIGW will receive 100 points. Proposals that settle at a node in CenterPoint electric service territory will receive 90 points. Proposals that settle at Indiana Hub will receive 50 points. Proposals that settle at a different node in LRZ 6, but outside of CenterPoint electric service territory will receive 25 points. Proposals that settle at a node outside of LRZ 6 will receive 0 points.

7.2.3 Interconnection and Development Status – 100 Points

Existing resources will receive full credit under this evaluation category. Plants that have not achieved commercial operation but that are in the MISO Generation Interconnection (GI) Queue will be awarded points based on the Definitive Planning Phase (DPP) they are in. Facilities failing to meet critical development milestones may be disqualified from consideration at CenterPoint's sole discretion.

Up to 100 points will be awarded based on the achievement of certain development milestones towards the facility COD. These directly relate to which stage of the DPP the resource is in at the time of the proposal. The point distribution is given as follows:

- 25 points will be awarded to a resource in DPP Phase 1
- 50 points will be awarded to a resource in DPP Phase 2
- 75 points will be awarded to a resource in DPP Phase 3
- Full points in this category will be awarded to a resource for which a MISO Generator Interconnection Agreement has been executed and a maximum limit on interconnection and network upgrade costs that will be passed through to CenterPoint is included in the Proposal.

7.2.4 Project Risk Factors – 100 Points for Renewables / 150 Points for Thermal and Storage

The Project Risk Factors attempt to identify and score potential risks which may compromise the future performance of the asset. In situations where the level of risk is not accurately represented, scoring may be adjusted. Potential considerations include, but may not be limited to the following:

- Credit and financial plan - Proposals will be evaluated based on a rating 0 through 10 (financial score) that takes into account credit ratings from S&P, Moody's, and D&B, years in business, and provided financial statements. The points will be awarded as percent of the maximum financial score as shown below:

$$Points\ Awarded = \frac{Financial\ Score}{10} \times (30\ for\ Thermal\ and\ Storage\ or\ 20\ for\ Renewables)$$

- Development experience - Relevant technology development experience is an important risk factor. Proposals will receive up to 30 points based on the following formula:

$$Points\ Awarded = \frac{Nameplate\ MW\ In\ Service\ (same\ technology\ as\ proposed)}{1{,}500} \times (30\ for\ Thermal\ and\ Storage\ or\ 20\ for\ Renewables)$$

- Site Control - Proposals will receive points proportionately based on the amount of verifiable site control. Respondents should be as detailed and thorough as possible in describing and providing evidence of site control. Proposals will receive up to 30 points based on the following formula:

$$Points\ Awarded = \frac{Percent\ of\ Verifiable\ Site\ Control}{100\%} \times (30\ for\ Thermal\ and\ Storage\ or\ 20\ for\ Renewables)$$

- Permits - Proposals that have all permits necessary for construction and operation will receive max points. Partial points may be assigned based on level of documentation provided.
- Zoning - Proposals that have fulfilled zoning requirements will receive max points. Partial points may be assigned based on level of documentation provided.
- Fuel risk - For applicable Proposals, sites with firm and reliable fuel supply will receive max points.
- Operational control - Proposals which offer CenterPoint operational control will receive max points.
- Pro Forma Comments – Respondent's comments on the term sheets and Pro Forma Agreements, and the associated risk allocations, will be evaluated holistically and scored out of [__].

Any such risks shall be disclosed along with a description of the associated measures taken to mitigate the risk. Failure to disclose a reasonably foreseeable risk or risks may be a basis to disqualify a Proposal.

Proposals with no such risks as determined by 1898 & Co. will receive the full number of points available in this category. Proposals with asset or project-specific risks that are not able to be fully mitigated may receive fewer points depending on 1898 & Co.'s assessment.

Please note, the total points allocated for the LCOE scoring category differ slightly between renewable and storage and thermal resources. The total possible points for renewable bids are 100 points with thermal and storage bids having 150 possible points.

7.2.5 Agreement to Terms – 100 Points (Renewables Only)

For scoring of Renewable Proposals only, the Agreement to Terms category is used to determine to what extent the vendor agrees to the legal terms and conditions proposed by CenterPoint, should submitted proposals advance in the proposal process. In addition to meeting the minimum legal requirements (as outlined in Section 3.1.8), proposals will be awarded points based on their agreement to terms. The breakdown is as follows:

- Full points (100) awarded for no material changes (redlines) and affirmative statement of acceptance
- 75 points awarded for 1 to 4 material changes (redlines)
- 50 points awarded for 5 to 7 material changes (redlines)
- 0 points awarded for more than 7 material changes (redlines)

7.3 Evaluation Criteria – LM/DR Resources

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming LMR/DR Proposals. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

CenterPoint will accept Proposals from LMR and DR providers that meet the requirements as established in this RFP and conform to MISO requirements. These requirements include but are not limited to, the ability to respond to Curtailment Events initiated either by MISO or by CenterPoint.

LMR/DR Proposals will be evaluated across the following criteria:

Table 10: Demand-Side Resource Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
Cost Evaluation (40%)	200	Proportionately from 0 (awarded to highest cost in group) to 200 (lowest cost in group)
Historical Performance (20%)	100	Awarded based on time in-service and absence of a non-performance penalty.
Response Time (20%)	100	Awarded based on response time to specific control signals.
Project Risk Factor (20%)	100	Allocated based on material risk of reduced deliverability.

7.3.1 Cost Evaluation – 200 Points

The cost of each Proposal will be evaluated based on the annual payment per MW for the LMR/DR. The lowest $/MW cost Proposal will receive 200 points for the cost evaluation category. Points awarded to higher cost Proposals will be scaled inversely proportional with the highest cost Proposal receiving 0 points for this metric.

7.3.2 Historical performance – 100 Points

An end use customer or CSP with a historical performance record of successfully providing demand response services for three or more years without being assessed a non-performance penalty will receive 100 points for this category.

An end use customer or CSP that has provided such services for between one year and three years without being assessed a non-performance penalty will receive 50 points for this category.

An end use customer or CSP that has not provided such services in the past or that has been assessed a non-performance penalty will receive zero points for this category.

7.3.3 Response Time – 100 Points

While the product defines a load reduction response time within a Respondent's Proposal, there is a preference for resources that can provide a more rapid response to specific control signals.

Proposals for LMR/DR that have the ability to follow a real-time signal will be awarded 100 points for the response time category. Proposals for LMR/DR that can achieve the load reduction target within 30 minutes of notification will receive 75 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 60 minutes of notification will receive 50 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 120 minutes of notification will receive 25 points for this category.

7.3.4 Proposal Risk Factors - 100 Points

The Proposal risk factors category will be used to adjust the overall scoring in cases where there is a material risk identified that may create concerns about the ability of the provider to deliver on their Proposal or that may create a material uncertainty about the cost to CenterPoint or its customers, significant regulatory uncertainty, or other considerations.

7.4 Discussion of Proposals During Evaluation Period

CenterPoint may or may not select candidates for further discussions. CenterPoint will contact any selected Respondent in writing to confirm interest in commencing contract negotiations. All negotiations will begin with the relevant Pro Forma Agreement, and the Respondent's comments on such Pro Forma Agreement. CenterPoint's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals, as provided therein.

7.5 Selection of Highest Scoring Proposal(s)

Proposals will be rank ordered consistent with the RFP evaluation criteria. Resources will be selected consistent with the RFP evaluation, short-term capacity needs, and the IRP determined need. CenterPoint will seek to secure, subject to CenterPoint board approval, resources consistent with the preferred portfolio identified in the 2025/2026 IRP. There is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected.

7.6 Contract Execution

CenterPoint does not, by this RFP, obligate itself to purchase any generation facility or facilities, or to execute an Asset Purchase Agreement or PPA, with any Respondent. CenterPoint may, in its discretion, reject any or all Proposals, as such are described in this RFP.

Selection of a winning Proposal shall not be construed as a commitment by CenterPoint to execute an agreement. During the period between 1898 & Co.'s delivery of results to CenterPoint and the date of execution of any agreement, CenterPoint will conduct additional due diligence on the Proposal which may include, but not be limited to, onsite visits, management interviews, legal and regulatory due diligence, and detailed engineering assessments and facility dispatch modeling.

8.0 FB Culley 2 Site Option

CenterPoint currently owns and operates FB Culley 2. The 2022/2023 IRP calls for the retirement of FB Culley 2 in 2025. CenterPoint will consider generator replacement bids that can reuse the FB Culley 2 Interconnection Agreement with MISO for up to 90MW. All technology types are welcome for the generator replacement bids. All Proposals must demonstrate compliance with all aspects of this ASRFP, except that these Proposals do not need to be for resources in the MISO Interconnection Queue.

CenterPoint has the following preferences for FB Culley 2 generator replacement bids:

- Bids for the FB Culley 2 site are preferred to be purchase and sale agreements (with asset purchases specifically preferred) per MISO's current direction which is under review; PPAs will be considered but not preferred. CenterPoint desires to be the owner of the new generating facility and retain the ability to direct the performance of the asset.
- The preferred COD of the project is 2028 or earlier due to the 3-year MISO requirement between generator retirement and replacement.

Qualifying Proposals shall include a discussion of the required MISO studies, project ownership, and timing of commercial operation under the existing interconnection agreement. Respondents shall include an estimate of the costs required to build gen-tie lines connecting the project to the point of interconnection and shall not assume that existing transmission lines or other utility easements will be available to host the gen-tie circuit.

Additional details regarding the FB Culley 2 site option will be shared at the Pre-Bid Meeting once an NDA in the form of Appendix B has been signed.

9.0 Proposal Submission

All Proposal documents must be submitted to the RFP website (http://CenterPoint2024ASRFP.rfpmanager.biz/).

9.1 Format and Documentation

All Proposals submitted in response to this RFP must be received by 1898 & Co. to the website (http://CenterPoint2024ASRFP.rfpmanager.biz/) no later than the Proposal Submittal Due Date shown in Section 2.3. 1898 & Co. and CenterPoint will not evaluate Proposals as part of this RFP process if submitted after this date and time. Multiple Proposals submitted by the same Respondent must be identified and submitted separately. Financial statements, annual reports, technical specification documents, and other large documents can be sent electronically to the RFP email address. Each Respondent must submit the following prior to the Proposal deadline:

1. Appendix A: Notice of Intent to Respond
2. Appendix B: Non-Disclosure Agreement (NDA) in its present form
3. Appendix C: Application
4. Appendix D: Proposal Data in Excel format

Additionally, each Respondent must submit its comments on the applicable term sheet, and should submit its comments on the applicable Pro Forma Agreement. While a full markup of the Pro Forma Agreement is not mandatory, submission of a comprehensive markup will be viewed positively for evaluation of the Proposal and will be viewed as Respondent's first responsive mark-up in the Agreement negotiation process.

9.2 Certification

A Respondent's Proposal must certify that:

1. There are no pending legal or civil actions that would impair the Respondent's ability to perform its obligations under the proposed PPA or Asset Purchase Agreement.
2. The Respondent has not directly or indirectly induced or solicited any other Respondent to submit a false Proposal.
3. The Respondent has not solicited or induced any other person, firm, or corporation to refrain from submitting a Proposal.
4. The Respondent has not sought by collusion to obtain any advantage over any other Respondent.

10.0 Reservation of Rights

Nothing contained in this RFP shall be construed to require or obligate CenterPoint to select any Proposals or limit the ability of CenterPoint to reject all Proposals in its sole and exclusive discretion. CenterPoint further reserves the right to withdraw and terminate this RFP at any time prior to the Proposal Submittal Due Date, selection of projects or execution of a contract. All final contracts will be contingent on IURC and CenterPoint board approval.

All Proposals submitted to CenterPoint pursuant to this RFP shall become the exclusive property of CenterPoint and may be used for any reasonable purpose by CenterPoint. CenterPoint and 1898 & Co. shall consider materials provided by Respondent in response to this RFP to be confidential only if such materials are clearly designated as Confidential. Respondents should be aware that their Proposal, even if marked Confidential, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by CenterPoint. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, CenterPoint may produce the material in response to such order without prior consultation with the Respondent.

11.0 Confidentiality of Information

All Proposals submitted in response to this RFP become the property of 1898 & Co. and CenterPoint upon submittal. Respondents desiring confidential treatment by 1898 & Co. and CenterPoint should clearly identify each page of information considered to be confidential or proprietary. Consistent with the RFP NDA (Appendix B), 1898 & Co. will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all information so identified. CenterPoint reserves the right to release any Proposals, or portions thereof, to agents, attorneys, or consultants for purposes of Proposal evaluation. Regardless of the confidentiality claimed, however, and regardless of the provisions of this RFP, all such information may be subject to review by, and disclosable by CenterPoint, to the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters, and may also be subject to discovery by other parties subject to fully executed NDAs/confidentiality agreements. Further, because CenterPoint is conducting this RFP as part of the IRP public advisory process, CenterPoint will disclose the UCAP MW offered, technology/resource type, average price, general location, proposed ownership structure, and Proposal duration of all Proposals unless a given technology has less than three Respondents in order to inform stakeholders of the summary results of the RFP.

12.0 Regulatory Approvals

Pursuant to the terms of the definitive agreement(s), the Respondent will agree to use its reasonable best efforts, including, if necessary, providing data and testimony, to obtain any and all State, Federal, or other regulatory approvals required for the consummation of the transaction.

Please note in particular, as will be set forth in the definitive agreement(s), that approval by the IURC and MISO may be required before the transaction can be consummated between the selected Respondent and CenterPoint. In addition to disclosure to state authorities or any other governmental authorities or judicial bodies heretofore described, as part of the regulatory process, responses to the RFP may be provided to parties who have executed a NDA/confidentiality agreement, specifically acknowledging that they are neither affiliated with any party responding to the RFP or serving as a conduit for any party responding to the RFP.

13.0 Credit Qualification and Collateral

CenterPoint will review the creditworthiness of Respondents and the risk associated with any potential transaction to determine what credit requirements may be necessary to protect CenterPoint's ability to serve its customers in a reliable manner. For Proposal pricing purposes, Respondents shall assume that required project collateral shall be in the form of (i) a cash deposit, (ii) a letter of credit from a qualified institution (including "A-" / "A3" rating) or (iii) for certain resource types, a guaranty from a creditworthy parent company ("A-" / "A3") from a US entity, as will be set forth in the definitive agreement(s). Respondents should also include in their Proposal how they expect to meet these requirements.

For LM/DR contracts, Respondents may be required to post operating collateral over the term of any agreement consistent with the terms and conditions of final agreements as negotiated between CenterPoint and the supplier. LM/DR Resource Agreements will require collateral in the amount of 12 months' expected revenues.

Respondents shall refer to the Term Sheets in Appendix F, Appendix G, and Appendix H for resource-specific requirements. CenterPoint and 1898 & Co. reserve the right to require a Respondent to post collateral in an amount that exceeds the amounts listed herein and in the appendices as conditions warrant.

14.0 Miscellaneous

14.1 Non-Exclusive Nature of RFP

CenterPoint may procure more or less than the amount of assets solicited in this RFP from one or more Respondent(s). Respondents are advised that any definitive agreement executed by CenterPoint and any selected Respondent may not be an exclusive contract for the provision of assets. In submitting a Proposal(s), Respondent will be deemed to have acknowledged that CenterPoint may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

14.2 Information Provided in RFP

The information provided in this RFP, or on the RFP website (http://CenterPoint2024ASRFP.rfpmanager.biz/), has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts. CenterPoint makes no representation or warranty, express or implied, as to the accuracy, reliability or completeness of the information in this RFP, and shall not be liable for any representation, expressed or implied, in this RFP or any omissions from this RFP, or any information provided to a Respondent by any other source.

14.3 Proposal Cost

CenterPoint shall not reimburse Respondent and Respondent is responsible for any cost incurred in the preparation or submission of a Proposal(s), in negotiations for an agreement, and/or any other activity contemplated by the Proposal(s) submitted in connection with this RFP.

14.4 Indemnity

Supplementing Respondent's assumption of liability pursuant to this RFP, Respondent shall indemnify, hold harmless and defend CenterPoint, its affiliates, and its and their respective officers, employees and agents, from any and all damages, liabilities, claims, expenses (including reasonable attorneys' fees), losses, judgments, proceedings or investigations incurred by, or asserted against, CenterPoint, its affiliates, and its and their respective officers, employees or agents, arising from or related to this RFP or the execution or performance of one or more definitive agreements.

14.5 Hold Harmless

Respondent shall hold CenterPoint, its affiliates, and its and their respective officers, employees and agents, harmless from all damages and costs, including but not limited to legal costs in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a Proposal pursuant to the RFP or the execution or performance of a definitive agreement.

14.6 Further Assurances

By submitting a Proposal, Respondent agrees, at its expense, to enter into additional agreements, and to provide additional information and documents, in either case as requested by 1898 & Co. in order to facilitate: (a) the review of a Proposal, (b) the execution of one or more definitive agreements, or (c) the procurement of regulatory approvals required for the effectiveness of one or more definitive agreements.

14.7 Licenses and Permits

Respondent shall obtain, at its cost and expense, all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to perform hereunder. Respondent's subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.



1898andco.com

Attachment 2.2 2025 Technology Assessment Summary (Confidential)

Confidential information is redacted

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
INDIANA

Simple Cycle Gas Turbine & Reciprocating Engine Project Options
April 2025 - Revision 3

Project Type	Simple Cycle - 50 MW Aeroderivative		Simple Cycle - F-Class Frame		Simple Cycle - J-Class Frame		Reciprocating Engine (18MW Engines)	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit	First Unit	Next Unit	First Block	Next Block
Number of Gas Turbines/Engines	1	1	1	1	1	1	6	6
Representative Class Gas Turbine	GE LM6000 PF+		GE 7FA.05		GE 7HA.03		Wartsila 18V50DF	
Capacity Factor, %	10%		10%		10%		10%	
Startup Time to Base Load, min (Notes 1)	5		11		10		5	
Startup Time to MECL, min (Note 2)	4		8		8		4	
Cold Startup Time to SCR Compliance, min (Note 2)	45		45		45		20	
Maximum Ramp Rate, MW/min (Online)	30		40		75		50% Per Minute	
Book Life, Years	35		35		35		35	
Forced Outage Factor (%) (Notes 3, 13)	2.9%		2.0%		2.8%		3.9%	
Equivalent Forced Outage Rate (%) (Notes 3, 13)	18.0%		9.5%		20.4%		12.9%	
Availability Factor (%) (Notes 3, 13)	91.3%		91.2%		88.7%		92.4%	
Assumed Land Use, Acres	30	15	30	15	30	15	45	30
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)	
Heat Rejection	Fin Fan Heat Exchanger		Fin Fan Heat Exchanger		Fin Fan Heat Exchanger		Fin Fan Heat Exchanger	
NO_x Control	DLN Combustors		DLN Combustors		SCR		SCR	
CO Control	Good Combustion Practice		Good Combustion Practice		CO Catalyst		Oxidation Catalyst	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Technology Rating	Mature		Mature		Mature		Mature	
Total Project Duration Including Long Lead Equipment	60		64		64		60	
EPC Execution Excluding Long Lead Equipment	24		24		24		24	
ESTIMATED PERFORMANCE (ALL BASED ON NATURAL GAS OPERATION) (Notes 4, 11)								
ISO CONDITIONS								
Base Load Performance @ 59°F								
Net Plant Output, kW	52,200	52,200	235,000	235,000	426,400	426,400	109,800	109,800
Net Plant Heat Rate, Btu/kWh (HHV)	9,310	9,310	9,930	9,930	8,940	8,940	8,340	8,340
Heat Input, MMBtu/h (HHV)	490	490	2,330	2,330	3,810	3,810	900	900
Minimum Load (Single Turbine at MECL) @ 59°F								
Net Plant Output, kW	25,800	25,800	117,500	117,500	106,600	106,600	9,200	9,200
Net Plant Heat Rate, Btu/kWh (HHV)	12,980	12,980	11,980	11,980	14,780	14,780	9,160	9,160
Heat Input, MMBtu/h (HHV)	330	330	1,410	1,410	1,580	1,580	80	80
WINTER DESIGN								
Base Load Performance @ 20°F								
Net Plant Output, kW	57,100	57,100	245,800	245,800	437,100	437,100	109,800	109,800
Net Plant Heat Rate, Btu/kWh (HHV)	9,230	9,230	9,800	9,800	8,830	8,830	8,290	8,290
Heat Input, MMBtu/h (HHV)	530	530	2,410	2,410	3,860	3,860	900	900
Minimum Load (Single Turbine at MECL) @ 20°F								
Net Plant Output, kW	28,700	28,700	122,900	122,900	109,300	109,300	9,200	9,200
Net Plant Heat Rate, Btu/kWh (HHV)	12,460	12,460	11,870	11,870	14,740	14,740	9,100	9,100
Heat Input, MMBtu/h (HHV)	360	360	1,460	1,460	1,610	1,610	80	80
SUMMER DESIGN								
Base Load Performance @ 90°F								
Net Plant Output, kW	43,100	43,100	222,100	222,100	385,400	385,400	109,800	109,800
Net Plant Heat Rate, Btu/kWh (HHV)	9,720	9,720	10,150	10,150	9,130	9,130	8,370	8,370
Heat Input, MMBtu/h (HHV)	420	420	2,260	2,260	3,520	3,520	900	900
Minimum Load (Single Turbine at MECL) @ 90°F								
Net Plant Output, kW	21,400	21,400	111,100	111,100	96,400	96,400	9,200	9,200
Net Plant Heat Rate, Btu/kWh (HHV)	13,970	13,970	12,350	12,350	15,430	15,430	9,190	9,190
Heat Input, MMBtu/h (HHV)	300	300	1,370	1,370	1,490	1,490	80	80
ESTIMATED CAPITAL AND O&M COSTS (Notes 5, 12)								
EPC Project Capital Costs, MM$ (w/o Owner's Costs)	**$161**	**$107**	**$328**	**$241**	**$472**	**$338**	**$268**	**$170**
Owner's Costs, MM$	**$19**	**$4**	**$29**	**$9**	**$35**	**$14**	**$23**	**$8**
Owner's Project Development	$0.7	$0.0	$0.7	$0.0	$0.7	$0.0	$0.7	$0.0
Owner's Operational Personnel Prior to COD	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Owner's Engineer	$1.3	$0.0	$1.3	$0.0	$1.3	$0.0	$1.3	$0.0
Owner's Project Management	$1.2	$0.0	$1.2	$0.0	$1.2	$0.0	$1.2	$0.0
Owner's Legal Costs	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Owner's Start-up Engineering and Commissioning	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1	$0.7	$0.3
Land	$0.3	$0.1	$0.3	$0.1	$0.3	$0.1	$0.4	$0.2
Construction Power and Water	$0.5	$0.1	$0.5	$0.1	$0.5	$0.1	$0.5	$0.1
Permitting and Licensing Fees	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Switchyard	$8.4	$1.6	$8.4	$1.6	$8.4	$1.6	$13.1	$5.8
Political Concessions & Area Development Fees	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$0.6	$0.5	$2.8	$2.5	$4.3	$3.9	$1.0	$0.9
Initial Fuel Inventory	$0.7	$0.7	$3.2	$3.2	$5.2	$5.2	$0.4	$0.4
Site Security	$0.7	$0.0	$0.7	$0.0	$0.7	$0.0	$0.7	$0.0

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
INDIANA

Simple Cycle Gas Turbine & Reciprocating Engine Project Options
April 2025 - Revision 3

Project Type	Simple Cycle - 50 MW Aeroderivative		Simple Cycle - F-Class Frame		Simple Cycle - J-Class Frame		Reciprocating Engine (18MW Engines)	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit	First Unit	Next Unit	First Block	Next Block
Operating Spare Parts	$2.3	$0.6	$7.2	$1.8	$10.1	$2.5	$0.9	$0.2
Water Supply Infrastructure	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Natural Gas Supply Infrastructure	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Transmission Interconnect	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Transmission Upgrade Costs	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Firm Gas Supply Reservation Charge	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Permanent Plant Equipment and Furnishings	$0.4	$0.0	$0.4	$0.0	$0.4	$0.0	$0	$0
AFUDC (12.2% of EPC Project Capital Costs)	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Builders Risk Insurance (0.45% of Construction Costs)	$0.7	$0.5	$1.5	$1.1	$2.1	$1.5	$1.2	$0.8
Owner's Contingency (5% for Screening Purposes)	$9.0	$5.5	$17.9	$12.6	$25.5	$17.7	$14.6	$8.9
Total Project Costs, MM$	**$180**	**$110**	**$357**	**$250**	**$507**	**$352**	**$291**	**$178**
Project Cost Per kW, $/kW (excl. Owner's Costs)	**$3,080**	**$2,040**	**$1,340**	**$980**	**$1,080**	**$770**	**$2,440**	**$1,550**
Total Cost Per kW, $/kW	**$3,440**	**$2,110**	**$1,520**	**$1,070**	**$1,190**	**$830**	**$2,650**	**$1,620**
FIXED O&M COSTS (Notes 6, 7)								
Fixed O&M Cost - LABOR, 2025$MM/Yr	$1.1	$0.2	$1.1	$0.2	$1.1	$0.2	$1.1	$0.2
Fixed O&M Cost - OTHER, 2025$MM/Yr	$1.0	$0.9	$1.4	$1.3	$1.5	$1.5	$2.0	$2.0
LEVELIZED CAPITAL MAINTENANCE COSTS (Note 8)								
Major Maintenance Cost, 2025$/GT-hr or $/engine-hr	$300		$600		$750		$71	
Major Maintenance Cost, 2025$/GT-start	No starts-based maintenance		$15,400		$26,700		No starts-based maintenance	
Major Maintenance Cost, 2025$/MWh	$5.75		$2.55		$1.76		$3.82	
Catalyst Replacement Cost, 2025$/MWh	NA		NA		$0.18		$0.67	
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 9)								
Total Variable O&M Cost, 2025$/MWh	$0.9	$0.9	$0.9	$0.9	$1.2	$1.2	$4.0	$4.0
Water Related O&M, $/MWh	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SCR Reagent, $/MWh	$0.0	$0.0	$0.0	$0.0	$0.3	$0.3	$0.9	$0.9
Other Consumables and Variable O&M, $/MWh	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$3.1	$3.1
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 10)								
Turbine Only (lb/MMBtu, HHV)								
NO_x	0.09		0.03		0.01		0.39	
SO_2	<0.002		<0.002		<0.002		0.24	
CO	0.01		0.02		0.01		0.59	
CO_2	120		120		120		120	

NOTES

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available. Recip engine start times assume the engines are kept warm when not operational.
Note 2: MECL start time assumes the time for the GT to emissions compliance load (not stack compliance). The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired stack emissions.
Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2014 or later. Reporting period is 2014-2023.
Note 4: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 5: Capital costs are presented in 2025 USD $MM. $/kW values are calculated based on base load performance at ISO conditions.
Note 6: All Gas Turbine FOM costs assume 7 full time personnel for first unit. No additional personnel are included for the next unit(s). FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
Note 7: Recip engine FOM assumes 7 FTE for the first 100 MW plant. Major maintenance $/hr is per engine. LTSA costs are split in two categories: major overhauls and catalyst replacements are shown as capitalized maintenance, while scheduled minor maintenance supervision is shown in VOM.
Note 8: Major maintenance for Aeroderivative gas turbines are hours based. Major maintenance costs for F-Class frame gas turbines are hours based ($/GT-hr) when average hours per start is >26. When average hours per start over the interval are <26, then major maintenance costs would be starts based. Major maintenance costs for J-Class frame gas turbines are hours based ($/GT-hr) when average hours per start is >36. When average hours per start over the interval are <36, then major maintenance costs would be starts based.
Note 9: VOM assumes the use of temporarily trailers for demineralized water treatment, where applicable.
Note 10: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Note 11: Performance ratings are based on elevation of 120 ft above msl.
Note 12: Estimated Costs exclude decommissioning costs.
Note 13: EFOR data from GADS may not accurately represent the benefits of a reciprocating plant, depending on how events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so the plant would not be completely offline as it may be during an event at 1x gas turbine plant.

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
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Combined Cycle Project Options
April 2025 - Revision 3

Project Type	F-Class 1x1 CCGT - Unfired	F-Class 1x1 CCGT - Fired	G/H-Class 2x1 CCGT - Unfired	G/H-Class 2x1 CCGT - Fired	J-Class 1x1 CCGT - Unfired	J-Class 2x1 CCGT - Unfired	J-Class 2x1 CCGT - Fired
BASE PLANT DESCRIPTION							
Number of Gas Turbines	1	1	2	2	1	2	2
Number of Steam Turbines	1	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7FA.05	GE 7FA.05	GE 7HA.01	GE 7HA.01	GE 7HA.03	GE 7HA.03	GE 7HA.03
Steam Conditions (Main Steam / Reheat)	1,050˚F / 1,050˚F	1,050˚F / 1,050˚F	1,050˚F / 1,050˚F	1,050˚F / 1,050˚F	1,050˚F / 1,050˚F	1,050˚F / 1,050˚F	1,050˚F / 1,050˚F
Main Steam Pressure	2400 Psia	2400 Psia	2400 Psia	2400 Psia	2400 Psia	2400 Psia	2400 Psia
Steam Cycle Type	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Capacity Factor (%)	70%	70%	70%	70%	70%	70%	70%
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 1)	150	150	160	160	150	180	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 1)	115	115	120	120	115	130	130
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 1)	80	80	80	80	80	80	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (Note 2)	60	60	60	60	60	60	60
Book Life	35	35	35	35	35	35	35
Maximum Ramp Rate (Online)	37	37	85	85	62	125	124
Forced Outage Factor (FOF), % (Note 3)	1.6%	1.6%	2.8%	2.8%	1.6%	1.6%	1.6%
Equivalent Forced Outage Rate (EFOR), % (Note 3)	3.0%	3.0%	5.8%	5.8%	3.0%	3.0%	3.0%
Availability Factor (AF), % (Note 3)	86.5%	86.5%	88.8%	88.8%	86.5%	86.5%	86.5%
Assumed Land Use (acres)	70	70	100	100	70	100	100
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling Tower	Wet Cooling Tower	Wet Cooling Tower	Wet Cooling Tower	Wet Cooling Tower	Wet Cooling Tower	Wet Cooling Tower
NO_x Control	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR
CO Control	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Total Project Duration Including Long Lead Equipment	86	86	88	88	86	88	88
EPC Execution Excluding Long Lead Equipment	34	34	36	36	34	36	36
ESTIMATED PERFORMANCE (Notes 4, 5, 6)							
ISO CONDITIONS							
Base Load Performance @ 59˚F							
Net Plant Output, kW	365,500	364,700	848,000	847,100	619,600	1,253,900	1,244,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,470	6,490	6,260	6,260	6,150	6,080	6,120
Heat Input, MMBtu/h (HHV)	2,370	2,370	5,310	5,310	3,810	7,620	7,620
Incremental Duct Fired Performance @ 59˚F							
Incremental Duct Fired Output, kW	N/A	80,000	N/A	187,200	N/A	N/A	209,600
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,450	N/A	8,590	N/A	N/A	8,700
Incremental Heat Input, MMBtu/h (HHV)	N/A	680	N/A	1,610	N/A	N/A	1,820
Minimum Load Performance (Single Turbine at MECL) @ 59˚F							
Net Plant Output, kW	201,600	197,000	226,700	217,700	346,100	334,600	326,800
Net Plant Heat Rate, Btu/kWh (HHV)	7,000	7,180	6,960	7,250	6,650	6,880	7,040
Heat Input, MMBtu/h (HHV)	1,410	1,410	1,580	1,580	2,300	2,300	2,300
WINTER DESIGN							
Base Load Performance @ 20˚F							
Net Plant Output, kW	371,500	371,100	860,400	860,200	624,200	1,264,000	1,255,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,520	6,530	6,310	6,310	6,210	6,130	6,170
Heat Input, MMBtu/h (HHV)	2,420	2,420	5,430	5,430	3,880	7,750	7,750
Incremental Duct Fired Performance @ 20˚F							
Incremental Duct Fired Output, kW	N/A	82,900	N/A	191,700	N/A	N/A	219,100
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,450	N/A	8,700	N/A	N/A	8,840
Incremental Heat Input, MMBtu/h (HHV)	N/A	700	N/A	1,670	N/A	N/A	1,940
Minimum Load Performance (Single Turbine at MECL) @ 20˚F							
Net Plant Output, kW	207,100	201,000	232,500	222,300	353,420	341,500	334,600
Net Plant Heat Rate, Btu/kWh (HHV)	7,040	7,270	7,020	7,340	6,710	6,940	7,080
Heat Input, MMBtu/h (HHV)	1,460	1,460	1,630	1,630	2,370	2,370	2,370

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
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INDIANA
Combined Cycle Project Options
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Project Type	F-Class 1x1 CCGT - Unfired	F-Class 1x1 CCGT - Fired	G/H-Class 2x1 CCGT - Unfired	G/H-Class 2x1 CCGT - Fired	J-Class 1x1 CCGT - Unfired	J-Class 2x1 CCGT - Unfired	J-Class 2x1 CCGT - Fired
SUMMER DESIGN							
Base Load Performance @ 90°F							
Net Plant Output, kW	343,600	338,600	788,900	793,400	568,000	1,143,600	1,136,200
Net Plant Heat Rate, Btu/kWh (HHV)	6,510	6,610	6,300	6,260	6,200	6,160	6,200
Heat Input, MMBtu/h (HHV)	2,240	2,240	4,970	4,970	3,520	7,040	7,040
Incremental Duct Fired Performance @ 90°F							
Incremental Duct Fired Output, kW	N/A	83,700	N/A	183,900	N/A	N/A	224,600
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,280	N/A	8,910	N/A	N/A	8,530
Incremental Heat Input, MMBtu/h (HHV)	N/A	690	N/A	1,640	N/A	N/A	1,920
Minimum Load Performance (Single Turbine at MECL) @ 90°F							
Net Plant Output, kW	194,200	183,800	209,600	197,200	320,800	301,100	293,900
Net Plant Heat Rate, Btu/kWh (HHV)	7,040	7,450	7,080	7,530	6,690	7,130	7,300
Heat Input, MMBtu/h (HHV)	1,370	1,370	1,490	1,490	2,150	2,150	2,150
Incremental Performance with 90% Carbon Capture @ All Ambient Conditions (Note 7)							
Incremental Output with Carbon Capture, kW	-46,400	N/A	N/A	N/A	N/A	N/A	N/A
Incremental Heat Rate with Carbon Capture, Btu/kWh (HHV)	1,020	N/A	N/A	N/A	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS (Note 7)							
EPC Project Capital Costs, $MM (w/o Owner's Costs)	**$740**	**$823**	**$1,525**	**$1,610**	**$1,147**	**$1,976**	**$2,079**
Owner's Costs, $MM	**$90**	**$95**	**$139**	**$143**	**$117**	**$166**	**$172**
Owner's Project Development	$4.4	$4.4	$4.4	$4.4	$4.4	$4.4	$4.4
Owner's Operational Personnel Prior to COD	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3
Owner's Engineer	$3.6	$3.6	$3.6	$3.6	$3.6	$3.6	$3.6
Owner's Project Management	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5
Owner's Legal Costs	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Owner's Start-up Engineering and Commissioning	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Land	$0.1	$0.1	$0.9	$0.9	$0.6	$0.9	$0.9
Temporary Utilities	$1.4	$1.4	$1.4	$1.4	$1.4	$1.4	$1.4
Permitting and Licensing Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Switchyard	$13.1	$13.1	$15.8	$15.8	$13.1	$15.8	$15.8
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.6	$0.6	$0.9	$0.9	$0.8	$1.6	$1.6
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
Operating Spare Parts	$8.5	$8.5	$9.5	$9.5	$11.4	$11.4	$11.4
Water Supply Infrastructure (5 Mile Pipeline)	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Natural Gas Supply Infrastructure	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Transmission Interconnect	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Transmission Upgrade Costs	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Firm Gas Supply Reservation Charge	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Permanent Plant Equipment and Furnishings	$1.3	$1.3	$1.7	$1.7	$1.3	$1.7	$1.7
AFUDC (12.2% of EPC Project Capital Costs)	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Builders Risk Insurance (0.45% of Construction Costs)	$3.3	$3.7	$6.9	$7.2	$5.2	$8.9	$9.4
Owner's Contingency (5% for Screening Purposes)	$39.5	$43.7	$79.2	$83.5	$60.2	$102.0	$107.2
Total Project Costs, $MM	**$830**	**$918**	**$1,663**	**$1,753**	**$1,263**	**$2,142**	**$2,250**
EPC Cost Per UNFIRED kW, $/kW	***$2,023***	***$2,258***	***$1,798***	***$1,900***	***$1,851***	***$1,576***	***$1,670***
Total Cost Per UNFIRED kW, $/kW	**$2,271**	**$2,518**	**$1,962**	**$2,070**	**$2,039**	**$1,708**	**$1,809**
EPC Cost Per FIRED kW, $/kW	***N/A***	***$1,852***	***N/A***	***$1,556***	***N/A***	***N/A***	***$1,430***
Total Cost Per FIRED kW, $/kW	**N/A**	**$2,065**	**N/A**	**$1,695**	**N/A**	**N/A**	**$1,548**
FIXED O&M COSTS (Note 8)							
Fixed O&M Cost - LABOR, $MM/Yr	$3.5	$3.5	$3.5	$4.0	$3.5	$4.0	$3.5
Fixed O&M Cost - OTHER, $MM/Yr	$2.4	$2.4	$2.7	$2.7	$2.5	$2.8	$2.8

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PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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Combined Cycle Project Options
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Project Type	F-Class 1x1 CCGT - Unfired	F-Class 1x1 CCGT - Fired	G/H-Class 2x1 CCGT - Unfired	G/H-Class 2x1 CCGT - Fired	J-Class 1x1 CCGT - Unfired	J-Class 2x1 CCGT - Unfired	J-Class 2x1 CCGT - Fired
LEVELIZED CAPITAL MAINTENANCE COSTS (Note 9)							
Major Maintenance Cost, $/GT-hr	$600	$600	$650	$650	$750	$750	$750
Major Maintenance Cost, $/GT-start	$15,400	$15,400	$21,700	$21,700	$26,700	$26,700	$26,700
Major Maintenance Cost, $/MWh	$1.68	$1.68	$1.53	$1.53	$1.21	$1.22	$1.22
Catalyst Replacement Cost, $/MWh	$0.17	$0.17	$0.07	$0.07	$0.12	$0.06	$0.06
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) (Note 10)							
Total Variable O&M Cost, Unfired $/MWh	$1.40	$1.40	$1.55	$1.53	$1.45	$1.45	$1.47
Water Related O&M, $/MWh	$0.45	$0.45	$0.39	$0.41	$0.38	$0.37	$0.39
SCR Reagent, $/MWh	$0.05	$0.05	$0.18	$0.18	$0.18	$0.18	$0.18
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
Incremental Duct Fired Variable O&M, $/MWh (For Incremental Output Only)	N/A	$1.76	N/A	$1.83	N/A	N/A	$1.85
CARBON CAPTURE ADD-ON COST (Note 11)							
Carbon Capture Solvent Based Technology Capital Costs, $MM	$613	N/A	N/A	N/A	N/A	N/A	N/A
Owner's Costs, $MM	$33	N/A	N/A	N/A	N/A	N/A	N/A
CARBON CAPTURE O&M COSTS							
Incremental Fixed O&M Cost, $MM/Yr	$10	N/A	N/A	N/A	N/A	N/A	N/A
Incremental Variable O&M Cost, $/MWh	$4	N/A	N/A	N/A	N/A	N/A	N/A
Carbon Transportation and Sequestration Capital Costs, 2025 MM$ $/tonne	$20	N/A	N/A	N/A	N/A	N/A	N/A
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS, lb/MMBtu (HHV) (Note 12)							
NO_X	0.008	0.008	0.008	0.008	0.008	0.008	0.008
SO_2	< 0.001	< 0.001	< 0.001	< 0.001	< 0.001	< 0.0003	< 0.0003
CO	0.005	0.005	0.005	0.005	0.005	0.005	0.005
CO_2	120	120	120	120	120	120	120

NOTES

Note 1: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. For the purpose of startup times, a Cold start is defined as being shutdown for >72 hours. A Hot start is defined as shutdown for <8 hours.

Note 2: Startup time to stack emissions compliance is not the same as the start time for gas turbine to MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.

Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2014 or later. Reporting period is 2014-2023.

Note 4: New and clean performance is assumed. No performance degradation is included.

Note 5: Performance ratings based on elevation of 120 ft above msl.

Note 6: Options with duct firing include a design of firing up to 1,600˚F.

Note 7: Capital and fixed O&M costs are presented in 2025 USD $MM. Capital costs include duct firing to 1,400 ˚F for all fired options. Estimated costs exclude decommisioning costs and salvage values.

Note 8: Fixed O&M costs assume 22 full time equivalent (FTE) personnel for 1x1 plants and 25 FTE for 2x1 plants.

Note 9: Major maintenance $/GT-hr and $/GT-start values are the same information shown in different units. The values are NOT additive. F-Class Frame: $/hr when hours per start > 25.6, $/GT-Start when hours per start < 25.6. J-Class Frame: $/hr when hours per start > 35.6, $/GT-Start

Note 10: Variable O&M costs assume onsite demin treatment system.

Note 11: Carbon capture costs are from publically available studies, including sources from NREL, EIA, and BMcD estimates. Carbon capture cost scope is split into two categories: the carbon capture technology itself and carbon compression, transportation, and sequestration.

Note 12: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts.

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Simple Cycle Gas Turbine to Combined Cycle Gas Turbine Conversion Project Option
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Project Type	2x1 F-class SCGT to CCGT Conversion, Unfired	2x1 F-class SCGT to CCGT Conversion, Fired
BASE PLANT DESCRIPTION		
Number of Gas Turbines	2	2
Number of Steam Turbines	1	1
Representative Class Gas Turbine	GE 7F.05	GE 7F.05
Steam Conditions (Main Steam / Reheat)	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F
Main Steam Pressure	2,400 psia	2,400 psia
Steam Cycle Type	Subcritical	Subcritical
Capacity Factor (%)	1	1
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 1)	180	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 1)	130	130
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 1)	80	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (Note 2)	60	60
Maximum Ramp Rate, MW/min (Online)	72	72
Book Life (Years)	35	35
Forced Outage Factor (FOF), % (Note 3)	1.7%	1.7%
Equivalent Forced Outage Rate (EFOR), % (Note 3)	3.0%	3.0%
Availability Factor (AF), % (Note 3)	87.2%	87.2%
Fuel Design	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling Towers	Wet Cooling Towers
NOx Control	DLN/SCR	DLN/SCR
CO Control	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature
ESTIMATED PERFORMANCE (ALL BASED ON NATURAL GAS OPERATION) (Note 4)		
ISO CONDITIONS		
Base Load Performance @ 59°F		
Net Plant Output, kW	735,400	734,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,430	6,440

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Simple Cycle Gas Turbine to Combined Cycle Gas Turbine Conversion Project Option
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Project Type	2x1 F-class SCGT to CCGT Conversion, Unfired	2x1 F-class SCGT to CCGT Conversion, Fired
Heat Input, MMBtu/h (HHV)	4,730	4,730
Incremental Duct Fired Performance @ 59°F		
Incremental Duct Fired Output, kW	N/A	158,800
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,610
Incremental Heat Input, MMBtu/h (HHV)	N/A	1,370
Minimum Load (Single Turbine at MECL) @ 59°F		
Net Plant Output, kW	196,100	187,900
Net Plant Heat Rate, Btu/kWh (HHV)	7,200	7,510
Heat Input, MMBtu/h (HHV)	1,410	1,410
WINTER DESIGN		
Base Load Performance @ 20°F		
Net Plant Output, kW	749,700	748,600
Net Plant Heat Rate, Btu/kWh (HHV)	6,460	6,470
Heat Input, MMBtu/h (HHV)	4,850	4,850
Incremental Duct Fired Performance @ 20°F		
Incremental Duct Fired Output, kW	N/A	163,100
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,710
Incremental Heat Input, MMBtu/h (HHV)	N/A	1,420
Minimum Load (Single Turbine at MECL) @ 20°F		
Net Plant Output, kW	201,500	189,300
Net Plant Heat Rate, Btu/kWh (HHV)	7,240	7,710
Heat Input, MMBtu/h (HHV)	1,460	1,460
SUMMER DESIGN		
Base Load Performance @ 90°F		
Net Plant Output, kW	691,200	695,600
Net Plant Heat Rate, Btu/kWh (HHV)	6,470	6,430

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Simple Cycle Gas Turbine to Combined Cycle Gas Turbine Conversion Project Option
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Project Type	2x1 F-class SCGT to CCGT Conversion, Unfired	2x1 F-class SCGT to CCGT Conversion, Fired
Heat Input, MMBtu/h (HHV)	4,470	4,470
Incremental Duct Fired Performance @ 90°F		
Incremental Duct Fired Output, kW	N/A	154,100
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,980
Incremental Heat Input, MMBtu/h (HHV)	N/A	1,380
Minimum Load (Single Turbine at MECL) @ 90°F		
Net Plant Output, kW	185,700	174,000
Net Plant Heat Rate, Btu/kWh (HHV)	7,370	7,860
Heat Input, MMBtu/h (HHV)	1,370	1,370
ESTIMATED STARTUP FUEL USAGE		
Start to Stack Emissions Compliance, MMBtu	1,720	1,720
Start to Unfired Base Load, MMBtu	8,530	N/A
ESTIMATED WATER USAGE (Note 5)		
Water Consumption (kgal/yr)	1,379,300	1,542,100
Water Consumption with Evap Cooler (kgal/yr)	N/A	N/A
ESTIMATED REAGENT USAGE (Note 5)		
Ammonia Consumption (tons/yr)	580	920
ESTIMATED CAPITAL AND O&M COSTS (Note 6)		
EPC Project Capital Costs, MM$ (w/o Owner's Costs)	[redacted]	[redacted]
Engineering		
Gas Turbines		
HRSGs		
Steam Turbine		
GSUs		
BOP Equipment and Materials		

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Simple Cycle Gas Turbine to Combined Cycle Gas Turbine Conversion Project Option
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Project Type	2x1 F-class SCGT to CCGT Conversion, Unfired	2x1 F-class SCGT to CCGT Conversion, Fired
Construction	[redacted]	[redacted]
Indirects and Fees		
EPC Contingency		
Owner's Costs, MM$	**$89**	**$93**
Owner's Project Development	$4.4	$4.4
Owner's Operational Personnel Prior to COD	$2.3	$2.3
Owner's Engineer	$3.6	$3.6
Owner's Project Management	$8.5	$8.5
Owner's Legal Costs	$1.0	$1.0
Owner's Start-up Engineering and Commissioning	$0.5	$0.5
Land	Excluded	Excluded
Construction Power and Water	$1.4	$1.4
Permitting and Licensing Fees	$0.5	$0.5
Switchyard	$13.1	$13.1
Political Concessions & Area Development Fees	Excluded	Excluded
Startup/Testing (Fuel & Consumables)	$0.6	$0.6
Initial Fuel Inventory	$0.0	$0.0
Site Security	$1.3	$1.3
Operating Spare Parts	$10.6	$10.6
Water Supply Infrastructure	Excluded	Excluded
Natural Gas Supply Infrastructure	Excluded	Excluded
Transmission Interconnect	Excluded	Excluded
Transmission Upgrade Costs	Excluded	Excluded
Firm Gas Supply Reservation Charge	Excluded	Excluded
Permanent Plant Equipment and Furnishings	$1.7	$1.7
AFUDC (12.2% of EPC Project Capital Costs)	Excluded	Excluded
Builders Risk Insurance (0.45% of Construction Costs)	$3.1	$3.4
Owner's Contingency (5% for Screening Purposes)	$36.7	$40.5
Total Project Costs, MM$	[redacted]	[redacted]

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Simple Cycle Gas Turbine to Combined Cycle Gas Turbine Conversion Project Option
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Project Type	2x1 F-class SCGT to CCGT Conversion, Unfired	2x1 F-class SCGT to CCGT Conversion, Fired
EPC Cost Per UNFIRED kW, $/kW	[redacted]	[redacted]
Total Cost Per UNFIRED kW, $/kW		
EPC Cost Per FIRED kW, $/kW		
Total Cost Per FIRED kW, $/kW		
FIXED O&M COSTS (Note 7)		
Fixed O&M Cost - LABOR, $MM/Yr	$3.5	$3.5
Fixed O&M Cost - OTHER, $MM/Yr	$2.7	$2.7
LEVELIZED CAPITAL MAINTENANCE COSTS		
Major Maintenance Cost, $/GT-hr or $/engine-hr (Note 8)	$600	$600
Major Maintenance Cost, $/GT-start	$15,400	$15,400
Major Maintenance Cost, $/MWh	$1.64	$1.64
Catalyst Replacement Cost, $/MWh	$0.16	$0.16
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 9)		
Total Variable O&M Cost, $/MWh	$1.37	$1.37
Water Related O&M, $/MWh	$0.42	$0.42
SCR Reagent, $/MWh	$0.05	$0.05
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90
Incremental Duct Fired Variable O&M, $/MWh (For Incremental Output Only)	N/A	$1.54
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 10)		
Turbine Only (lb/MMBtu, HHV)		
NO_X	0.008	0.008
SO_2	< 0.001	< 0.001
CO	0.005	0.005
CO_2	120	120

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Simple Cycle Gas Turbine to Combined Cycle Gas Turbine Conversion Project Option
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Project Type	2x1 F-class SCGT to CCGT Conversion, Unfired	2x1 F-class SCGT to CCGT Conversion, Fired

NOTES

Note 1: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. For the purpose of startup times, a Cold start is defined as being shutdown for >72 hours. A Hot start is defined as shutdown for <8 hours.

Note 2: Startup time to stack emissions compliance is not the same as the start time for gas turbine to MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.

Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2014 or later. Reporting period is 2014-2023.

Note 4: New and clean performance assumed. All performance ratings are based on NATURAL GAS operation. Min load ratings are based on OEM performance information at specified ambient conditions.

Note 5: Water and ammonia consumption are based on performance at annual average conditions and the capacity factors shown.

Note 6: Capital and O&M costs are presented in 2025 USD $MM.

Note 7: Base O&M costs are based on performance at annual average conditions. Fixed O&M labor assumes 17 additional FTE for conversion to CCGT.

Note 8: Major maintenance costs for F-Class frame gas turbines are hours based ($/GT-hr) when average hours per start is >26. When average hours per start over the interval are <26, then major maintenance costs would be starts based.

Note 9: Variable O&M costs assume onsite demin treatment system.

Note 10: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts.

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Renewable Project Options
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Project Type	Wind Energy		Solar Photovoltaic	
BASE PLANT DESCRIPTION	Onshore - Southern IN	Onshore - Northern IN	10MW Single Axis Tracking - IN	100MW Single Axis Tracking - IN
Nominal Output, MW	200	200	10	100
Number of Turbines	44 x 4.5 MW turbines	44 x 4.5 MW turbines	N/A	N/A
Capacity Factor, % (Notes 1, 2)	35%	42%	24%	24%
Book Life, Years	30	30	30	30
Scheduled Outage Factor	< 2%	< 2%	< 2%	< 2%
Forced Outage Factor	< 2%	< 2%	< 2%	< 2%
Availability Factor, % (Note 3)	97%	97%	98%	98%
Assumed Land Use (Acres)	Development: 125 AC/MW Operation: 200 AC/WTG Physical Footprint: 2 AC/WTG + 30 AC	Development: 125 AC/MW Operation: 200 AC/WTG Physical Footprint: 2 AC/WTG + 30 AC	70	700
Interconnection Voltage Assumption	230 kV	230 kV	115 kV	115 kV
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	1.35	1.35
PV Degradation, %/Yr	N/A	N/A	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%
Technology Rating	Mature	Mature	Mature	Mature
Estimated EPC Execution Schedule Duration, Months	24	24	18	24
Estimated Development Schedule Duration, Months	36	36	14	18
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Output, kW	200,000	200,000	10,000	100,000
Net Plant Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	N/A
Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS				
Project Capital Costs, 2024 MM$ (w/o Owner's Costs) (Note 4)	**$389**	**$389**	**$20.0**	**$165**
Wind Capital Cost Breakdown				
Engineering	Included in BOP	Included in BOP	N/A	N/A
Equipment and Materials	-	-	N/A	N/A
Turbine Components	$245	$245	N/A	N/A
Nacelle and Nacelle Components	Included in Turbine Comp	Included in Turbine Comp	N/A	N/A
SCADA Equipment	Included in BOP	Included in BOP	N/A	N/A
Construction	-	-	N/A	N/A
Turbine Foundation and Erection	$68	$68	N/A	N/A
BOP Costs	$76	$76	N/A	N/A
Collector Substation	Included in BOP	Included in BOP	N/A	N/A
Indirects and Fees	Included in BOP	Included in BOP	N/A	N/A
EPC Contingency	Included in BOP	Included in BOP	N/A	N/A

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Renewable Project Options
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Project Type	Wind Energy		Solar Photovoltaic	
BASE PLANT DESCRIPTION	Onshore - Southern IN	Onshore - Northern IN	10MW Single Axis Tracking - IN	100MW Single Axis Tracking - IN
PV Capital Cost Breakdown				
Major Generating Equipment				
Modules	N/A	N/A	Included in Project Cost	Included in Project Cost
Inverters & MV Transformer	N/A	N/A	Included in Project Cost	Included in Project Cost
Racking	N/A	N/A	Included in Project Cost	Included in Project Cost
Construction	N/A	N/A	Included in Project Cost	Included in Project Cost
Indirects and Fees	N/A	N/A	Included in Project Cost	Included in Project Cost
Engineering	N/A	N/A	Included in Project Cost	Included in Project Cost
EPC Contingency	N/A	N/A	Included in Project Cost	Included in Project Cost
Owner's Cost Allowances, 2025 MM$ (Notes 5, 6, 7)	**$50.2**	**$50.2**	**$11.6**	**$21.5**
Owner's Project Development	$31.9	$31.9	$0.5	$0.7
Owner's Operational Personnel Prior to COD	Included in Owner's Proj. Man.	Included in Owner's Proj. Man.	$0.03	$0.03
Owner's Engineer	$0.5	$0.5	$0.5	$0.6
Owner's Project Management	$6.8	$6.8	$0.5	$0.7
Owner's Legal Costs	$2.3	$2.3	$0.4	$0.6
Owner's Start-up Engineering and Commissioning	Included in BOP	Included in BOP	$0.1	$0.1
Sales Tax	Excluded	Excluded		
Land	$4.3	$4.3	Excluded	Excluded
Temporary Utilities During Construction	Included in BOP	Included in BOP	$0.1	$0.2
Permitting Support	$2.9	$2.9	$0.2	$0.2
Switchyard	Collector Sub Included in BOP	Collector Sub Included in BOP	$7.0	$7.4
Transmission Line	No IX Infrastructure	No IX Infrastructure	No IX Infrastructure	No IX Infrastructure
Public Outreach & Area Development	$0.8	$0.8	$0.2	$0.3
Startup/Testing (Fuel & Consumables)	Included in BOP	Included in BOP	$0.01	$0.02
Site Security	Included in BOP	Included in BOP	$0.1	$0.3
Operating Spare Parts	Excluded	Excluded	$0.3	$1.0
Builder's Risk Insurance	$0.7	$0.7	$0.1	$0.7
Owner's Contingency (10% for Screening Purposes)	Allowance Included	Allowance Included	$1.6	$8.9
Total Project Costs, 2025 MM$	**$439**	**$439**	**$32**	**$187**
Total Cost Per kW_{AC}, 2025 $/kW	**$2,194**	**$2,194**	**$3,164**	**$1,866**
Fixed O&M Cost, 2025$MM/Yr (Notes 8, 9, 10)	**$6.9**	**$6.9**	**$0.14**	**$1.2**
Annual Fixed Labor Cost, 2025$MM/Yr	$0.9	$0.9	Allowance Included	Allowance Included
Equipment Maintenance Cost, 2025$MM/Yr	$3.4	$3.4	Allowance Included	Allowance Included
BOP and Other Cost, 2025$MM/Yr	$2.6	$2.6	Allowance Included	Allowance Included
Land Lease Allowance, 2025$MM/Yr	Excluded	Excluded	Excluded	Excluded
Property Tax Allowance, 2025$MM/Yr	Excluded	Excluded	Excluded	Excluded
Capital Replacement Allowance, 2025$/MWh	Excluded	Excluded	Allowance Included	Allowance Included

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Renewable Project Options
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Project Type	Wind Energy		Solar Photovoltaic	
BASE PLANT DESCRIPTION	Onshore - Southern IN	Onshore - Northern IN	10MW Single Axis Tracking - IN	100MW Single Axis Tracking - IN
Variable O&M Cost, 2025$/MWh (excl. major maint.)	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Co-located Energy Storage (Note 11)				
Add-on Costs	**100 MW / 400 MWh**	**100 MW / 400 MWh**	**N/A**	**50 MW / 200 MWh**
Capital Costs, 2025 $MM	**$132**	$132	N/A	$66
Owner's Cost, 2025 $MM	**$12**	$12	N/A	$7.6
Incremental O&M Cost, 2025 $MM/Yr	**$3.3**	$3.3	N/A	$1.7

NOTES

1. Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on Vestas 4.5 MW turbines (V163-4.5) with 113 meter hub height and 6.5 m/s (Southern Indiana) and 7.5 m/s (Northern Indiana) average wind speeds. This does not include site-specific losses for items such as bat curtailment.
2. PV capacity factor is reflective of a bifacial module array with a 1.3 inverter loading ratio and 34% GCR. PV capacity factor is based on the 100 MW_{AC} grid limit at the POI.
3. NERC GADS performance statistics are not available for PV and wind technologies. Availability estimates are based on 1898 & Co. experience.
4. Wind and PV capital costs include a 34.5 kV collection system and a GSU.
5. Wind assumes that land is leased with costs of land procurement efforts and development term payments included in Owner's Costs. Land lease payments during operation are part of O&M and excluded in this estimate.
6. Wind owner's costs assume that a development transfer would occur at a late stage development point (such as 100% land control) versus a greenfield development given the efforts required for land coordination and the physical size the project boundaries at utility scale wind farms.
7. Switchyard owner's costs for PV include a 3 position ring bus for interconnection at 115kV. Owner's costs exclude gen-tie and interconnection and network upgrade costs.
8. Estimated Costs exclude decommisioning costs and salvage values.
9. PV O&M assumes fixed contracts for all maintenance activities and that the system is remotely controlled. Capital maintenance assumes an inverter replacement allowance levelized over the first 15 years. O&M costs exclude property taxes and land lease allowances.
10. Wind O&M does not include land payments, property tax, or royalties
11. Co-located energy storage options assume a shared GSU with the generating asset. The co-located energy storage capital costs account for cost efficiencies related to civil work, construction management, transmission engineering, and other indirects when co-locating with a generating asset. Cost efficiency estimates are based on 1898 & Co. project experience for similar projects.

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Storage Project Options
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Project Type	Battery Storage	Battery Storage	Battery Storage	Battery Storage
BASE PLANT DESCRIPTION	Lithium Ion	Lithium Ion	Lithium Ion	Non-Lithium Long Duration
Nominal Output, MW/MWh	50 MW / 200 MWh	100 MW / 400 MWh	100 MW / 800 MWh	100 MW / 1,000 MWh
Use Case Assumption	365 Cycles per Year Capability	365 Cycles per Year Capability	365 Cycles per Year Capability	366 Cycles per Year Capability
Operational Useful Life, Years	20	20	20	20
Equivalent Planned Outage Rate (%)	< 2%	< 2%	< 2%	< 5%
Equivalent Forced Outage Rate (%)	< 2%	< 2%	< 2%	< 5%
Equivalent Availability Factor (AF), % (Note 1)	98%	98%	98%	95%
Assumed Land Use, Acres	6	10	18	20-150
Total System Cycles	7,300	7,300	7,300	7,300
Interconnection Voltage Assumption	115 kV	115 kV	115 kV	115 kV
Storage System Usable AC Capacity at POI, MWh_{AC}	200	400	800	1,000
Storage System Installed AC Capacity, MWh_{AC} (Note 2)	230	460	920	1,000
Storage System AC Roundtrip Efficiency, %	85%	85%	85%	60% - 75%
Technology Rating	Mature	Mature	Mature	Developing
Estimated EPC Execution Schedule Duration, Months (Note 3)	20	24	28	33
Estimated Development Schedule Duration, Months (Note 4)	18	18	18	18
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Rated Power at POI, kW_{AC}	50,000	100,000	100,000	100,000
Discharge Duration at Rated Power, hours	4	4	8	10
Net Plant Rated Capacity at POI, kWh_{AC}	200,000	400,000	800,000	1,000,000
ESTIMATED CAPITAL AND O&M COSTS				
Project Capital Costs, 2025 MM$ (w/o Owner's Costs) (Note 5)	**$70**	**$137**	**$254**	**$462**
Battery Storage Capital Cost Breakdown				
Batteries	Included	Included	Included	Included
Inverters	Included	Included	Included	Included
BOP	Included	Included	Included	Included
Construction and Indirects	Included	Included	Included	Included
Owner's Cost Allowances, 2025 MM$	**$16**	**$20**	**$27**	**$40**
Generation Project Development Support	$0.8	$1.2	$1.3	$1.4
Owner's Operational Personnel Prior to COD	$0.03	$0.03	$0.03	$0.03
Owner's Engineer	$0.5	$0.5	$0.5	$0.6
Owner's Project Management	$0.5	$0.5	$0.6	$0.6
Owner's Legal Costs (Gen Facility)	$0.5	$0.5	$0.5	$0.5
Owner's Start-up Engineering and Commissioning	$0.06	$0.09	$0.1	$0.2
Sales Tax	Exempt	Exempt	Exempt	Exempt
Land	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Temporary Utilities During Construction	$0.1	$0.1	$0.1	$0.1
Permitting Support	$0.4	$0.4	$0.5	$0.5

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
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Storage Project Options
April 2025 - Revision 3

Project Type	Battery Storage	Battery Storage	Battery Storage	Battery Storage
BASE PLANT DESCRIPTION	Lithium Ion	Lithium Ion	Lithium Ion	Non-Lithium Long Duration
Switchyard (Note 6)	$7.4	$7.4	$7.4	$7.4
Transmission Line and Electrical Interconnection	Excluded	Excluded	Excluded	Excluded
Gas Interconnection	Excluded	Excluded	Excluded	Excluded
Transmission System Network Upgrades	Excluded	Excluded	Excluded	Excluded
Water Supply Infrastructure	Excluded	Excluded	Excluded	Excluded
Emission Reduction Costs	Excluded	Excluded	Excluded	Excluded
Public Outreach & Area Development	$0.3	$0.3	$0.3	$0.3
Startup/Testing (Fuel & Consumables)	$0.0	$0.0	$0.1	$0.2
Site Security	$0.2	$0.2	$0.2	$0.3
Operating Spare Parts	$0.5	$0.8	$1.0	$2.0
Builder's Risk Insurance (Note 7)	$0.3	$0.6	$1.1	$2.1
Owner's Contingency (Note 8)	$4.1	$7.5	$13.4	$23.9
Total Project Costs, 2025 MM$	**$85**	**$157**	**$281**	**$502**
Project Capital Cost Per kWh, 2025 $/kWh	**$303**	**$298**	**$276**	**$462**
Total Project Cost Per kWh, 2025 $/kWh	**$370**	**$341**	**$305**	**$502**
Fixed O&M Cost - TOTAL, 2025$MM/Yr (Note 9)	**$2.0**	**$3.5**	**$6.3**	**$4.2**
Annual Fixed Labor Cost, 2025$MM/Yr	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Equipment Maintenance Cost, 2025$MM/Yr	Allowance Included	Allowance Included	Allowance Included	Allowance Included
BOP and Other Cost, 2025$MM/Yr	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Land Lease Allowance, 2025$MM/Yr	Excluded	Excluded	Excluded	Excluded
Property Tax Allowance, 2025$MM/Yr	Excluded	Excluded	Excluded	Excluded
Capital Replacement Allowance, 2025$/MWh	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Variable O&M Cost, 2025$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM

NOTES

Note 1: NERC GADS performance statistics are not available for battery storage. Availability estimates are based on vendor correspondence and industry publications.

Note 2: Lithium-ion installed MWh capacity is in terms of AC capacity and accounts for approximately 3 years of overbuild.

Note 3: Estimated EPC execution schedule duration assumes reasonable lead times on equipment.

Note 4: Estimated development schedule duration does not account for extended interconnection study timelines.

Note 5: Estimated project capital costs assume full-wrap engineering, procurement, and construction (EPC). Estimated project capital costs exclude decommissioning costs and salvage values. Battery cost assumes Owner procurement of

Note 6: Switchyard estimate assumes three-position ring bus for battery options. Project capital cost includes project substation with main power transformer.

Note 7: Builder's risk insurance assumes 0.45% of project cost.

Note 8: Owner's contingency assumes 5% (in addition to contingencies included in project capital cost).

Note 9: Estimated fixed O&M costs include allowances for routine BESS O&M, BESS augmentation (as applicable), and routine BOP O&M. O&M costs assume the site is remotely operated. Battery auxiliary load is factored into RTE and not included as an O&M cost. BESS augmentation plan (as applicable) maintains the system nameplate capacity over the useful life of the project.

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
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Small Modular Reactor Project Option
April 2025 - Revision 3

Project Type	Small Modular Nuclear Reactor
BASE PLANT DESCRIPTION	
Representative Technology	Small Modular Reactor and Advanced Reactor Generalized Technologies
Number of Modules	1
Number of Steam Turbines	1
Capacity Factor (%)	95.0%
Startup Time, Minutes (Cold Start to Unfired Base Load)	72 Hours (20-100%)
Maximum Ramp Rate, %/min	~1%/min or 40%/hr
Scheduled Outage Factor (SOF), %	2%
Forced Outage Factor (FOF), %	5%
Availability Factor (AF), %	95%
Book Life (Years)	60
Fuel Design	≤ 5% Enriched Uranium
Heat Rejection	Dry Cooling
Technology Rating	Developing
Permitting & Construction Schedule (Years from FNTP)	10
ESTIMATED PERFORMANCE	
Base Load Performance @ (Annual Average)	
Gross Plant Output, kW	300,000
Net Plant Output, kW	287,000
Net Plant Heat Rate, Btu/kWh (HHV)	11,580
ESTIMATED CAPITAL AND O&M COSTS	
EPC Project Capital Costs, MM$ (Note 1)	**$3,750**
Owner's Costs, MM$ (Note 2)	**$994**
Owner's Cost	$563
Owner's Contingency (10% for Screening Purposes) (Note 5)	$431

CENTERPOINT 2025 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE
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INDIANA

Small Modular Reactor Project Option
April 2025 - Revision 3

Project Type	Small Modular Nuclear Reactor
Total Project Costs, MM$	**$4,744**
Project Cost Per kW, $/kW (excl. Owner's Costs)	**$12,500**
Total Cost Per kW, $/kW	**$16,528**
O&M Cost - TOTAL, $MM/Yr (Note 3)	**$65**
Fixed O&M Cost - Labor, $MM-Yr	$24
Fixed O&M Cost - Other, $MM-Yr	$41
Variable O&M Cost, $/MWh (Note 4)	**$2.80**

NOTES

Note 1: Costs based on EPC contracting approach from publically available data produced by NREL. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.

Note 2: Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, water infrastructure costs, land acquisition costs, and security.

Note 3: Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.

Note 4: Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included. Values based on publicly available date published by NREL.

Note 5: Owner's contingency shown at 10% for screening against other technologies. It is likely that significantly higher contingency will need to be carried based on historical risks to nuclear technology product development and uncertainties for this Developing technology and pending greater cost estimate development by the Original Equipment Manufacturer.

Attachment 2.3 Transmission Study (Confidential)

SEE ATTACHMENT: CONFIDENTIAL – Attachment 2.3
Transmission Study

Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report








CENTERPOINT ENERGY INDIANA SOUTH

2025 Long-Term Electric Energy and Demand Forecast Report

Submitted to:
CenterPoint Energy Indiana South

Prepared by:

Itron

20 Park Plaza
4th Floor
Boston, MA 02116
USA
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October 17, 2025




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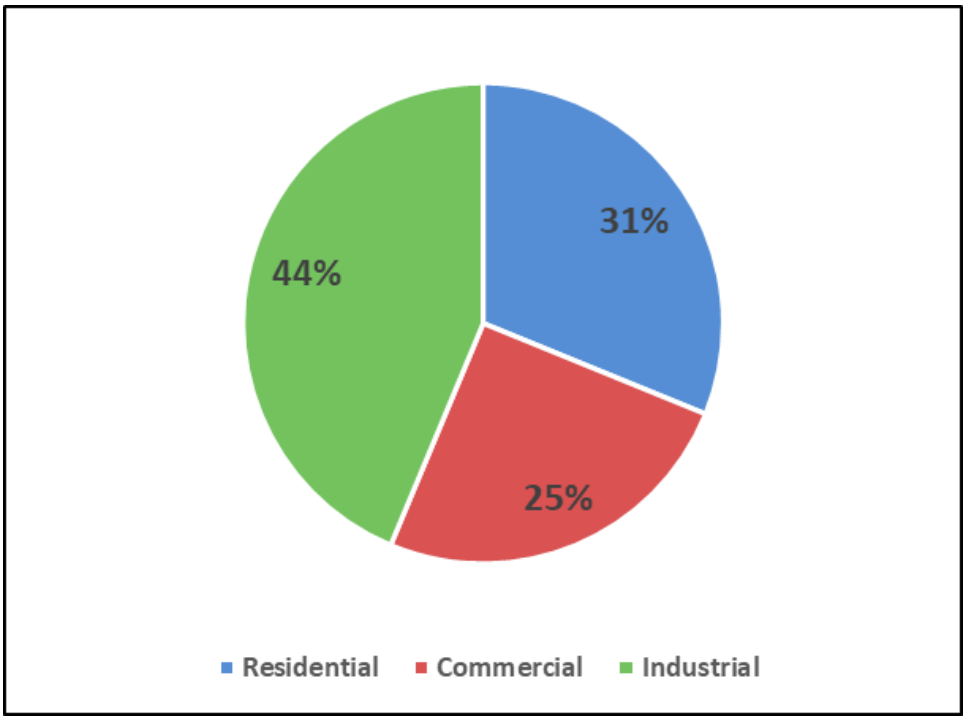
1 OVERVIEW

Itron, Inc. was contracted by CEI South to develop a long-term load forecast to support the 2025 Integrated Resource Plan. The energy and demand forecasts extend through 2045. The forecast is based on a bottom-up approach that starts with residential, commercial, industrial, and street lighting load forecasts that then drive system energy and peak demand. This forecast is then adjusted for behind-the-meter (BTM) solar and electric vehicle load projections. This report presents the results, assumptions, and overview of the forecast methodology.

1.1 CEI SOUTH SERVICE AREA

CEI South serves approximately 153,000 electric customers in Southwest Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of sales in 2024. The residential class accounts for 31% of sales with approximately 133,000 customers and the commercial class 25% of sales; there are approximately 19,000 non-residential customers. System 2024 energy requirements are 5,032 GWh with system peak reaching 1,065MW. Figure 1 shows 2024 class-level sales distribution.

FIGURE 1: 2024 ANNUAL SALES BREAKDOWN



CEI South has seen moderate customer growth with residential customer growth averaging 0.7% per year since 2015. Customer growth increased in 2020 and 2021 showing the strongest growth of the last ten years, averaging 0.9%; since 2019, customer growth has averaged 0.7% per year.

Commercial customer annual growth averaged 0.4% since 2015, and 0.5% since 2019. Prior to the economic slowdown brough on by the COVID-19 pandemic, GDP averaged 1.9% annual growth, following the 2020 drop and subsequent 2021 rebound, long-term GDP growth is forecasted at 1.5% average annual rate with employment growth of 0.3% per year.

Despite moderate economic and customer growth, system energy and peaks demand have been declining. Energy requirements declined 0.3% and demand 0.1% annually since 2017. CEI South lost significant load in 2017 from one large customer installing co-generation, which makes comparing loads prior to 2017 problematic. Energy efficiency gains have been contributing factors to the decline.

Since 2015 weather-normalized residential average use has declined on average 0.5% per year, while residential sales increased on average 0.2% per year as the customers grew. Commercial sales have also been declining; normalized sales have declined 1.1% per year, this is heavily impacted by the drop in 2020 sales due to COVID-19. Excluding 2020, commercial sales have declined 0.3% per year. The industrial sector is showing growth with industrial sales averaging 0.9% annually (excluding loss of a large customer account).

1.2 FORECAST SUMMARY

While DSM activity has had a significant impact on sales, for the IRP filing, the energy and demand forecasts do not include future DSM energy savings; DSM savings are treated as a resource on a consistent and comparable basis to supply side resources as part of the integrated resource planning process. Excluding DSM but including the impact of future customer-owned generation and electric vehicles results in energy requirements increasing 0.3% per year, summer peak demand increases of 0.5% per year and winter peak demand growth of 0.3% per year. Table 1-1 shows the CEI South energy and demand forecasts. CEI South's utility scale solar and other distributed generation are not included in this report but are accounted for within the IRP.

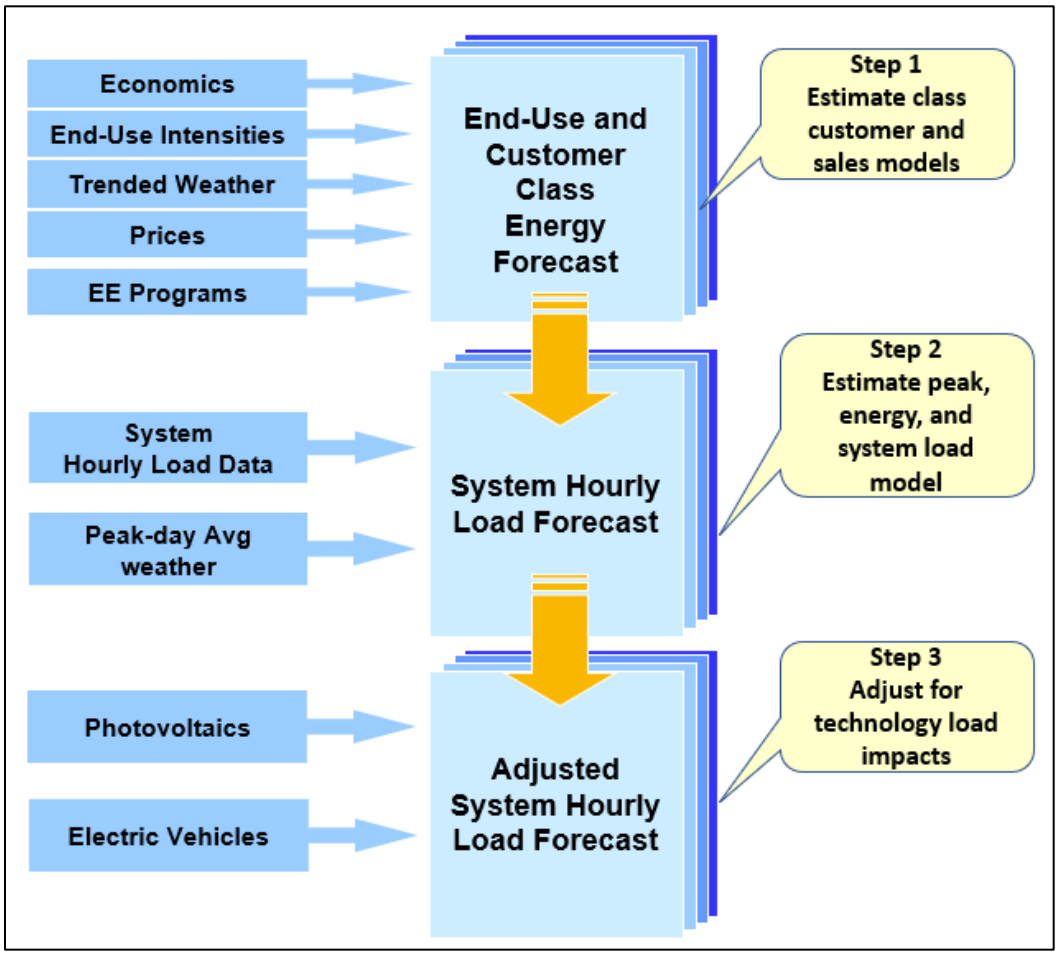
TABLE 1-1: ENERGY AND DEMAND FORECAST (EXCLUDING DSM PROGRAM SAVINGS)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2025	5,201,610		1,083		813	
2026	5,191,351	-0.2%	1,083	0.0%	810	-0.4%
2027	5,203,796	0.2%	1,088	0.5%	811	0.1%
2028	5,222,633	0.4%	1,093	0.5%	813	0.2%
2029	5,235,038	0.2%	1,098	0.5%	815	0.2%
2030	5,251,045	0.3%	1,104	0.5%	817	0.2%
2031	5,262,958	0.2%	1,108	0.4%	818	0.1%
2032	5,275,867	0.2%	1,113	0.4%	819	0.2%
2033	5,271,139	-0.1%	1,115	0.2%	818	-0.2%
2034	5,272,156	0.0%	1,118	0.3%	818	0.0%
2035	5,288,369	0.3%	1,124	0.5%	821	0.4%
2036	5,321,526	0.6%	1,133	0.8%	826	0.6%
2037	5,342,859	0.4%	1,140	0.6%	830	0.4%
2038	5,367,527	0.5%	1,148	0.7%	834	0.5%
2039	5,391,397	0.4%	1,155	0.6%	838	0.5%
2040	5,422,019	0.6%	1,163	0.7%	842	0.6%
2041	5,438,402	0.3%	1,169	0.5%	846	0.4%
2042	5,460,741	0.4%	1,177	0.7%	849	0.4%
2043	5,483,087	0.4%	1,186	0.7%	852	0.4%
2044	5,512,360	0.5%	1,196	0.9%	857	0.5%
2045	5,535,614	0.4%	1,204	0.7%	860	0.4%
CAGR 25-45		0.3%		0.5%		0.3%

2 FORECAST APPROACH

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial, and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts. Figure 2 shows the general framework and model inputs.

FIGURE 2: CLASS BUILD-UP MODEL



In the long term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of residential appliance saturation and efficiency trends, housing square footage and thermal shell efficiency, and commercial building end-use intensity trends. The long-term structural drivers are captured in the residential and commercial sales forecast models through a

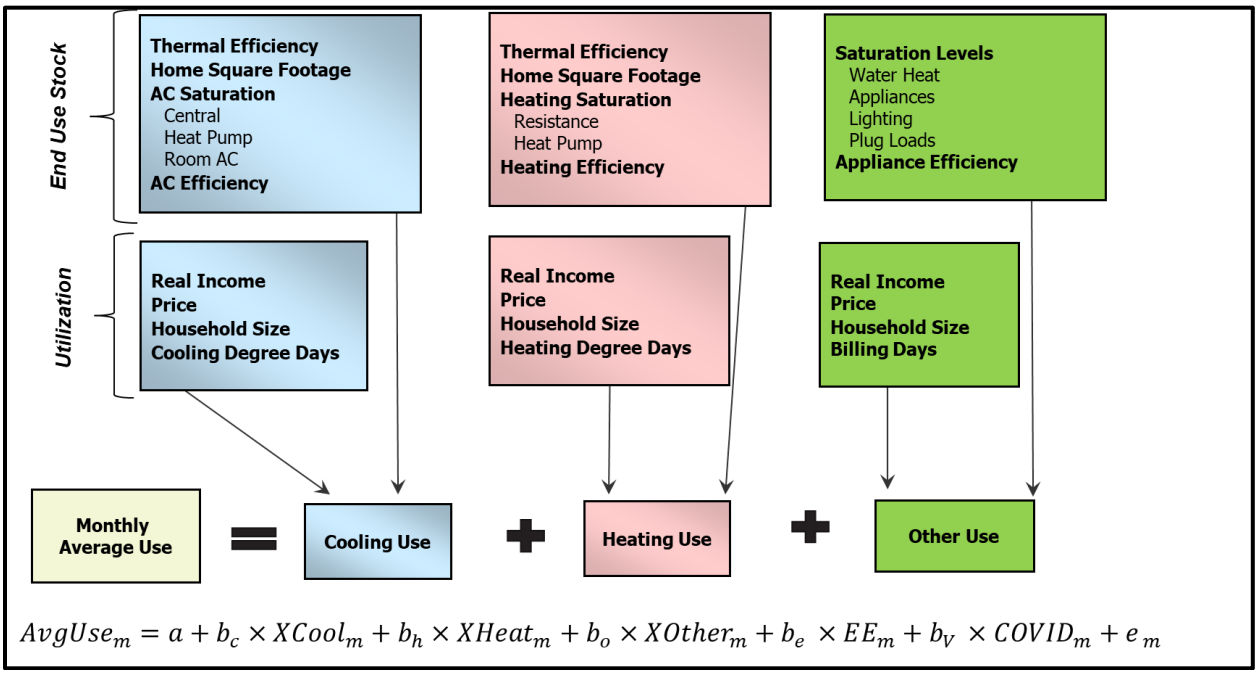
specification that combines economic drivers with structural drivers. This type of model is known as a Statistically Adjusted End-Use (SAE) model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. Both residential average use and commercial sales are forecasted using an SAE specification.

Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

2.1 RESIDENTIAL MODEL

Residential average use and customers are modeled separately. The residential sales forecast is then generated as the product of the average use and customer forecasts. Average use is defined in terms of the average customer's heating (XHeat), cooling (XCool), and other use (XOther) electricity requirements. Figure 3 shows the residential average use model.

FIGURE 3: RESIDENTIAL SAE MODEL



The end-use model variables XCool, XHeat, and XOther are constructed by integrating the end use intensity trends with weather, economics, and price. For XOther, it is the monthly number of billing days that impacts much of the monthly short-term variation. The model coefficients – $\mathbf{b_c}$, $\mathbf{b_h}$ and $\mathbf{b_o}$ are estimated using linear regression; the model is estimated over the period January 2013 to December 2024. The model also includes a separate DSM variable (EE) to capture the historical DSM savings that are not

captured in the primary model variables. Figure 4 to Figure 6 show the constructed monthly heating, cooling, and other end-use variables. Appendix B shows the SAE end-use variable calculations.

FIGURE 4: RESIDENTIAL XHEAT (KWH)

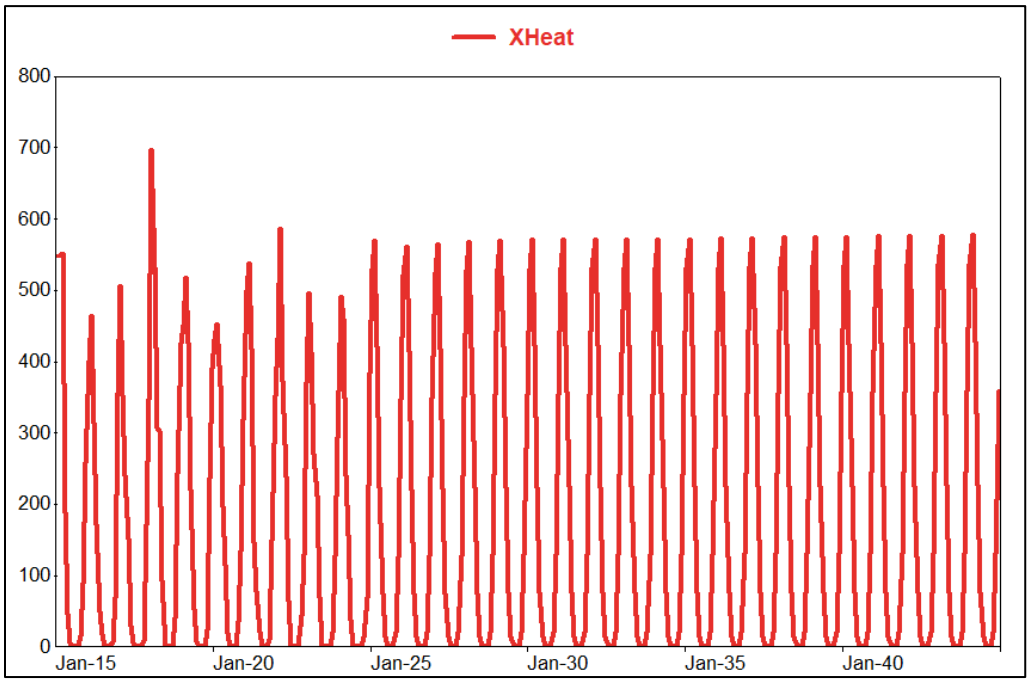


FIGURE 5: RESIDENTIAL XCOOL (KWH)

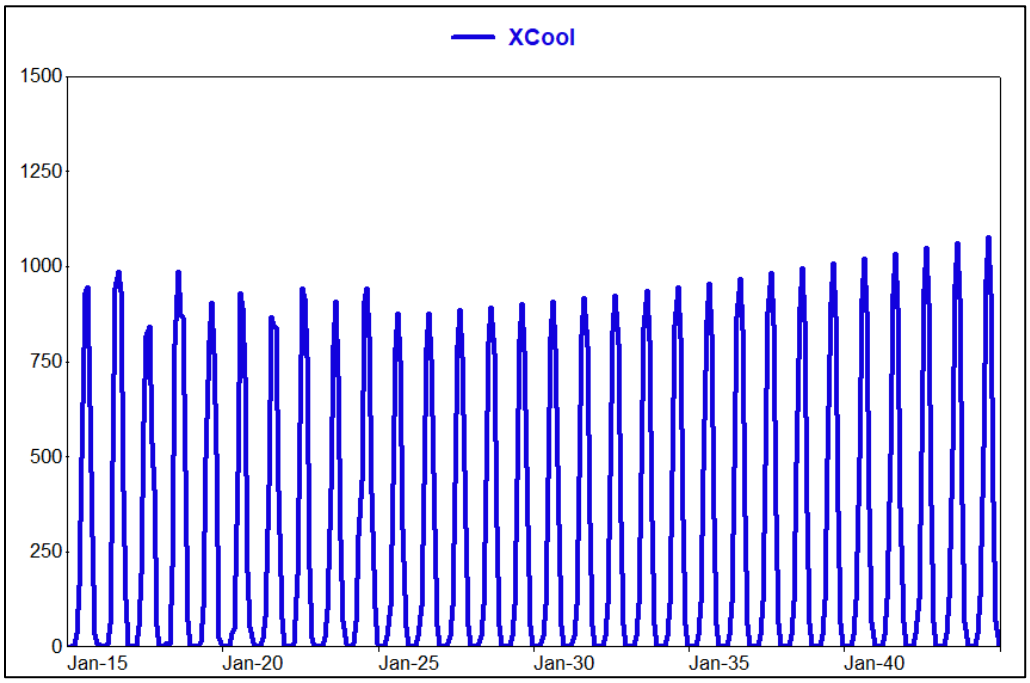


FIGURE 6: RESIDENTIAL XOTHER (KWH)

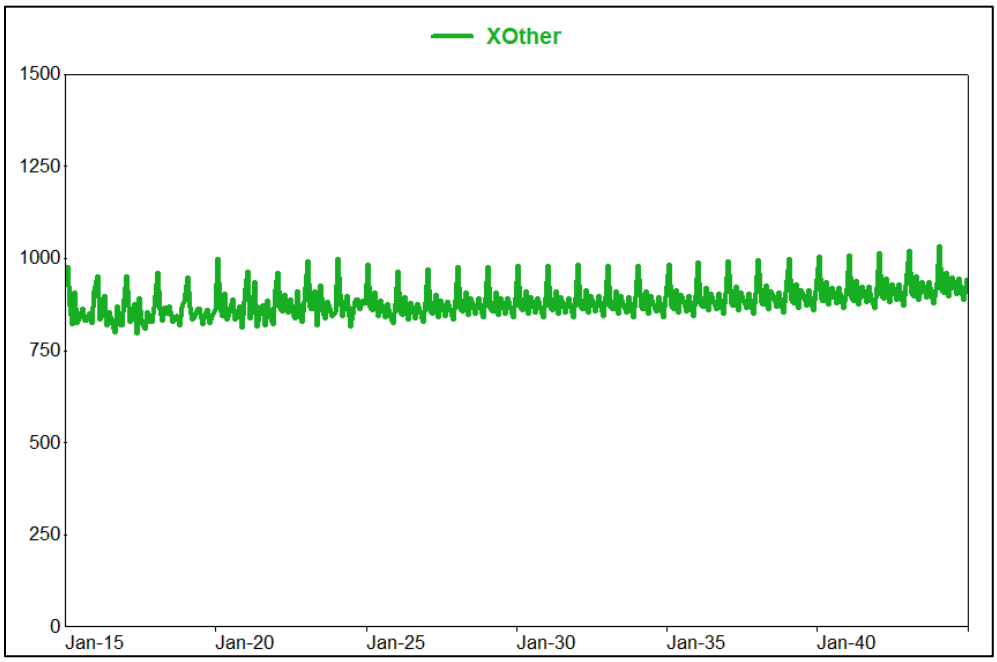
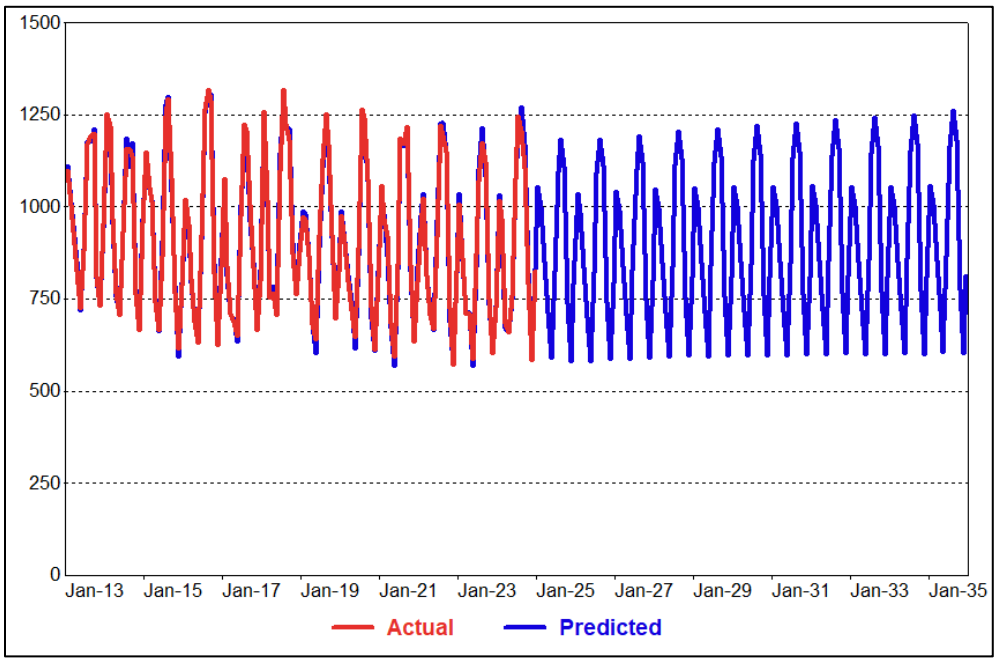


Figure 7 shows the model results.

FIGURE 7: RESDENTIAL AVERAGE USE – BASELINE FORECAST (KWH)



The model also includes a COVID variable to account for the jump in residential average use in 2020. The variable is based on Google Mobility Data that measures cell phone activity near the home. Average use has trended back to pre-COVID levels with businesses and schools reopening. Customer use remains slightly elevated as some households continue to work at home either full-time or as part of new Hybrid work schedules. Overall, the SAE model explains historical average use variation and trend well with an Adjusted R^2 of 0.99 and in-sample Mean Absolute Percent Error (MAPE) of 1.97%. Model coefficients are statistically significant at the 95% level of confidence and higher. Model coefficients and statistics are provided in Appendix A. Excluding DSM; Baseline average use increases 0.6% annually through the forecast period.

The customer forecast is based on a monthly regression model that relates the number of customers to Indiana population projections. This is a change from prior IRPs where customers were forecasted as a function of Evansville MSA household projections. Over the past 3-4 years the correlation between CEI South residential customers and Evansville households has declined. Over the past 10 years the correlation coefficient between state population and CEI South residential customers is 0.99 while the correlation between Evansville households and CEI South residential customers is only 0.87. These relationships can be seen in the Figure 8 which indexes state population, Evansville households and CEI South residential customers. Visually, state population tracks closer to customer counts. Additionally, there is no forecasted growth in Evansville households in 2027 or 2028. Based on this analysis, state population was chosen as the variable used to forecast residential customers.

FIGURE 8: RESIDENTIAL CUSTOMER DRIVERS (INDEX 2005=1)

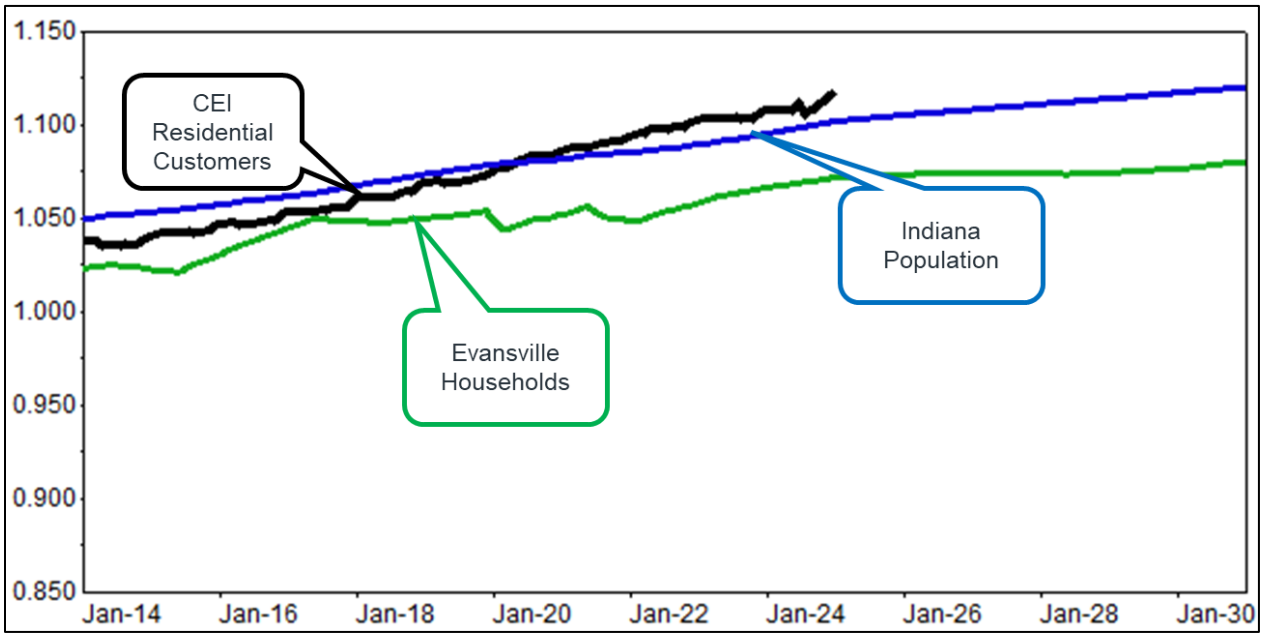


Table 2-1 shows the residential sales forecast before solar and EV adjustments.

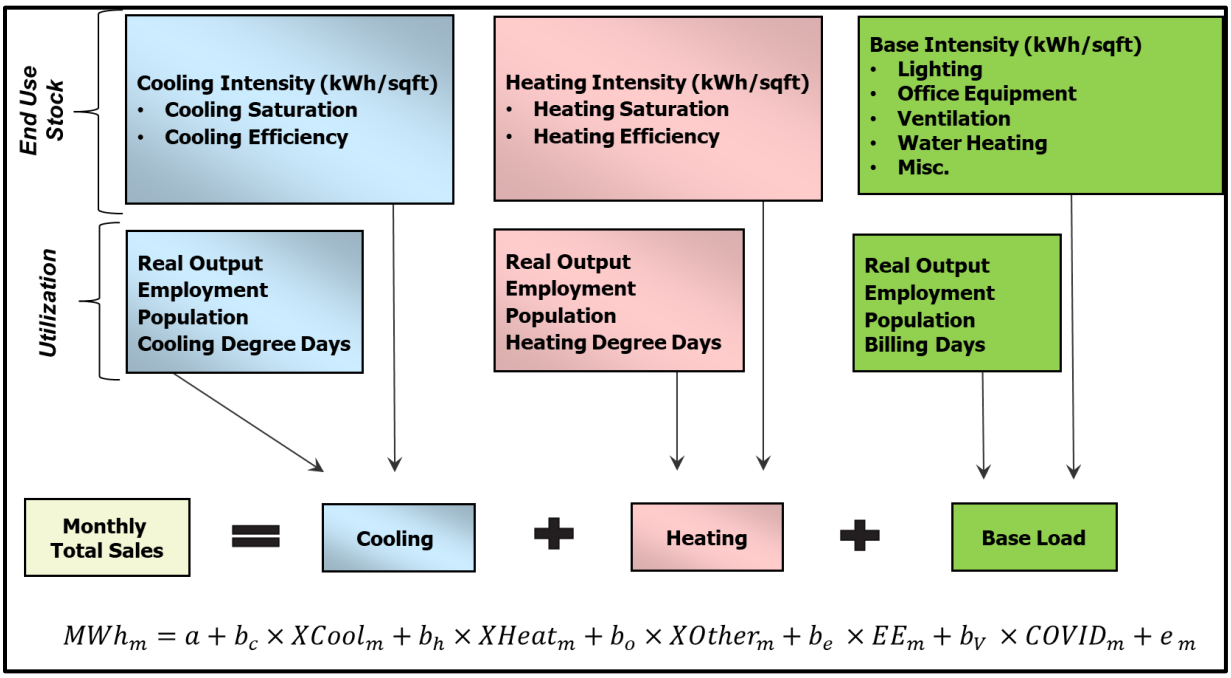
TABLE 2-1: RESIDENTIAL BASELINE FORECAST (EXCLUDES FUTURE DSM)

Year	Sales (MWh)		Customers		AvgUse (kWh)	
2025	1,411,613		133,653		10,562	
2026	1,406,993	-0.3%	134,017	0.3%	10,499	-0.6%
2027	1,421,573	1.0%	134,373	0.3%	10,579	0.8%
2028	1,438,768	1.2%	134,722	0.3%	10,680	0.9%
2029	1,447,150	0.6%	135,080	0.3%	10,713	0.3%
2030	1,456,629	0.7%	135,457	0.3%	10,753	0.4%
2031	1,465,038	0.6%	135,815	0.3%	10,787	0.3%
2032	1,475,348	0.7%	136,155	0.3%	10,836	0.5%
2033	1,480,897	0.4%	136,477	0.2%	10,851	0.1%
2034	1,488,271	0.5%	136,778	0.2%	10,881	0.3%
2035	1,499,552	0.8%	137,057	0.2%	10,941	0.6%
2036	1,515,180	1.0%	137,314	0.2%	11,034	0.9%
2037	1,525,680	0.7%	137,548	0.2%	11,092	0.5%
2038	1,537,643	0.8%	137,759	0.2%	11,162	0.6%
2039	1,549,827	0.8%	137,949	0.1%	11,235	0.7%
2040	1,565,486	1.0%	138,117	0.1%	11,334	0.9%
2041	1,575,922	0.7%	138,265	0.1%	11,398	0.6%
2042	1,590,329	0.9%	138,393	0.1%	11,491	0.8%
2043	1,605,574	1.0%	138,502	0.1%	11,592	0.9%
2044	1,624,229	1.2%	138,596	0.1%	11,719	1.1%
2045	1,637,906	0.8%	138,676	0.1%	11,811	0.8%
CAGR 25-45		0.7%		0.2%		0.6%

2.2 COMMERCIAL MODEL

The commercial sales model is also estimated using an SAE specification. Figure 9 shows the commercial SAE model.

FIGURE 9: COMMERCIAL SAE MODEL



Commercial end-use intensities are mapped to cooling (XCool), heating (XHeat), and other use (XOther). A linear regression model is used to estimate a set of coefficients that calibrate the end-use variables to commercial monthly sales. The model includes historical cumulative DSM savings (EE) to account for EE savings above captured by the model and a COVID model variable based on Google Mobility Data.

The model input variables include end-use intensities, HDD, CDD, number of billing days, price, and economic deriver that incorporates state-level GDP, employment, and number of households. Figure 10 to Figure 12 show the model variables. The specific variable construction is provided in Appendix C.

FIGURE 10: COMMERCIAL XHEAT (MWH)

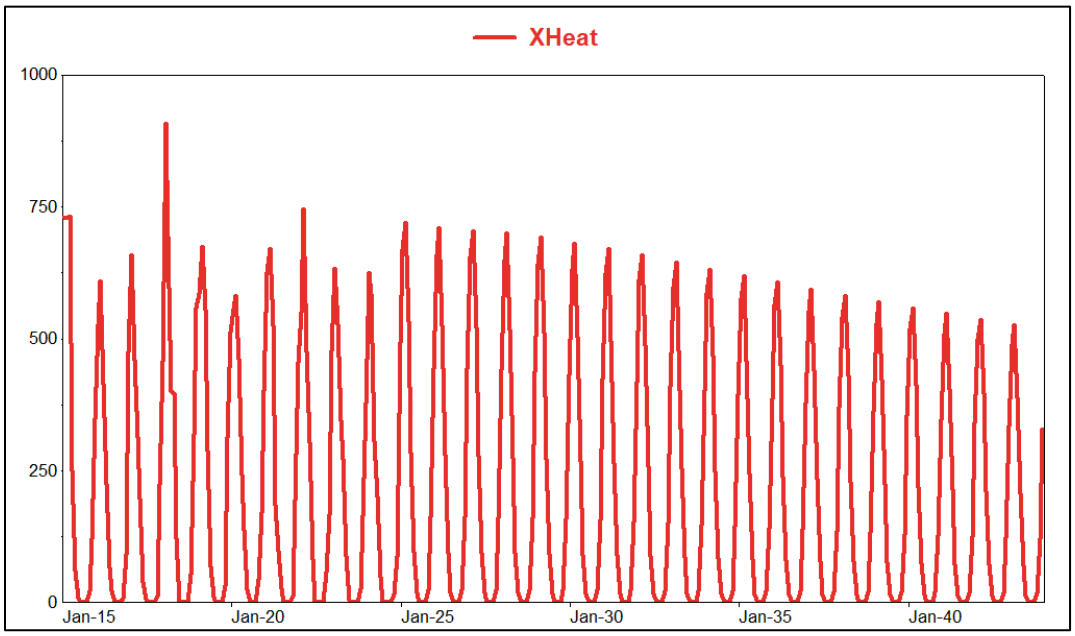


FIGURE 11: COMMERCIAL XCOOL (MWH)

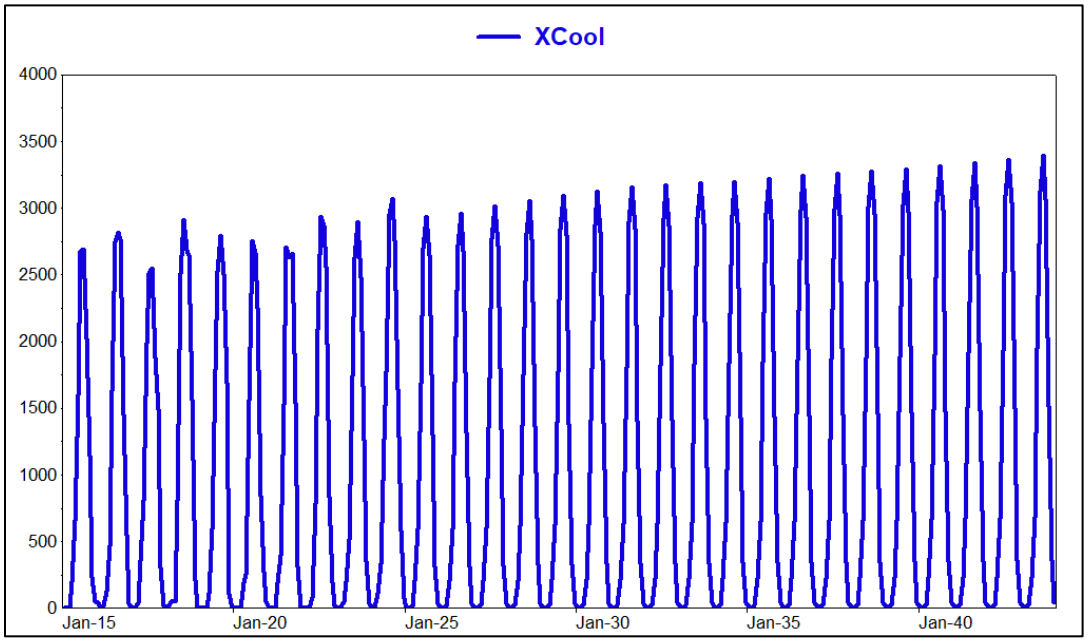


FIGURE 12: COMMERCIAL XOTHER (MWH)

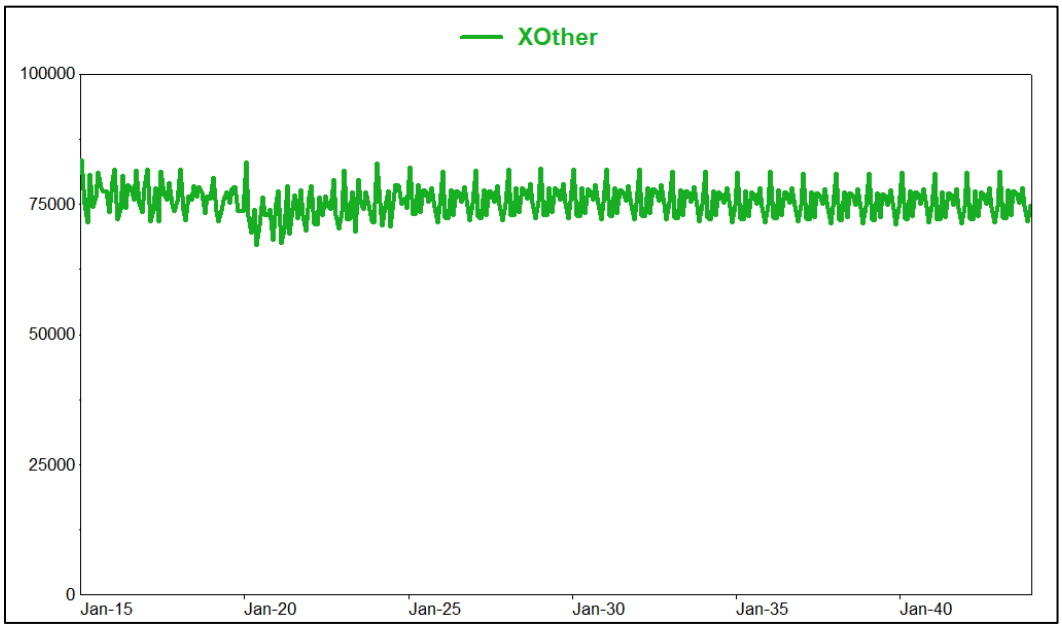
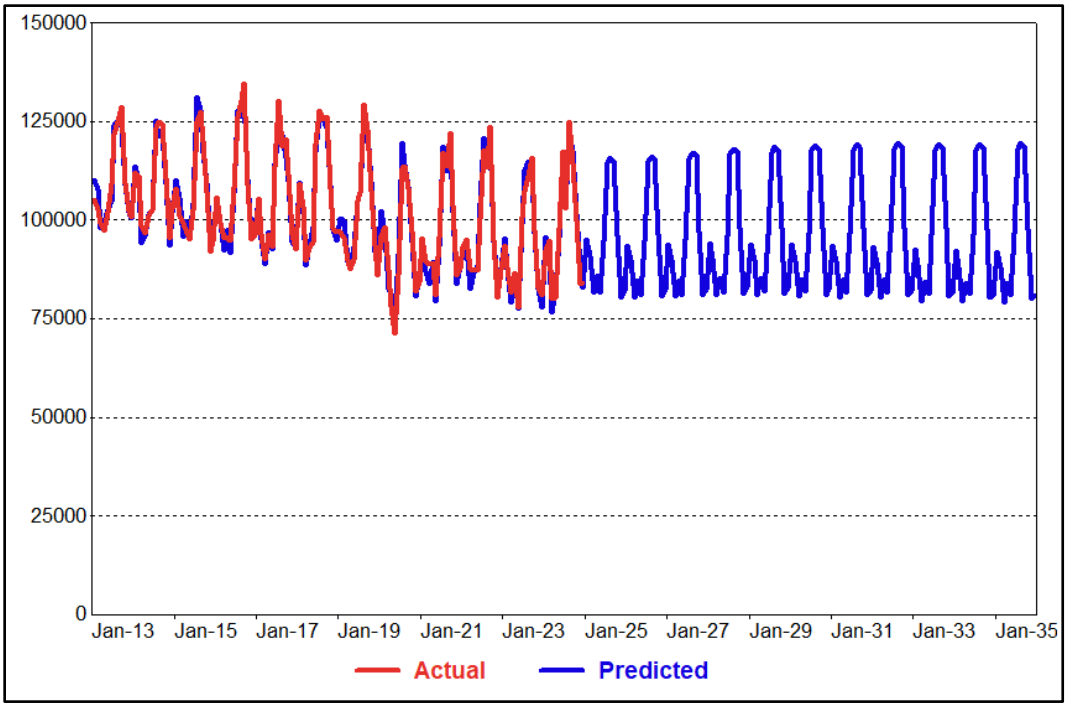


Figure 13 shows model results.

FIGURE 13: COMMERCIAL SALES BASELINE FORECAST (MWH)



The commercial model specification explains historical sales variation and growth relatively well with an Adjusted R^2 of 0.96 and an in-sample MAPE of 2.09%. The model is estimated with monthly billed sales data from January 2013 to December 2024. Since 2020, commercial sales have been recovering but never get back to pre-COVID levels. Model statistics are included in Appendix A. The forecast reflects expected increase in efficiency due to standards, but does not include future DSM, solar self-generation, or electric vehicle charging.

TABLE 2-2: COMMERCIAL BASELINE FORECAST

Year	Sales (MWh)		Customers	
2025	1,133,934		19,392	
2026	1,131,066	-0.3%	19,424	0.2%
2027	1,135,227	0.4%	19,456	0.2%
2028	1,143,864	0.8%	19,487	0.2%
2029	1,144,633	0.1%	19,518	0.2%
2030	1,144,800	0.0%	19,551	0.2%
2031	1,143,378	-0.1%	19,583	0.2%
2032	1,144,356	0.1%	19,613	0.2%
2033	1,138,978	-0.5%	19,641	0.1%
2034	1,136,800	-0.2%	19,668	0.1%
2035	1,136,113	-0.1%	19,693	0.1%
2036	1,138,395	0.2%	19,715	0.1%
2037	1,134,043	-0.4%	19,736	0.1%
2038	1,132,970	-0.1%	19,755	0.1%
2039	1,131,416	-0.1%	19,771	0.1%
2040	1,135,713	0.4%	19,786	0.1%
2041	1,134,524	-0.1%	19,799	0.1%
2042	1,137,614	0.3%	19,810	0.1%
2043	1,141,209	0.3%	19,820	0.1%
2044	1,148,087	0.6%	19,828	0.0%
2045	1,150,192	0.2%	19,835	0.0%
CAGR 25-45		0.1%		0.1%

2.3 INDUSTRIAL MODEL

The industrial sales forecast is developed with a two-step approach. The forecast for the first 12 months is derived from CEI South's expectation of specific customer activity. The forecast after the first 12 months

is based on the industrial forecast model. CEI South determines baseline volume based on historical consumption use. The baseline use is then adjusted to reflect expected closures and expansions. Near-term sales are also adjusted for the addition of new industrial customers. Starting in the second year, the forecast is derived from the industrial sales model; forecasted growth is applied to the 12-month industrial sales forecast.

The industrial sales model is a generalized linear regression model that relates monthly historical industrial billed sales to manufacturing employment, manufacturing output, CDD, and monthly binaries to capture seasonal load variation and shifts in sales data. The industrial economic driver is a weighted combination of manufacturing employment and manufacturing output. The industrial economic (*IndVar*) variable is defined as:

$$IndVar_{ym} = \left(ManufEmploy_{ym}^{0.5}\right) \times \left(ManufOutput_{ym}^{0.5}\right)$$

Where:

y = year
m = month

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The model Adjusted R^2 is 0.49 with a MAPE of 6.05%. The relatively low Adjusted R^2 and high MAPE, in comparison to the residential and commercial models, are a result of the large month-to-month variations in industrial billing data. The industrial model excludes sales to one of CEI South's largest customers, which is currently meeting most of its load through onsite cogeneration.

Excluding DSM, industrial sales average 0.3% annual growth. Table 2-3 summarizes the industrial sales forecast.

TABLE 2-3: INDUSTRIAL FORECAST (EXCLUDING FUTURE DSM, PV, EV)

Year	Sales (MWh)	
2025	2,347,569	
2026	2,347,539	0.0%
2027	2,342,528	-0.2%
2028	2,336,831	-0.2%
2029	2,341,443	0.2%
2030	2,349,281	0.3%
2031	2,356,121	0.3%
2032	2,360,027	0.2%
2033	2,358,157	-0.1%
2034	2,357,067	0.0%
2035	2,365,232	0.3%
2036	2,382,643	0.7%
2037	2,400,268	0.7%
2038	2,416,862	0.7%
2039	2,433,415	0.7%
2040	2,447,840	0.6%
2041	2,459,594	0.5%
2042	2,469,466	0.4%
2043	2,478,466	0.4%
2044	2,488,222	0.4%
2045	2,501,523	0.5%
CAGR 25-45		0.3%

2.4 STREET LIGHTING MODEL

Streetlight sales are fitted with a regression model with monthly binaries. Streetlighting sales are held constant with variation only due to seasonal consumption patterns . Table 2-4 shows the streetlight forecast.

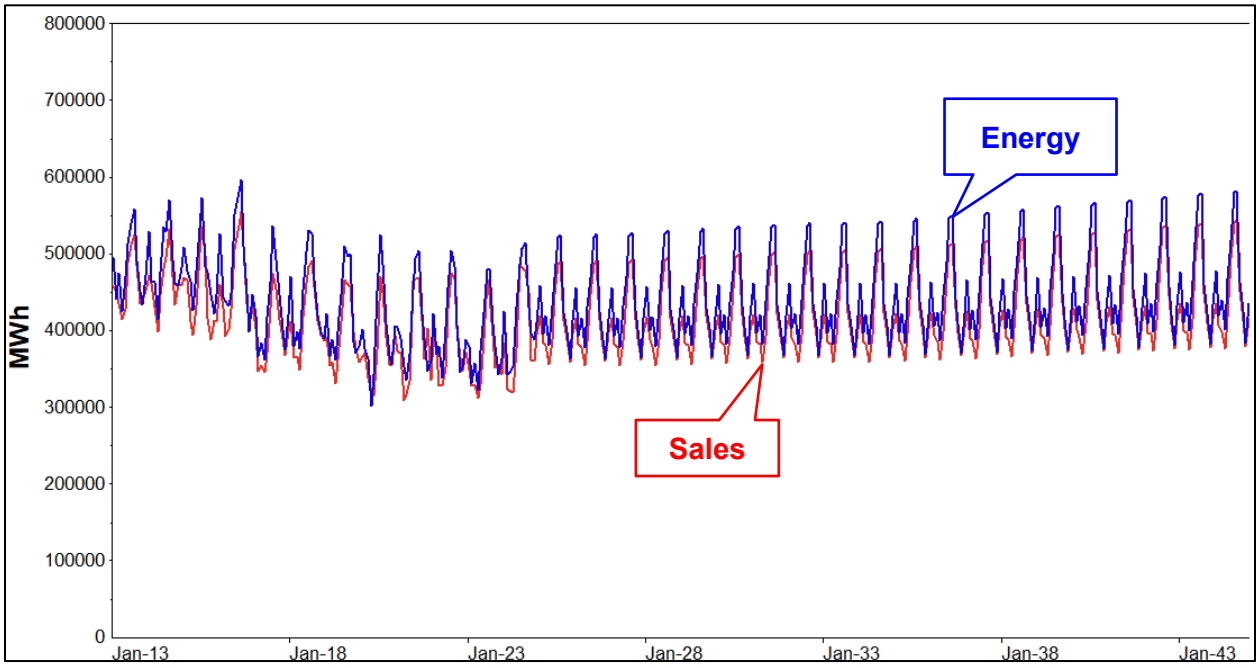
TABLE 2-4: STREET LIGHTING FORECAST

Year	Sales (MWh)	
2025	12,421	
2026	12,421	0.0%
2027	12,421	0.0%
2028	12,421	0.0%
2029	12,421	0.0%
2030	12,421	0.0%
2031	12,421	0.0%
2032	12,421	0.0%
2033	12,421	0.0%
2034	12,421	0.0%
2035	12,421	0.0%
2036	12,421	0.0%
2037	12,421	0.0%
2038	12,421	0.0%
2039	12,421	0.0%
2040	12,421	0.0%
2041	12,421	0.0%
2042	12,421	0.0%
2043	12,421	0.0%
2044	12,421	0.0%
2045	12,421	0.0%
CAGR 25-45		0.0%

2.5 ENERGY FORECAST MODEL

The baseline energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (*unaccounted for energy*). Monthly adjustment factors are calculated based on the historical relationship between energy and sales. Figure 14 shows the monthly sales and energy forecast, excluding the impact of future DSM, PV or electric vehicles.

FIGURE 14: ENERGY AND SALES FORECAST (EXCLUDING DSM, EV, PV)



2.6 PEAK FORECAST MODEL

The baseline system peak forecast is derived through a monthly peak regression model that relates peak demand to heating, cooling, and base load requirements:

$$Peak_{ym} = B_0 + B_1 HeatVar_{ym} + B_2 CoolVar_{ym} + B_3 BaseVar_{ym} + e_{ym}$$

Where:

y = year
m = month

End-use energy requirements are estimated from class sales forecast models.

Heating and Cooling Model Variables

The residential and commercial SAE model coefficients are used to isolate historical and projected weather-normal heating and cooling requirements. Heating requirements are interacted with peak-day HDD and cooling requirements with peak-day CDD; this interaction allows peak-day weather impacts to change over time with changes in heating and cooling requirements. The peak model heating and cooling variables are calculated as:

- $HeatVar_{ym} = HeatLoadIdx_{ym} \times PkHDD_{ym}$
- $CoolVar_{ym} = CoolLoadIdx_{ym} \times PkCDD_{ym}$

Where $HeatLoadIdx_{ym}$ is an index of total system heating requirements in year y and month m and $CoolLoadIdx_{ym}$ is an index of total system cooling requirements in year y and month m. $PkHDD_{ym}$ is the peak-day HDD in year y and month m and $PkCDD_{ym}$ is the peak-day CDD in year y and month m.

Figure 15 and Figure 16 show *HeatVar* and *CoolVar*. The variation in the historical period is a result of variation in peak-day HDD and CDD.

FIGURE 15: PEAK-DAY HEATING VARIABLE

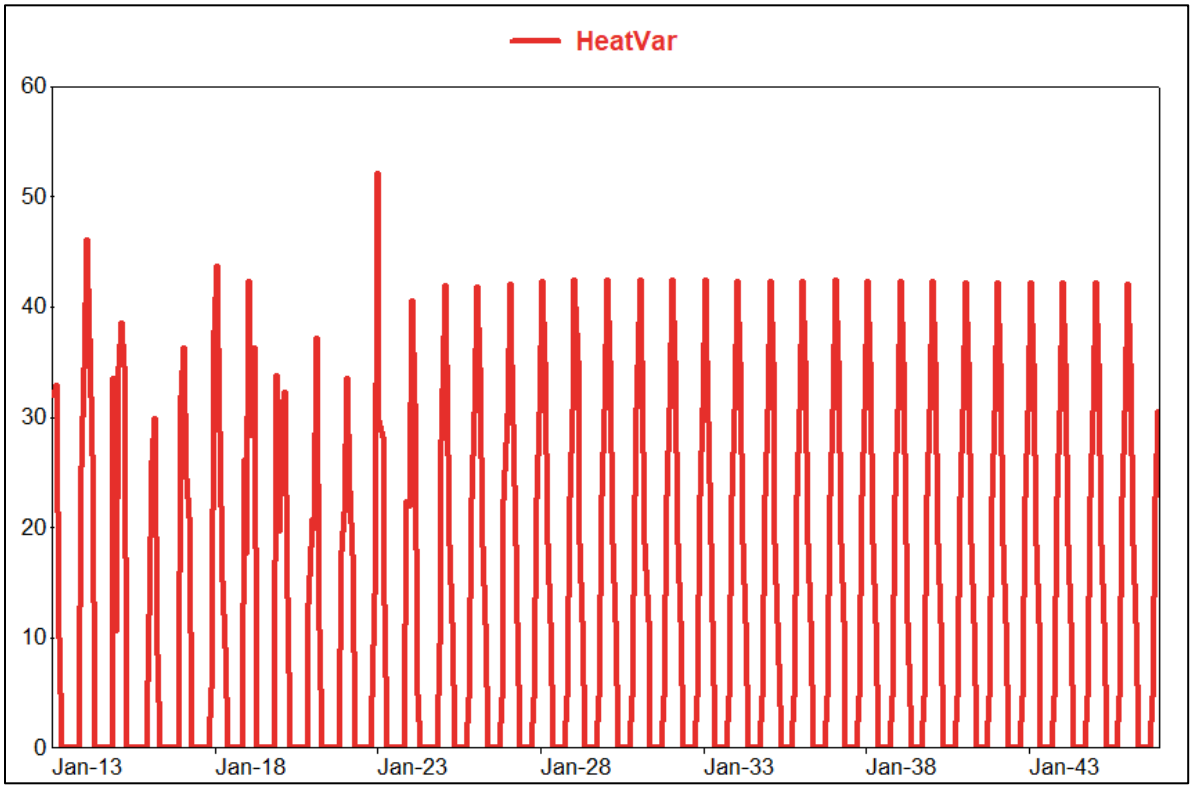
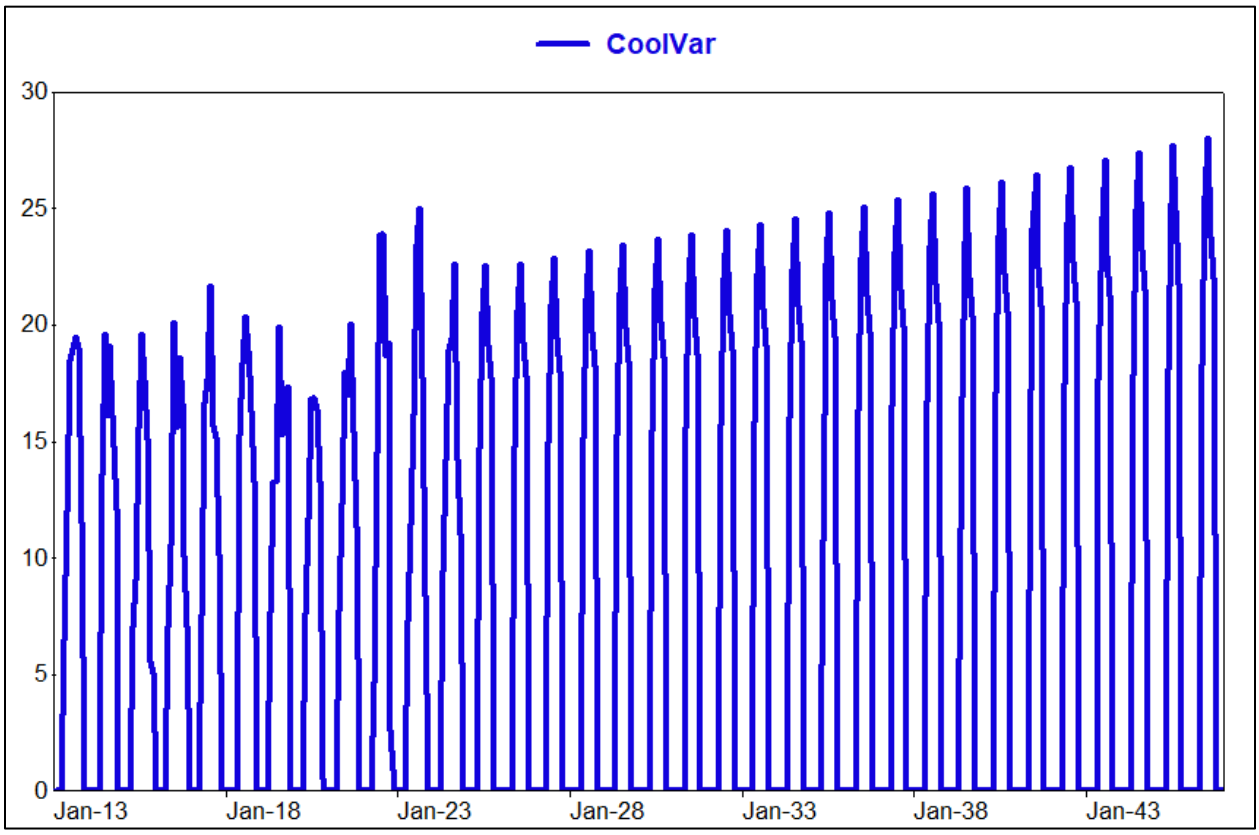


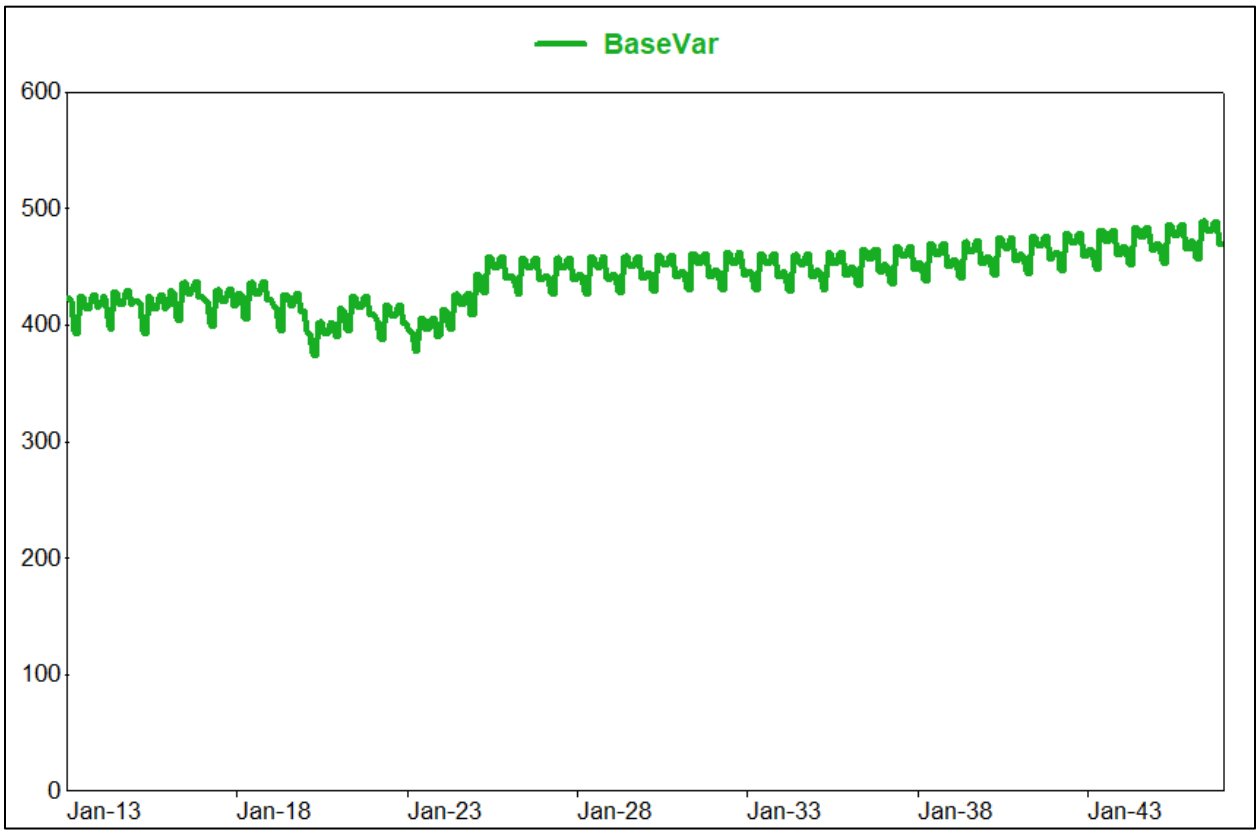
FIGURE 16: PEAK-DAY COOLING VARIABLE



Base Load Variable

The base-load variable ($BaseVar_{ym}$) captures non-weather sensitive load at the time of the monthly peak. Monthly base-load estimates are calculated by allocating non-weather sensitive energy requirements to end-use estimates at the time of peak. End-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 17 shows the non-weather sensitive peak-model variable.

FIGURE 17: PEAK-DAY BASE-USE VARIABLE

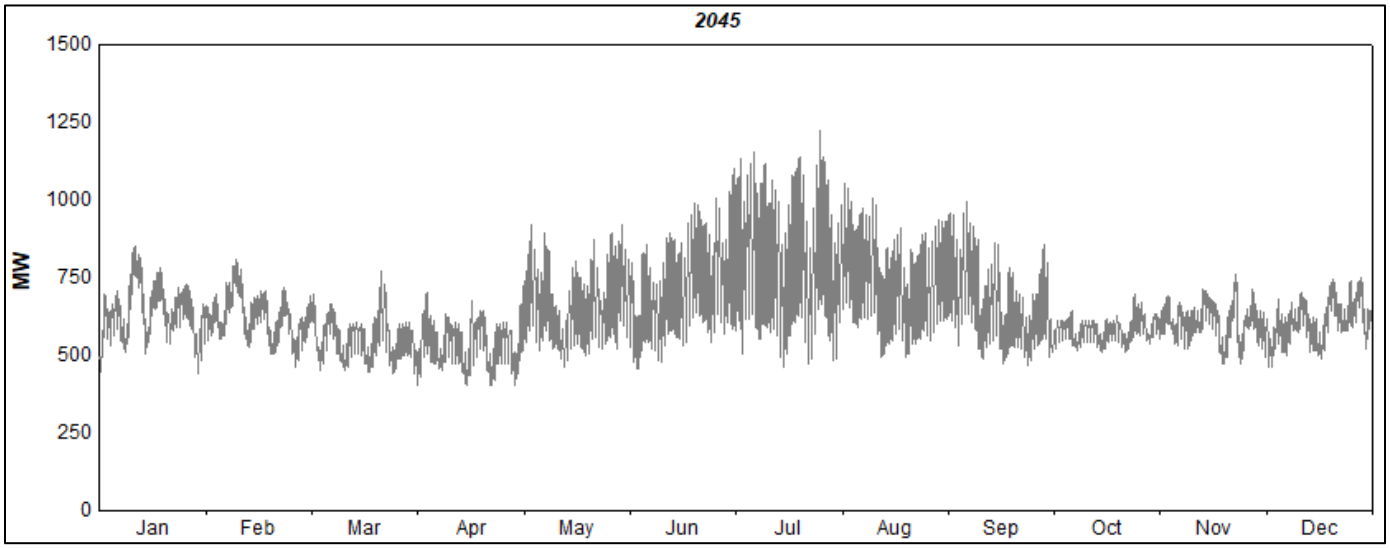


Model Results

The peak model is estimated over the period January 2013 to December 2024. The model explains monthly peak variation well with an adjusted R^2 of 0.93 and an in-sample MAPE of 3.61%. The end-use variables – *HeatVar*, *CoolVar*, and *BaseVar* are all highly statistically significant. Model statistics and parameters are included in Appendix A.

The baseline energy and peak forecast, excluding DSM, PV, and electric vehicles, are combined with a system hourly load profile to derive the baseline hourly load forecast. Figure 18 shows the hourly load forecast for 2045.

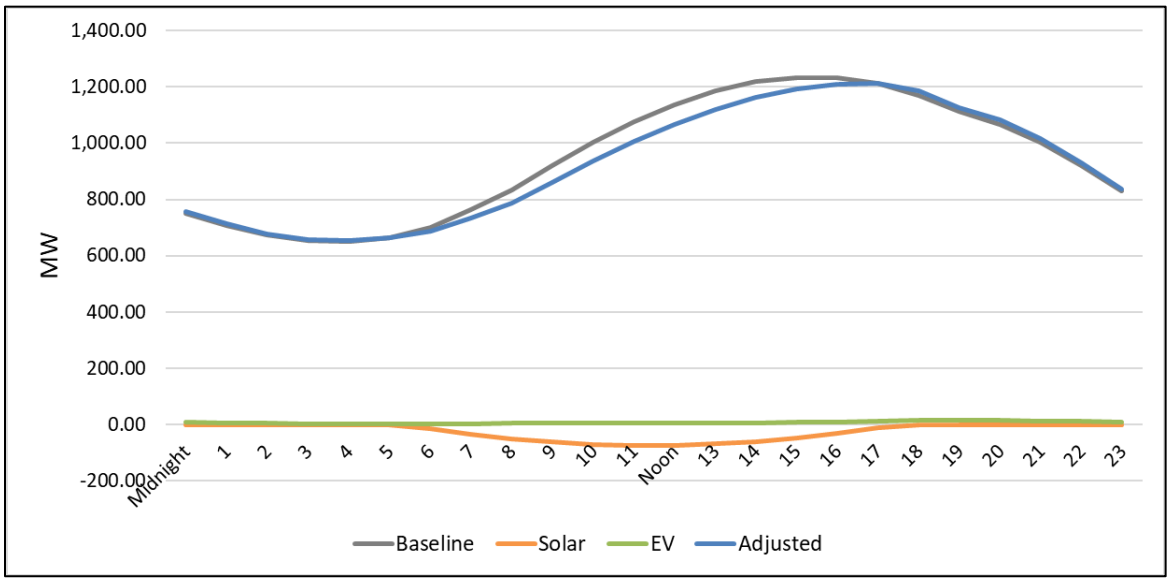
FIGURE 18: BASELINE SYSTEM HOURLY LOAD FORECAST



2.7 ADJUSTED ENERGY & PEAK FORECAST

The final adjusted energy and peak forecast is produced by adding additional solar and electric vehicle hourly load forecasts to the baseline forecast. This approach is a change from the prior IRP in which coincident peak load factors for PV and electric vehicles were used to estimate peak impacts. The advantage of the hourly approach is the ability to capture the changing impact of PV and electric vehicles with changes to the timing of the system peak. Due to the additional PV and electric vehicles, the summer system peak shifts forward one hour beginning in 2027 (4:00PM), and an additional hour beginning in 2042 (5:00PM), reducing the impact of solar. Figure 19 shows the baseline hourly load, PV and electric vehicles loads, and final adjusted system load for a summer peak day in 2045.

FIGURE 19: ADJUSTED SYSTEM HOURLY LOAD FORECAST



The final adjusted energy and peak forecast is derived from the adjusted hourly system forecast. Table 2-5 shows adjusted energy and peak demand forecast.

TABLE 2-5: ENERGY AND PEAK FORECAST (EXCLUDING DSM)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2025	5,201,610		1,083		813	
2026	5,191,351	-0.2%	1,083	0.0%	810	-0.4%
2027	5,203,796	0.2%	1,088	0.5%	811	0.1%
2028	5,222,633	0.4%	1,093	0.5%	813	0.2%
2029	5,235,038	0.2%	1,098	0.5%	815	0.2%
2030	5,251,045	0.3%	1,104	0.5%	817	0.2%
2031	5,262,958	0.2%	1,108	0.4%	818	0.1%
2032	5,275,867	0.2%	1,113	0.4%	819	0.2%
2033	5,271,139	-0.1%	1,115	0.2%	818	-0.2%
2034	5,272,156	0.0%	1,118	0.3%	818	0.0%
2035	5,288,369	0.3%	1,124	0.5%	821	0.4%
2036	5,321,526	0.6%	1,133	0.8%	826	0.6%
2037	5,342,859	0.4%	1,140	0.6%	830	0.4%
2038	5,367,527	0.5%	1,148	0.7%	834	0.5%
2039	5,391,397	0.4%	1,155	0.6%	838	0.5%
2040	5,422,019	0.6%	1,163	0.7%	842	0.6%
2041	5,438,402	0.3%	1,169	0.5%	846	0.4%
2042	5,460,741	0.4%	1,177	0.7%	849	0.4%
2043	5,483,087	0.4%	1,186	0.7%	852	0.4%
2044	5,512,360	0.5%	1,196	0.9%	857	0.5%
2045	5,535,614	0.4%	1,204	0.7%	860	0.4%
CAGR 25-45		0.3%		0.5%		0.3%

3 CUSTOMER OWNED DISTRIBUTED GENERATION

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline, which is partially offset by changes in net metering laws that will credit excess generation at a rate lower than retail rates in the future. As of December 2024, CEI South had 1,217 residential solar customers and 176 commercial solar customers, with an approximate installed capacity of 27.3 MW.

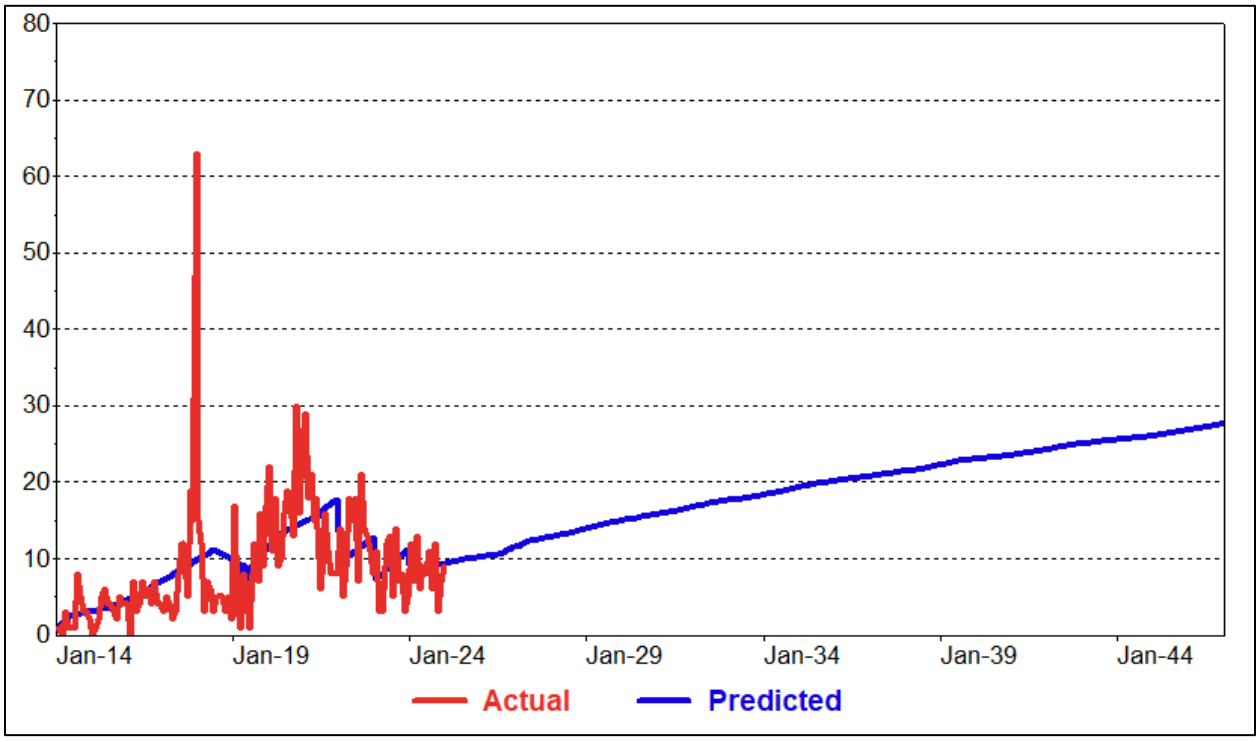
3.1 MONTHLY ADOPTION MODEL

The primary factor driving system adoption is a customer's return-on-investment. A simple payback model is used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity is "free." Simple payback also works well to explain leased system adoption as return on investment drives the leasing company's decision to offer leasing programs. Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid). The payback calculation incorporates the impact of switching from net metering to Excess Distributed Generation (EDG).

One of the most significant factors driving adoption is declining system costs; costs have continued declining over the last five years. In 2019, residential solar system cost was approximately $4.6 per watt. By 2024 costs had dropped to $4.0 per watt. For the forecast period, we assume system costs continue to decline 3% annually.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 20 shows the resulting residential solar adoption forecast.

FIGURE 20: RESIDENTIAL SOLAR ADOPTION FORECAST



In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill), and physical constraints as to the placement of the system. For this forecast, we assume there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates. Table 3-1 shows projected solar adoption.

TABLE 3-1: SOLAR CUSTOMER FORECAST

Year	Residential Systems	Commercial Systems	Total Systems
2025	1,281	185	1,466
2026	1,403	203	1,606
2027	1,542	223	1,765
2028	1,697	245	1,943
2029	1,865	270	2,135
2030	2,046	296	2,342
2031	2,237	323	2,560
2032	2,439	353	2,792
2033	2,652	384	3,036
2034	2,873	415	3,288
2035	3,105	449	3,554
2036	3,347	484	3,831
2037	3,598	520	4,118
2038	3,855	558	4,413
2039	4,124	596	4,720
2040	4,400	636	5,036
2041	4,683	677	5,360
2042	4,975	719	5,694
2043	5,275	763	6,038
2044	5,583	807	6,390
2045	5,896	853	6,749
CAGR 25-45	7.9%	7.9%	7.9%

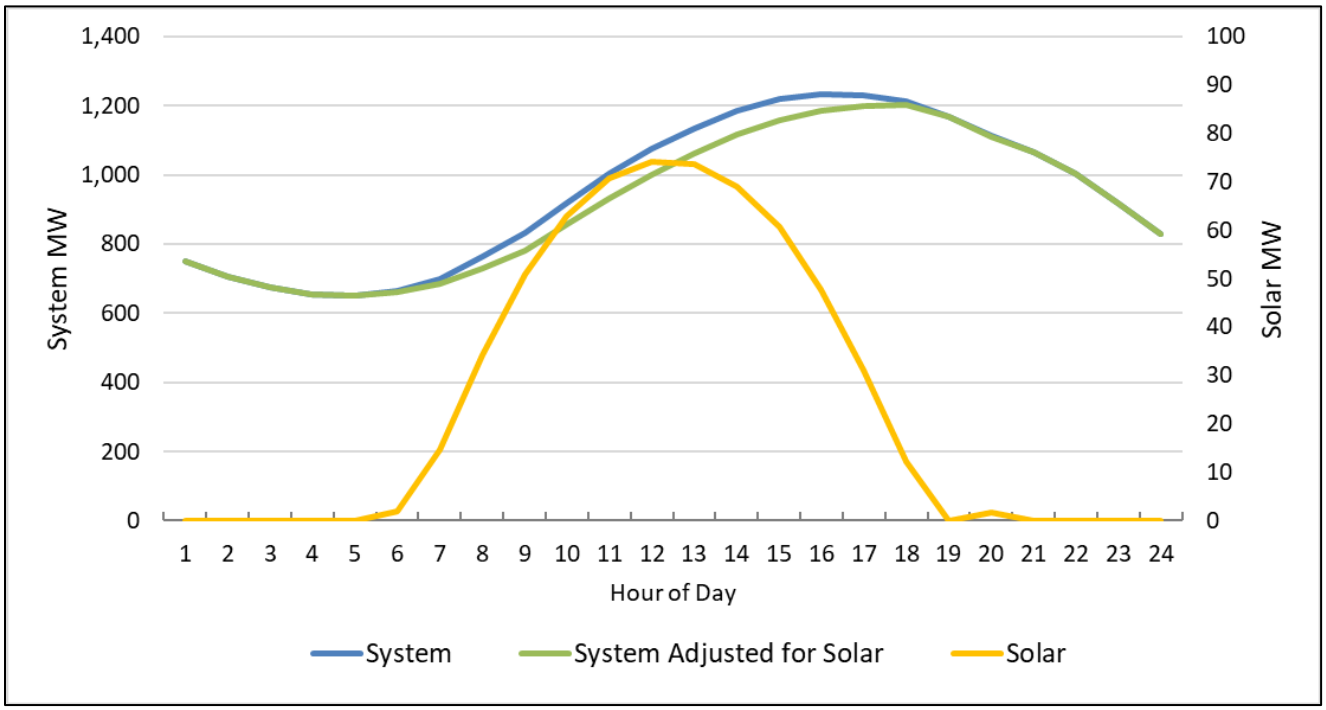
3.2 SOLAR CAPACITY AND GENERATION

Installed solar capacity forecast is the product of the solar customer forecast and average system size (measured in kW). Based on recent solar installation data, the residential average size is 10.26 KW, and commercial average system size is 84.03 KW.

The capacity forecast (MW) is translated into system generation (MWh) forecast by applying monthly solar load factors to the capacity forecast. Monthly load factors are derived from a typical PV load profile for Evansville, IN. The PV shape is from the National Renewable Energy Laboratory (NREL) and represents a typical meteorological year (TMY).

The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. Solar output peaks during the mid-day while system peaks later in the afternoon. Figure 21 shows the system profile, solar adjusted system profile, and solar profile for a peak producing summer day.

FIGURE 21: SOLAR HOURLY LOAD IMPACT



Based on system and solar load profiles, 1.0 MW of solar capacity reduces summer peak demand by approximately 0.43 MW through 2027. In 2027, the timing of the system peak shifts forward one hour, resulting in diminished solar impact per installed MW. In 2027 1.0 MW of solar capacity reduces summer peak demand by approximately 0.15 MW. In 2042 the timing of the system peaks shift forward an additional hour, resulting in a further diminished solar impact per installed MW. In 2042 1.0 MW of solar capacity reduces summer peak demand by approximately 0.11 MW.

Table 3-2 shows the incremental new PV capacity forecast, expected annual generation, and demand at time of peak.

TABLE 3-2: NEW SOLAR CAPACITY AND GENERATION

Year	Total Generation MWh	Installed Capacity MW (July)	Demand Impact MW
2025	1,968	1.5	0.7
2026	5,787	4.3	1.8
2027	10,125	7.4	1.1
2028	15,004	10.9	3.0
2029	20,224	14.7	4.1
2030	25,864	18.7	5.2
2031	31,839	23.0	6.4
2032	38,243	27.6	7.6
2033	44,826	32.4	8.8
2034	51,721	37.3	10.2
2035	58,990	42.5	11.7
2036	66,687	47.9	13.4
2037	74,391	53.6	14.8
2038	82,442	59.4	15.7
2039	90,839	65.4	17.8
2040	99,691	71.6	19.7
2041	108,335	77.9	21.7
2042	117,455	84.5	9.3
2043	126,838	91.2	9.9
2044	136,782	98.1	10.1
2045	146,270	105.1	11.3
CAGR 25-45	24.0%	23.5%	15.2%

4 ELECTRIC VEHICLE FORECAST

The 2025 IRP forecast also includes the impact of electric vehicle adoption. Currently CEI South has relatively few electric vehicles, but this is expected to increase significantly over the next twenty years with improvements in EV technology and declines in battery and vehicle costs. Multiple private and public institutions produce electric vehicle forecasts that vary from conservative to aspirational. Major manufactures have continued to pledge increased EV availability and options. At the time of the forecast CEI South had 1,512 registered electric vehicles in the counties that CEI South serves: this included full electric (i.e., battery electric vehicles - BEV) as well as plug-in hybrid electric (PHEV) vehicles. The 1,521 vehicles were comprised of 991 BEVs and 521 PHEVs, with a total of 19 different make/model vehicles represented.

4.1 METHODOLOGY

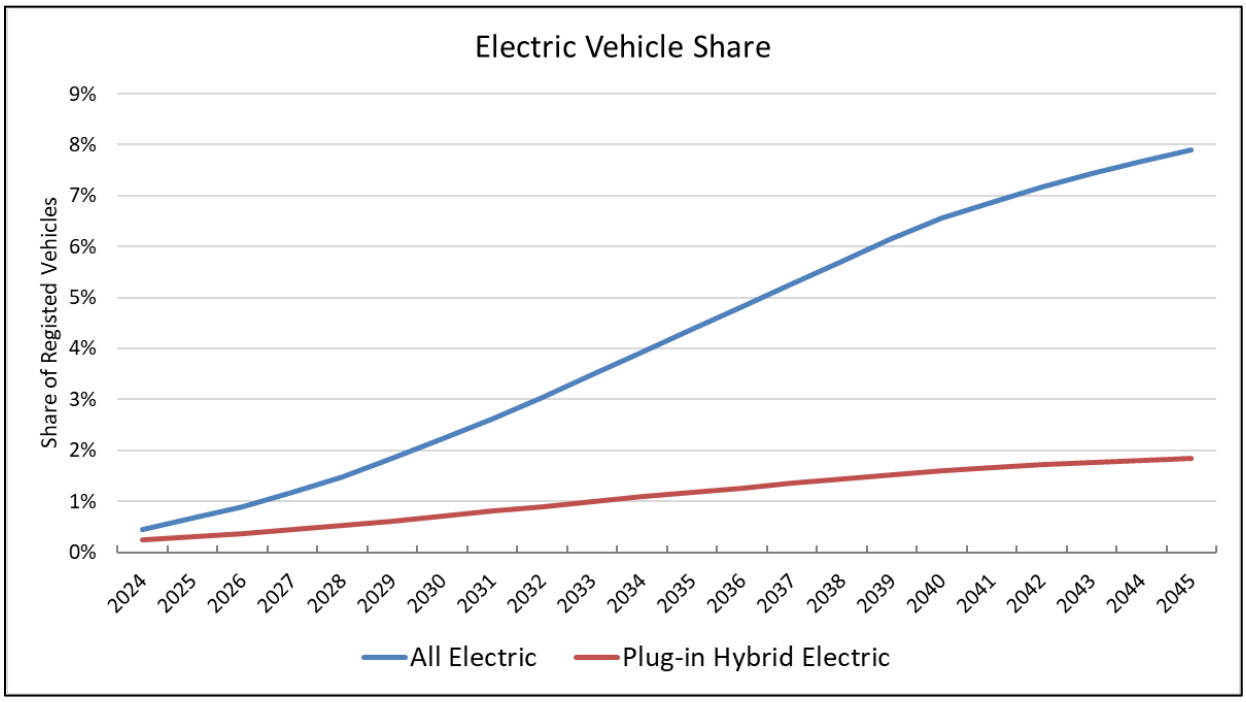
The Energy Information Administration (EIA) Annual Energy Outlook is a commonly referenced source for electric vehicle forecasts. The forecast uses the EIA forecast to calculate the share of registered light-duty vehicles which are electric, BEV and PHEV. We rely on the EIA's assumption of total light-duty vehicles per household. Using these data, we calculate the average number of cars per household and projected electric vehicle share - BEV and PHEV.

Total service area vehicles are calculated as the product of forecasted customers times EIA projected vehicles per household:

$$Ttl\ Vehicles = Custs_{yr} \times EIA\ Vehicle\ Per\ HH_{yr}$$

The number of BEV and PHEV are calculated by applying projected BEV and PHEV saturation to the service area total vehicle forecast. A calibration step is first taken to adjust to the known number of registered EV in CenterPoint's service territory as of 2024. The share of electric vehicles is projected to increase from less than 1% to 8% BEV and 2% PHEV by 2045. The BEV and PHEV saturation forecast is shown in Figure 22.

FIGURE 22: BEV & PHEV MARKET SHARE



The resulting electric vehicle forecast is summarized in Table 4-1:

TABLE 4-1: ELECTRIC VEHICLE FORECAST

Year	BEV Count	PHEV Count
2025	1,451	659
2026	1,984	817
2027	2,595	988
2028	3,292	1,176
2029	4,083	1,374
2030	4,952	1,581
2031	5,862	1,793
2032	6,823	2,011
2033	7,814	2,231
2034	8,831	2,451
2035	9,866	2,662
2036	10,903	2,858
2037	11,951	3,071
2038	12,982	3,273
2039	13,981	3,460
2040	14,914	3,622
2041	15,649	3,776
2042	16,351	3,908
2043	16,988	4,024
2044	17,556	4,127
2045	18,046	4,217

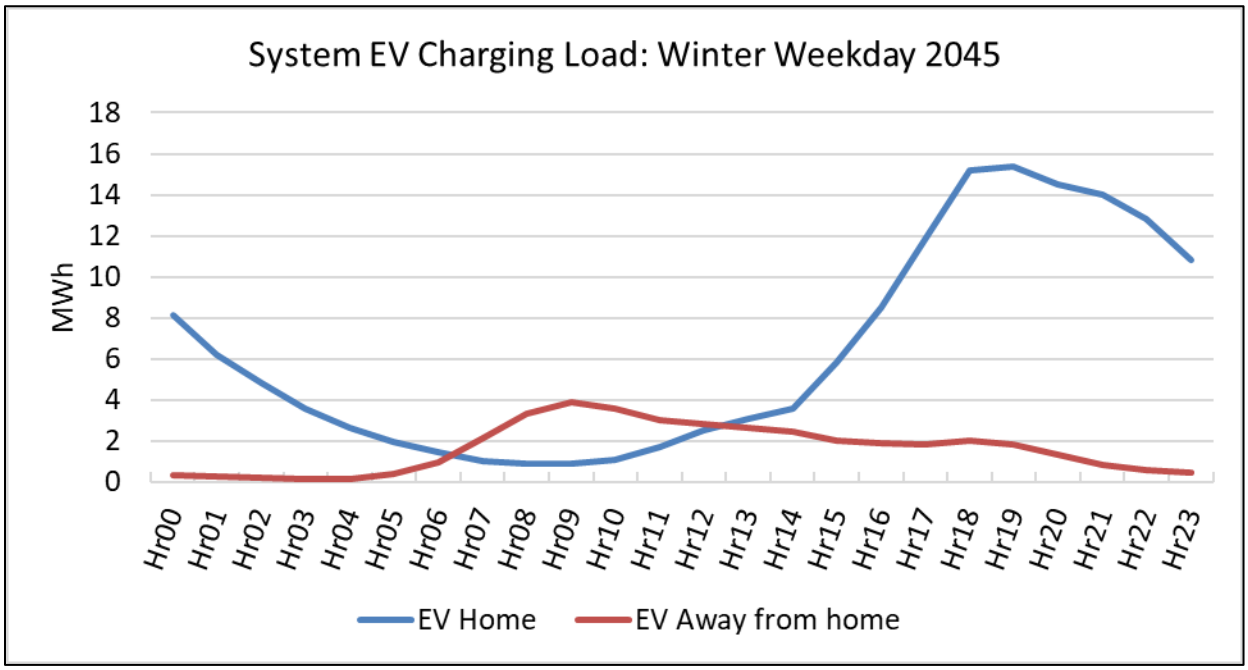
4.2 ELECTRIC VEHICLE ENERGY & LOAD FORECAST

Electric vehicles' impact on CEI South's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. BEVs consume more electricity than PHEVs and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual kWh for the current mix of EVs registered in CEI South's service territory is 2,844 kWh for BEV and 2,092 kWh for PHEV based on annual mileage of 9,500 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since CEI South does not have incentivized BEV/PHEV charging rates, it is assumed the majority of charging will occur at home in the evening hours. We assume 80% of charging will occur at home and 20% away from home

using public or workplace chargers. There is a distinction made for weekend and weekday charging and seasonal variation due to temperature. The charging profiles are derived from the National Renewable Energy Laboratory's EVI-Pro Lite tool. Figure 23 shows a winter weekday total system EV charging load for 2045.

FIGURE 23: EV CHARGING LOAD



The EV load forecast is derived by combining EV energy requirements with the hourly charging load profile. The forecast is only adjusted for the incremental new EVs as of 2025, the impact of the 1,512 EV currently in CEI South's service territory is already accounted for in their sales and load data. Table 4-2 shows the electric vehicle load forecast.

TABLE 4-2: ELECTRIC VEHICLE IMPACT FORECAST

Year	Total Vehicle (MWh)	Summer Peak Impact (MW)	Winter Peak Impact (MW)
2025	1,677	0.1	0.2
2026	3,614	0.2	0.4
2027	5,818	0.4	0.9
2028	8,312	0.4	1.3
2029	11,108	0.5	1.7
2030	14,158	0.7	2.1
2031	17,345	0.8	2.6
2032	20,689	1.0	3.1
2033	24,134	6.4	3.6
2034	27,655	7.4	4.2
2035	31,211	8.3	4.7
2036	34,738	9.2	5.2
2037	38,334	10.2	5.8
2038	41,858	11.2	6.3
2039	45,252	12.1	6.8
2040	48,395	12.9	7.3
2041	50,930	13.6	7.7
2042	53,315	14.2	10.8
2043	55,471	14.8	11.3
2044	57,396	15.3	11.6
2045	59,058	15.7	12.0

5 FORECAST ASSUMPTIONS

5.1 WEATHER DATA

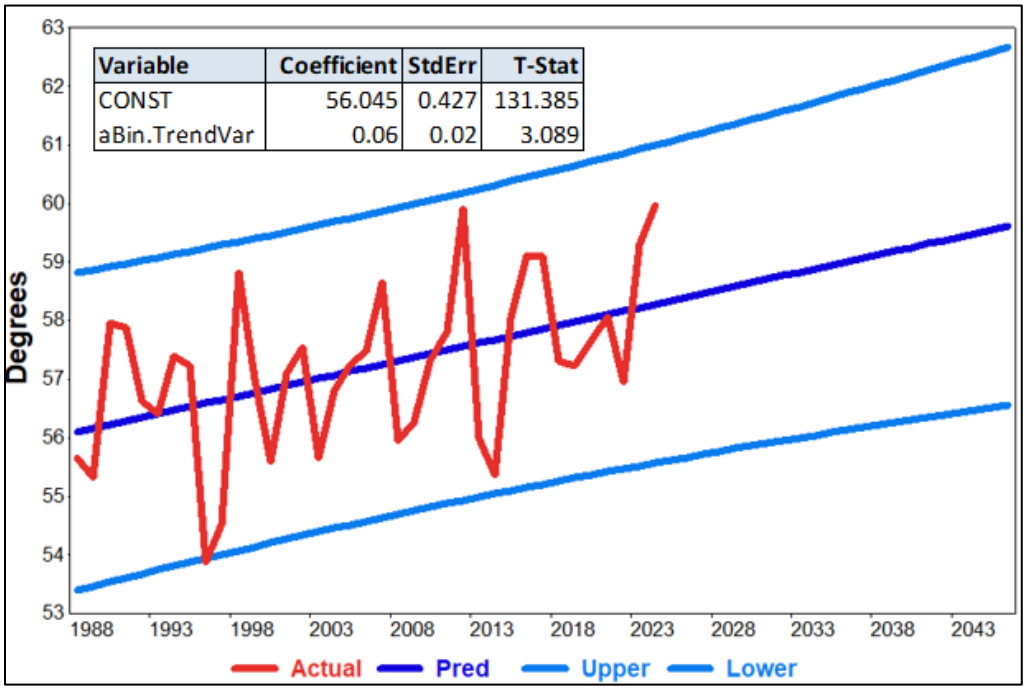
Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport. HDD and CDD are often referred to as spline variables as they either take on a positive value or are 0. HDD are positive when temperatures are below a specified temperature reference point and are 0 when temperatures are at or above the temperature reference point. CDD are positive when temperatures are above a temperature reference point and are 0 when temperatures are at or below the temperature reference point. The best temperature breakpoints in terms of statistical model fit varies by customer class. Commercial heating and cooling generally start at lower temperature points than residential.

Temperature breakpoints are evaluated as part of the model estimation process. For the residential rate classes, the best temperature breakpoints are 60 degrees for HDD and 65 degrees for CDD. In the non-residential classes, HDD with a 60-degree reference point and CDD with a 60-degree reference point improve the overall model fit.

Traditionally, utilities base their long-term forecast on what the industry calls normal weather. Normal weather is calculated by averaging historical weather usually over a 20-year or 30-year period. Given the large variation in month-to-month and year-over-year weather conditions, it seemed reasonable to assume that the best representation of current and forecast weather is an average of the past.

Recent studies that Itron and others have conducted have shown that this is probably not the best assumption; over the last fifty years, average temperatures have been increasing. In reviewing historical Evansville weather data, we found a statistically significant positive, but slow, increase in average temperature. Figure 24 shows long-term Evansville temperature trend, and 90% confidence interval.

FIGURE 24: EVANSVILLE TEMPERATURE TRENDS



Since 1988, average annual temperatures have been increasing 0.06 degrees per year, or 0.6 degrees per decade. The trend coefficient is highly statistically significant, indicating a high probability of increasing temperatures. This results in HDDs decreasing 0.4% per year while CDDs are increasing 0.5% per year. These trends are incorporated into the forecast. Starting normal HDD are allowed to decrease 0.4% over the forecast period while CDD increase 0.4% per year. Figure 25 and Figure 26 show historical and forecasted monthly HDD and CDD.

FIGURE 25: HEATING DEGREE DAYS

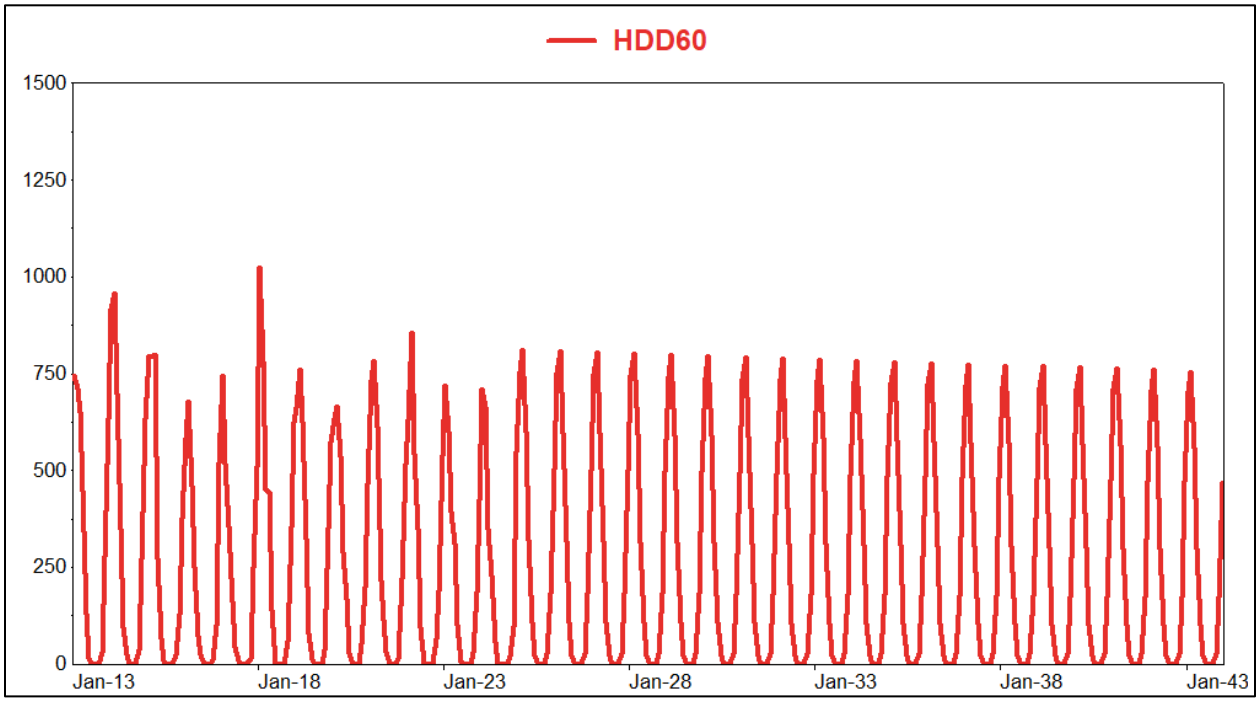
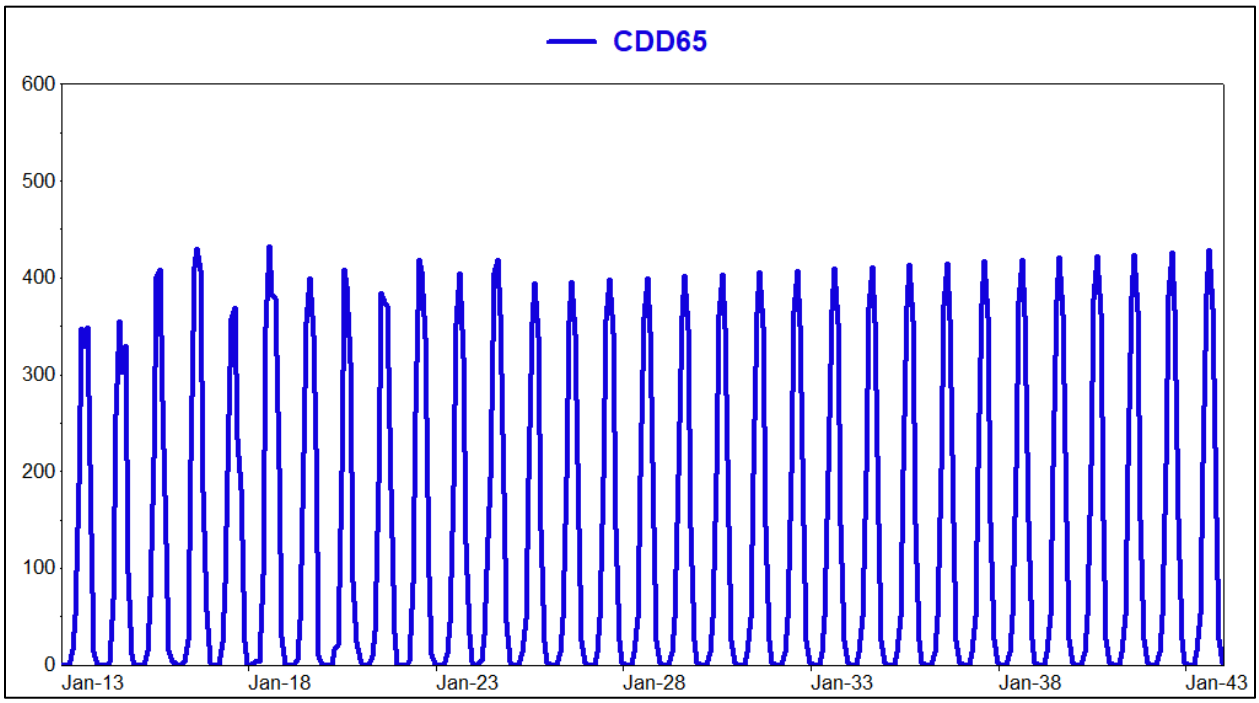


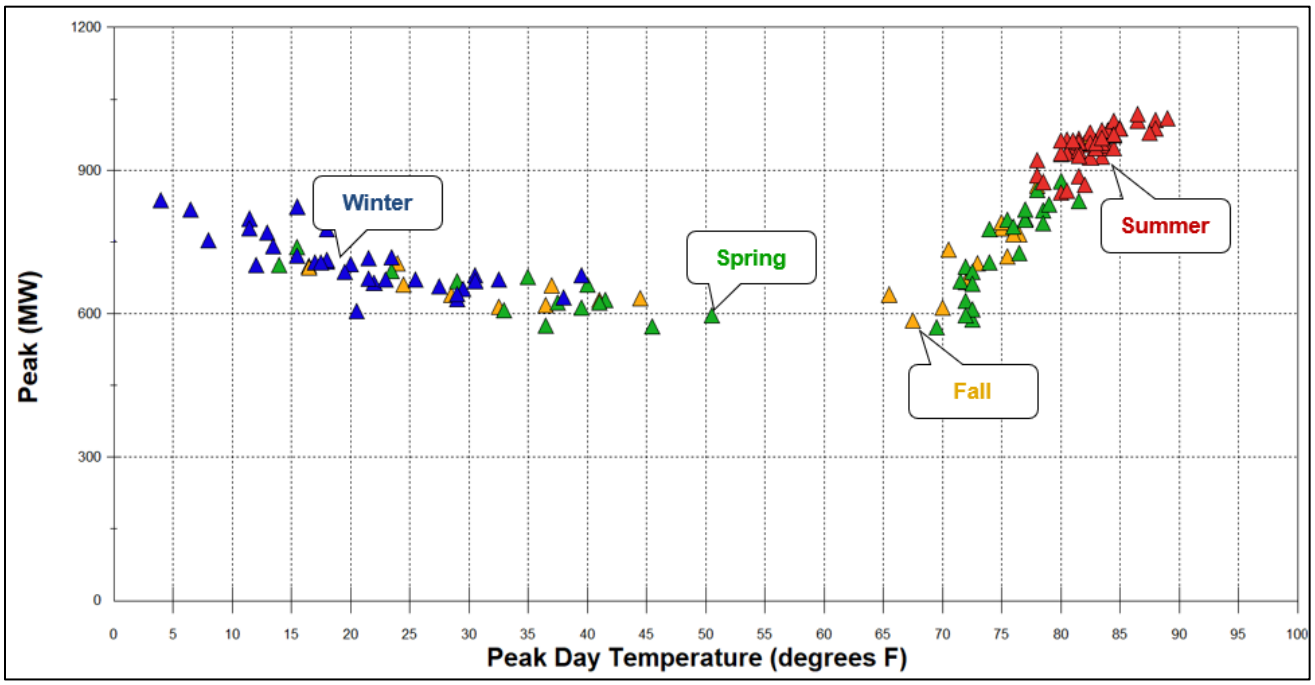
FIGURE 26: COOLING DEGREE DAYS



Peak-Day Weather Variables

Peak-day CDD and HDD are used in forecasting system peak demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature, as shown in Figure 27.

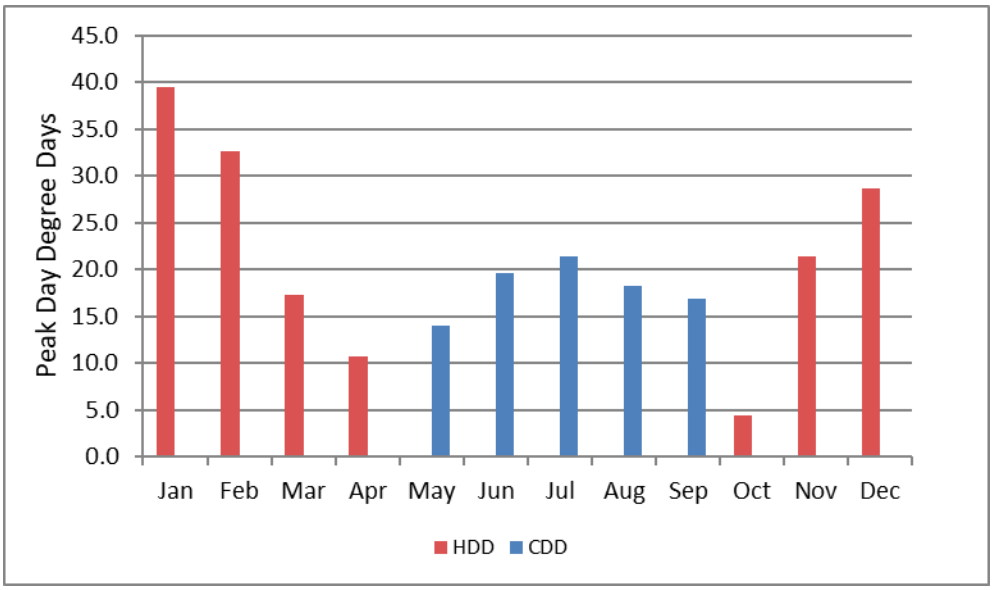
FIGURE 27: MONTHLY PEAK DEMAND /TEMPERATURE RELATIONSHIP



Peak-day cooling occurs when temperatures are above 65 degrees, and peak-day heating occurs when temperatures are below 55 degrees.

Normal peak-day HDD and CDD are calculated using 20 years of historical weather data, based on a rank and average approach, these are not trended. The underlying rate class sales models incorporate trended normal weather; derived heating and cooling sales from these models are an input into the peak model. Using a trended peak weather would double count the impact of increasing temperatures. Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. Figure 28 shows the normal peak-day HDD and CDD values used in the forecast.

FIGURE 28: NORMAL PEAK-DAY HDD & CDD



5.2 ECONOMIC DATA

The class sales forecasts are based on *S&P Global* December 2024 economic forecast for the Evansville Metropolitan Statistical Area (MSA) and Indiana. The primary economic drivers in the residential sector are household income and Indiana state population. Population is stable with consistently increasing growth through the forecast period with 0.2% average annual growth, while household growth is flat towards the later years of the forecast period. Real household income growth is modest, averaging 1.8% over the forecast period.

Commercial sales are driven by nonmanufacturing output, nonmanufacturing employment, and population. Non-manufacturing output is forecasted to grow at 1.5% per year through the forecast period with non-manufacturing employment growing 0.3% per year and population about 0.2% per year.

The industrial model relates sales to manufacturing output and employment. Manufacturing output is projected to increase more rapidly than non-manufacturing output, with output increasing 1.7% per year. While output increases, associated manufacturing employment is projected to decline at a 0.6% annual rate.

Table 5-1 through Table 5-3 shows economic forecasts applicable to each customer class.

TABLE 5-1: RESIDENTIAL ECONOMIC DRIVERS

Year	Population (Thou)		Households (Thou)		Household Income (Thou $)	
2025	6,938.2		132.8		144.0	
2026	6,957.4	0.3%	132.9	0.1%	146.6	1.8%
2027	6,976.1	0.3%	132.9	0.0%	150.0	2.4%
2028	6,994.5	0.3%	132.9	0.0%	153.7	2.4%
2029	7,013.3	0.3%	133.1	0.2%	156.5	1.8%
2030	7,033.1	0.3%	133.5	0.3%	159.1	1.7%
2031	7,052.0	0.3%	133.9	0.3%	161.7	1.6%
2032	7,069.8	0.3%	134.2	0.2%	164.1	1.5%
2033	7,086.8	0.2%	134.5	0.2%	166.7	1.6%
2034	7,102.6	0.2%	134.8	0.2%	169.4	1.6%
2035	7,117.3	0.2%	134.9	0.1%	172.2	1.7%
2036	7,130.9	0.2%	135.0	0.1%	175.2	1.8%
2037	7,143.2	0.2%	135.1	0.0%	178.3	1.7%
2038	7,154.3	0.2%	135.2	0.1%	181.2	1.6%
2039	7,164.2	0.1%	135.3	0.1%	184.2	1.7%
2040	7,173.1	0.1%	135.4	0.0%	187.3	1.7%
2041	7,180.9	0.1%	135.4	0.0%	190.5	1.7%
2042	7,187.6	0.1%	135.4	0.0%	193.8	1.7%
2043	7,193.4	0.1%	135.4	0.0%	197.2	1.8%
2044	7,198.3	0.1%	135.4	0.0%	200.7	1.8%
2045	7,202.5	0.1%	135.4	0.0%	204.3	1.8%
25-45		0.2%		0.1%		1.8%

TABLE 5-2: COMMERCIAL ECONOMIC DRIVERS

Year	Non-Manufacturing GDP (Mil $)		Non-Manufacturing Employment (Thou)		Population (Thou)	
2025	306,401		2,796		6,938	
2026	313,300	2.3%	2,801	0.2%	6,957	0.3%
2027	320,064	2.2%	2,806	0.2%	6,976	0.3%
2028	327,000	2.2%	2,814	0.3%	6,994	0.3%
2029	332,513	1.7%	2,826	0.4%	7,013	0.3%
2030	337,321	1.4%	2,839	0.5%	7,033	0.3%
2031	341,756	1.3%	2,846	0.3%	7,052	0.3%
2032	346,290	1.3%	2,851	0.2%	7,070	0.3%
2033	351,532	1.5%	2,856	0.2%	7,087	0.2%
2034	357,005	1.6%	2,862	0.2%	7,103	0.2%
2035	362,261	1.5%	2,867	0.1%	7,117	0.2%
2036	366,714	1.2%	2,873	0.2%	7,131	0.2%
2037	370,982	1.2%	2,881	0.3%	7,143	0.2%
2038	375,367	1.2%	2,891	0.3%	7,154	0.2%
2039	379,834	1.2%	2,900	0.3%	7,164	0.1%
2040	384,765	1.3%	2,910	0.4%	7,173	0.1%
2041	389,489	1.2%	2,918	0.3%	7,181	0.1%
2042	394,784	1.4%	2,926	0.3%	7,188	0.1%
2043	400,069	1.3%	2,933	0.2%	7,193	0.1%
2044	405,384	1.3%	2,942	0.3%	7,198	0.1%
2045	410,962	1.4%	2,951	0.3%	7,203	0.1%
25-45		1.5%		0.3%		0.2%

TABLE 5-3: INDUSTRIAL ECONOMIC DRIVERS

Year	Manufacturing GDP (Mil $)		Manufacturing Employment (Thou)	
2025	120,921		529.6	
2026	121,647	0.6%	525.9	-0.7%
2027	122,381	0.6%	518.0	-1.5%
2028	123,116	0.6%	509.5	-1.6%
2029	124,875	1.4%	505.7	-0.7%
2030	126,845	1.6%	503.9	-0.4%
2031	128,868	1.6%	501.1	-0.6%
2032	130,787	1.5%	496.4	-0.9%
2033	132,454	1.3%	488.2	-1.7%
2034	134,297	1.4%	480.2	-1.6%
2035	136,922	2.0%	476.9	-0.7%
2036	140,314	2.5%	478.2	0.3%
2037	143,669	2.4%	479.9	0.4%
2038	147,074	2.4%	480.8	0.2%
2039	150,563	2.4%	481.5	0.1%
2040	153,865	2.2%	481.3	0.0%
2041	157,007	2.0%	479.7	-0.3%
2042	159,878	1.8%	477.8	-0.4%
2043	162,837	1.9%	475.1	-0.6%
2044	165,864	1.9%	472.8	-0.5%
2045	169,217	2.0%	472.3	-0.1%
25-45		1.7%		-0.6%

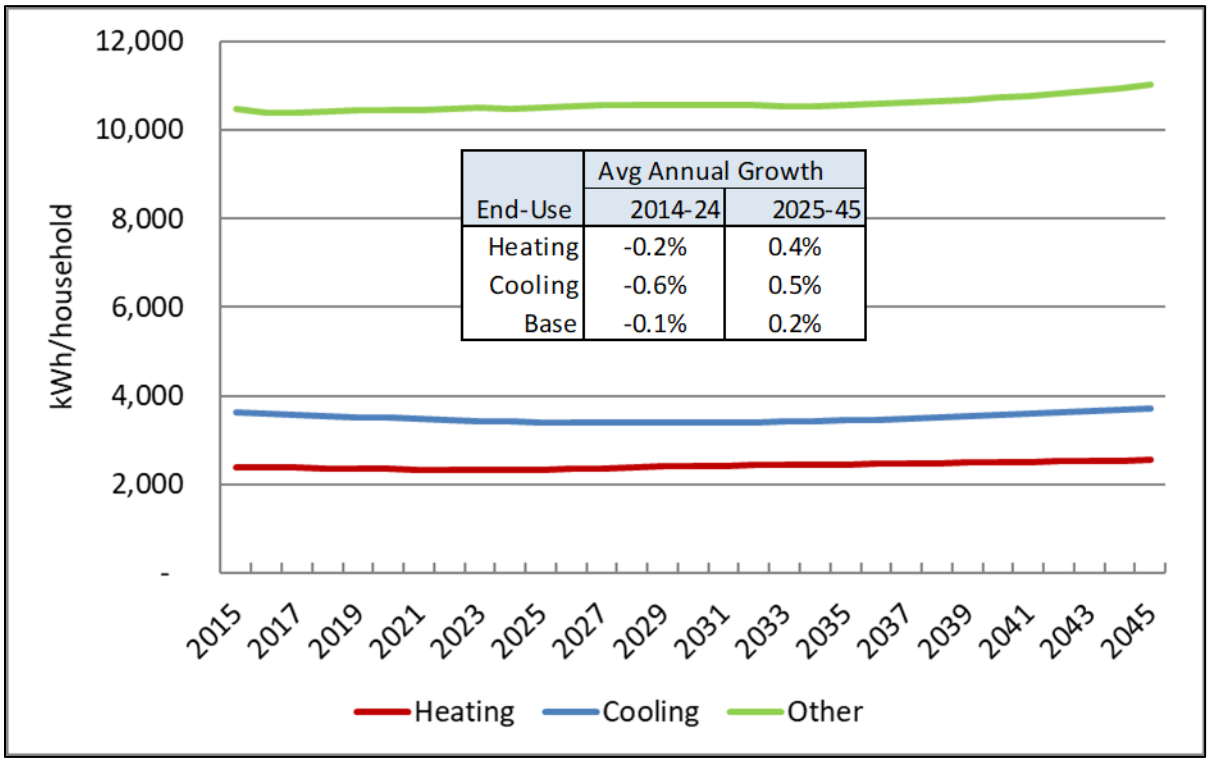
Historical electric prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars. Prices impact residential and commercial sales through imposed short-term price elasticities. Short-term price elasticities are small; residential and commercial price elasticities are set at -0.10. Price is not an input to the industrial sales model. Price projections are based on the Energy Information Administration's (EIA) Short-term Energy Outlook and Annual Energy Outlook. Over the forecast period, residential and commercial prices are flat in real dollars.

5.3 APPLIANCE SATURATION & EFFICIENCY TRENDS

Over the long-term, changes in end-use saturation and stock efficiency impact class sales, system energy, and peak demand. End-use energy intensities, expressed in kWh per household for the residential sector and kWh per square foot for the commercial sectors, are incorporated into the constructed forecast model variables. Energy intensities reflect both change in ownership (saturation) and average stock efficiency. In general, efficiency is improving faster than end-use saturation resulting in declining end-use energy use. Energy intensities are derived from Energy Information Administration's (EIA) 2023 Annual Energy Outlook and CEI South's appliance saturation surveys. The EIA did not release a 2024 Annual Energy Outlook, EIA used 2024 to rework and update their National Energy Modeling System, the tool used to generate the Annual Energy Outlook. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types.

Residential end-use intensities are used in constructing the model end-use variables. Figure 29 shows the resulting aggregated end-use intensity projections.

FIGURE 29: RESIDENTIAL END-USE ENERGY INTENSITIES

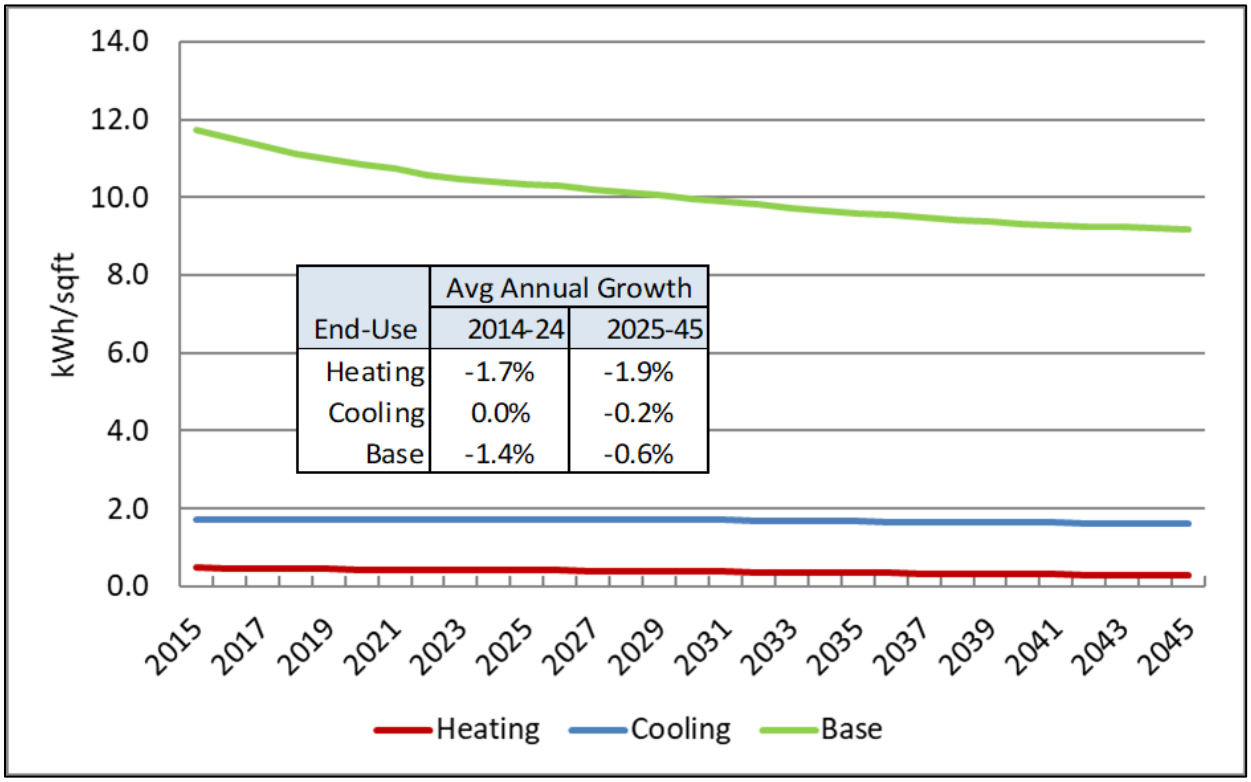


Heating intensity increases 0.3% annually through the forecast period, reflecting an increasing share in heat-pump saturation. Cooling intensity increases 1.2% annually through the forecast period as overall air

conditioning efficiency improvements are offset by increased growth in heat-pump saturation. Total non-weather sensitive end-use intensity increases 0.6% annually.

Commercial end-use intensities (expressed in kWh per sqft) are based on the EIA's East South Central Census Division forecast; the starting intensity estimates are calibrated to CEI South commercial sales. As in the residential sector, end-use energy use has been declining as a result of new codes and standards and utility DSM programs. Figure 30 shows commercial end-use energy intensity forecasts for total heating, cooling, and non-weather sensitive loads.

FIGURE 30: COMMERCIAL END-USE ENERGY INTENSITY



End-Use	Avg Annual Growth 2014-24	2025-45
Heating	-1.7%	-1.9%
Cooling	0.0%	-0.2%
Base	-1.4%	-0.6%

Commercial usage is dominated by non-weather sensitive (Base) end-uses, which over the forecast period are projected to decline 0.1% per year. Cooling intensity increases 0.8% annually through the forecast period. Heating intensity declines at 1.6% annual rate though commercial electric heating is relatively small.

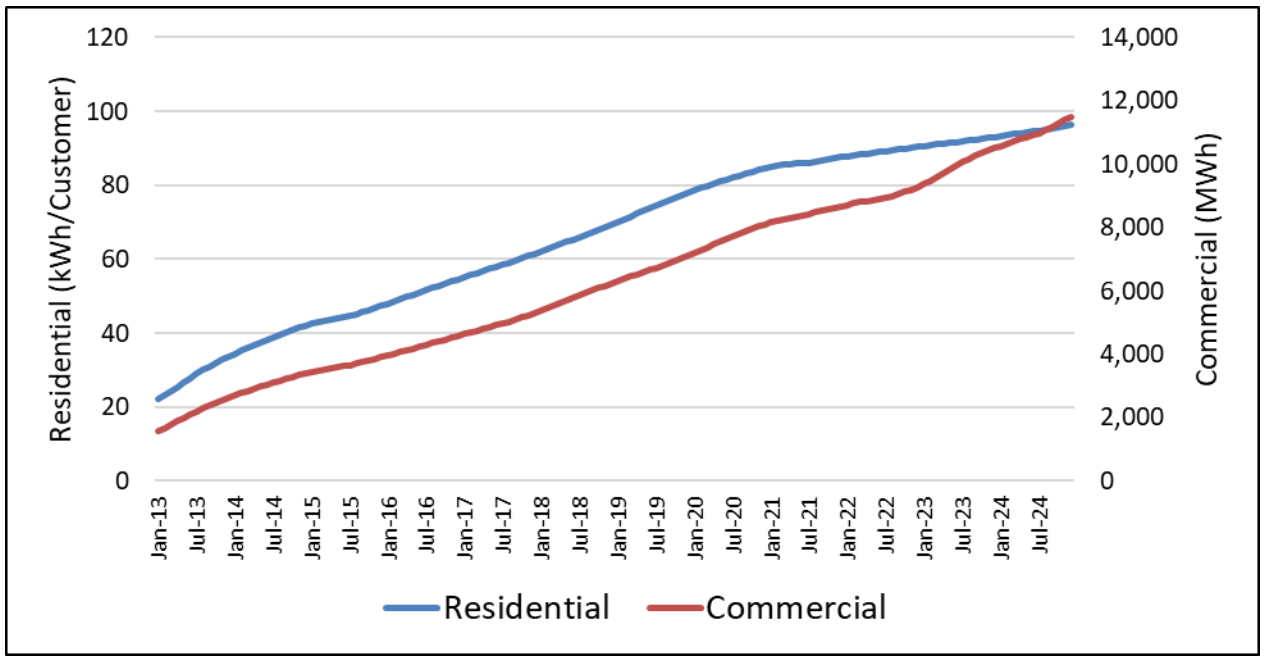
5.4 HISTORICAL DSM SAVINGS

For more than ten years CEI South has promoted energy efficiency savings through utility sponsored programs. These programs have had a significant impact on electricity usage across nearly all customer

classes. The DSM program savings are above and beyond naturally occurring savings, and impact of federal codes and standards.

The residential and commercial models incorporate historical DSM to account for historical program savings. The DSM variables help explain historical usage trends. In the forecast period DSM are held constant, as incremental program savings are modeled on a consistent and comparable basis as supply-side resources in the IRP modeling framework. The DSM variables are based on annual verified DSM savings that are converted to a monthly series. In the residential average use models, DSM is expressed as savings per customer. Figure 31 shows the cumulative DSM saving for the residential and commercial classes.

FIGURE 31: HISTORICAL DSM



6 SCENARIO FORECASTS

6.1 ALTERNATIVE SCENARIO FORECASTS

Three alternative scenario load forecasts were developed as part of the IRP; they include a Low Regulatory, High Regulatory, and High Regulatory with Electrification forecast. These forecasts are developed by altering the model inputs such as the EV/PV forecasts, economics, and end-use saturations and efficiencies.

The Low Regulatory forecast results in a higher load forecast driven by a stronger economic forecast and lower solar forecast. The stronger economic forecast is based on S&P Global's optimistic outlook which assumes economic policy will moderate inflation and increase economic growth. The S&P scenarios are noticeably different through 2028, after which point the forecasts begin to revert to the reference forecast. Due to this issue, alternative economic drivers were created which rely on the S&P scenarios through 2028 but are then based on the standard deviation of the historical growth of the concept. The lower solar forecast is driven by assuming solar installation costs decline at a slower rate compared to the reference case.

The High Regulatory forecast results in a lower load forecast driven by increased efficiency assumptions and weaker economic forecast. Assumes end-use efficiency projections increase by 10%-20% over the forecast period in comparison to the reference case. The weaker economic forecast is based on S&P Global's pessimistic outlook which assumes strict trade and immigration policy will create near-term financial stress, increase inflation, and reduce economic growth. The same issue described above with the optimistic forecast is present with the pessimistic forecast. Due to this, alternative economic drivers were created which rely on the S&P scenarios through 2028 but are then based on the standard deviation of the historical growth of the concept.

The High Regulatory with Electrification forecast results in a higher load forecast driven by increased adoption of electric vehicles and greater miles per year and increased saturation of building electrification such as electric water heaters, clothes dryers, cooking, and heat-pumps for heating. The higher EV forecast is based on an EPA target of the percentage of new vehicle sales which are electric. The forecast assumed 56% of new vehicles sales are electric by 2032. The assumption of annual miles driven increases from 9,500 used in the reference case to 12,000. Table 6-1 shows the summer peak forecast for the reference and scenario forecasts. Table 6-2 shows the winter peak forecast for reference and scenario forecasts. The High Regulatory with Electrification winter peak forecast is significantly higher due to increases in electric heating saturations.

TABLE 6-1: SUMMER PEAK SCENARIO FORECASTS (MW)

Year	Reference Case	Low Regulation	High Regulation	High Regulation Electrification
2025	1,083	1,084	1,082	1,082
2026	1,083	1,087	1,078	1,080
2027	1,088	1,095	1,080	1,085
2028	1,093	1,102	1,083	1,090
2029	1,098	1,110	1,085	1,095
2030	1,104	1,117	1,088	1,102
2031	1,108	1,124	1,090	1,108
2032	1,113	1,131	1,091	1,116
2033	1,115	1,136	1,090	1,122
2034	1,118	1,141	1,089	1,129
2035	1,124	1,149	1,090	1,140
2036	1,133	1,161	1,093	1,155
2037	1,140	1,171	1,095	1,172
2038	1,148	1,181	1,098	1,185
2039	1,155	1,191	1,099	1,197
2040	1,163	1,202	1,102	1,210
2041	1,169	1,211	1,104	1,222
2042	1,177	1,221	1,106	1,234
2043	1,186	1,231	1,109	1,247
2044	1,196	1,243	1,112	1,261
2045	1,204	1,254	1,114	1,274
CAGR	**0.5%**	**0.7%**	**0.1%**	**0.8%**

TABLE 6-2: WINTER PEAK SCENARIO FORECASTS (MW)

Year	Reference Case	Low Regulation	High Regulation	High Regulation Electrification
2025	813	814	813	819
2026	810	814	807	823
2027	811	816	804	830
2028	813	820	804	839
2029	815	823	804	849
2030	817	827	803	862
2031	818	829	802	876
2032	819	832	801	892
2033	818	832	798	907
2034	818	833	796	923
2035	821	838	796	942
2036	826	845	799	965
2037	830	850	800	1,014
2038	834	856	801	1,023
2039	838	862	802	1,033
2040	842	868	803	1,042
2041	846	873	804	1,051
2042	849	878	804	1,059
2043	852	883	804	1,067
2044	857	889	804	1,076
2045	860	894	804	1,084
CAGR	**0.3%**	**0.5%**	**-0.1%**	**1.4%**

6.2 LARGE LOAD SENSITIVITY FORECASTS

In addition to scenario forecasts, Itron developed three large load forecasts. These forecasts assume the additional of a large load such as an industrial customer or data center. It is assumed the load is added in 2030. The forecasts assume a 100MW, 300MW, or 1,000MW load is added, the MWh are based on a 90% load factor. Table 6-3 shows the summer peak forecast for the reference and large load forecasts. Table 6-4 shows the winter peak forecast for the reference and large load forecasts.

TABLE 6-3: SUMMER PEAK LARGE LOAD FORECASTS (MW)

Year	Reference Case	100 MW Adder	300 MW Adder	1000 MW Adder
2025	1,083	1,083	1,083	1,083
2026	1,083	1,083	1,083	1,083
2027	1,088	1,088	1,088	1,088
2028	1,093	1,093	1,093	1,093
2029	1,098	1,098	1,098	1,098
2030	1,104	1,204	1,404	2,104
2031	1,108	1,208	1,409	2,109
2032	1,113	1,213	1,413	2,113
2033	1,115	1,216	1,416	2,116
2034	1,118	1,218	1,418	2,119
2035	1,124	1,224	1,424	2,124
2036	1,133	1,233	1,433	2,133
2037	1,140	1,240	1,440	2,141
2038	1,148	1,248	1,448	2,150
2039	1,155	1,255	1,455	2,158
2040	1,163	1,263	1,463	2,167
2041	1,169	1,270	1,471	2,174
2042	1,177	1,278	1,479	2,183
2043	1,186	1,286	1,487	2,191
2044	1,196	1,297	1,498	2,202
2045	1,204	1,305	1,506	2,210
CAGR	**0.5%**	**0.9%**	**1.7%**	**3.6%**

TABLE 6-4: WINTER PEAK LARGE LOAD FORECASTS (MW)

Year	Reference Case	100 MW Adder	300 MW Adder	1000 MW Adder
2025	813	813	813	813
2026	810	810	810	810
2027	811	811	811	811
2028	813	813	813	813
2029	815	815	815	815
2030	817	917	1,117	1,816
2031	818	918	1,118	1,817
2032	819	919	1,119	1,819
2033	818	917	1,117	1,816
2034	818	917	1,117	1,815
2035	821	921	1,120	1,819
2036	826	926	1,125	1,824
2037	830	930	1,129	1,827
2038	834	934	1,133	1,831
2039	838	938	1,137	1,834
2040	842	942	1,141	1,839
2041	846	945	1,145	1,843
2042	849	949	1,148	1,846
2043	852	952	1,151	1,849
2044	857	956	1,156	1,853
2045	860	960	1,159	1,857
CAGR	**0.3%**	**0.8%**	**1.8%**	**4.2%**

APPENDIX A: MODEL STATISTICS

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRevRes.XHeat	0.974	0.019	50.313	0.00%
mStructRevRes.XCool	0.829	0.011	73.83	0.00%
mStructRevRes.XOther	0.665	0.012	53.484	0.00%
mBin.Jan	17.627	8.759	2.013	4.62%
mBin.Aug	32.501	9.599	3.386	0.09%
mBin.Sep	33.022	8.994	3.671	0.04%
mBin.Oct	32.322	8.176	3.953	0.01%
mBin.Jun14	-92.852	25.605	-3.626	0.04%
mBin.May16	63.834	25.576	2.496	1.38%
mBin.Jun24	306.098	25.571	11.97	0.00%
mDSMFcst.ResDSM_Const	-1.331	0.113	-11.827	0.00%
COVID.ResIdx	36.155	15.516	2.33	2.13%

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	132
R-Squared	0.987
Adjusted R-Squared	0.986
AIC	6.522
BIC	6.769
Model Sum of Squares	6,163,138.05
Sum of Squared Errors	82,855.96
Mean Squared Error	627.7
Std. Error of Regression	25.05
Mean Abs. Dev. (MAD)	18.24
Mean Abs. % Err. (MAPE)	1.97%
Durbin-Watson Statistic	1.732

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ.Pop_State	19.005	0.016	1224.144	0.00%
mBin.Dec24_Plus	1794.078	654.803	2.74	0.69%
MA(1)	0.954	0.026	36.768	0.00%

Model Statistics	
Iterations	14
Adjusted Observations	144
Deg. of Freedom for Error	141
R-Squared	0.957
Adjusted R-Squared	0.956
AIC	12.979
BIC	13.04
Model Sum of Squares	1,323,915,737.88
Sum of Squared Errors	59,815,062.62
Mean Squared Error	424,220.30
Std. Error of Regression	651.32
Mean Abs. Dev. (MAD)	552.6
Mean Abs. % Err. (MAPE)	0.43%
Durbin-Watson Statistic	0.354

Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRevCom.XHeat	20.149	1.912	10.541	0.00%
mStructRevCom.XCool	14.45	0.421	34.291	0.00%
mStructRevCom.XOther	1.184	0.015	78.08	0.00%
mBin.Feb	5501.195	996.639	5.52	0.00%
mBin.Jun	-6081.859	980.037	-6.206	0.00%
mBin.Oct	4395.005	928.708	4.732	0.00%
mBin.Nov	3723.698	946.558	3.934	0.01%
mBin.Jun14	-8244.82	2968.228	-2.778	0.63%
mBin.Jul19	-11803.208	2870.276	-4.112	0.01%
mBin.Jun24	29574.321	3014.105	9.812	0.00%
mBin.Jul24	-13889.021	2925.496	-4.748	0.00%
mDSMFcst.ComDSM_Const	-1.015	0.145	-6.977	0.00%
COVID.ComIdx	-6447.324	1782.206	-3.618	0.04%
mBin.Yr23Plus	-4296.832	1066.432	-4.029	0.01%

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	130
R-Squared	0.963
Adjusted R-Squared	0.959
AIC	15.977
BIC	16.265
Model Sum of Squares	26,827,868,546.33
Sum of Squared Errors	1,029,089,628.15
Mean Squared Error	7,916,074.06
Std. Error of Regression	2,813.55
Mean Abs. Dev. (MAD)	2,114.49
Mean Abs. % Err. (MAPE)	2.09%
Durbin-Watson Statistic	1.834

Industrial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	68605.032	20657.529	3.321	0.12%
mEcon.IndVar	75475.565	19463.62	3.878	0.02%
mWthrRev.CDD65	72.656	8.172	8.891	0.00%
mBin.Feb	5553.919	4320.632	1.285	20.08%
mBin.Mar	-10393.981	4317.628	-2.407	1.74%
mBin.Nov	17471.746	4271.036	4.091	0.01%
mBin.Yr23	-10544.29	4399.548	-2.397	1.79%
COVID.ComIdx	-7191.429	6412.183	-1.122	26.40%

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	136
R-Squared	0.513
Adjusted R-Squared	0.488
AIC	19.062
BIC	19.227
Model Sum of Squares	25,789,462,720.13
Sum of Squared Errors	24,462,182,242.11
Mean Squared Error	179,868,987.07
Std. Error of Regression	13,411.52
Mean Abs. Dev. (MAD)	9,636.21
Mean Abs. % Err. (MAPE)	6.05%
Durbin-Watson Statistic	2.017

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mCPkEndUses.HeatVar	4.038	0.344	11.747	0.00%
mCPkEndUses.CoolVar	19.16	0.584	32.82	0.00%
mCPkEndUses.BaseVar	1.44	0.023	63.593	0.00%
mBin.May	-41.663	11.178	-3.727	0.03%
mBin.Oct	-26.73	11.513	-2.322	2.17%
mBin.Jan16	145.723	35.774	4.073	0.01%
mBin.Apr20	-9345.60%	35.797	-2.611	1.01%
mBin.Apr21	-103.542	35.857	-2.888	0.45%
mBin.Yr23Plus	-22.139	7.914	-2.797	0.59%

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	135
R-Squared	0.935
Adjusted R-Squared	0.932
AIC	7.196
BIC	7.382
Model Sum of Squares	2,454,727.19
Sum of Squared Errors	169,600.24
Mean Squared Error	1,256.30
Std. Error of Regression	35.44
Mean Abs. Dev. (MAD)	27.43
Mean Abs. % Err. (MAPE)	3.61%
Durbin-Watson Statistic	1.66

APPENDIX B: RESIDENTIAL SAE MODELING FRAMEWORK

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the SAE spreadsheets is the 2023 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

RESIDENTIAL STATISTICALLY ADJUSTED END-USE MODELING FRAMEWORK

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left({Sat_y^{Type}} / {Eff_y^{Type}} \right)}{\left({Sat_{base\,yr}^{Type}} / {Eff_{base\,yr}^{Type}} \right)} \quad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{base\ yr} \times SurfaceArea_{base\ yr}} \quad (5)$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \quad (6)$$

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 0-1.

TABLE 0-1: ELECTRIC SPACE HEATING EQUIPMENT WEIGHTS

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps is given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{base\ yr}}\right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}}\right)^{-0.1} \quad (7)$$

Where:

- *HDD* is the number of heating degree days in year (y) and month (m).
- *HHSize* is average household size in a year (y)
- *Income* is average real income per household in year (y)
- *ElecPrice* is the average real price of electricity in month (m) and year (y)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year. The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \quad (8)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_{y}$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left({Sat_y^{Type}} / {Eff_y^{Type}} \right)}{\left({Sat_{base\ yr}^{Type}} / {Eff_{base\ yr}^{Type}} \right)} \quad (9)$$

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 0-2.

TABLE 0-2: SPACE COOLING EQUIPMENT WEIGHTS

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{base\ yr}} \right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}} \right)^{0.25} \times \left(\frac{Income_y}{Income_{base\ yr,m}} \right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}} \right)^{-0.1} \quad (10)$$

Where:

- *CDD* is the number of cooling degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year. The first term, which involves cooling degree days, serves to allocate annual values to months of the

year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (11)$$

The first term on the right-hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{base\ yr}^{Type} \Big/ \frac{1}{UEC_{base\ yr}^{Type}} \right)} \times MoMult_m^{Type} \times \quad (12)$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}}\right)^{0.26} \times \left(\frac{Income_y}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}}\right)^{-0.1} \quad (13)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (14)$$

APPENDIX C: COMMERCIAL SAE MODELING FRAMEWORK

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2023 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

COMMERCIAL STATISTICALLY ADJUSTED END-USE MODEL FRAMEWORK

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \quad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_{m} = a + b_1 \times \mathrm{XHeat}_{m} + b_2 \times \mathrm{XCool}_{m} + b_3 \times \mathrm{XOther}_{m} + \varepsilon_{m} \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\text{XHeat}_{y,m} = \text{HeatIndex}_{y} \times \text{HeatUse}_{y,m} \quad (3)$$

Where:

- *$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),*
- *$HeatInde_{xy}$ is the annual index of heating equipment, and*
- *$HeatUse_{y,m}$ is the monthly usage multiplier.*

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{base\ yr} \times \frac{\left({HeatShare_y}/{Eff_y}\right)}{\left({HeatShare_{base\ yr}}/{Eff_{base\ yr}}\right)} \quad (4)$$

The ratio on the right is equal to 1.0 in the base year. In other years, it will be greater than one if equipment saturation levels are above their base year level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{base\ yr} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{base\ yr}}{\sum_e {kWh}/{Sqft_e}}\right) \quad (5)$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting *$HeatIndex_y$* value in the base year will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{base\ yr}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}}\right)^{-0.10} \quad (6)$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).

- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year. The first term, which involves heating degree days, serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\text{XCool}_{y,m} = \text{CoolIndex}_{y} \times \text{CoolUse}_{y,m} \quad (7)$$

Where:

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{base\ yr} \times \frac{\left(CoolShare_y / Eff_y\right)}{\left(CoolShare_{base\ yr} / Eff_{base\ yr}\right)} \quad (8)$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in the base year. In other years, it will be greater than one if equipment saturation levels are above their base year level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{base\ yr} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{base\ yr}}{\Sigma_e {}^{kWh}/_{Sqft_e}}\right) \quad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in the base year will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{base\ yr}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}}\right)^{-0.15} \quad (10)$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year. The first term, which involves cooling degree days, serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\text{XOther}_{y,m} = \text{OtherIndex}_{y,m} \times \text{OtherUse}_{y,m} \quad (11)$$

The second term on the right-hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{base\ yr}^{Type} \times \left(\frac{Share_{y}^{Type} \Big/ Eff_{y}^{Type}}{Share_{base\ yr}^{Type} \Big/ Eff_{base\ yr}^{Type}} \right) \quad (12)$$

Where:

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{base\ yr}^{Type} = \left(\frac{kWh}{Sqft}\right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e {kWh}/{Sqft_e}} \right) \quad (13)$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end-uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y.m}}{Price_{base\ yr,m}}\right)^{-0.15} \quad (14)$$

Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs

SEE ATTACHMENT: Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs

Attachment 3.3 CEIS 2024 System Hourly Load

Date/Time	Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1/1/2024	455.4	443.4	442.2	429.6	431.5	442	447.6	457.3	457.6	470.2	475.9	491.4	501.1	490.9	492	498.6	496.4	515.8	525	520.5	501.6	495.7	477.7	467.6
1/2/2024	446	445.1	430.2	434.1	445.8	459.8	489.9	520.4	549.7	557.6	568.4	575.6	567.6	567.2	557.4	547.3	556.9	563.7	585.2	588	594.8	592.1	575.6	556.5
1/3/2024	537.6	540.4	531	532.4	534.2	547.4	579.6	610.4	615.7	610.5	584.2	564.2	554	528.7	510.9	524.7	547.5	546.5	578	579.3	582.1	574.3	560.5	534.4
1/4/2024	513.6	504.2	494.8	498.2	499.4	507	534.4	568.7	588.2	563	559.1	549.9	536.8	527.8	518.2	526.6	526.5	552.4	573.6	576.6	586.5	582.9	564.1	543.1
1/5/2024	529.8	521.7	519.2	524.5	538	546.7	564.3	605.6	621.6	614.7	615.5	588.9	572.2	571.6	566.4	571.1	565.4	566.3	572.9	568.6	561	549.3	535.5	506
1/6/2024	488	475.1	471.7	464	460.1	460.5	464.1	471.9	478.8	485.6	504.7	508.1	507.3	509.4	501.9	501.8	492.8	511	526.5	510.8	507.6	493.2	484.4	466.6
1/7/2024	458.4	446.4	431	438.8	434.7	449.3	453.4	469.4	475.5	491.2	488.7	491.2	495.1	508.5	518.9	504.9	516.7	526.8	548.4	541.2	523	518.2	511.8	493.8
1/8/2024	489.7	488.4	470.9	487.5	496.3	518.9	547.2	590.8	602.9	608.7	594.7	584.6	568.8	581	567.6	576.2	580.5	586	598.5	596.3	585.2	584.3	561.1	535.4
1/9/2024	514.4	500.8	483.5	486.1	480.3	497.7	504	540	564.1	571.6	549.6	557.8	557.7	562.5	559.8	561	569.5	584.5	597.1	603	604.5	597.3	581.3	555.5
1/10/2024	548.7	527.3	528.4	525.8	527.6	538.4	566.4	599.4	606.7	610.9	620.6	623.4	613.1	608.3	599.1	576.7	576	585.5	618.4	610.4	619	608	590.1	566.5
1/11/2024	536.6	528.4	517.3	514.3	523.6	523.7	556.9	585.5	589.7	572.1	561.8	550	530.6	520.8	517.6	516.3	526.2	530.3	550.9	541.3	553.6	556	532.2	517.1
1/12/2024	489.1	483.8	480.5	478.5	482.7	488.2	504.5	528.6	547.2	549.8	565.8	550.9	558.9	561.7	557.2	545.4	548.7	547.3	563.7	584.2	587.6	594.7	587.6	583.5
1/13/2024	565.6	599	645.4	640.3	633.6	628.3	638.2	645.3	654	662.7	663.7	646.8	649.3	645.9	634.7	634.7	633.1	635.5	667.5	663.2	656.3	651.9	647.2	637.9
1/14/2024	623.5	630.2	639.6	638.1	658.4	669.3	688.8	709.7	721	720.5	721.1	708.4	706.7	716.4	720.8	731	738.1	754.3	777.5	770.8	755.2	738.1	738.5	725.8
1/15/2024	709.8	708	707.9	701	714.4	720.2	739.3	771.9	779.3	792.3	785.6	785.5	695.2	764	754.6	757.4	759.8	783.3	790.8	787.5	792.2	789.5	768.4	730.7
1/16/2024	722.5	716.9	713.6	712.2	722.8	730.1	760.3	805.4	830.3	834.5	815.2	834	788.8	771.8	765.8	759.8	741.1	731	760.5	762	766.9	759.2	735.6	721.7
1/17/2024	704	696	699.2	696.9	695.8	716.2	702.3	735.9	740.4	724.4	691	689.3	679.5	661.2	639.1	624.4	629.2	644.4	681.9	685.6	680.4	675.3	657.3	626.6
1/18/2024	608.6	594.3	594.4	587.3	601.1	605.3	630.6	665.1	673.3	664.8	661.3	658.2	656.2	627.8	612.9	609.3	615	623.7	638.7	631.6	627.9	618.8	603.2	576.2
1/19/2024	563.8	550.6	553.5	555.3	554.2	573.1	610.4	655.2	680.7	691.4	697.4	687.9	688.5	680.4	693.7	691.1	696.3	685.1	729.8	726.3	734.6	728.2	713	702
1/20/2024	687.6	685.8	680.7	684.8	691.9	701.7	703.7	709.9	712.4	711.3	689.2	686.6	669.7	639.7	626	615.1	624.9	643.3	678.7	683.9	695.4	677.7	669.4	658.8
1/21/2024	648.9	639.8	650.6	645.1	656.5	661	668.7	739.4	691.8	680.7	650.2	624.2	604.7	613.7	600.1	598.2	601.4	598.7	639.2	641.1	627	613.8	603	582.6
1/22/2024	569.3	560.6	558.9	551.8	550.3	563.8	591	626.6	629.6	627.5	641.5	607.1	601.7	634.5	598.4	582.8	588	589.4	589.2	593.1	581.4	578	553.8	531.8
1/23/2024	509.2	492.6	485.5	480.5	489.7	492.8	515.5	552.8	567.9	571.6	569.3	580.9	573.7	564.6	562.2	558.7	551	555	562.3	557.9	548.6	534.9	519.9	484
1/24/2024	485.6	473.8	470.7	469.5	464.7	476.4	496.4	530.5	540.3	532.6	543.9	552.4	541.8	537.3	534.5	527.6	526.7	530.7	548.1	537.4	531.3	527.7	502.6	480.3
1/25/2024	461.2	444.3	434.5	436.2	435.8	447.4	467.5	504.8	523.6	530.6	528.1	537.6	536	533.5	532.3	534	530.6	532.4	543.8	533.8	533.1	520.3	503.1	482
1/26/2024	464.3	453.7	451.5	445.5	440.1	453.5	482.9	512.6	526.6	533.3	535.6	533	531.2	527.3	524	519.4	521.8	525.2	530	527.8	521.5	515.3	499.9	484.3
1/27/2024	455.5	448.8	440.5	437.4	436.4	441.5	451.4	463.7	482.5	497.8	506.8	512.5	515.9	515	513.6	517.2	525.1	523.4	539.2	529.8	529.8	518.8	504.2	492.8
1/28/2024	476.4	471.6	460.1	460.3	458	450.4	462.8	467.6	482.5	490.6	502	515.1	512.4	524.6	524	517.8	525.3	538.2	551.6	544.1	544	532.3	519.6	492.3
1/29/2024	488.1	483.1	482	483	488.4	504.6	536.4	577.6	596.7	605	602.1	601.7	601.9	592.2	583.8	584.4	574	578	599	599.2	611.4	602.1	583	558.6
1/30/2024	542.3	533.2	522.8	526.6	532.2	540.6	565.4	593.2	608.8	601.4	588.7	565.3	567	565	572.6	575.5	574.6	580.5	590.4	583.3	582.8	571.5	551.8	524
1/31/2024	502.7	492.9	486.6	491.5	483.1	503.7	513.4	559.1	564.5	569.5	553.1	558.7	542.6	540.8	534.8	529.6	519.5	525.7	551.9	573.4	567.8	568.5	557.7	535.5
2/1/2024	519	515	514.8	508.3	515.5	522	552.4	588.2	590.6	573.6	552.2	539.5	528.4	513.4	504.8	493.9	513.4	512.8	524.8	514.9	528.2	510.4	499.4	482
2/2/2024	463.5	446.1	452.9	452.6	455	467.3	495.8	530.5	548.6	527.1	524.4	516.1	497.2	493.3	488.9	481.1	484.1	483.3	505	488.5	519.6	505.5	497.2	477
2/3/2024	463.4	452.6	455.6	458.4	453.5	457.8	463.3	476.8	476	479.2	468.1	453.7	448.6	437.7	424.3	419.6	433	442.7	466.3	470.3	474	465.1	451.4	443.6
2/4/2024	421	419.3	413	413.2	407.5	413.1	428.3	441.7	450.7	452.3	450.8	443.9	439.7	437.6	434.5	430.9	440	461	485.6	490	490.5	478.4	463	447.5
2/5/2024	427.3	436.5	432.1	445.5	447.6	465.5	506.8	554.7	560.1	538.1	536.9	519	506.6	507.9	493.2	492.1	489.7	503.5	522.1	530.9	531.9	525.2	514.3	491.9
2/6/2024	474.6	473.3	472.3	476	485.9	494.1	525.9	562.9	565.6	572.3	574.2	567.3	553.8	528.7	513.7	502.1	509.1	509	538.4	554.2	558.4	560.9	549.8	526.3
2/7/2024	508.8	507.1	511.4	517.1	511.3	517.9	548.7	580.7	586.5	581.5	541.3	534.2	518.5	498.5	509	493.3	502.7	507.1	522.6	531.7	531	526.2	509.6	490.5
2/8/2024	476	456.5	460.3	480.3	544.2	542.6	559.5	593.3	601.3	604.3	603.4	594.7	576.2	576.3	526.4	519.1	511.6	515.8	522.7	521.8	521.5	503.3	487.9	464.7
2/9/2024	440.1	436.9	425.7	413.9	421.9	428	451.2	487.9	496.4	505.9	505.1	506.1	505	488.3	490.7	490.5	484.5	480.9	490.7	487.9	484.7	480.1	458	449.5
2/10/2024	421.9	418.9	412.8	399.3	401.9	400.3	408.2	407.6	422.1	441.3	455.6	449	463	462.4	468.7	468	477.3	485.4	495.4	494.7	507.8	485.2	473.3	454.1
2/11/2024	437.9	430.4	432	428.1	417.8	426.1	428.7	449.2	470.3	450.6	443.2	444.3	438.9	429.8	437.1	437.4	441.5	458.2	476.4	467.9	460.7	464.5	452.1	452.4
2/12/2024	437.1	429.3	424.7	429.1	430.7	446.6	487.4	534	545.6	525	511.8	493.6	484.1	487.8	499.6	506.1	514.8	525.4	536	545.9	547	539.3	526.4	498.4
2/13/2024	486	483.3	487.4	490.4	496.1	500.2	536.4	553.1	555.4	537.6	515.6	509.6	489.6	472.9	469.6	457	461.9	486.2	517.6	528	529.2	532.4	519.8	499.6
2/14/2024	479.1	471.9	465.9	465.9	471.6	483.2	506.7	543	542.6	528.8	519.7	505.5	494.1	497.9	490.1	484.7	489.2	491.2	506.3	514.4	514.9	507.7	501	478.3
2/15/2024	462.6	458	459.7	462.9	463.4	465.1	498.6	520.2	530.7	510.6	512.4	506.6	501.9	492.1	489.5	481.1	485.5	490.5	506.3	518.1	520.3	515	504.9	488.4
2/16/2024	475.5	467.5	466.4	469.4	468.6	478.1	504.8	544	554.9	556.7	555.4	561.1	560.4	568.1	562.3	566.2	579.7	580.1	593.8	587.5	589.3	594.7	583	555
2/17/2024	543.1	530.2	530.3	534.2	534.5	542.1	561.9	560.9	576.6	570.2	569.6	566.8	556.2	543.5	528.3	523.1	533	548.3	576.9	605.6	602.2	598	591	566.7
2/18/2024	557.2	544.1	542.5	537.1	546.9	543.2	553.2	553.2	548.3	523.8	501.5	492.5	476.2	464.1	447.4	440.3	446.5	466.4	498.9	515.1	513.4	516.3	504.6	489.9
2/19/2024	481.8	480.2	485.6	501.2	498.7	515.4	554.3	575.4	578.4	556.4	533.5	519.1	494.9	489.8	479.9	476.9	473.9	479.6	501.7	515.5	510.5	512.2	487	480.8
2/20/2024	469.7	462	460.6	460.7	468	478.3	520.9	538	553	532.9	504.4	496.8	483	475.3	471.4	469.8	468.6	477.4	499	514.7	502.1	498.7	488.7	475.1
2/21/2024	456.8	446.6	449.9	446.8	461.4	469.5	500.8	546.1	540.5	535.2	527.5	501.2	491.8	489.1	484.9	488.1	488.3	500.7	510.9	511.1	509.7	498.2	478.8	451.6
2/22/2024	438.2	420.8	417.9	408.2	414.2	425.5	444.6	485	482.2	489.8	500	503.3	506.6	495.2	497.5	501.6	494.9	502	508.5	501.9	502.3	491.3	480.1	459.6
2/23/2024	463.4	432.2	430.5	433.6	439.9	451.6	476.9	504.6	513.9	510.8	501	487.2	482.1	466.2	462.5	460	450.8	464.6	480.9	490.8	494.2	492	483.1	469.2
2/24/2024	440.4	434.4	423.8	423.1	431.3	429.1	437.2	457.3	467.5	485.6	490.4	479.3	459.1	443.4	436	421.4	433	446.3	474	484	491.5	491.2	477.7	466.7
2/25/2024	457.1	453.9	447.7	451.3	442	451.9	457.5	466.3	455.7	444.8	449.3	453.7	428.8	411.6	400.9	398.4	405.1	435.9	456.4	481.9	467.7	457	445.4	426.2
2/26/2024	413.2	412.9	408.1	413.7	420.7	441.5	464.8	510.8	509.9	501.8	506.1	493.8	481.8	487.4	481.4	473.4	480.2	498.3	515.8	531.5	520.6	506.4	490.3	464.4
2/27/2024	442.2	427.1	420.5	421.7	415.4	429.9	448.2	472.1	497.2	507.1	510.3	516.1	520.8	519	525.5	530.4	522.3	518.9	530.4	528.9	532.3	530.5	502	487.4
2/28/2024	462.4	445	441.9	426	412.4	416.9	435.6	479.4	509.5	529.5	536	526.8	545.5	544.5	522.6	514.5	508.6	521.3	550.1	569.7	571.5	569.1	549.9	528.6
2/29/2024	521.9	515.4	515.7	521.8	502.2	515.3	541.8	570.4	574.1	571.4	526.1	508.7	504.1	477.8	458.7	449.5	462.2	465	506.1	514.2	537	530	537.4	521.6
3/1/2024	498.8	496.1	492.2	470.9	484.5	489.8	507.2	550.5	549.6	553.4	553.1	545.9	553.6	543.3	546.6	536.5	530.6	527	528.6	540.4	525.5	506	507	477.4
3/2/2024	453.2	441.6	439.7	420.3	423.4	427.3	436.2	437.3	446.5	454	455.2	448.7	449.6	435	425.4	423.3	426.2	433.2	444.7	458.1	460.2	455.6	443.4	438.4
3/3/2024	424.8	412.8	417.1	402.8	407.3	406	419.2	403.8	463.7	422.4	414.5	410.8	411.8	403.5	399.4	409.9	415.3	445.9	468.3	480	469.1	468.1	436.4	428.3
3/4/2024	398.9	385.2	388.9	388.6	388.2	400	426.4	461.1	479.7	487.7	489.1	496	497.4	514.1	514.5	519.9	515.9	518.4	522.9	525.3	529.4	506.5	485.9	488.3
3/5/2024	436.7	422.9	416.1	410.1	409.6	414.7	432.1	461.6	480.8	493.6	503.7	502.6	510	523.4	515.7	517.5	516.6	519.5	520	524.5	515.8	504.6	478.5	453.8
3/6/2024	421.6	415.5	408.7	402.6	405.9	411.4	432.6	464.9	482.1	495.6	499.5	500.2	512.4	503.3	501.6	503.6	491.8	493.2	503.8	511.3	512.9	493.9	473.7	452.3
3/7/2024	430.4	426.6	418.7	419.9	416.4	426.6	443.9	473.1	495.3	495.2	488.3	496.8	493	498.3	496.8	491.9	482.4	487.2	504.8	513.8	506.8	502.6	481.4	458.7
3/8/2024	437.6	427.5	408.1	422.5	421.8	432.2	452.8	483.2	497.5	491	502.9	510.5	505.1	510.9	508.9	495.2	496.7	494	497.2	496.4	505.8	491.7	470.3	450.5
3/9/2024	422.9	406	405.5	399.2	395.9	395.5	399.7	402.8	414.8	429.9	449.3	447	453.8	446.5	445	447.3	439.2	437.2	446.7	464.9	457.4	454.9	439.7	423.9
3/10/2024	416	406	409.3	403.5	420.4	423.5	433.6	441	439.4	426.1	417.3	414.5	414.2	407.5	405.9	401.5	409.7	421.3	447.4	467.6	474.1	466.9	448.1	439.9
3/11/2024	439.2	436.9	443.8	457.7	471.5	507	558	574.4	553.8	541	520.9	511.2	503.7	532.6	473.6	475.1	473.2	480.2	491.9	512.1	504.4	493.6	470.4	452.3
3/12/2024	447	436.2	446	449.2	460.4	481	519.4	536.4	521.4	506.3	508.3	501.7	514.7	496.2	485.5	485.8	482	493.6	497.8	508.9	505.8	486.1	464.1	442.9
3/13/2024	433.7	430.7	424.1	428.7	428	456.2	498.3	501.9	491	482.1	481	487.9	491.1	501.1	512.5	526.2	536.9	522.4	525.8	538.5	530.4	510.2	478.8	484.2
3/14/2024	443.2	430.3	424	425	430.1	451.3	482.9	491	522.4	527.9	523.1	518.4	529.1	537.3	549.4	542	555.3	548	551.1	570.7	558.2	523.7	471	444.9
3/15/2024	428	419.8	415.8	409	416.6	430.2	464.2	473.8	488.4	489.9	506.3	500.2	495.5	501.5	494.6	485.4	476.7	480.5	472.4	480.3	486.9	458.9	449	432.8
3/16/2024	440.5	418.9	416	421.2	413.9	428.2	445	457.9	455.5	427.4	428.7	398.9	395.9	387	391.3	392.7	408.5	412.6	434.5	458	443.2	427.2	411	387.6
3/17/2024	376.8	375.4	378.7	387.8	386.2	391.8	400.1	406.2	425.3	395.9	406	394.4	392.6	383.9	378.6	384.2	398.3	438.1	456.8	486.6	474.3	456.2	447.6	432.8
3/18/2024	433.8	433.3	436.7	447.3	464.1	466	537.8	548.5	543.5	532	522.6	536.3	541.1	535	524.8	525.2	513.6	517.2	523.7	536.1	523.9	519.3	532	516
3/19/2024	509.5	513	519.8	522.1	508.8	514	547.5	570.5	542	524.5	502.3	533.3	522.5	517.6	495	476.6	463.2	440.2	460.9	481.8	485.1	468.2	448.4	436.1
3/20/2024	460.2	452.4	453.6	457.7	476.2	502.7	547.6	555.2	519	514.3	496	487.8	471.2	478.1	469	470	474.5	444.7	457.2	486.4	489.2	477.7	458.8	446.8
3/21/2024	441.3	435.4	441.6	447.3	472.5	505.2	522.8	542.3	524.3	495.3	481.9	502.9	502.3	500.7	483.9	490.2	471.5	460.4	476.6	507.8	494.7	480.7	461.3	444.1
3/22/2024	434	432.5	430.6	437.9	448.5	480.9	477.1	520.8	518.5	520.4	524.1	535.8	520.1	513.8	503.3	487.5	492.3	488.7	495.6	507.1	512.2	486.2	467.2	442.4
3/23/2024	438.4	430.4	431.9	433.4	435.5	445.2	458.5	460.4	478	475	453.4	444.1	426.7	416.9	412.1	401.8	415.7	422.4	439.1	461.7	462	455.4	441.6	435.5
3/24/2024	422.4	422.3	423.1	421.1	426.3	446.7	453.3	464.2	454.5	458.7	429.3	412.6	410.7	403.8	399.4	380.7	422.8	441.6	453.2	469.6	463.4	453.4	435.5	417.8
3/25/2024	414.9	414.3	412.9	414.2	431.6	462.3	489.8	508.2	518.2	519.1	510.6	518.4	515.4	510.5	508.8	500.9	510.1	503.4	510.8	527.2	511.1	495.2	469.9	459.2
3/26/2024	447	441.6	434.9	437.3	446	460	486.2	511.8	511.7	513.9	514.4	511.4	508.1	509.7	494.8	517.4	471	476	499.4	528.3	497.6	489.5	474.4	455.9
3/27/2024	445.1	448.4	445.9	445.1	459	490.1	514.8	537.5	546.2	538.5	530.7	504	494.6	484.5	471	455	454.1	464	454.8	483.8	493.5	474.3	454.6	434.6
3/28/2024	437.3	434.5	443.2	446.4	467.1	488.6	523.3	527.1	486.9	475.2	459	484.1	466.5	453.3	458.1	452	444	460.2	477.4	507.2	498.6	478.7	464.2	438.1
3/29/2024	435	425	419.6	425.1	432.9	439.2	467.2	472.1	468.4	463.5	455.6	454.8	440.3	441.8	435.4	444.8	441.9	458	463.1	478.6	475.2	463	440.2	418.4
3/30/2024	404.8	394.8	389	384.6	383.2	382.1	391.1	391.8	409.2	402.3	394.3	401.2	399	406.8	413.9	422.8	442.1	459.9	474	482.8	473.3	454.3	433.5	411.4
3/31/2024	393.9	378.3	370.4	359.3	353.8	365.3	371.6	379.8	398.5	406	416.4	427.9	431.1	443	449.8	460	465	477.6	491.8	501.1	497.2	469.5	451.5	427.9
4/1/2024	409.2	404.6	398.7	401.8	415.7	442.5	500.1	504.4	534.2	549.4	560	573.1	586.8	594.5	587.9	589.2	608.9	616	601.7	616.7	601.1	582.7	529.5	502
4/2/2024	483.7	475.5	465.3	458.1	468.3	475.2	364.3	464.1	464.3	477.7	492.7	505.8	527.5	551.5	541.3	536.5	546.2	525.5	507.7	512.8	499.4	479.4	444.8	435.6
4/3/2024	421.4	409.1	407.8	415.1	420.5	459.9	488.5	495.2	511.3	490.3	500.4	486.7	486.9	464.6	480.9	475.3	479.6	503.5	502.5	527.3	524.8	502.9	481.2	454
4/4/2024	455.1	428.7	418.6	435.2	431.5	474.2	486.8	504.1	506.5	534.5	532.3	529.6	524.4	518.7	513.9	496.7	485.6	490.7	497.4	488	497.6	476.7	469.4	451.7
4/5/2024	451.5	440	447.5	450.7	448.3	473.6	515	506.8	501.8	503	492.6	504.4	514.5	518.1	512.6	503.7	498.6	496.4	489.7	506.9	503.1	476.8	460.2	452.4
4/6/2024	448.4	441.7	443.3	449.6	451	463.8	477.7	478.2	443.6	438.8	419.6	410.6	396.6	387.8	375.3	384.4	396.2	405.7	429.5	443.4	443.4	429.3	415.6	413.4
4/7/2024	376.5	375.5	382.5	379.7	387.8	404.6	410.1	408.1	421	412.6	409.6	393.7	384	388.2	388	398.9	435.6	454.4	459.2	473.6	463.2	441.2	424.4	407.3
4/8/2024	393.8	385.9	381.6	387.7	409.8	432.9	454.7	479.9	486.5	495.5	482.7	498	503.5	505.4	479.7	500	495.3	500.7	510.7	543.5	532	498.9	476.9	433.1
4/9/2024	442.4	429.9	429.4	421	427.6	454.3	487.4	512.5	517.8	524.9	537	532.5	539.2	521.7	528.9	527.7	522.6	532.2	530.6	538.9	524	505.3	468.8	444.9
4/10/2024	441.7	436.7	424.2	423.9	436.9	460.7	495.2	506.8	520.6	502.1	507.3	527.8	533.8	534.4	544.7	535	539.1	556.4	541.9	546.6	532.9	508.4	479	464.4
4/11/2024	457.8	447.7	429.2	446.7	446.2	462.2	495.8	509.4	524.3	525.8	549.7	535.8	527.9	532.4	533	519.4	519.6	522.4	517.6	525.1	515	502.8	478.5	442.7
4/12/2024	446	437.6	438.5	435.3	448	474.6	498.5	501	504.7	514.4	524.1	534.2	506.5	494.6	497.8	483	471.7	460.1	467	488.9	499	481.6	461.6	437.3
4/13/2024	431.6	429.9	414.7	419.2	422.2	437.5	442.7	440.7	435.4	434.8	433.6	421.7	422.3	432.9	427.1	436.6	458.8	479.1	493.5	506.2	506.8	489.3	471.9	450.3
4/14/2024	439.6	423.1	421.5	412.6	409.7	395.3	389.2	393.8	388.6	397.6	407.2	418.1	437.8	450	467.6	494.3	511	536.6	550.6	535.7	530.7	503.8	477.7	449.5
4/15/2024	433.3	422.1	407.7	419.7

CEI South 2025 IRP
CEI South 2024 System Hourly Load

Date/Time	Hour																						
5/1/2024	479.7	463.4	457.1	454.8	456.6	468.5	501.4	537.4	551	563.2	643.8	627.5	658.9	674.5	702.4	724.3	712.8	715.3	694.9	674	661.9	619	579.1	534.3
5/2/2024	514.6	497.1	490.9	479.4	481.8	508.4	527.2	560.4	568.9	627.8	655	673.3	693.9	704.6	724.1	733.4	743.1	725.4	710.4	691.8	714.9	655.8	616.5	568.6
5/3/2024	543.7	525.6	507.3	497	502.4	512.4	534.1	558.8	571.8	577.7	593.2	611.3	624.1	636.5	655.9	658.8	649.4	645.7	631.8	624.6	629.7	591.9	552.9	518
5/4/2024	489.3	483.1	471.8	459.3	443.8	445.9	440.9	461.9	486.3	512	541.6	563.6	593.9	609.4	629.9	638	652.5	660.8	639.4	625.1	605.7	561	529.3	480.3
5/5/2024	455.2	436.5	436.1	421.9	421.3	422.5	423.9	442.2	464.4	489.6	504.8	534	562.7	577.3	601.5	616.3	637.1	635.7	627.1	625.1	598	574.2	550.9	510
5/6/2024	479.6	467.4	462	462.8	478.3	506.4	545.2	571	567.5	594.2	641	676.5	673.7	634.7	632.2	627.5	654.1	675.5	660.5	655.1	648.4	615.2	569.6	536.6
5/7/2024	507.7	526.3	501.9	502.7	500.8	521.5	559	597.8	614.5	616.8	618.7	661	655.4	680.9	713.1	730.6	734.3	742.6	737.5	732.8	728.3	697.3	665.6	627.5
5/8/2024	556.6	530.2	526.7	513.4	498.9	513.6	544.8	589.5	614.8	646.6	665.3	704.2	732.6	717.3	747.1	754.1	683.2	654.8	636.2	626.2	609.4	584.8	561.3	535.6
5/9/2024	520.7	508.6	508.9	500.8	510.3	521.5	541	556.3	574.2	585.5	597.4	624.2	648.5	683.9	675.4	677.3	689.4	694.6	667.8	644.5	636.7	588.5	564.4	527.5
5/10/2024	510.6	479.2	470.1	465.3	472.2	492.4	503.3	506.6	529.1	524.1	533.9	543.8	555.9	563.3	577.9	565.6	563.1	570.5	558.3	553.5	553.3	529.9	499	460.4
5/11/2024	451.1	447.9	435.3	427	419	419.1	424.4	429.6	441.9	438.8	443.2	440.5	447.1	451.4	469.6	484.4	505.9	504.6	517	525.4	510.2	488.5	455.7	421.6
5/12/2024	419.1	396.7	398.8	389.8	393.8	384.9	384.6	404.6	417	434.7	452.7	470.8	493.7	506.3	535.6	560.2	580.5	611	603.9	579.7	586.6	548.8	504.3	484.5
5/13/2024	460.9	449.5	441.1	433.7	446.1	471.2	505.3	517.6	562.5	575.3	605.3	615.3	619.5	663.8	679.1	680	684.9	666	630.4	621.2	615.3	587.2	558.8	535.6
5/14/2024	505.2	497.7	494.5	484.4	491.1	508.5	528.7	556.8	566.3	585.5	600.2	600.3	589.6	600.6	592.2	592.9	594	603.4	589.3	584.9	592	585.4	549.9	516.1
5/15/2024	494	496.4	493.2	489.4	487.4	499.3	542.9	559.7	572.6	575.6	588.3	583.5	599.3	590.7	589	588.1	585.7	589.9	583	589.8	594.1	574	543.8	508.5
5/16/2024	499.6	481.6	471	464.6	474.3	498.3	568.5	545.9	573.9	590	612.8	634.1	650	656.8	659.2	669.4	684.1	691	673.5	666.7	652	624.8	569.5	537.9
5/17/2024	511.8	502.3	505.2	485.7	479.1	511.1	537.3	565.7	576.1	578.7	604.1	619.6	643.3	638.3	655.5	665.7	656.8	665.5	650	621.5	617.2	601	562.6	511
5/18/2024	485.7	465.2	446.6	464.3	460.9	459	468.5	494.9	524.2	562.5	591.7	625.4	651	677.1	695.1	711.9	700	703.9	707.3	690	667.3	629.6	590.8	548.4
5/19/2024	523.1	514.3	480.6	471.1	455.2	449.3	443.9	464.6	512.4	544	598.8	627.4	607.9	649.5	675.5	730.6	720	745.5	749.8	720	684.2	654.8	620.2	564.9
5/20/2024	539.8	509.5	510.9	511.8	504.9	521.7	569.5	602.5	639.3	688.7	714.9	747.3	735.4	750.4	766.6	780.3	783.2	766.1	776.4	758.8	752.4	717.4	670.3	623.2
5/21/2024	594.5	563.6	542.9	540.8	544	553.5	581.5	623.8	687.2	700.6	710.4	766.5	817.4	798.3	814.8	816.3	810.7	810.1	798.5	799.6	766	737.6	697.5	652.7
5/22/2024	617.9	602.3	568.8	570.5	560.8	565.5	604.6	638.7	639.8	674.9	707.4	749.3	763.4	762	788.4	785.8	806.4	759.8	720.1	694.4	679.3	656.9	614.5	571.7
5/23/2024	554.9	542.3	526	512.4	521.7	553.8	571.3	579.7	602.6	621.2	645.7	656.1	673.6	659.3	649.8	645.3	628.3	632.7	635.8	632.9	633.8	611.7	566.2	530.9
5/24/2024	512.9	502.8	495.5	490	495.4	505.2	529.6	563	601.8	653.9	675.2	681.2	668.1	675.1	653.1	667.9	699.1	701.9	685.8	672.3	664.8	636.5	586.2	543
5/25/2024	521.2	504	474.2	472.2	458.8	449.4	442.4	460.8	504.6	550.9	564.3	583.3	591.3	602.4	608.7	644.2	667.7	664.7	669.3	638.9	613.4	594.1	547.2	506.7
5/26/2024	491	476.5	475.9	472.2	469.9	471.6	468.2	485.3	502.9	531.4	522.5	525.5	505.9	503.5	521.8	567.1	605.3	619.2	600.4	610.4	568.4	520.2	475.9	472
5/27/2024	425.5	422.3	428.4	422.6	440.9	434.4	423.7	438.2	475.1	490.6	533.5	540.7	562.6	582.8	583.7	598.7	625.9	647.5	647.6	635	616.6	588.1	530.7	497.7
5/28/2024	482.6	464.7	453	447	468.3	481.9	511.8	553.1	595.5	564.3	654.3	659.5	687.4	716.1	713.8	721.2	728	728.5	720.3	698.4	679.5	643	599.4	539.5
5/29/2024	522.8	504.6	504	488.8	502.5	497.4	511.3	540.2	561.4	577.1	590.1	606.9	633.1	640.1	649.8	662.5	662.6	665.3	654.4	636.8	625.1	592.4	544.2	505.5
5/30/2024	483.2	472.6	461.9	466.8	470.5	477.3	497.5	552.5	552.9	581.5	597.1	620.2	641.7	673.1	683.6	689.2	698.8	691.2	677.9	666.2	645.6	617.2	567.8	530.8
5/31/2024	502.5	496	479.1	471	472.7	493.6	501.8	526.1	547.9	572.5	587.3	607.7	635.3	654.8	669.7	698.1	686.9	676.4	655.6	646.2	643	620	606.7	546.4
6/1/2024	524.6	512.4	492	487.3	472.1	473.1	472.9	487.4	494.9	516.5	534.5	552	541	551.6	530.1	512.2	543.7	553.1	534.4	533.5	528.5	519.6	500.2	487.4
6/2/2024	467.8	468.4	454.7	458.4	438	458.4	452.5	467.1	490.3	505.6	531.5	550.8	573.9	605.5	624.6	636.3	663.2	675.2	678.7	651.6	634.1	608.1	573.9	530.8
6/3/2024	514.8	492.4	482.5	476.8	493.1	522.6	546.6	582.1	617.1	644.9	694.3	705.5	773.5	787.7	799.4	807.6	811.2	829.6	811.1	809	774.5	732.2	679.5	631.2
6/4/2024	589.9	574	545.5	543.6	523.6	542.8	567.6	608.7	607.6	626.4	655.2	670.6	697.4	723.8	757.9	788.3	793.6	780.6	776.1	759.8	752.1	731.1	677.5	634.5
6/5/2024	596.5	582	565	548.6	541.7	558.7	591.1	622.4	658.6	689.4	700.3	731.1	738.2	738.4	761.8	777.5	746.4	730.7	715.5	697.6	704.1	687.8	640.1	601.7
6/6/2024	574.8	560.4	530	518.9	527.4	531.7	552.3	593.1	620.9	668.6	704	738.2	757.4	789.6	795.7	811.6	824.5	803.2	789.4	749.2	700	662.8	618.3	571.4
6/7/2024	528.9	511.5	499.8	497	509.1	515.9	533.6	570.9	580.5	608.5	645.5	664.2	683.8	705.9	725.9	738.9	756.8	763	745.1	741.1	699.2	646.3	609.5	550
6/8/2024	520.9	502.4	492.5	482.1	489.6	465.1	457.6	482.8	496.9	508.8	519.4	527.9	536.8	543.9	546.9	553.9	563.5	598.9	616.6	626.4	619.5	592.4	572.9	545.9
6/9/2024	521.8	500.7	494.9	466.4	475.8	477	471	461	498.5	499.3	507.6	521.9	523.9	541.6	555.3	564.9	587.8	603.5	621.2	603.3	582.5	564.1	531.2	503.1
6/10/2024	482.1	475.5	469	458	462.1	477.2	522.7	543.3	566.4	588.4	620.2	637.4	675	660.4	675.3	684.5	670.6	679.3	654.2	640.7	631.9	600.6	575.6	536
6/11/2024	513.3	495	482.5	482.2	479.5	485.8	493.3	525.1	543.4	563.9	575.5	598.9	612.8	641.4	656.4	670.2	699.6	703.1	705.2	683.9	662.5	624.3	567.6	544.3
6/12/2024	531	511.9	506.1	481.4	488.3	482.7	520.8	548.5	564.5	593.2	618.7	635	675.1	697	719.4	762.2	766	782.6	780.7	740.9	726.2	691.5	625.4	574.9
6/13/2024	545.3	515.5	503.1	495	496.9	489.4	518.9	561.8	597.1	640.8	679.1	720.7	752.1	796.1	822.2	850.1	863.6	854.4	841.2	814.5	787.5	749.2	681.3	630.1
6/14/2024	600.3	583.3	577.8	550.9	546.7	560.2	570	604.7	641.3	695.4	736.3	787.9	837.7	877.3	892.6	918.4	924.1	912.7	905.4	872.5	833.5	787.1	714.3	660.2
6/15/2024	621.3	577.5	536.3	527.3	513	496	497.5	522.6	567.3	610	661.5	718.1	763.4	758.9	799.3	814.1	833.3	827.8	806.5	786	755.5	710	667.1	606.9
6/16/2024	571.9	548.5	512.3	481.6	470.1	457.5	470.8	489	547.2	588.4	658.5	720.5	786.8	841	861.5	878.3	899	892.7	867.1	841.5	824.8	810.9	743	713.7
6/17/2024	667.3	630.5	597.6	591.6	594.1	598.4	639.5	696.2	752	800.7	868.8	898.1	938.7	952.8	960.1	972.8	930.6	941.5	912.5	882.5	852.3	805	746.2	707.3
6/18/2024	671.8	639.8	631.6	604.2	590.3	614.8	617.1	678.9	680.7	707.7	750.8	776	828.2	868.9	880	818.6	791.8	784.8	757.3	757.4	753.2	741.2	690.7	655.3
6/19/2024	628.7	603.4	590.6	582.6	597.8	602.9	629.3	649.5	694.1	707.9	771	797.4	827.3	865.3	899.7	902.5	915.2	895.1	871.7	862.4	879	793.8	741.2	679.8
6/20/2024	650	623.4	601.8	587.3	575.2	574.9	614.8	666.2	712.6	753	801.8	835.9	874.2	897.4	920.9	925.6	900	932.7	917.4	872	853.8	819.7	759	691.7
6/21/2024	653.6	619.5	598.9	596.4	581.2	583.1	608.8	667.9	709	766.1	820	860.9	893.1	920.7	928.8	935.6	943.4	935.6	923.8	892.1	846.7	817.5	748.5	687.6
6/22/2024	641.5	616	597.7	576.8	560.2	556.3	561.1	602.9	651.3	709.8	755.6	775.7	794.6	818.5	835	847.9	866.6	865	849.2	833.6	806	770	735.3	686.3
6/23/2024	651.9	623.8	604.5	591	585.3	578.6	588.2	579.3	600.6	617.6	647.3	695.3	727.4	754.6	798.9	828.6	841.5	846.4	835.9	798	755.6	708.7	663.6	610.2
6/24/2024	579.1	547.8	532.6	535.2	546.2	544.8	595.3	632.5	651	703.1	737.7	763	820.6	815.9	847.9	866.7	878.2	890.3	874	845.2	805.8	766.4	698	648.6
6/25/2024	606.4	579.3	565.4	559.5	554.3	558.9	601.4	650.7	678.1	738.7	801.5	824.2	862.9	891	927.1	952.9	905.6	809.3	782.6	748.9	734.1	702	675.5	628.7
6/26/2024	611.3	591.2	570.2	555.5	542	562.4	583.4	613.1	659.2	713.3	750.3	787.5	810.7	829.7	808.7	800.5	784.6	793	740.7	718	718.1	692.8	652.2	597.3
6/27/2024	574.1	552	534.9	522.9	519.2	539.7	564.7	602.6	646.3	690.2	730.7	775.7	806.3	837.8	859.5	881	885	877.7	869.4	825.1	784.1	746.3	690.9	641.2
6/28/2024	592.1	569.1	539	540.6	534.5	536.4	563.4	599.1	653.9	702.9	745.8	816.2	865.1	892.9	916.2	921.8	937.8	899.2	876.4	869.3	855.3	825.1	773.4	737
6/29/2024	699.3	681.4	674.1	652.6	650.4	620.7	629.2	666.6	689.8	709.1	749.6	781.8	817	845.6	867.7	875.8	891.7	893.3	883.9	862.6	846.4	796.6	753.1	703.3
6/30/2024	669.7	641.2	613.7	603.3	588.7	574	576	589.1	617.8	642.3	681.3	675.4	711.1	738.6	757.7	749.9	757.1	757	746.9	727.1	691.8	640.6	593.6	552.9
7/1/2024	520.3	491.7	484.3	465.9	486.1	484.6	526.8	539.6	562.6	592.5	611.6	641	660.8	676.1	694.8	709.9	723.9	730.9	710.4	689.7	662.7	636.1	596.8	553.9
7/2/2024	529.2	501.7	481.9	471.7	464.1	488	508.2	516.6	541.8	588.7	605.6	655.4	699.3	724.3	762.9	795.5	831.4	856.9	844.8	834.9	799.9	755.2	690.9	642.3
7/3/2024	613.8	595.6	579.2	559.2	573.3	578.1	614.3	655	700.7	761.9	805.6	830.7	850.6	881.8	926.6	950.6	945.1	937.8	884.8	809.7	793.7	745.6	690.2	648.9
7/4/2024	615	585.8	562.9	557.7	546	543.6	530.8	562.7	606.3	671.7	688.4	668.9	700.4	808.8	875.7	864.8	825.2	832.5	813	785.9	759.9	715.4	691.2	647.1
7/5/2024	620	581.2	570.8	548.5	560.8	565.1	568.5	585.8	588.7	626.1	664.1	699.3	742.6	754.7	785.4	785.1	807.9	802.4	771	734.4	691.5	670.8	632.6	581.9
7/6/2024	551.7	522	506.8	485.1	482.7	481	495.8	497.4	540.8	594.2	641.3	664.8	695.9	721.3	738.5	769.7	780.9	775.9	759.3	724.8	693.6	661	626.8	577.3
7/7/2024	557.5	525.8	505.9	475.5	464.1	466.5	468.8	498.4	554.4	600.7	648.9	688.1	727.5	761.1	783.2	809.5	821.4	827.4	814.2	788.3	755	704.8	660	616.1
7/8/2024	571.7	551	526.7	516.5	521	545.4	567.9	617.9	642.1	694.9	750.7	798.9	827.9	856.1	871.2	882.3	878.8	836.6	788.6	755.9	740.6	705.3	662	625.2
7/9/2024	602.3	592.3	574.4	574.9	577.8	578.4	609.2	623.7	654.3	649.4	655.5	673.2	697.7	709	743.6	809.6	805.9	778.4	698.5	670.7	669.5	655.4	632.4	580
7/10/2024	549.7	525.4	515.8	517.9	525.8	518	558.1	587.3	618.5	665.1	695	717.8	757.5	773.5	799	806.6	826.1	832.8	838.5	805.5	787	745.9	680.4	630.3
7/11/2024	593.6	569.4	549	540.8	548	543.5	576	633.2	674.7	723.8	741.9	763	812.3	838.7	853.3	865.9	878.4	868.4	828.8	808.1	760.2	745.5	697.2	645.8
7/12/2024	609.2	592.9	574.4	562.9	567.3	568.1	599	641.4	678.9	698.3	768.1	811.4	845.7	872.6	865.6	804.8	771.9	788.8	785.5	742.2	728	692.9	647	592.8
7/13/2024	565.2	537.1	519.2	504.4	516.7	502.8	506.3	529.5	581.1	637.9	655.6	736.3	761	759.3	737.9	724.1	746.1	767.4	782.4	763.6	740	712.5	670.1	630.8
7/14/2024	609.2	564.2	553.7	527.2	532.2	526.3	531.6	564.2	634.3	693.2	738.6	798.9	832.8	858.9	882.6	915.5	926	930.5	911.9	876	846.4	811.9	768.1	713.6
7/15/2024	672.6	643.6	617.1	610.9	599.1	618.7	634	676.6	722.8	773.8	822.7	860	906.2	934.1	980.8	977.2	987.4	979.6	954.1	914.4	876.8	838.4	781.2	740.4
7/16/2024	695.5	667.5	651.5	633	635	643.5	631.1	642.9	630.1	628.6	670.5	681.3	705	690.5	711.7	728.7	730.1	758.4	744.6	748.2	719.6	700.2	663.7	632.5
7/17/2024	606.5	572.6	554.9	547.5	548.3	554	569	602.8	620.4	661.4	722.6	758.2	791.9	827.5	842.8	832.7	828.4	804.2	791.6	779.4	757.2	726.6	678.1	617.3
7/18/2024	586.1	548	533.4	535.9	529.4	541.2	539.6	579	612.9	625.8	671	691.7	702.8	721.8	745.2	737	743.4	727.2	719.9	690.2	644.6	669.4	574.9	545.7
7/19/2024	516.2	484.3	478.6	475.2	472.4	477.1	493.9	517.8	551.3	574.9	618.8	648	681.7	716.7	729.8	735.3	744.3	761.5	743.8	713.1	680.5	655.1	600.5	553.6
7/20/2024	528.9	507.6	494.2	492.1	486.5	478.3	475.6	492	542.3	587.6	645.2	675	700.1	701.5	729.6	741.2	756.6	765.6	743.9	701.9	682.6	648.8	608.2	573.7
7/21/2024	544.5	515.4	502.7	484.4	484.8	479.7	491.9	511.2	516.4	554	592.3	623.2	657.1	664.2	686.2	704.6	732.3	753.2	733.5	712.4	696.9	658.5	623.3	585.4
7/22/2024	556.1	532.8	526.3	514.2	532.1	541.8	556	611.2	649.6	691.8	714.9	752.9	799.4	803.4	805.4	814.5	838.5	839.7	808	793.1	761.6	722.8	661.4	610.2
7/23/2024	581.8	563.8	543.3	521.6	525.2	536.2	557	591.3	597.3	641.4	698.3	741.6	779.8	808.9	827	828.6	847	834.5	820.5	793.5	773	728.8	672.5	631.7
7/24/2024	601.2	578.5	562.4	560.6	559.3	575	604.6	645.2	653.7	721.3	779	812.5	850.1	871.3	880.3	903.7	915.6	915.4	887.9	848.2	830.5	787.6	727.2	683.4
7/25/2024	666.5	600.2	576.6	571.2	558.7	577.8	611.9	634.8	674.3	717.8	768.1	817.6	849.9	858.9	890.4	911.1	879.8	847.7	819.2	780.3	784	745.4	709.9	682.1
7/26/2024	630.6	610.2	587.2	578.6	563.1	583.3	589.9	620.2	651.6	686.8	700.1	710.4	797	828.8	852.2	861.4	845.1	832.2	800.9	766.9	725.8	716.6	671.1	621.2
7/27/2024	585.9	561.4	529.1	515.3	512.4	505	500.5	511.5	549.4	591.8	628.2	680.3	751.2	766.3	780.2	781.7	785.7	784.4	770.3	748.6	725.7	699.6	653.8	631.1
7/28/2024	603.7	574.8	559.2	545.5	537.7	538	535.9	555.5	598.4	640.5	656.2	661.3	692.5	715.5	757.2	782.8	746.3	716.6	693.7	671.8	661.9	635.6	605.7	579.4
7/29/2024	568.3	543.4	537.2	539.1	546.2	551.4	576.2	593.6	654.1	705.6	749	804.6	822.3	843.3	865.8	895.9	895.3	896.7	873.7	866.1	839.4	812.1	781	746.7
7/30/2024	708.3	661.1	638.6	622.6	615.8	623.4	639.8	704	747.9	810.7	868.1	874.1	784.6	851.9	927.7	955.7	982.9	977.5	851	741.7	730	724.1	709.9	688.5
7/31/2024	667.4	647.3	648.4	630	630.3	658.7	674.3	723.3	773.1	833.8	891.6	934.2	989.7	1024.3	964.1	953.5	966.6	969	937.5	900.1	873.2	817.9	761.3	710.1
8/1/2024	676.7	639.9	624.8	617	628.7	644.3	667.9	713.4	771.5	816.2	859.5	903.4	940.2	963.2	829.3	727.6	708.6	710.6	734.1	742.3	728.7	705.6	668.1	660.4
8/2/2024	591.5	583.6	572.5	574.8	569.1	584	610.4	660	700.5	748.9	786.2	819.6	796.7	795.7	793.6	798.9	786.4	782.8	775.4	753	730.4	702.9	658.2	619.3
8/3/2024	591.3	564.8	549.8	527	531.7	529.7	508.6	540.9	584.4	634	685.3	707.5	754.5	783	812.8	817.2	831.7	832.1	813.8	782.1	755.1	725.7	670.7	624.1
8/4/2024	582.7	557.6	541.9	528.8	532.7	528	508.1	554.3	602.4	668.6	719.8	758.2	793.6	820.1	845.7	873	893.2	891.2	868.7	814.2	794.5	743.1	692.6	642.2
8/5/2024	595.3	579.4	552.6	550	550	560.5	584.7	634.5	683.7	749.7	811.6	853.5	879.6	919.6	944.3	953.7	969.2	966.9	944.4	926.3	888.6	823.4	761.9	710.5
8/6/2024	674.5	642.5	612.5	598.7	586.5	597.2	617.4	668.2	715.4	778.6	831.1	882.9	900.6	963.2	981.6	983.5	979.6	981.7	972.5	939	922.4	868.2	804.9	732.9
8/7/2024	689.7	652.6	626.1	599.7	602.1	627.2	628.9	652.5	651	680.6	695.5	715.8	742.2	747.4	780.6	780.6	795.1	767.6	761.6	759.6	748.4	700.6	648.6	626.5
8/8/2024	588.9	581.3	569.4	556.4	556.4	585.4	603	639.7	668.1	704.8	737.4	777.6	806.8	834.4	853.5	848.3	866.2	842.8	831.2	787.9	755.3	718.8	668.7	620.3
8/9/2024	585.4	567.5	546.4	551.6	552.4	568.6	592.4	632	673.6	691	721.3	754	774.9	788.7	798.7	812.8	806.6	796.3	776.7	722.4	688.8	659.2	606.2	554.4
8/10/2024	528.7	506.8	492.3	465.3	469.3	477	479	505.7	534.4	545.4	561.9	586	612.2	639.1	668.1	685.7	717.5	703.9	685.7	659.7	634	615.6	567.7	536.2
8/11/2024	514.5	510.1	492.1	480	469.7	474.4	465.1	483.7	516	538	563.6	606.4	629.2	657.2	675.9	707.2	721.6	733	720.4	687.4	656.7	621.3	580.1	538
8/12/2024	510.1	486.9	479.4	475.3	486.3	504.6	535.5	553.9	595.6	618.2	655.5	677.1	701.6	713.8	734.6	756.2	756.7	743.7	726.8	715.7	718.7	681.7	628.1	600.7
8/13/2024	566.9	549.8	531.4	531.3	527.8	549.7	579.5	593.7	614.6	642.3	670	715.2	746.6	779	800.1	820.3	824.5	820.6	806.4	772	747.9	707.8	653.4	585.3
8/14/2024	552.7	538	520.5	513.5	514.3	518.3	548.4	587	623.2	661.2	722.5	757.7

Date/Time	Hour																							
9/1/2024	589.6	570.4	560.7	551.6	549	534.4	535.3	549.3	600.8	630.2	673.6	701.9	732.3	774.3	804.6	821.5	850.6	847.5	818.1	763.2	718	698.1	655.5	662.2
9/2/2024	558.4	541.7	516.8	488.6	479.1	478.6	484.1	482.8	500.5	534.4	574.4	629.4	641.9	657.4	687.2	701.6	722.9	714.6	704.2	680.7	637.4	608.9	560.6	530.8
9/3/2024	498	486.7	477.1	456	470.7	489.5	528	551	563.7	601	611.9	644.3	673.5	696.5	707.6	716.8	727.2	720.7	693.9	686	676.4	645.2	595.1	547.5
9/4/2024	520.5	515.9	505.2	508.1	517	529.2	562.8	570	589.3	631.4	649.7	682.5	757.2	806.7	831.5	852.3	868.7	849.7	848.4	830.2	786.9	737.2	678	632.4
9/5/2024	597.4	574.5	564.7	548.8	556.9	571.3	591.6	614.3	661.6	699.7	753.5	805.3	835.1	874.4	894.8	912.8	914	894.7	873.3	851.5	805.1	758.2	695.3	637.1
9/6/2024	609.1	582.7	561.8	560.8	553.9	579.4	609.8	641.6	679	718.4	767.9	815.6	844.4	891.6	903.9	900.1	891.4	855	783.8	754.8	726.7	686.3	617	574
9/7/2024	539.9	507.8	483.9	481.9	479.8	472	456.9	472.4	500.6	514.5	526.8	522.4	543.4	554.7	540	576.7	590.9	605.5	589.4	550.9	545.1	525.6	490.1	470.1
9/8/2024	436.7	433.8	428.7	412.6	417.3	435.5	432.1	432.3	450.2	463.7	465.6	480.4	489.4	498.2	519.4	539.7	560.2	557.5	549.5	543.4	532.1	506.6	477.1	454.1
9/9/2024	439.6	433.4	429.9	442.8	441.9	459	492.6	512.2	514.9	530.6	605.1	571.1	584.6	597.1	612.1	627.8	650.1	656.8	639.7	638.9	604.1	568.5	526.5	497.4
9/10/2024	475.3	470.6	456.8	463.4	460.8	470.2	503.1	525.7	539.9	555.1	586.5	606.5	629.3	663.5	688.3	716.9	735.6	729.3	704.1	683.3	650.1	609.3	557.2	525.7
9/11/2024	479.4	468.6	467.5	464.5	471.7	491.7	511.2	531.3	538.6	579.3	606.8	658.3	699	722.4	779.1	786.1	817.4	798.9	767.8	736.8	695.8	644.7	591.7	558
9/12/2024	536.7	519.9	493.9	485.9	494.4	500.2	518.7	551	568.3	587.5	620	650.7	687.2	701.3	715.9	714.1	710.8	677.6	672.8	666.8	661.8	631.1	587.6	538.4
9/13/2024	519.3	512.6	495.7	497.2	501	532.1	564.3	566.7	575.2	590.7	612.4	644.2	665.7	692.8	717.4	744.6	762.1	755.2	712.4	701.7	676.4	647	602.9	567.5
9/14/2024	540.1	515.6	483.1	503.3	507.8	489.2	506	514.2	551	585	630.4	683.1	709.4	742.2	766.9	766.4	775.5	745.2	730.8	708.7	679.1	643.9	609.2	572.1
9/15/2024	554.3	527.2	502.6	486.9	484.8	482.7	484.4	490.2	527.4	556.6	597.3	633.4	683.6	706.6	735.4	759.7	778.1	760.5	726.4	709.5	672	645.7	597.6	559.8
9/16/2024	544.5	502.8	480.2	479.7	489.3	516.6	535.7	571	596.6	629	672.2	685.1	729.9	771.5	786.7	797.6	807.1	791.1	757	728.4	702	650.9	597.3	549.2
9/17/2024	522.1	510.6	497.4	498.5	500.5	526.8	542.5	554.2	577	605.8	650.3	724.6	729.6	771.2	793.3	805.5	817.3	801.1	768	743.1	719.1	664.6	607.3	564.1
9/18/2024	541.6	510.9	490.8	492.2	494.6	516	534.2	557.7	591.3	634	665.3	710.6	753.3	788.7	795.5	794	799.3	798.6	755.9	748.5	719.9	676.8	618	583.6
9/19/2024	551.5	534.5	521.3	514	512.7	539.2	566.7	596.7	623.7	664.2	698.9	750.1	796.7	824.6	845.5	868.4	867.9	873.6	828.5	801.1	767.9	717.9	670.5	615.4
9/20/2024	576.2	542	547.4	537.1	528.8	546.6	572.3	589.9	630.8	678.6	720.4	781	809.9	824.4	854.3	881.6	888.9	881.5	859.4	827.2	801.1	757.4	709.5	669.1
9/21/2024	630.9	612.1	577.1	560.6	553.6	560.4	559.2	561	594.3	652	701.4	750.7	807.9	848	869.4	877.8	877.8	825.9	757.2	717.8	687.1	651.9	609.3	570.2
9/22/2024	536.6	516.8	506.3	487.5	490.5	499.8	509.5	525.6	552.7	584.6	604.2	611	625.8	673.9	718.6	715.8	731.7	723.5	717.2	710.3	680.7	642.2	603.7	577.3
9/23/2024	536.4	520.6	529.8	514.8	521.2	543.4	571	595.5	611	632.3	652	645.4	636.1	635.8	638.2	639.5	652	667.4	683.5	676.4	661.6	639	599.4	565.4
9/24/2024	546.7	546	528.1	528	532.3	556.5	584.6	604.9	631.1	645.4	656.1	688.1	705.5	719	736.5	740.6	742.1	727.9	706.2	700.8	663.8	633.6	605.6	568
9/25/2024	539.9	510.4	497.3	495.4	496.7	513.9	565	565.4	573.5	590.5	616.9	643.1	667.8	694.2	707.5	711.3	712.8	714	694.5	672.2	644.1	605.1	577.2	530.9
9/26/2024	503.9	498.8	489.5	489.1	488.4	506.5	545.5	542.1	565	598.8	624.2	653.6	661.7	688	708	705.7	694.1	677.8	671.8	660.1	638	619.1	589.9	541
9/27/2024	536.1	520.2	523.6	517.2	508.2	540.9	575.4	585.1	602.3	622.5	620.3	621.3	642.4	647.5	624.5	619.9	608.6	608.3	614	597.4	600.3	564.8	552.8	514.6
9/28/2024	500.3	501.4	486.3	485	485.3	481	490.1	498.9	517	538.9	544.1	547.5	544	551	553.3	557.2	560.2	547	563.6	553.3	539.6	531.9	504.6	484.8
9/29/2024	464.3	449.2	440.7	443.8	430.1	430.8	441.9	443.8	466.5	490.7	504.8	514.9	538.8	541.5	534.3	555.9	576.2	574.2	589.1	581.1	571.5	545.5	515.8	496.9
9/30/2024	482	475.8	470.5	472.3	482.1	504.9	544.8	558.5	572.7	591.1	629.3	631.1	659.9	660.7	656.1	651.6	660.7	657.6	662.3	660.4	644.1	610	579.2	543.1
10/1/2024	516.9	497.8	489.2	484.8	497	510.4	547.3	571.9	591.7	627.3	653.6	686.9	704.8	740.4	722.8	733	736.8	714.6	669.1	666.6	646.3	582.4	545.1	512
10/2/2024	498.1	478.5	464.5	471.5	468	484.5	515.8	526.9	528.7	529.5	538	554.4	575	597.2	606.4	617.8	623.1	622.4	614.1	614.9	600	564.6	536.7	495.4
10/3/2024	490.4	481.9	476.1	474.5	478.9	492.6	520.3	515	529.5	553.5	562.3	580	599.4	614.5	626.2	647.5	655.7	656.1	629.4	616.5	592.6	564.2	524.8	498.3
10/4/2024	482.3	466.7	459	446.9	462.8	471.8	504.8	517.6	545.4	560.1	587.8	611.4	650	675.5	694.3	712.6	723.4	711.2	683.5	650.1	630	597.2	561.6	529.9
10/5/2024	497.1	478.4	469.7	457.8	455.9	457.9	470.5	478.9	490.8	506.6	537.6	562.6	600.7	627.5	673.5	701.8	724.1	711.8	669.4	643.5	618.9	586.6	549.7	515.8
10/6/2024	488.9	474.5	449.5	450	449.9	456.8	461.7	471.2	502.4	532.7	583.1	616.6	678.5	697.1	717.3	726.8	740.3	710.4	669.6	633.5	597.6	564.7	521.9	495.8
10/7/2024	472.8	446.7	448.5	446.8	464.8	473	448.6	526.8	536	552.9	524.9	562.1	589.9	595.2	604.8	602.7	615.5	606.9	599.4	592.7	575.9	541.9	526.7	476.7
10/8/2024	461	449.5	443	442.1	449.9	471	500.2	512.8	513.7	539.1	537.9	541.1	549.1	564.5	576	571.6	570.1	578.6	584	583.9	573.6	538.6	501.9	469.1
10/9/2024	463.8	452	447.1	446.1	446.9	463.2	500.5	514.9	518.9	535.5	547.8	553.6	567.8	578.6	592.4	609.9	613.3	608	594	592	574.5	548.1	517.5	490.7
10/10/2024	479.2	468.1	461.3	454.9	466.3	485	502.6	517.3	530.2	542.8	557.6	570.1	581.4	612.9	627.6	639.2	644.2	633.5	629.8	610.6	585.4	553.1	531.4	494.9
10/11/2024	478.3	461.7	451.3	458.4	456.6	464.3	492.5	507.9	520.4	490.4	590.8	557.5	584.7	605.6	632.9	644.6	645.2	627.8	613.1	588.9	573.8	553.9	532.9	496.1
10/12/2024	475.3	459.1	453.3	433.5	430.3	428.2	446.9	456.4	470.3	495.3	511.1	521.8	538.8	555.4	576.6	590.2	602.8	605.1	596.4	591.4	572.8	549.9	525.6	503.7
10/13/2024	480.4	460.7	452.8	450.2	444.1	438.1	440.5	443	457.8	482.4	497.8	525.7	541.8	547	557.2	561.9	578.8	579	558	548.6	515.3	488.8	460.7	436
10/14/2024	420.8	413.3	410.1	414.2	425.2	449.9	482	501.5	513.6	536.6	534.2	544.2	539.2	540.8	537.6	545.3	534.6	539.7	543.7	550.6	541.5	514	499.1	483.1
10/15/2024	461.8	456.3	459	444.1	471.4	494.7	526.2	537.9	547.7	552.1	549.6	537.4	537.1	536.2	541.8	534.4	538.6	546.6	573.8	579.7	571.1	543.9	531	503
10/16/2024	480.9	471.6	482.7	481.5	484.1	505.3	540.9	544.4	538.6	557.4	540.9	528.1	524.9	522.3	532.4	525.2	528.4	537.6	555.4	562.4	564.2	543.3	527.1	507.9
10/17/2024	501.3	491	492.9	493.4	499.7	521.8	548.7	568.3	569.2	575.1	547.1	537.3	537	537.3	537.6	526.1	531.1	538.3	550.4	549.8	545.3	537.4	517.1	495.4
10/18/2024	490.5	495.5	486.6	495.7	485.9	512.6	534.9	543.7	554.1	544.1	541.3	529.3	540.1	539.2	534.2	539.8	536.7	534.5	539.3	542.8	545.4	520.9	503.7	466.9
10/19/2024	461	460.9	455.2	443.6	446.3	449	464.3	486.7	489.7	480.8	478.3	484.2	479.3	481.8	469.4	482.9	505.2	516.2	514.2	511.7	477.4	488.1	467.7	443.8
10/20/2024	444.5	457.4	449.5	435.1	447.2	449.8	463.4	457.5	472.7	473.5	463.1	472.7	471.5	481	495.3	501.8	517	529.7	541.4	536.3	518.5	492.6	463.2	445
10/21/2024	439.8	429.7	437.1	436.1	465.9	490.7	516.7	556.3	554.1	564	559.6	567.1	560.5	574.8	576.3	590.2	592.7	591.8	588.7	591.3	559.5	539.1	507.7	483.9
10/22/2024	474	468	462.2	469.5	461.9	484.5	527.5	542.7	541.9	540.9	543.1	568.4	578	586.7	591.8	596.9	584.8	584.9	590.7	594.2	590.1	572.3	536.3	504.8
10/23/2024	498.4	475.9	462.7	456.6	462.2	478	513.1	532.8	537.1	554.6	569.7	581.1	599.3	615.7	612	582	581	575.6	582.3	583.5	573.1	550.7	523.7	488.3
10/24/2024	479.8	477.9	466.6	502.8	477.9	503.2	533.3	542.9	543.8	541	560.2	547	565	564.2	555.3	548.2	566	581	588.2	579.9	565.3	543.9	518.1	489
10/25/2024	484.7	476.9	469.8	466.9	466.6	484.9	530.2	536.4	546.1	550.3	560.3	578.2	582.5	576.4	584.4	603.7	607.3	606	608.3	594.6	585.4	563.8	551	517.2
10/26/2024	487.7	482.3	466.4	455.6	453.5	458.2	460.6	473.9	464.6	475.2	478.3	475.6	478.8	491.1	474.2	486	499.5	544.1	536.5	532.4	510.3	501.1	475.1	468.1
10/27/2024	465.4	454	449.3	444.2	447.8	449.5	455.1	460.8	472.5	451.4	467.4	459.3	459.1	448.5	452	456.9	491.6	507.1	522.4	517.9	525.7	504.3	475.2	469.9
10/28/2024	452.9	451.7	451.2	446.6	469.5	503.9	542.2	556.4	561.8	563.2	558.2	565.1	555.1	566.3	570.9	572.2	589.1	596.4	610.6	595.5	590	570.5	538.8	512.8
10/29/2024	501.9	492	492.8	484.8	504.4	522	553	566.3	571.7	589.6	595.2	598.8	620.7	626.1	631.4	641.4	643.6	638.9	648.9	639.5	628.5	592.9	570.5	545.3
10/30/2024	522.6	513	496.6	486.3	492.8	502.8	546.8	571	568.9	586.5	595.7	621.8	604.1	582.6	567.1	569.4	578.7	622.2	632.8	568.1	539.7	519.8	496.5	461.2
10/31/2024	440.1	434.9	495.9	500.1	498	518.6	556.8	587.4	585.5	584.3	594	585.5	587.2	588.3	587.6	580.7	575.6	572.6	572.8	579.5	579.1	553.6	518.4	494.5
11/1/2024	474.5	464.4	456.6	445.8	456.4	478.5	502.4	524	528.2	528.4	527.1	525.8	528.1	534.1	535.1	536.6	539.4	530.6	544.7	524.4	531.5	515.1	492.7	466.5
11/2/2024	451.5	450.4	439.5	442.2	447.2	438.3	456.2	473	477.8	480.3	483.5	482.5	471	489.8	475.8	472.5	493.9	502.7	501.9	498.1	496.2	470.5	459	450.3
11/3/2024	431.5	423.2	434	424.1	418.4	438.9	438.9	440.7	457.1	456.1	471.5	473.1	488.3	498.3	514.9	524.8	526	539.1	562	559.7	546.8	525.4	517.8	496.3
11/4/2024	471.3	458.4	453.5	452.7	454.1	459.1	488.3	530.8	595.1	565.9	566.3	578.2	583.2	580.8	594.3	591.2	595.9	604.7	629.7	627	608	590.4	569.8	533.7
11/5/2024	506.7	488.6	478.9	468.5	469.3	478.2	502.8	528.4	551.3	571.3	597.5	613.3	619.3	629.2	630.5	627.3	617.1	619.8	621.2	619.3	604.4	605.1	582.2	531
11/6/2024	477.4	462.3	464.7	456.3	444.9	459.4	482.9	517.6	537.8	562	570.8	576.9	573.4	573	580.1	567.5	571.4	568.9	558.4	577.3	566.7	555.5	508.6	484.2
11/7/2024	489.3	474	468.8	469	465.5	463.5	493.3	521.3	542.6	555.6	563.8	569.9	576.4	597.6	572.2	572.2	559.9	566.6	587.2	587.7	583.5	567	551.5	523.6
11/8/2024	506.8	489.4	479.2	493.8	488.8	496.8	502.2	530.5	549.9	551.4	556.6	556.2	563.4	549.1	547.4	546.3	545.5	551.2	567	565.4	561.1	549.6	525	512.7
11/9/2024	484.4	467.3	462.6	453.7	460	441.6	455.5	469.6	478.8	492.2	471.9	473.7	498	500.4	484.2	489	499.8	514.2	514.1	511.8	497.9	500.7	481.2	474.3
11/10/2024	451.1	449.9	441.5	438.7	443.8	441.3	451.3	457	467.2	491.8	514.2	514.9	516.6	497.6	509.4	531	538.2	548.4	566.1	561.5	551.8	529.9	514.7	479.8
11/11/2024	458.2	441.5	438.1	438.5	445.1	463.3	494.3	523.1	543.2	547.5	543	551.7	558.7	565.1	572.4	557.2	570.9	591.8	613.2	606.8	597.9	594.3	567.1	548.2
11/12/2024	534.9	520.7	520.5	507.3	513.2	516.5	537.9	566.6	573.9	585.4	555.4	497.1	484.5	491.3	488	483.9	494.9	502	510.4	526.6	559.2	573.7	571.9	553.9
11/13/2024	537.7	533.4	523.1	520.2	518.8	532	554.7	588.5	598.8	599.4	603.6	597.1	594.4	601.9	619.4	620.6	623.6	617.6	633.2	618.7	612.2	601.5	601.1	570.9
11/14/2024	552.2	540.7	514.9	503.6	499.9	521.7	531.7	571.9	584	598.8	606.1	605.4	602.7	609.2	603.4	600.8	594.5	602.5	619.3	616.2	614.5	603.1	583.3	552.9
11/15/2024	531.5	518.3	502.7	513.5	507.7	514.7	516.8	560.9	577.5	594.9	605.9	607.6	584.5	582.6	599	591.6	593.2	601.5	603.8	597.2	589.5	576.1	566.6	536.4
11/16/2024	519.1	511.9	499.4	497.7	477.8	483	490.8	496.7	503.9	513.9	509.3	521.9	507.8	501.5	488.8	493.1	494.5	523.1	540.5	545.5	538.1	520.4	512.4	506.3
11/17/2024	484.2	478.9	469.3	477.7	463	483.8	491.5	508.7	508.7	494.4	496.7	493.9	493.4	499.5	523	517.1	513.4	537.6	565.6	559.9	542.1	541.5	515.7	502.4
11/18/2024	484.7	489.1	482.6	483.8	481.5	494	526	565.1	582.8	583.5	600.9	603	603.8	595	607.8	597.2	592.2	616.2	619	632.7	617.6	602.8	574.4	546.6
11/19/2024	522.8	497.4	497.3	499.1	488.9	503.7	537.7	571.5	585.9	589	603.7	586.9	589.8	601.5	596.7	608.7	610.3	619.8	636.3	614.2	610.3	586.4	572.5	550.7
11/20/2024	523.9	511.1	502.9	494.7	494.6	500.4	524.4	564.3	607.7	600.1	602.9	600.2	596.9	596.4	597.1	574.6	573.8	596.3	629.6	622.3	611.5	612.1	599.1	587.7
11/21/2024	569.8	559.5	555.8	555.6	547.2	550	580.8	623.6	652.4	655.6	670.9	674	683.4	675	669.5	660.2	664.2	669.3	671.9	678.4	662.4	654.8	629.8	606.7
11/22/2024	588.4	574.7	564.8	560.1	556.9	565.1	583.9	620.3	629.5	636.2	636.1	629	635.9	635.9	630.3	618	627.7	641	644.1	634.7	619.6	609.9	606.6	596.7
11/23/2024	572.6	556.2	549.8	551	552.4	542.9	541.5	545.6	552.2	566.8	575.5	585.5	582.4	574.2	571.3	573.7	587.5	603.4	614.9	609.5	613.9	607.2	598	578.2
11/24/2024	570.9	552.8	541.1	537.3	537.5	549.3	547.6	565.8	571.9	556.9	544.5	543.2	540.3	526.9	519.8	520.6	542	572.4	601.1	605.7	589.5	582.9	564.4	533.2
11/25/2024	518.1	499.1	496.5	503.1	495.1	521.7	545.1	588.7	584.8	592.8	608.2	600.6	565.9	561.6	576.2	570.6	573.6	574.8	585	578.5	568.6	560	535.7	519.2
11/26/2024	494.2	486.4	505.6	497.4	490.8	506.5	540.9	587.7	607.1	605.9	584.8	565.6	556.7	543.4	541.9	540.5	543.7	563.1	586.8	589.8	585	578.2	574	550.5
11/27/2024	526.6	517.3	510.8	498.2	495.7	494.7	506.9	534.1	557.3	559.8	565.4	580.3	572.5	573.5	576.4	562.8	561.9	568.3	579.1	585.6	562.7	555.4	524.7	476.9
11/28/2024	446	430.3	429.1	414.2	413.1	408.6	419.5	435.9	441.5	473.5	490.8	500.4	500.2	478	466.9	462	462.4	469.5	473.9	482.2	483.2	483.6	477.1	459.9
11/29/2024	446.8	438.6	449.1	444.1	443.2	443.1	469.2	486	487.9	481.7	474.8	479.2	472.2	457.5	458.7	466.2	477.7	511.6	573.9	533.1	533.5	537.8	537.4	517.4
11/30/2024	495.5	489.2	489.3	489.2	481.3	499.6	510.7	533.3	533.1	545.6	551.8	555.2	537.6	536.9	531.4	536.3	536.5	554.8	578.1	585.2	573.8	569.1	552.1	517.3
12/1/2024	499.4	493.5	487.1	489.2	482.6	490.2	499.4	507.3	528.2	547	554.3	549.1	542.2	554.1	556.3	554.6	578.3	594	635.9	626.1	623.7	597	585	572.2
12/2/2024	560.9	551.9	555.7	568	565.1	585.4	630.1	674.5	681.8	653.3	646.2	659	662.1	662.6	667.4	670.4	678.7	694.1	712.8	706.6	709	698.2	685.4	657.1
12/3/2024	637.2	630.2	622.9	618.4	598	611.7	634	669.4	682.8	691.4	688.8	694.4	682.5	680.1	679.4	678.9	675.2	682.6	705.4	699.1	703.8	690.2	677.9	654.7
12/4/2024	629.7	626.8	611.8	602.6	599.1	605.6	613	644.1	647.2	636.4	625.7	602.4	588.2	590.4	589.6	602.1	596.2	607.7	633.4	630.6	615.4	620.3	594.3	559.8
12/5/2024	539.7	542.6	552	566.8	589.5	615.4	645	689.9	710.4	707.4	702.6	687.1	672.2	666.3	671.6	653.9	655.6	691.1	714.1	720.6	725.5	712.4	701.5	680.7
12/6/2024	668.6	661.5	653.4	655.3	652.6	666.7	675.1	707.1	729.4	699.9	675.1	653	635.9	632.8	622.9	609.7	623.3	651.7	659.8	664.2	648.8	648	633	611.8
12/7/2024	602	585.2	587	567.5	574.5	572	574.4	598.1	600.6	580.4	560	546.7	522.2	500.1	492.3	488.1	492.1	534.6	557.5	555.5	554.7	542.6	530.4	512.4
12/8/2024	492.3	486.6	464.1	462.9	462.6	474.2	487.3	504.1	499	514.9	496.2	492.2	475.2	474.1	479	486.1	503.5	532.4	543.7	544.5	515.2	496.4	469.2	434.2
12/9/2024	467.2	451.8	438.1	437.8	442.8	454.4	479.4	528.1	546.4	556.5	560.3	564.9	552.7	557.6	558.2	555.9	557.5	570.4	580.4	579	578.4	576	553.2	522.5
12/10/2024	506.6	483.6	479	476.6	478	481.5	491.4	546.4	566.6	565.6	575.5	586.1	577.3	550.7	562	561.4	565.4	593	611.3	616.4	619.5	616	589.4	570.5
12/11/2024	547.2	540.6	528	529.7	531.8	548	574.7	619.1	634.8	632.7	619.6	629.4	621.4	618.3	632.4	619.3	620.4	649.1	671.6	675.5	671.8	675.5	648	613.7
12/12/2024	590	596.2	594.6	596.9	591	601.4	616.1	659.2	672.5	656.4	651.8	635.3	621.9	618.9	594.5	589.8	600.1	616.6	633.9	636.1	640.3	636.3	621.8	592.5
12/13/2024	572.9	571.8	559.3	565.6	566.7	582.9	605.1	643.4	659.2	650.6	650.7	657.3	629	606.4	606.8	595.1	593.9	616.4	622.7	620.7	617.2	617.3	602.6	581.1
12/14/2024	551	546.9	541	535.3	535.2	541.2	544.6	549.6	554.4	555.2	549.4	542.9	539.5	533.8	531.3	535.4	536.4	557.2	568.7	570.9	546.3	527	520.5	492.3
12/15/2024	477.6	466.3	447.5	441.9	452.

Attachment 3.4 CEIS Electric 2025-2027 DSM Plan



CenterPoint Energy Indiana 2025-2027 Electric Energy Efficiency Plan

Prepared by:
CenterPoint Energy Indiana South (CEI South)

6/24/2024

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List of Acronyms & Abbreviations

Acronym	Description
AFUE	Annual Fuel Utilization Efficiency
BAS	Building Automation System
BTU	Building Tune-Up
BYOT	Bring Your Own Thermostat
CAC	Central Air Conditioning
C&I	Commercial & Industrial
CVR	Conservation Voltage Reduction
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EAP	Energy Assistance Program
ECM	Electronically Commutated Motors
EDA	Energy Design Assistance
EE	Energy Efficiency
ES	Energy Star
FPL	Federal Poverty Level
GPM	Gallons Per Minute
H&S	Health and Safety
HEA	Home Energy Assessment
HEMS	Home Energy Management System
HERS	Home Efficiency Rating System
EM&V	Evaluation, Measurement & Verification
HVAC	Heating, Ventilation and Air Conditioning
IQW	Income Qualified & Weatherization
kW/kWh	Kilowatt, Kilowatt hour
LED	Light Emitting Diode
MAT	Mobile Assessment Tool
MW,MWh	Megawatt, Megawatt hour
NPV	Net Present Value
NTG	Net to Gross
O&M	Operations and Maintenance
PCT	Participant Cost Test
RBS	Residential Behavioral Savings
RFQ	Request for Qualification
RIM	Ratepayer Impact Measure
SBES	Small Business Energy Solutions
SEER	Seasonal Energy Efficiency Ratio
SEM	Strategic Energy Management
TRC	Total Resource Cost
TRM	Technical Reference Manual
UCT	Utility Cost Test
VFD	Variable Frequency Drive

1. Introduction

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc. headquartered in Houston, TX. CEI South provides energy delivery services to approximately 147,000 electric customers and 112,000 natural gas customers located in Southwestern Indiana. This CEI South 2025-2027 Electric Demand Side Management (DSM) Plan ("2025-2027 Plan" or "Plan") describes the details of the electric Energy Efficiency (EE) and Demand Response (DR) programs CEI South plans to offer in its service territory in 2025-2027.

CEI South is proposing a 2025-2027 Plan designed to cost effectively reduce energy use by approximately 1.1% of eligible retail sales each year over the three-year plan. The EE savings goals are consistent with CEI South's 2022 Integrated Resource Plan ("2022 IRP"), reasonably achievable and cost effective. The Plan includes program budgets, including the direct and indirect costs of energy efficiency programs. The 2025-2027 Plan recommends electric EE and DR programs for the residential and commercial & industrial (C&I) sectors in CEI South's service territory. Where appropriate, it also describes opportunities for coordination with some of CEI South's gas EE programs to leverage the best total EE and DR opportunities for customers and to share costs of delivery. CEI South utilizes a portfolio of DSM programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. CenterPoint's DSM programs have been approved by the Indiana Utility Regulatory Commission ("Commission" or "IURC") and implemented pursuant to various IURC orders over the years.

2. CEI South DSM Strategy

Energy efficiency remains at the core of CenterPoint's culture as one of the company's objectives is to partner with customers to help them use energy wisely. CenterPoint proactively works with its oversight boards in each state it serves to assemble progressive, cost-effective programs that work toward achieving that objective.

CEI South's 2022 Integrated Resource Plan ("2022 IRP") includes EE programs for all customer classes and sets an annual savings target of 1.2% of retail sales for 2025-2027. The framework for the 2025-2027 Plan was modeled at a savings level of 1.2% of retail sales adjusted for an opt-out rate of 77% eligible load, as provided for in Indiana Code § 8-1-8.5-10 ("Section 10"). The IRP load forecast also includes an ongoing level of EE related to codes and standards embedded in the load forecast projections. Ongoing

EE and DR programs are also important given the integration of CEI South's natural gas and electric EE and DR programs.

A. Integration with CEI South Gas

Opportunities exist to gain both natural gas and electric savings from some EE programs and measures. In these instances, energy savings will be captured by the respective utility. For the programs where integration opportunities exist, CEI South has allocated implementation costs based on the net benefits split between natural gas and electric. Below is a list of programs that CEI South has identified as integrated:

- Home Energy Solutions
- Residential Prescriptive
- Residential Midstream
- Home Energy Assessment
- In Store Discount
- Multi Family Energy Solutions
- Residential New Construction
- Income Qualified Weatherization
- Residential Marketplace
- Residential Behavioral Savings
- Commercial and Industrial (C&I) Prescriptive
- Commercial and Industrial (C&I) Midstream
- Commercial and Industrial (C&I) Custom
- Small Business Energy Solutions

B. CenterPoint Oversight Board

The CenterPoint Oversight Board (OSB) provides input into the planning and evaluation of CEI South's EE programs. The OSB was formed in 2010 pursuant to the Final Order issued in Cause No. 43427 and included the Indiana Office of the Utility Consumer Counselor (OUCC) and CEI South as voting members. The Citizens Action Coalition was added as a voting member of the OSB in 2013 pursuant to the Final Order issued in Cause No. 44318. In 2014, the CEI South Electric Oversight Board merged with the CEI South Gas Oversight Board and CEI North Gas Oversight Board to form one governing body, the OSB. CenterPoint and the OSB have worked collaboratively over the last several years and CenterPoint requests to continue the current voting structure.

3. CEI South Planning Process

CEI South has offered a variety of EE programs since April 2010 and has engaged in a similar planning process each time a new portfolio is presented to the Commission for approval.

The 2025-2027 Plan was developed in conjunction with the 2022 IRP planning process and therefore the 2022 IRP served as a key input into the 2025-2027 Plan. As such, this process aligns with Indiana Code § 8-1-8.5-10 ("Section 10"), which requires that EE goals be consistent with an electricity supplier's IRP.

Consistent with the 2022 IRP, the framework for the 2025-2027 Plan was modeled at a savings level of 1.2% of retail sales with opt-out assumptions incorporated. Once the level of EE programs to be offered from 2025 through 2027 was established, CEI South engaged in a process to develop the 2025-2027 Plan. The objective of the planning process was to develop a plan based upon market-specific information for CEI South's territory, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The program design used the Electric Market Potential Study (MPS) for guidance to validate that the plan estimates were reasonable. While building from the bottom up with estimates from program implementers to help determine participation, this comparison to the MPS allowed the planning team to determine if the results were reasonable.

In 2021, CEI South engaged GDS Associates, Inc., to conduct an MPS and Action Plan. For this effort, GDS evaluated electric energy-efficiency resources in the residential, commercial, and industrial sectors for the years 2025-2030. The study included a detailed, bottom-up assessment of the CEI South market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally

deliver those savings. The study assessed various tiers of technical, economic and achievable potential by sector, customer type and measure.

In addition, vendors and other implementation partners who operate the current programs were involved in the planning process by providing recommendations for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimated participation and estimated implementation costs. This data provided a foundation for the 2025-2027 Plan based on actual experience within CEI South's territory. These companies also bring their experience operating programs for other utilities. Once the draft version of the 2025-2027 Plan was developed, CEI South solicited feedback from the OSB for consideration in the final design.

Other sources of program information were also considered. Current evaluations and the Indiana Technical Resource Manual (TRM) were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful EE and DR programs implemented by other utility companies.

OSB feedback was incorporated into the planning process, as applicable.

4. Cost Effectiveness Analysis

CEI South's last step of the planning process was the cost benefit analysis. CEI South retained Mr. Richard Morgan, President of Morgan Marketing Partners, to complete the cost benefit modeling. Utilizing DSMore, the measures and programs were analyzed for cost effectiveness. The DSMore tool is nationally recognized and used in many states across the country to determine cost-effectiveness. Developed and licensed by Integral Analytics based in Newport, KY, the DSMore cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for the EE program, and then correlates both to weather. This tool looks at more than 30 years of historic weather variability to get the full weather variances appropriately modeled. In turn, this allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the efficiency measure can be captured in comparison to other alternative supply options.

The outputs of DSMore include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant Cost Test (PCT) and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, and administrative costs,

incremental costs to the participant of the high efficiency measure, and escalation rates and discount rates. CEI South considers the results of each test and ensures that the portfolio passes the TRC test as it includes the total costs and benefits to both the utility and the consumer. The model includes a full range of economic perspectives typically used in EE and DSM analytics. The perspectives include:

- Total Resource Cost Test - shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.
- Utility Cost Test - shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.
- Participant Cost Test - shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the EE/DR program to the participant's cost of participation.
- Ratepayer Impact Measure Test - shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

Cost effectiveness analysis is performed using each of the four primary tests. The results of each test reflect a distinct perspective and have a separate set of inputs demonstrating the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test can be found in Appendix A.

5. 2025 - 2027 Plan Objectives and Impact

The framework for the 2025-2027 Plan aligns with CEI South's 2022 IRP and was designed to reach a reduction in sales of approximately 1.1% of eligible retail sales with opt-out assumptions incorporated. Table 1 below provides an overview of energy savings and demand impacts, participation, and budget by the residential and C&I sectors and for the total portfolio. Table 1 provides an overview of budget and energy savings by program and by year.

Table 1: 2025-2027 Portfolio Summary of Participation, Impacts & Budget

Program Year	Participants/ Measures	Annual Energy Savings (kWh)	Annual Demand Savings (kW)	Res & C&I Direct Program Budget	Cost/kWh*	Levelized Costs/kWh**	Indirect Portfolio Level Budget	Other Costs Budget	Portfolio Total Budget Including Indirect & Other
2025	143,091	34,777,868	11,186	$13,057,893	$0.38	$0.05	$1,323,981	$500,000	$14,881,874
2026	150,525	38,756,721	12,706	$14,099,467	$0.36	$0.36	$1,392,791	$200,000	$15,692,258
2027	146,487	39,062,535	11,512	$15,252,705	$0.39	$0.39	$1,447,196	$200,000	$16,899,901

* Cost per kWh is calculated by dividing program cost by total savings and does not include carry forward costs related to smart thermostat, BYOT and CVR programs. The cost per kWh excludes indirect and other costs for budget. Including indirect and other costs, the cost per kWh is $0.38/kWh.

** Levelized Costs per kWh are consistent with the 2022 IRP.

Table 2: CEI South 2025 - 2027 Plan Overview by Program

	Total Budget			Total Savings (kWh)			Total Demand (kW)		
Programs	2025	2026	2027	2025	2026	2027	2025	2026	2027
Home Energy Solutions	$1,400,880	$1,496,612	$1,605,665	3,151,328	3,295,993	3,471,049	838	828	825
Residential Prescriptive	$180,843	$178,017	$177,609	474,041	427,293	395,946	195	166	141
Residential Midstream	$942,135	$971,263	$1,009,157	1,841,874	1,861,980	1,896,389	581	587	597
Home Energy Assessment	$208,187	$263,800	$320,901	377,520	473,865	570,893	27	35	44
In Store Discount	$69,715	$83,532	$98,000	457,893	532,856	607,820	36	40	43
Multi Family Energy Solutions	$106,981	$108,233	$109,538	369,015	369,015	369,015	25	25	25
Community Connections	$244,120	$265,105	$276,585	778,800	778,800	778,800	22	22	22
Residential New Construction	$59,343	$62,762	$66,515	78,637	78,637	78,637	30	30	30
Income Qualified Weatherization	$1,275,328	$1,321,265	$1,369,022	779,346	784,991	790,637	83	86	90
Marketplace	$582,007	$605,716	$629,752	1,618,571	1,694,556	1,772,227	603	632	661
Residential Behavioral Savings	$384,102	$384,193	$384,288	3,925,117	3,925,117	4,925,117	1,850	1,850	1,850
Smart Cycle (DLC Change Out)	$2,312,607	$2,623,747	$3,245,409	1,477,053	1,477,053	1,477,053	3,300	3,300	3,300
BYOT (Bring Your Own Thermostat)	$883,490	$883,810	$884,141	0	0	0	1,430	1,430	1,430
CVR Residential	$105,472	$187,776	$246,820	0	1,328,231	0	0	1,011	0
Residential Subtotal	**$7,354,328**	**$7,939,220**	**$8,817,735**	**12,177,867**	**13,732,395**	**13,662,535**	**8,181**	**9,214**	**8,233**
Commercial Prescriptive	$2,228,509	$2,347,906	$2,408,626	10,751,737	12,032,995	12,824,803	1,709	1,883	1,964
Commercial Midstream	$67,107	$87,693	$104,221	448,263	567,005	675,197	53	82	72
Commercial Custom	$1,401,615	$1,761,353	$1,911,004	5,600,000	6,100,000	6,100,000	754	754	754
Small Business Energy Solutions	$1,585,801	$1,485,694	$1,482,621	4,300,000	4,300,000	4,300,000	470	470	470
Building Optimization	$309,955	$310,504	$311,072	1,500,000	1,500,000	1,500,000	20	20	20
CVR Commercial	$110,578	$167,096	$217,427	0	524,327	0	0	284	0
Commercial Subtotal	**$5,703,565**	**$6,160,247**	**$6,434,970**	**22,600,000**	**25,024,327**	**25,400,000**	**3,005**	**3,492**	**3,279**
Residential & Commercial Subtotal	**$13,057,893**	**$14,099,467**	**$15,252,705**	**34,777,868**	**38,756,721**	**39,062,535**	**11,186**	**12,706**	**11,512**
Indirect Portfolio Level Costs Subtotal	**$1,323,981**	**$1,392,791**	**$1,447,196**						
Other Costs Subtotal	**$500,000**	**$200,000**	**$200,000**						
DSM Portfolio Total (Including Other Costs)	**$14,881,874**	**$15,692,258**	**$16,899,901**	**34,777,868**	**38,756,721**	**39,062,535**	**11,186**	**12,706**	**11,512**
*Portfolio level costs include: Contact Center, Online Audit, Outreach & Education and Evaluation									
**Other costs include: Market Potential Study and Emerging Markets									

A. Plan Savings

The planned savings goal for 2025-2027 was calculated based on a percentage of forecasted weather normalized electric sales for 2025 to 2027 with a target of 1.2% of eligible retail sales. The forecast is consistent with CEI South's 2022 IRP sales forecast. Goals are based on gross energy savings with opt-out assumptions incorporated. Table 3 demonstrates the portfolio, residential and C&I energy savings targets at the 1.1% eligible retail sales level. Table 4 demonstrates the portfolio energy and demand savings by program and by year.

Table 3: CEI South 2025 - 2027 Plan Portfolio Summary Planned Energy Savings

Portfolio Summary	Total Savings (kWh)			Total Demand (kW)		
	2025	2026	2027	2025	2026	2027
Residential Subtotal	12,177,867	13,732,395	13,662,535	8,181	9,214	8,233
Commercial Subtotal	22,600,000	25,024,327	25,400,000	3,005	3,492	3,279
Residential & Commercial Subtotal	**34,777,868**	**38,756,721**	**39,062,535**	**11,186**	**12,706**	**11,512**

Table 4: CEI South 2025 - 2027 Plan Portfolio Planned Energy Savings

Program Savings	kWh	KW	kWh	KW	kWh	KW
Residential	**2025**	**2025**	**2026**	**2026**	**2027**	**2027**
Home Energy Solutions	3,151,328	838	3,295,993	828	3,471,049	825
Multi Family Energy Solutions	369,015	25	369,015	25	369,015	25
Community Connections	778,800	22	778,800	22	778,800	22
Residential New Construction	78,637	30	78,637	30	78,637	30
Income Qualified Weatherization	779,346	83	784,991	86	790,637	90
Marketplace	1,618,571	603	1,694,556	632	1,772,227	661
Residential Behavioral Savings	3,925,117	1,850	3,925,117	1,850	4,925,117	1,850
Smart Cycle (DLC Change Out)	1,477,053	3,300	1,477,053	3,300	1,477,053	3,300
BYOT (Bring Your Own Thermostat)	0	1,430	0	1,430	0	1,430
CVR Residential	0	0	1,328,231	1,011	0	0
Residential Subtotal	**12,177,867**	**8,181**	**13,732,395**	**9,214**	**13,662,535**	**8,233**
Commercial	**2025**	**2025**	**2026**	**2026**	**2027**	**2027**
Commercial Prescriptive	10,751,737	1,709	12,032,995	1,883	12,824,803	1,964
Commercial Midstream	448,263	53	567,005	82	675,197	72
Commercial Custom	5,600,000	754	6,100,000	754	6,100,000	754
Small Business Energy Solutions	4,300,000	470	4,300,000	470	4,300,000	470
Building Optimization	1,500,000	20	1,500,000	20	1,500,000	20
CVR Commercial	0	0	524,327	284	0	0
Commercial Subtotal	**22,600,000**	**3,005**	**25,024,327**	**3,492**	**25,400,000**	**3,279**
Residential & Commercial Subtotal	**34,777,868**	**11,186**	**38,756,721**	**12,706**	**39,062,535**	**11,512**

B. Plan Budget

The total planned program budget includes the direct and indirect costs of implementing CEI South's electric energy efficiency programs. In addition, a budget for other costs are being requested as described below.

Direct program costs include three main categories: vendor implementation, program incentives and administration costs. The program budgets were built based upon multiple resources. Program budgets were discussed with program implementers as a basis for the development of this plan. Vendor implementation budgets were estimated using historical data and estimates provided by the current vendors with consideration for MPS costs. This helps to assure that the estimates are realistic for successful delivery. Program incentives were calculated by assigning measures with appropriate incentive values based upon existing program incentives, evaluation results and vendor recommendations. Lastly, administrative costs are comprised of internal costs for CEI South's management and oversight of the programs. Administrative costs were allocated back to programs based on the percent of savings these programs represent as well as estimated staff time spent on programs.

Indirect costs are costs that are not directly tied to a single program, but rather support multiple programs or the entire portfolio. These include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

Other costs are also being requested in the 2025-2027 filed plan. CEI South requests approval to continue funding for Emerging Markets, which is discussed later in the Plan. Emerging Markets funding allows CenterPoint's EE portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the CEI South territory. This funding will not be used to support existing measures or programs, but rather support new program development or new measures within an existing program. Tables 5 through 8 below list the summary budgets by year, program and category.

Table 5: CEI South 2025 – 2027 Summary Budgets by Year

Residential	2025	2026	2027	Total Budget
Home Energy Solutions	$1,400,880	$1,496,612	$1,605,665	$4,503,157
Residential Prescriptive	$180,843	$178,017	$177,609	$536,469
Residential Midstream	$942,135	$971,263	$1,009,157	$2,922,554
Home Energy Assessment	$208,187	$263,800	$320,901	$792,887
In Store Discount	$69,715	$83,532	$98,000	$251,246
Multi Family Energy Solutions	$106,981	$108,233	$109,538	$324,751
Community Connections	$244,120	$265,105	$276,585	$785,811
Residential New Construction	$59,343	$62,762	$66,515	$188,620
Income Qualified Weatherization	$1,275,328	$1,321,265	$1,369,022	$3,965,616
Marketplace	$582,007	$605,716	$629,752	$1,817,475
Residential Behavioral Savings	$384,102	$384,193	$384,288	$1,152,582
Smart Cycle (DLC Change Out)	$2,312,607	$2,623,747	$3,245,409	$8,181,763
BYOT (Bring Your Own Thermostat)	$883,490	$883,810	$884,141	$2,651,440
CVR Residential	$105,472	$187,776	$246,820	$540,069
Residential Subtotal	**$7,354,328**	**$7,939,220**	**$8,817,735**	**$24,111,282**

Commercial	2025	2026	2027	Total Budget
Commercial Prescriptive	$2,228,509	$2,347,906	$2,408,626	$6,985,041
Commercial Midstream	$67,107	$87,693	$104,221	$259,021
Commercial Custom	$1,401,615	$1,761,353	$1,911,004	$5,073,972
Small Business Energy Solutions	$1,585,801	$1,485,694	$1,482,621	$4,554,116
Building Optimization	$309,955	$310,504	$311,072	$931,531
CVR Commercial	$110,578	$167,096	$217,427	$495,101
Commercial Subtotal	**$5,703,565**	**$6,160,247**	**$6,434,970**	**$18,298,782**
Total Direct Program Costs	**$ 13,057,893**	**$ 14,099,467**	**$ 15,252,705**	**$ 42,410,064**

Indirect Portfolio Level Costs	2025	2026	2027	Total Budget
Contact Center	$69,842	$71,239	$72,664	$213,745
Online Audit	$47,571	$48,523	$49,493	$145,587
Outreach & Education	$561,116	$572,338	$583,785	$1,717,239
Evaluation	$645,452	$700,691	$741,254	$2,087,397
Indirect Portfolio Level Costs Subtotal	**$1,323,981**	**$1,392,791**	**$1,447,196**	**$4,163,968**
Total Portfolio	**$ 14,381,874**	**$ 15,492,258**	**$ 16,699,901**	**$ 46,574,032**

Other Costs Subtotal	2025	2026	2027	Total Budget
Emerging Markets	$200,000	$200,000	$200,000	$600,000
Market Potential Study	$300,000	$0	$0	$300,000
Unallocated Budget	$0	$0	$0	$0
Other Costs Subtotal	**$500,000**	**$200,000**	**$200,000**	**$900,000**
DSM Portfolio Total (Including Other Costs)	**$ 14,881,874**	**$ 15,692,258**	**$ 16,899,901**	**$ 47,474,032**

Table 6: CEI South 2025 Summary Budgets by Category

2025 Program Budget	Administrative	Implementation	Incentives	Total Budget
Residential				
Home Energy Solutions	$94,298	$471,386	$835,195	$1,400,880
Multi Family Energy Solutions	$13,970	$19,698	$73,313	$106,981
Community Connections	$0	$244,120	$0	$244,120
Residential New Construction	$5,239	$32,824	$21,280	$59,343
Income Qualified Weatherization	$0	$797,193	$478,135	$1,275,328
Marketplace	$104,776	$92,387	$384,844	$582,007
Residential Behavioral Savings	$3,493	$380,609	$0	$384,102
Smart Cycle (DLC Change Out)	$24,448	$1,675,664	$612,495	$2,312,607
BYOT (Bring Your Own Thermostat)	$12,224	$269,136	$602,130	$883,490
CVR Residential	$37,510	$67,963	$0	$105,472
Residential Subtotal	**$295,956**	**$4,050,980**	**$3,007,392**	**$7,354,328**
Commercial				
Commercial Prescriptive	$153,671	$735,846	$1,338,992	$2,228,509
Commercial Midstream	$0	$21,363	$45,745	$67,107
Commercial Custom	$69,851	$490,332	$841,432	$1,401,615
Small Business Energy Solutions	$90,806	$428,379	$1,066,616	$1,585,801
Building Optimization	$20,955	$112,750	$176,250	$309,955
CVR Commercial	$39,326	$71,252	$0	$110,578
Commercial Subtotal	**$374,608**	**$1,859,922**	**$3,469,035**	**$5,703,565**
Residential & Commercial Subtotal	**$670,565**	**$5,910,902**	**$6,476,427**	**$13,057,893**
Indirect Portfolio Level Costs				
Contact Center				$69,842
Online Audit				$47,571
Outreach & Education				$561,116
Portfolio Costs Subtotal				**$678,529**
Subtotal - Before Evaluation				**$13,736,422**
Evaluation				$645,452
DSM Porfolio Total				**$14,381,874**
Other Costs Subtotal				
Emerging Markets				$200,000
Market Potential Study				$300,000
Unallocated Budget				$0
Other Costs Subtotal				**$500,000**
DSM Portfolio Total (Including Other Costs)				**$14,881,874**

Table 7: CEI South 2026 Summary Budgets by Category

2026 Program Budget	Administrative	Implementation	Incentives	Total Budget
Residential				
Home Energy Solutions	$96,767	$504,325	$895,520	$1,496,612
Multi Family Energy Solutions	$14,336	$20,584	$73,313	$108,233
Community Connections	$0	$265,105	$0	$265,105
Residential New Construction	$5,376	$36,106	$21,280	$62,762
Income Qualified Weatherization	$0	$832,531	$488,735	$1,321,265
Marketplace	$107,519	$95,159	$403,038	$605,716
Residential Behavioral Savings	$3,584	$380,609	$0	$384,193
Smart Cycle (DLC Change Out)	$25,088	$1,783,664	$814,995	$2,623,747
BYOT (Bring Your Own Thermostat)	$12,544	$269,136	$602,130	$883,810
CVR Residential	$38,492	$149,284	$0	$187,776
Residential Subtotal	**$303,705**	**$4,336,504**	**$3,299,011**	**$7,939,220**
Commercial				
Commercial Prescriptive	$157,694	$664,800	$1,525,412	$2,347,906
Commercial Midstream	$0	$31,326	$56,367	$87,693
Commercial Custom	$71,679	$828,242	$861,432	$1,761,353
Small Business Energy Solutions	$93,183	$325,895	$1,066,616	$1,485,694
Building Optimization	$21,504	$112,750	$176,250	$310,504
CVR Commercial	$40,355	$126,741	$0	$167,096
Commercial Subtotal	**$384,416**	**$2,089,754**	**$3,686,077**	**$6,160,247**
Residential & Commercial Subtotal	**$688,121**	**$6,426,257**	**$6,985,088**	**$14,099,467**
Indirect Portfolio Level Costs				
Contact Center				$71,239
Online Audit				$48,523
Outreach & Education				$572,338
Portfolio Costs Subtotal				**$692,100**
Subtotal - Before Evaluation				**$14,791,567**
Evaluation				$700,691
DSM Porfolio Total				**$15,492,258**
Other Costs Subtotal				
Emerging Markets				$200,000
Market Potential Study				$0
Unallocated Budget				$0
Other Costs Subtotal				**$200,000**
DSM Portfolio Total (Including Other Costs)				**$15,692,258**

Table 8: CEI South 2027 Summary Budgets by Category

2027 Program Budget	Administrative	Implementation	Incentives	Total Budget
Residential				
Home Energy Solutions	$99,322	$544,124	$962,219	$1,605,665
Multi Family Energy Solutions	$14,714	$21,511	$73,313	$109,538
Community Connections	$0	$276,585	$0	$276,585
Residential New Construction	$5,518	$39,717	$21,280	$66,515
Income Qualified Weatherization	$0	$869,687	$499,335	$1,369,022
Marketplace	$110,358	$98,014	$421,380	$629,752
Residential Behavioral Savings	$3,679	$380,609	$0	$384,288
Smart Cycle (DLC Change Out)	$25,750	$1,999,664	$1,219,995	$3,245,409
BYOT (Bring Your Own Thermostat)	$12,875	$269,136	$602,130	$884,141
CVR Residential	$39,508	$207,312	$0	$246,820
Residential Subtotal	**$311,725**	**$4,706,359**	**$3,799,652**	**$8,817,735**
Commercial				
Commercial Prescriptive	$161,859	$678,101	$1,568,666	$2,408,626
Commercial Midstream	$0	$35,701	$68,520	$104,221
Commercial Custom	$73,572	$976,000	$861,432	$1,911,004
Small Business Energy Solutions	$95,644	$320,361	$1,066,616	$1,482,621
Building Optimization	$22,072	$112,750	$176,250	$311,072
CVR Commercial	$41,421	$176,006	$0	$217,427
Commercial Subtotal	**$394,567**	**$2,298,919**	**$3,741,484**	**$6,434,970**
Residential & Commercial Subtotal	**$706,291**	**$7,005,277**	**$7,541,136**	**$15,252,705**
Indirect Portfolio Level Costs				
Contact Center				$72,664
Online Audit				$49,493
Outreach & Education				$583,785
Portfolio Costs Subtotal				**$705,942**
Subtotal - Before Evaluation				**$15,958,647**
Evaluation				$741,254
DSM Porfolio Total				**$16,699,901**
Other Costs Subtotal				
Emerging Markets				$200,000
Market Potential Study				$0
Unallocated Budget				$0
Other Costs Subtotal				**$200,000**
DSM Portfolio Total (Including Other Costs)				**$16,899,901**

C. Cost Effectiveness Results

The total portfolio for the CEI South programs passes the TRC and UCT test for both the Residential and Commercial & Industrial sectors. Table 9 below confirms that all programs pass the TRC at greater than one. In completing the cost effectiveness testing, CEI South used 6.03% as the weighted average cost of capital (WACC) as approved by the Commission on May 25, 2022 in Cause No. 44910. For the 2025 - 2027 Plan, CEI South utilized the avoided costs aligned with its 2022 IRP[1] adjusted down for fixed capacity.

Table 9: CEI South 2025-2027 Plan Cost Effectiveness Results without Performance Incentive

Programs	TRC	UCT	RIM	Participant	TRC NPV $	UCT NPV $	Levelized Cost/kWh	Cost/kWh
Residential								
Home Energy Solutions	1.20	1.42	0.57	2.34	$1,007,861	$1,773,561	$0.07	$0.45
Residential Prescriptive	1.45	2.04	0.73	1.85	$318,774	$527,223	$0.07	$0.41
Residential Midstream	1.07	1.25	0.58	2.27	$226,448	$680,091	$0.09	$0.52
Home Energy Assessment	1.03	1.03	0.42	2.40	$23,408	$23,408	$0.06	$0.56
In Store Discount	2.29	3.30	0.57	5.05	$439,232	$542,839	$0.03	$0.16
Multi Family Energy Solutions	1.91	1.72	0.49	4.34	$250,865	$220,509	$0.03	$0.29
Community Connections	2.12	2.12	0.48	0.00	$832,430	$832,430	$0.03	$0.34
Residential New Construction	1.35	1.09	0.52	0.00	$49,662	$15,613	$0.06	$0.80
Income Qualified Weatherization	0.52	0.33	0.25	0.00	$0	$0	$0.10	$1.68
Marketplace	10.48	3.51	0.83	0.00	$5,439,994	$4,300,218	$0.01	$0.36
Residential Behavioral Savings	1.22	1.22	0.58	0.00	$243,949	$243,949	$0.08	$0.09
Smart Cycle (DLC Change Out)	3.60	2.44	1.50	0.00	$13,525,563	$11,059,246	$0.09	$1.85
BYOT (Bring Your Own Thermostat)	2.96	2.96	2.25	0.00	$4,907,994	$4,907,994	$0.27	$0.00
Residential Subtotal	**2.40**	**1.94**	**0.93**	**6.59**	**$26,258,318**	**$23,353,520**	**$0.06**	**$0.61**
Commercial								
Commercial Prescriptive	1.77	2.76	0.50	3.37	$7,931,051	$11,591,404	$0.03	$0.20
Commercial Midstream	3.55	4.82	0.55	5.74	$839,197	$925,295	$0.02	$0.15
Commercial Custom	1.76	2.18	0.48	4.16	$4,504,700	$5,639,792	$0.03	$0.29
Small Business Energy Solutions	1.41	2.06	0.54	2.35	$2,596,703	$4,584,870	$0.05	$0.35
Building Optimization	8.54	3.69	0.53	0.00	$2,865,355	$2,366,106	$0.01	$0.21
Commercial Subtotal	**1.81**	**2.50**	**0.51**	**3.48**	**$18,737,006**	**$25,107,466**	**$0.03**	**$0.25**
CVR	2.94	2.94	0.93	0.00	$1,870,910	$1,870,910	$0.04	$0.56
Indirect Portfolio Level Costs Subtotal	0.00	0.00	0.00	0.00	-$4,791,358	-$4,791,358	$0.00	$0.00
DSM Portfolio Total (Including Other Costs)	**1.82**	**1.91**	**0.63**	**4.12**	**$42,074,877**	**$45,540,539**	**$0.05**	**$0.42**

* Cost per kWh is calculated by dividing program cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs. The cost per kWh excludes indirect and other costs for budget. Levelized cost per kWh is .05 per kWh, excluding IQW and CVR.

[1] Avoided costs aligned with CEI South's 2022 IRP, with an adjustment down to fixed capacity cost assumptions.

Table 10: CEI South 2025-2027 Plan Performance Incentives Based on Cost Effectiveness Results

2025 - 2027 Average PI	
UCT Net Total	**$45,540,539**
Exclude CVR	-$1,870,910
Total Net UCT	**$43,669,628**
100% Savings Achievement	8%
Total Performance Incentive	**$3,493,570**
Number of Years (2025-2027)	3
Annual Avg. PI	**$1,164,523**

6. New or Modified Program Initiatives

CEI South's 2025-2027 filing largely extends the existing momentum of the portfolio of programs from 2023 and 2024 while applying the lessons learned from CenterPoint's program experience and evaluations as well as making refinements to key data and assumptions as described in this document. Below is a summary which outlines notable changes for the 2025-2027 Plan from previous filings. More in depth details on the following topics can be found within the Program Descriptions portion of this document.

A. Home Energy Solutions

New delivery mechanisms will be added to the prescriptive program suite of offerings, which will complement the existing design. The mechanisms making up this suite of programs will be Residential Prescriptive, Residential Midstream, Home Energy Assessments and In Store Discounts. As new additional channels of program delivery are added to reach additional customers and markets, changing the name of this suite of programs to Home Energy Solutions was more fitting. The previous name of this suite of programs was Residential Prescriptive programs. This expansion will include many of the same measures from Residential Prescriptive to be offered through Residential Midstream and In Store Discounts. Home Energy Assessments, within this suite of programs will help homeowners understand where they have need for energy efficient measures and cross promote installation of other residential prescriptive measures.

B. Home Energy Assessment Program

The Home Energy Assessment program will be offered under our newly titled, Home Energy Solutions. This program will provide direct installation of energy-savings measures and educate consumers on ways to reduce energy consumption.

C. In Store Discount Program

Realizing how successful CEI South was at implementing our previous Residential Lighting program, we will be implementing other prescriptive measures in a similar way by implementing a new In Store Discount program. This program will be offered under the Home Energy Solutions suite. The program consists of a buy-down strategy that provides incentives to residential customers through retail outlets at the point of purchase.

D. Multi Family Energy Solutions

Following the success of our gas Multi-Family Direct Install program, CEI South is making this an integrated program to bring direct install energy efficient measures to owners and mangers of multi-family properties within the CEI South electric territory. As we focus on customer journey, this program will be called Multi Family Energy Solutions, rather than Multi-Family Direct Install.

E. Smart Cycle DLC Change Out & BYOT

CEI South will be increasing its focus on converting switches on hot water heaters and AC units to smart thermostats. This push will be assisted by a new Thermostat Load Control (TLC) Rider, informing customers that incentives will be increasing to make this switch and stay in our DR program.

F. Commercial Midstream

CEI South will be adding a midstream approach to their commercial and industrial portfolio.

7. Program Descriptions

A. Home Energy Solutions

Program Description

The program is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic insulation,. If a product vendor or contractor chooses to do so, the rebates can be presented as an "instant discount" to CEI South residential customers on their invoice. This program includes multiple delivery mechanisms to complement the traditional prescriptive program design. Many of the same measures from Residential Prescriptive will be offered within these expanded mechanisms through Residential Midstream, Home Energy Assessments and In Store Discounts. Programs encompassing our Home Energy Solutions program are:

- **Residential Prescriptive**: The Residential Prescriptive Program is a cash-back rebate program that helps CenterPoint Energy residential customers afford high efficiency equipment options when replacing space heating and cooling equipment through the Residential Prescriptive Program channel. The equipment rebates help to educate customers about the energy savings and non-energy benefits associated with higher efficiency equipment that reduces energy consumption. The Insulation channel of the Residential Prescriptive Program offers home weatherization rebates to residential customers for attic insulation.

- **Residential Midstream**: The Residential Midstream Program is very similar to the Residential Prescriptive Program, though it targets a smaller group of participating partners rather than focusing on end-use customers. By working with participating partners (Distributors and Contractors), the burden of the administrative paperwork is taken off end-use customers and absorbed through the partner. To help compensate participating partners for the administrative work, they receive a spiff for each piece of equipment submitted through the program.

- **Home Energy Assessments**: The Home Energy Assessment program is designed to produce long term energy and demand savings in the residential market through in-home and virtual energy assessments for market rate customers. The program will provide direct installation of energy-saving measures and educate consumers on ways to reduce energy consumption through additional weatherization measures such as air sealing, duct sealing, and insulation.
    - **Initial Measures, Products and Services**
        - Air Filter
        - Door Sweep
        - Door and Window Weatherstripping
        - Outlet Gaskets
        - High Efficiency Kitchen and Bathroom Aerators
        - High Efficiency Showerhead (Standard or Handheld)
        - Pipe Wrap
        - Smart Thermostat
        - Water Heater Temperature Setback
        - Smart Power Strips
        - Additional, deeper weatherization measures may be recommended to customers:
            - Aeroseal
            - Air Sealing
            - Attic Insulation
            - Duct repair, seal, and insulation
            - Wall Insulation

- **In Store Discounts**: The Residential In-Store Discount Program is a market-based residential energy efficiency program designed to reach residential customers through retail outlets. The

program consists of a buy-down strategy that provides incentives to consumers to facilitate the purchase of energy efficient products. The overall program goal is to increase the penetration of energy efficient products by influencing customer's purchase decisions at the point of purchase.

- **Initial Measures, Products and Services**
  - Advanced power strips
  - Air filters
  - Air purifiers
  - Bathroom vent fans
  - Dehumidifiers
  - Door and window weatherstripping
  - Door sweeps
  - Room AC units
  - Spray foam
  - Additional measures may be added upon confirming cost effectiveness

Table 12: Residential Prescriptive Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Home Energy Solutions**				
	Number of Measures	8,814	10,136	11,539	30,489
	Energy Savings kWh	3,151,328	3,295,993	3,470,805	9,918,126
	Peak Demand kW	838	828	825	2,490
	Total Program Budget $	$1,400,784	$1,496,519	$1,605,524	$4,502,827
	Per Participant Avg. Energy Savings kWh	358	325	301	325
	Per Participant Avg. Demand Savings kW	0.095	0.082	0.071	0.082
	Weighted Avg. Measure Life				14
	Net to Gross Ratio				84%
*Includes Prescriptive, Midstream, HEA and In Store Discount programs					

Eligible Customers

Any residential customer located in the CEI South electric service territory are eligible to participate in the programs. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation measures.

Marketing Plan

The marketing plan includes program specific marketing materials that will target contractors and trade allies in the Heating, Ventilation and Air Conditioning (HVAC) industry. The HVAC industry will be marketed to by using targeted direct marketing, direct contact by the program vendor personnel, trade shows and trade association outreach. The program will be promoted through trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets. CEI South will also use web banners, bill inserts, and mass market advertising. Program marketing directs customers and contractors to the CEI South website or call center for information.

The Midstream marketing plan will target distributors and large contractors through direct outreach to contractor trade networks. Co-branded materials will be available to participating distributors to draw attention to, and provide education on, the HVAC measures within the program. Fact Sheets will also be created to keep the program top of mind. CLEAResult will provide program approved verbiage for email blast content for Distributors to promote the program to their Contractors.

Barriers/Theory

The initial cost is one of the key barriers to the adoption of EE technology. Customers do not always understand the long-term benefits of the energy savings from these efficient alternatives. Trade allies are also often reluctant to sell the higher cost items as they do not want to be the high-cost bidder. Incentives help address the initial cost issue and provide a good reason for Trade Allies to promote these higher efficient options.

The main barrier for Midstream is the administrative burden and costs of implementation for the distributor. To address this burden, incentives are paid directly to the distributor, with savings passed along to the customer. With program activity focused on engaging distributors, customers find energy efficiency programs simple and appealing, as their participation varies little from their typical purchasing practices.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix B. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

Program Delivery

CEI South will oversee the program and will partner with CLEAResult. CLEAResult will work with local contractors to deliver the program.

Integration with CEI South Gas

CEI South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards and a

verification of 5% of the measures installed. A third-party evaluator will review the program using appropriate EM&V protocols.

B. Multi-Family Energy Solutions

Program Description

The Multi-family Energy Solutions program is designed to produce long term energy savings within multifamily properties. The program provides customers with information on energy best practices and promotes energy efficiency through the installation of energy efficient technologies including high efficiency showerheads, aerators, door and window weatherstripping, door sweeps and Smart Thermostats. In addition, the program will begin offering weatherization services such as air and duct sealing. Additional measures may be available to properties that also have electric service from CEI. The program is open for, and promoted to, owners and managers of multi-family properties in the CEI South and CEI North territory. The program will educate consumers on ways to reduce energy consumption and cross promote other programs to increase overall awareness.

Table 13: Multi-Family Energy Solutions Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Multi Family Energy Solutions**				
	Number of Homes	51	51	51	153
	Energy Savings kWh	366,701	366,701	366,701	1,100,102
	Peak Demand kW	29	29	29	86
	Total Program Budget $	$100,876	$102,122	$103,421	$306,420
	Per Participant Avg. Energy Savings kWh	7,190	7,190	7,190	7,190
	Per Participant Avg. Demand Savings kW	0.565	0.565	0.565	0.565
	Weighted Avg. Measure Life				11
	Net to Gross Ratio				100%

Eligible Customers

This program is available to multifamily properties located in the CEI South and CEI North territory. Properties must have electric and/or natural gas service from CEI and CEI service must be the source for primary space heating. Service should be in the tenant's name, though consideration will be given to properties that are master-metered where the property includes utilities in the monthly expense to the tenant. Eligible properties cannot have received an audit from this program within the last three years.

Marketing Plan

The Multifamily Energy Solutions Program will be marketed to multifamily property ownership and property management organizations, as well as through direct outreach to property managers.

Barriers/Theory

Identifying multifamily buildings that are eligible to participate. The main barrier is educating landlords and property managers, who are CEI South customers, to invest the initial funds into implementing high efficiency measures for their units and tenants.

Initial Measures, Products and Services

Measures available for installation will vary based on the property and may include:

- Air Filter*
- Door Sweep
- Door and Window Weather Stripping
- High Efficiency Kitchen and Bathroom Aerators
- High Efficiency Showerhead (Standard or Handheld)
- LED Nightlight*
- Pipe wrap
- Smart thermostat
- Water Heater Temperature Setback
- Smart power strips*

Additional, deeper weatherization measures may be recommended to customers:

- Infiltration reduction
- Aeroseal
- Attic insulation
- Duct repair, seal and insulation
- Air Sealing – Gas Furnace with CAC, Heat Pump, Electric Furnace with CAC
- Wall Insulation

*Measures available only to customers with CEI electric service

Program Delivery

CEI South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with CEI South Gas

CEI South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

The implementation contractor will verify the paperwork and properly record installations. A third-party evaluator will evaluate the program using standard EM&V protocols.

C. Community Connections

Program Description

The Community Connections program is designed to provide energy efficient products to low-income customers who receive assistance from local food banks, township trustees, and additional community-assistance organizations. The program is intended to educate low-income customers on the benefits of energy efficient measures and provide them with products which would otherwise be unaffordable.

Table 14. Community Connections Program Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Community Connections**				
	Number of Measures	45,000	45,000	45,000	135,000
	Energy Savings kWh	778,800	778,800	778,800	2,336,400
	Peak Demand kW	22	22	22	65
	Total Program Budget $	$244,120	$265,105	$276,585	$785,811
	Per Participant Avg. Energy Savings kWh	17	17	17	17
	Per Participant Avg. Demand Savings kW	0.000	0.000	0.000	0.000
	Weighted Avg. Measure Life				19
	Net to Gross Ratio				100%

Eligible Customers

The Community Connections program targets local food banks, township trustees, and additional community-assistance organizations who serve low-income homeowners and tenants within CEI South electric service territory.

Marketing Plan

Marketing materials will be created to educate product recipients on the benefits of energy efficiency products.

Barriers/Theory

Lower income homeowners do not have the money to make even simple improvements to lower their bill and often live in homes with the most need for EE improvements. This program provides those customers with products to help them start saving energy without needing to make the investment themselves.

Initial Measures, Products and Services

The below measures will be offered in CEI South's Community Connections program:

- LED Nightlight
- Outlet Gaskets
- Door and Window Weather Stripping
- Door Sweep

Program Delivery

CEI South will oversee the program and will partner with CLEAResult to deliver the program.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

D. Residential New Construction

Program Description

The Residential New Construction (RNC) program produces long-term energy savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall. The program will incentivize builders and help improve cost effectiveness.

The Residential New Construction program allows builders to individually select high-efficiency measures at a tiered approach, which improves flexibility enhancing the ability to meet participant demand. This approach also helps encourage a more energy efficiency focus at the measure level. Structuring this program around specific measures allows CEI to analyze specific measures, add or remove measures and ensure the program is cost-effective.

The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

Table 15: Residential New Construction Program Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Residential New Construction**				
	Number of Homes	154	154	154	462
	Energy Savings kWh	78,637	78,637	78,637	235,912
	Peak Demand kW	30	30	30	91
	Total Program Budget $	$59,343	$62,762	$66,515	$188,620
	Per Participant Avg. Energy Savings kWh	511	511	511	511
	Per Participant Avg. Demand Savings kW	0.197	0.197	0.197	0.197
	Weighted Avg. Measure Life				18
	Net to Gross Ratio				64%

Eligible Customers

Any customer or home builder constructing a home to the program specifications in the CEI South electric service territory are eligible to participate.

Marketing Plan

In order to move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

Barriers/Theory

The Residential New Construction Program addresses a few barriers. The first barrier is cost. The program provides incentives to help reduce the first-year cost of the EE upgrades. Another barrier is customer and builder knowledge of the positive impact of energy efficient measures around energy consumption, costs associated to measure life and benefits to the environment.

Incentive Strategy

To encourage home builders to implement more energy efficient measures, an incentive will be placed on each provided measure.

Initial Measures, Products and Services

Measures available for installation will vary based on the home and may include:

- Central AC (15+ SEER2)
- Heat Pump – Tier 1
- Heat Pump – Tier 2
- Heat Pump Water Heater
- Smart Tstat – Heat Pump
- Smart Tstat – Gas Furnace + CAC
- Whole Home – BOP 1 – Heat Pump
    - Heat Pump & Smart Thermostat
- Whole Home – BOP 2 – Heat Pump
    - Heat Pump, Heat Pump Water Heater and Smart Thermostat
- Whole Home – BOP 1 – Gas Heat + CAC
    - CAC or Heat Pump and Smart Thermostat
- Whole Home – BOP 2 – Gas Heat + CAC
    - CAC or Heat Pump, Tankless or Heat Pump Water Heater and Smart Thermostat

Program Delivery

CEI South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with CEI South Gas

CEI South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards. A third-party evaluator will review the program using appropriate EM&V protocols.

E. Income Qualified Weatherization

Program Description

The Income Qualified Weatherization (IQW) program is designed to produce long-term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Customers eligible through the Income Qualified Weatherization Program will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, air infiltration reduction and installation of new central air conditioner or air source heat pump.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. Vectren South is committed to finding innovative solutions to these areas. A health and safety (H&S) budget has been established, and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment. –CEI continues to look for ways to do more of a qualitative approach within this program to ensure the maximum savings is reached and H&S issues are addressed appropriately.

Table 16: Income Qualified Weatherization Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Income Qualified Weatherization**				
	Number of Homes	837	872	907	2,616
	Energy Savings kWh	778,688	784,334	789,979	2,353,001
	Peak Demand kW	83	86	90	259
	Total Program Budget $	$1,331,078	$1,377,020	$1,424,781	$4,132,879
	Per Participant Avg. Energy Savings kWh	930	899	871	899
	Per Participant Avg. Demand Savings kW	0.099	0.099	0.099	0.099
	Weighted Avg. Measure Life				11
	Net to Gross Ratio				100%

Eligible Customers

This program is available to residential customer who receive either electric only or gas and electric service from CEI where CEI is the homes primary heat source. Homes must be at least 5 years or older and have not received an audit within the last three years; and is owner occupied or authorized non-owner occupied where occupants have the service in their name. Eligible homes must be less than 4 total units,

and units should not be stacked. The traditional IQW will continue in its current state offering a home audit, direct install measures and air sealing for customers up to 300% of the Federal Poverty Level (FPL). Additionally, deeper measures including weatherization, air conditioner or air source heat pump replacement will be performed under a "Whole Home IQW" which is offered to customers who qualify with income of up to 200% FPL.

Marketing Plan

CEI South will provide a list to the implementation contractor of customers who have received Energy Assistance Program (EAP) funds within the past 12 months to help prioritize those customers who will benefit most from the program. This will also help in any direct marketing activities to specifically target those customers. In addition to utilizing the EAP List, the program will utilize census data to target low-income areas within CEI territory. CEI uses door-to-door canvassing for obtaining most of the appointments. The program is marketed to the public as "Neighborhood Weatherization" at various community events.

Barriers/Theory

Lower-income homeowners do not have the money to make even simple improvements to lower their bill and often live in homes with the most need for EE improvements. They may also lack the knowledge, experience, or capability to do the work. Health and safety can also be at risk for low-income homeowners, as their homes typically are not as "tight", and indoor air quality can be compromised. In order to increase participation and eligibility, CEI South has incorporated a H&S budget into the program. An average of $250 per fuel type or $500 per home has been budgeted, however H&S dollars can be spent up to $5,000 per home, upon approval by CEI. This program provides customers with basic improvements to help them start saving energy without needing to make the investment themselves.

Initial Measures, Products and Services

As specified above under program changes, the measures available for installation will vary based on the home and include:

Traditional IQW - Income requirement of up to 300% FPL

- GSL and Specialty LED Bulbs/Lamps (Interior/Exterior/Candelabras)
- High Efficiency Kitchen and Bathroom Aerators
- High Efficiency Showerhead (Standard or Handheld)
- Pipe Wrap

- Filter Whistles
- Infiltration Reduction
- Attic Insulation
- Duct Repair, Seal and Insulation
- Air Sealing - Gas Furnace with CAC, Heat Pump, Electric Furnace with CAC
- Refrigerator replacement
- Smart thermostat
- Water Heater Temperature Setback
- Smart power strips
- CAC or Furnace Tune-Up

Whole Home IQW - Income requirement of up to 200% FPL. Includes all the "Traditional" measures plus:

- Water heater replacement
- Attic Insulation
- Wall Insulation
- Exterior caulking
- CAC or Furnace Replacement

Program Delivery

CEI South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

CEI South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure quality installations, 5% of the installations will be field inspected. A third-party evaluator will evaluate the program using standard EM&V protocols.

F. Marketplace

Program Description

The online marketplace program encourages customers to purchase products online where an instant rebate is applied.

Table 17: Marketplace Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Marketplace**				
	Number of Measures	7,209	7,548	7,893	22,650
	Energy Savings kWh	1,618,571	1,694,556	1,772,227	5,085,354
	Peak Demand kW	603	632	661	1,895
	Total Program Budget $	$582,007	$605,716	$629,752	$1,817,475
	Per Participant Avg. Energy Savings kWh	225	225	225	225
	Per Participant Avg. Demand Savings kW	0.084	0.084	0.084	0.084
	Weighted Avg. Measure Life				14
	Net to Gross Ratio				100%

Eligible Customers

Residential customers who receive electric service from CEI South are eligible to participate in this integrated natural gas and electric EE program**.**

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, CEI South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Barriers/Theory

The initial cost is one of the key barriers to the adoption of EE technology. Customers do not always understand the long-term benefits of the energy savings from these efficient alternatives. Incentives help address the initial cost issue to promote higher efficient options.

Initial Measures, Products and Services

- Air Purifier
- Bathroom Aerator (Dual)
- Dehumidifier
- Deluxe (5) Window Insulation Kit
- High Efficiency Showerhead (Fixed)

- High Efficiency Showerhead (Handheld)
- Kitchen Aerator (Dual)
- Night Light
- Pipe Insulation
- Showerstart TSV
- Smart Power Strips
- Smart Thermostats
- Switch and Outlet Sealing Gaskets
- T8 Bulbs
- Weatherstripping

Program Delivery

CEI South will oversee the program and will partner with Franklin Energy to deliver the program.

Integration with CEI South Gas

CEI South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

G. Residential Behavior Savings

Program Description

The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of other customers with similar home size and demographics. Customers can view the past 12 months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. Once a consumer understands better how they use energy, they can adjust certain behaviors that will help them start conserving energy. A new wave of participants was launched in January 2023 which should continue to increase savings as customers become more aware of actions to lower energy use. The main delivery channel will be targeted mail and email with the addition of specific tips provided to the low-income customer segment.

Program data and design was provided by Oracle, the implementation vendor for the program. Oracle provides energy usage insight that drives customers to take action by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Table 18: Residential Behavior Savings Program Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Residential Behavioral Savings**				
	Number of Participants	49,700	49,700	49,700	149,100
	Energy Savings kWh	3,925,117	3,925,117	4,925,117	12,775,350
	Peak Demand kW	1,850	1,850	1,850	5,550
	Total Program Budget $	$384,102	$384,193	$384,288	$1,152,582
	Per Participant Avg. Energy Savings kWh	79	79	99	86
	Per Participant Avg. Demand Savings kW	0.037	0.037	0.037	0.037
	Weighted Avg. Measure Life				1
	Net to Gross Ratio				100%

Eligible Customers

Residential customers who receive electric service from CEI South are eligible to participate in this integrated natural gas and electric EE program**.**

Barriers/Theory

The Residential Behavioral Savings program keeps residential customers better informed by providing comprehensive energy information through personalized reports delivered by mail, email and an integrated web portal to help them put their energy usage in context and make better energy usage decisions. Behavioral science research has demonstrated that peer-based comparisons are highly motivating ways to present information. The program will leverage a dynamically created comparison group for each residence and compare it to other similarly sized and located households.

Implementation & Delivery Strategy

The program will be delivered by Oracle and include energy reports and a web portal. Customers typically receive between 4 - 6 reports annually. Additionally, customers receive monthly emails. These reports provide updates on energy consumption patterns compared to similar homes and provide energy savings strategies to reduce energy use. These reports can also promote other CEI South programs to customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy savings tips and be connected to other CEI South gas and electric programs. In efforts to enhance program savings to low-income customers, Oracle will provide specific tips to the low-income customer segment.

Program Delivery

CEI South will oversee the program and partner with Oracle to deliver the program.

Integration with CEI South Gas

CEI South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third-party evaluator will complete the evaluation of this program and work with CEI South to select the participant and non-participant groups.

H. Smart Cycle (DLC Change Out) Program

Program Description

Until recently, Direct Load Control (DLC) switches have been the default choice for residential load control programs. CEI South has had a DLC program since the early 1990's and currently has approximately 23,778 switches that remain in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, CEI South began replacing DLC switches with smart thermostats. Smart thermostats provide an alternative to traditional residential load control switches as well as enhance the way customers manage and understand their home energy use.

Within the 2025-2027 Plan, CEI South will continue to replace DLC switches with smart thermostats. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while utilities can learn from occupant behavior/preference, adjusting heating, ventilation, and air conditioning (HVAC) settings. Evaluation results are showing significantly more load reduction delivered by smart thermostats. The current DLC switch program is a well-established means for CEI South to shed load during peak demand; however, over time, to optimize results while minimizing cost to the customer, designing a program incorporating a change out from switches to smart thermostats is a strategic option for cost effective load control solutions.

Starting in 2025, during the months of March – November, the customers will receive a monthly bill credit of $7.50 for participating in the program. Customers will be notified of all events and have the capability of opting out of events at any time during the actual event. Additionally, the 2016 Pilot Smart T-Stat program budget is included with this program. No savings are captured for the 2016 Pilot Smart T-Stat program.

Table 19: Smart Cycle (DLC Change Out) Program & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**Smart Cycle (DLC Change Out)**				
	Number of Measures	3,000	3,000	3,000	9,000
	Energy Savings kWh	1,477,053	1,477,053	1,477,053	4,431,160
	Peak Demand kW	3,300	3,300	3,300	9,900
	Total Program Budget $	$2,312,607	$2,623,747	$3,245,409	$8,181,763
	Per Participant Avg. Energy Savings kWh	492	492	492	492
	Per Participant Avg. Demand Savings kW	1.100	1.100	1.100	1.100
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				100%

Eligible Customers

The Smart Cycle (DLC Change Out) Program will focus on residential single-family homes and apartment dwellers that have access to a Wi-Fi network and are currently direct load control switch customers participating in the DLC program.

Marketing Plan

Proposed marketing efforts include utilizing dict mailers, email blasts, CEI South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Barriers/Theory

The Smart Cycle (DLC Change Out) program exists to reduce residential energy use through enhancing users' control of home heating and cooling systems. The enhanced control afforded by Wi-Fi enabled thermostats reduces the costs of controlling the space heating and cooling systems and creates potential for energy savings by enabling users to better align cooling and heating use with customer occupancy. Smart thermostats provide customers increased visibility and control of their energy use through their mobile devices and apps.

Incentive Strategy

Customers will receive a professionally installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $7.50 during the months of March to November.

Program Delivery

CEI South will oversee the program and are currently partnered with Schneider Heating and Air to complete the work.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

I. Bring Your Own Thermostat (BYOT)

Program Description

The BYOT program allows customers with a compatible thermostat to participate in demand response (DR) events – utility managed load curtailing programs during periods when electricity demand is high. The BYOT program allows the utility to avoid the costs of hardware, installation, and maintenance associated with traditional load control methods. Customers choose to participate in this program by enrolling their eligible device. Upon enrolling, they receive a one-time credit. A customer actively participating in the program will also receive monthly credits during the months DR events are called.

By taking advantage of two-way communicating smart thermostats, BYOT programs can help utilities curtail load, reduce acquisition costs associated with typical load curtailment programs and improve customer satisfaction. With smart enabled thermostats, the utility can remotely verify how many customers are participating in DR events. Customers will be notified of all events and have the capability of opting out of events at any time during the actual event.

Table 20: BYOT Program Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Residential	**BYOT (Bring Your Own Thermostat)**				
	Number of Participants	1,300	1,300	1,300	3,900
	Energy Savings kWh				
	Peak Demand kW	1,430	1,430	1,430	4,290
	Total Program Budget $	$883,490	$883,810	$884,141	$2,651,440
	Per Participant Avg. Energy Savings kWh				0
	Per Participant Avg. Demand Savings kW	1.100	1.100	1.100	1.100
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				100%

Eligible Customers

Any eligible residential customer who receives electric service from CEI South at a single-family residence.

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, CEI South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Barriers/Theory

The BYOT program allows customers, who have purchased their own smart thermostat, to participate in the DR load curtailing programs managed by CEI South. Targeting those that have smart thermostats enables many more residential customers to participate in DR programs without the need to work through a direct installation program. This lowers the substantial barrier to program participation and avoids the potential impediment of a customer wishing to keep their existing thermostat (as they might in an installation program). This program can also help increase customer engagement and satisfaction as it allows customers to interact with its utility.

Smart thermostats are true consumer products, valued by customers for more than their ability to enable participation in DR programs. Customers tend to place a high value on the aesthetics and user interface of their thermostats and appreciate the ability to monitor and control the HVAC system in their homes remotely via their mobile phone to get information on their energy usage and to integrate thermostat operation with other smart-home devices. They also provide energy efficiency savings for space heating and cooling through enhancing users' control of home heating and cooling systems.

Incentive Strategy

Customers will receive a one-time enrollment incentive of $75 and a bill credit of $7.50 during the months of March to November.

Program Delivery

CEI South oversees the program and has partnered with Energy Hub to provide delivery of the BYOT program.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

J. Conservation Voltage Reduction - Residential and Commercial & Industrial

Program Description

Conservation Voltage Reduction (CVR) achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served. The first CVR was put into service in July 2017, for the Buckwood substation. The second CVR was put into service in February 2020, for the Eastside substation The third CVR was put into service in August 2023, for the Tekoppel substation. These substations contain approximately 16,223 customers: 14,409 Residential and 1,814 Commercial. This filing has the fourth CVR being planned in 2026.

Energy and demand savings occur when CVR is applied to distribution circuits. Once applied, a step change in energy and demand consumption by customers is realized, dependent upon where customer loads are located within the voltage zones, the load characteristics of the circuit, and how end-use loads respond to the voltage reduction. The resultant energy and demand consumption reduction persists at the new levels if tighter voltage bandwidth operation is applied. As a result, ongoing energy and demand savings persists for the duration of the life of the CVR equipment and if the equipment is maintained and operated in the voltage bandwidth mode.

As approved in Cause 44645, CEI South capitalized the costs to implement the CVR program and will recover the program budget, consisting of ongoing maintenance, carrying cost, and depreciation expense associated with the implementation along with annual ongoing O&M expense through the annual DSMA rider. The 2025-2027 Plan will contain these expenses for the Buckwood, Eastside and Tekoppel substation as well as the substation for the 2026 year.

Table 21: Conservation Voltage Reduction Energy Savings Targets[2]

Market	Program	2025	2026	2027	Total Program
Residential	**CVR Residential**				
	Number of Participants	0	5,097	0	5,097
	Energy Savings kWh	0	1,328,231	0	1,328,231
	Peak Demand kW	0	1,011	0	1,011
	Total Program Budget $	$105,472	$187,776	$246,820	$540,069
	Per Participant Avg. Energy Savings kWh		261		261
	Per Participant Avg. Demand Savings kW		0.198		0.198
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				100%

Market	Program	2025	2026	2027	Total Program
Commercial	**CVR Commercial**				
	Number of Participants	0	674	0	674
	Energy Savings kWh	0	524,327	0	524,327
	Peak Demand kW	0	284	0	284
	Total Program Budget $	$110,578	$167,096	$217,427	$495,101
	Per Participant Avg. Energy Savings kWh		778		778
	Per Participant Avg. Demand Savings kW		0.422		0.422
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				100%

Eligible Customers

Customers receiving service from the respective substations.

Barriers/Theory

CVR is both a DR and an EE program. It targets distribution circuits, in part to reduce the peak demand experienced on CEI's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization allows the customer's equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

[2] For purposes of this filing, the CVR savings include only the 2026 CVR substation because savings are recognized fully the first year of implementation, therefore Buckwood substation, Eastside substation and Tekoppel substation savings were recognized fully in 2017, 2020 and 2023.

Program Delivery

Delivery of the CVR Program will be achieved through the installation of control logic, telecommunication equipment, and voltage control equipment in order to control the voltage bandwidth on CVR circuits within voltage compliance levels required by the Indiana Utility Regulatory Commission.

Initial Measures, Products and Services

CEI South will install the required communication and control equipment on the appropriate circuits from the substation. No action is required of the customers.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

K. Commercial and Industrial Prescriptive

Program Description

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around EE. Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Table 22: Commercial & Industrial Prescriptive Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Commercial	**Commercial Prescriptive**				
	Number of Measures	13,561	13,651	13,653	40,865
	Energy Savings kWh	11,200,000	12,600,000	13,500,000	37,300,000
	Peak Demand kW	1,797	1,986	2,054	5,837
	Total Program Budget $	$2,189,973	$2,435,137	$2,477,390	$7,102,500
	Per Participant Avg. Energy Savings kWh	826	923	989	913
	Per Participant Avg. Demand Savings kW	0.132	0.145	0.150	0.143
	Weighted Avg. Measure Life				12
	Net to Gross Ratio				84%

Eligible Customers

Any participating commercial or industrial customer receiving electric service from CEI South.

Marketing Plan

Proposed marketing efforts include trade ally outreach, trade ally meetings, direct mail, face-to-face meetings with customers, targeted marketing campaigns (food service industry, healthcare, BTU, etc.) potential bonuses, web-based marketing, and coordination with key account managers.

Barriers/Theory

Customers often have the barrier of higher first cost for EE measures which precludes them from purchasing the more EE alternative. They also lack information on high efficiency alternatives. Trade allies often run into the barrier of not being able to promote more EE alternatives because of first cost or lack of knowledge. Trade allies also gain credibility with customers for their EE claims when a measure is included in a utility prescriptive program. Through the program the trade allies can promote EE measures directly to their customers encouraging them to purchase more efficient equipment while helping customers get over the initial cost barrier.

Initial Measures, Products and Services

Measures will include high-efficient lighting and lighting controls, HVAC equipment including variable frequency drives, commercial kitchen equipment including electronically commutated motors (ECMs), and miscellaneous items including efficient compressed air equipment. Note that measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified. Detailed measure listings, participation and incentives are in Appendix B.

Implementation & Delivery Strategy

The program will be delivered primarily through the trade allies working with their customers. CEI South and its implementation partners will work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the Commercial & Industrial Custom program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentive Strategy

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the highly efficient option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much to motivate customers. Incentives will be adjusted to respond to market activity and bonuses may be available for limited time, if required, to meet goals.

Program Delivery

CEI South will oversee the program and partner with Resource Innovations to deliver the program.

Evaluation, Measurement and Verification

Site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000, to verify the correct equipment was installed. Standard EM&V protocols will be used for the third-party evaluation of the program.

L. Commercial and Industrial Midstream

Program Description

The Commercial & Industrial (C&I) Midstream Program is designed to capture additional energy savings by expanding CEI South's customer reach. This approach helps influence distributors to supply a higher volume of energy efficient products in an effort to transform the market. By promoting higher stocking practices of energy efficient products, such as HVAC and food service equipment, CEI South will be able to close potential savings gaps left on the table from commercial customers not taking full advantage of our commercial prescriptive program. This design pays out incentives at the distributor level, which is then passed on to contractors or customers. Increased supply, lower costs and less hassle will encourage contractors to purchase more energy efficient products.

Table 23: Commercial & Industrial Midstream Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Commercial	**Commercial Midstream**				
	Number of Measures	32	38	33	103
	Energy Savings kWh	448,263	567,005	675,197	1,690,466
	Peak Demand kW	53	82	72	206
	Total Program Budget $	$67,107	$87,693	$104,221	$259,021
	Per Participant Avg. Energy Savings kWh	14,008	14,921	20,461	16,412
	Per Participant Avg. Demand Savings kW	1.658	2.150	2.170	2.004
	Weighted Avg. Measure Life				20
	Net to Gross Ratio				84%

Eligible Customers

Any participating commercial or industrial customer receiving electric service from CEI South.

Marketing Plan

Proposed marketing efforts include targeting distributors through direct outreach to contractor trade networks, direct mail, face-to-face meetings with customers, targeted marketing campaigns, potential bonuses, web-based marketing, and coordination with key account managers.

Barriers/Theory

Customers often have the barrier of higher first cost for EE measures which precludes them from purchasing the more EE alternative. They also lack information on high efficiency alternatives or are turned away due to the hassle of applying for rebates. Encouraging distributors to stock more energy efficient products will help reduce costs and hassle for trade allies and increase adoption of energy efficient products and continue to promote these measures to CEI South commercial customers. A midstream approach makes the purchasing and installation of energy efficient products seamless for our

trade allies and commercial customers as they are able to benefit from the distributor level incentive immediately at the time of purchase. Another barrier is lack of readily available energy efficient measures. By helping distributors stock more energy efficient measures, when a customer suddenly finds themselves in need of a replacement measure, there will be energy efficient products already stocked and ready to be installed in these emergency situations.

Initial Measures, Products and Services

Measures include HVAC, refrigeration, and commercial kitchen equipment. Note that measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified. Detailed measure listings, participation and incentives are in Appendix B.

Implementation & Delivery Strategy

The program will be delivered primarily by partnering with distributors. CEI South and its implementation partners will work with these distributors to encourage them to stock more energy efficient products by paying an incentive directly to the participating distributor. The implementation partner will provide training and technical support to the distributor to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the Commercial & Industrial Custom program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentive Strategy

Incentives are provided directly at the distributor level to reduce the difference in first cost between the lower efficient technology and the highly efficient option and to encourage increasing supply of energy efficient products into our market. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much to motivate customers. Incentives will be adjusted to respond to market activity and bonuses may be available for limited time, if required, to meet goals.

Program Delivery

CEI South will oversee the program and partner with Resource Innovations to deliver the program.

Evaluation, Measurement and Verification

Site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000, to verify the correct equipment was installed. Standard EM&V protocols will be used for the third-party evaluation of the program.

M. Commercial and Industrial Custom

Program Description

To maximize cost-effectiveness and streamline program delivery, the Commercial Custom Program encompasses several different options for commercial & industrial customers to participate. These include: Custom Program, Commercial New Construction, Building Tune Up, Strategic Energy Management (SEM) and Refrigeration Tune-up.

The **Custom Program** promotes the implementation of customized energy-saving projects at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible.

Specific to **Commercial New Construction-Energy Design Assistance (EDA)**, this program provides value by promoting EE designs with the goal of developing projects that are more energy efficient than current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g. lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions.

The **Building Tune-Up** program provides a targeted, turnkey, and cost-effective retro-commissioning solution for small- to mid-sized customer facilities. It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. Most of these measures will be no- or low-cost with low payback periods and will capture energy savings from building automation systems.

CenterPoint Energy will offer a **Strategic Energy Management (SEM)** offering to select large energy users throughout 18-month training process. Upon enrollment, the customer is assigned an energy manager to provide personalized service, as well as technical support, and a facility audit. Due to the 18-month training process, anticipated savings from this will be realized across program years. Savings will capture both prescriptive/custom capital investments and behavioral changes through on-site consultation.

The **Refrigeration Tune-up** program helps to implement energy efficiency into buildings with refrigeration systems where the opportunity for energy savings often times goes unnoticed by maintenance staff. CEI South customers utilizing this program will gain easy access to extensive engineering expertise and direct assistance with a fully incentivized refrigeration system study. The study will help customers fine-tune the operations of their refrigeration equipment, controls, and schedules with no- and low-cost measures. This program also opens the opportunity to identify more capital-intensive equipment upgrades that will improve efficiency and result in significant energy savings. This program offers two types of measures: operational and capital.

- Operational Measures include:
    - Floating head control
    - Optimize suction pressure setpoints

- Suction float controls
- Anti-sweat heater controls
- Repair anti-sweat heater controller
- Optimize defrost cycles

- Capital Measures include:
  - Night curtains
  - Retrofit doors
  - Anti-sweat heater controls
  - Replace shaded pole motors with ECMs
  - Control Evaporator Fans
  - VFDs on condenser fans

Table 24: Commercial & Industrial Custom Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Commercial	**Commercial Custom**				
	Number of Participants	89	93	93	275
	Energy Savings kWh	5,600,000	6,100,000	6,100,000	17,800,000
	Peak Demand kW	754	754	754	2,261
	Total Program Budget $	$1,552,295	$1,761,353	$1,911,004	$5,224,652
	Per Participant Avg. Energy Savings kWh	62,921	65,591	65,591	64,727
	Per Participant Avg. Demand Savings kW	8.468	8.106	8.106	8.223
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				84%

Eligible Customers

Any participating commercial or industrial customer receiving electric service from CEI South.

Marketing Plan

Proposed marketing efforts include individualized outreach to large C&I customers through a variety of channels and coordination with key account managers to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, marketing campaigns and bonuses, trade ally meetings, and educational seminars could also be used to promote the program. The Building Tune-Up, Commercial New Construction, and Refrigeration Tune-up programs will be marketed through the Commercial Custom Program through outreach and direct personal communication from CEI South staff and third-party contractors. The program implementer will provide service provider specific-marketing collateral to support these companies as they connect with customers. SEM marketing includes individualized outreach to large C&I customers through a variety of channels to solicit program participants. We anticipate these outreach efforts will include several on-site meetings at customer facilities.

Barriers/Theory

Applications of some specific EE technologies are unique to that customer's application or process. The energy savings estimates for these measures are highly variable and cannot be assessed without an engineering estimation of that application; however, they offer a large opportunity for energy savings. To promote the installation of these highly efficient technologies or measures, the Commercial & Industrial Custom programs will provide incentives based on the kWh saved as calculated by the engineering analysis. To assure savings, these projects will require program engineering reviews and preapprovals. The custom energy assessments offered will help remove customer barriers regarding opportunity identification and determining energy savings potential.

The Building Tune-Up program will typically target customers with buildings between 50,000 square feet and 150,000 square feet. Customers in this size range face unique barriers to energy efficiency. For example, although they are large enough to have a Building Automation System (BAS), they are usually too small to have a dedicated facility manager or staff with experience achieving operational efficiency. Also, most retro-commissioning service companies prefer larger projects and are too expensive for small-to-midsized customers. We have specifically tailored the incentive structure and program design to eliminate these barriers. The Building Tune-Up program is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures eligible for incentive offerings.

Initial Measures, Products and Services

All technologies or measures that save kWh qualify for the program. There are different services offered in the Building Tune-Up, New Construction, Refrigeration Tune-up and SEM sub-programs. The BTU program will specifically target measures that provide no- and low-cost operational savings. Most measures involve optimizing the building automation system (BAS) settings, but the program will also investigate related capital measures, like controls, operations, processes, and HVAC.

The New Construction service provides energy design assistance at the design phase to encourage new buildings to go beyond what Indiana code requires. Each recommendation is provided to the customer through a report that estimates the savings and cost impacts. Customers are then provided additional rebates for each recommendation they select and install from the report.

The refrigeration tune-up program will provide customers with a study that helps optimize the operations of their refrigeration equipment, controls, and schedules with no- and low-cost measures. This study will also identify more capital-intensive equipment upgrades and provide a seamless link for customers to the appropriate prescriptive and custom rebates. The service within the SEM program provides in-depth consulting and support to large energy users who are interested in becoming ISO 50001 Ready. The program assigns a certified trainer to help set up their Energy Management System and trains them on best practices of energy management over an 18-month period. The participating customer will also receive an energy audit that will identify areas of opportunity to optimize the energy use in their facility.

Implementation & Delivery Strategy

The implementation partner will work collaboratively with CEI South staff to recruit and screen customers for receiving facility energy assessments, technical assistance and energy management education. The implementer will staff an energy manager to meet with large energy users and offer assistance with identifying savings opportunities and program participation. The implementation partner will also provide engineering field support to customers and trade allies to calculate the energy savings. Customers or trade allies with a proposed project will complete an application form with the energy savings calculations for the project. The implementation team will review all calculations and where appropriate complete site visits to assess and document pre installation conditions. Customers will be informed, and funds reserved for the project. Implementation engineering staff will review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings.

C&I New Construction - The new construction program is designed as a proactive, cost-effective way to achieve energy efficiency savings and foster economic growth. Typically, program participants face time and cost constraints throughout the project that make it difficult to invest in sustainable building practices. Participants need streamlined and informed solutions that are specific to their projects and locations. This scenario is particularly true for small- to medium-sized new construction projects, where design fees and schedules provide for a very limited window of opportunity.

To help overcome the financial challenge, a Standard Energy Design Assistance (EDA) is offered. This provides additional engineering expertise during the design phase to identify energy-saving opportunities. Commercial and industrial projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for CEI South's Enhanced EDA incentives which include energy modeling. The CEI South implementation partner staff expert will work with the design team through the conceptual design, schematic design and design development processes providing advice and counsel on measures that should be considered and EE modeling issues. Incentives will be paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements. For those projects that are past the phase where EDA can be of benefit, the C&I New Construction program offers the opportunity to receive prescriptive or custom rebates towards eligible equipment.

The **Building Tune-Up** program provides customers a way to improve operational efficiency. By offering a study at no cost to customers, CEI is able to identify retro commissioning-type savings from applying best practices to building controls. CEI also offers additional incentives to encourage customers to convert these opportunities into implemented measures.

Using a similar model to Building Tune-Up, the **Refrigeration Tune-Up** program will provide fully funded studies of commercial refrigeration systems by a refrigeration specialist. Identified opportunities will have estimated savings, project costs and available rebates presented in a program-issued report. A verification of operational improvements recommended by the program will be conducted to ensure

measures were installed as intended. This offering is geared specifically for grocery stores, but can be scaled to provide its service to convenience stores and refrigerated warehouses.

SEM is a comprehensive new approach to energy management; customers are provided with comprehensive support during their participation in the program. As soon as a customer enrolls in the program, an energy manager is assigned to provide personalized service throughout the 18-month training process. That process starts with a series of trainings that will introduce SEM and ISO 50001 concepts to the customer and gives them specific instructions on how they can implement lasting change within their organization. Key strategies include:

- **Energy Managers.** Program-provided energy managers guide customers through the process, helping them complete program requirements, and supporting their implementation of SEM.

- **High-Quality Training.** Energy Managers prepare each customer's energy champion for the cohort training, which is conducted in which customers learn the basic elements of ISO 50001 and how to apply them to their facilities.

- **Free Facility Audit.** SEM is focused on long-term change, and the program provides each customer with a free facility audit to identify both operational and capital energy efficiency projects. The energy audit also serves as a teaching moment for the companies' energy team on how to systematically identify opportunities for improvement. The low- and no-cost operational projects can be completed almost immediately, while the capital projects help customers continue to take advantage of savings.

Incentive Strategy

Incentives will be calculated on a per kWh basis. The initial kWh rate will be $0.14/kWh and is paid based on the first-year annual savings reduction. Rates may change over time and vary with some of the special initiatives. Incentives will not pay more than 50% of the project cost nor provide incentives for projects with paybacks less than 12 months. CEI South will offer a cost share on facility energy assessments that will cover up to 100% of the assessment cost.

The Commercial New Construction program will provide incentives to help offset some of the expenses for the design team's participation in the EDA process with the design team incentive. The design team incentive is a fixed amount based on the new/renovated conditioned square footage and is paid when the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions. Program specific savings and incentive include:

Facility Size – Square Feet	Design Team Incentives	Minimum Savings
Small <25,000	$750	25,000 kWh
Medium 25,000 - 100,000	$2,250	75,000 kWh
Large >100,000	$3,750	150,000 kWh
Enhance Large >100,000	$5,000	10% beyond code

Program Delivery

CEI South will oversee the program and partner with Resource Innovations to deliver the program. Additionally, Resource Innovations will oversee the SEM Program's implementation, training and modeling.

Integration with CEI South Gas

CEI South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. CEI South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

Given the variability and uniqueness of each project, all projects will be pre-approved. Pre and post visits to the site to verify installation and savings will be performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. A third-party evaluator will be used for this project and use standard EM&V protocols.

N. Small Business Energy Solutions (SBES)

Program Description

The Small Business Energy Solutions Program provides value by directly installing EE products such as high efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically commutated motors, smart thermostats and vending machine controls. The program helps small businesses, multi-family and not-for-profit customers identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business. The Multi-Family Retrofit program that began in 2017 will continue to be offered in 2024 under the SBES program. This program is an integrated gas and electric and is targeting dual fuel customers. The program also permits eligible non-profit establishment of any size to participate within the program.

In 2023 CEI began implementing a new HVAC check-up program that encourages small business, non-profit, and multi-family customers to proactively maintain the efficiency of their HVAC systems by incentivizing air conditioner tune-ups economizer repairs, thermostat upgrades, and Advanced Rooftop Controls (ARC). The program will continue in 2024 and offers on-site HVAC assessments conducted by a program-approved HVAC Savings Partner, at no cost to the customer. Customers also receive a customized assessment report and instant discounts on selected improvements, therby eliminating the need to wait for a rebate check. This program focuses on both gas and electric HVAC savings potential and is targeting dual fuel customers and past SBES participants. Measures included in the HVAC check-up program are: Air conditioner tune-up, economizer repair, refrigerant charge, reprogramming existing t-stats, smart & programmable t-stats, ARC and packaged rooftop unit sealing.

Table 25: Small Business Energy Solutions Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Commercial	**Small Business Energy Solutions**				
	Number of Measures	13,873	13,873	13,873	41,619
	Energy Savings kWh	4,300,000	4,300,000	4,300,000	12,899,999
	Peak Demand kW	470	470	470	1,409
	Total Program Budget $	$1,477,776	$1,485,694	$1,482,621	$4,446,091
	Per Participant Avg. Energy Savings kWh	310	310	310	310
	Per Participant Avg. Demand Savings kW	0.034	0.034	0.034	0.034
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				84%

Eligible Customers

Any participating CEI South business customer with a maximum peak energy demand of less than 400 kW or any designated non-profit, opt-in customer of any peak energy demand usage. Additionally, multifamily building owners with CEI South general electric service may qualify for the program, including apartment buildings, condominiums, cooperatives, duplexes, quadraplexes, townhomes, nursing homes and retirement communities.

Marketing Plan

The SBES Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to individual customer segments (e.g., hospitality, grocery stores, and non-profit organizations) to increase participation in under-performing segments, including direct customer outreach and enhanced incentive campaigns. Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from CEI South staff and third-party contractors. Marketing efforts will continue to target Multi-Family, Non-Profit and Civil/Governmental sectors within this program.

Barriers/Theory

Small business customers generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these small businesses with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost. There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

Implementation & Delivery Strategy

Trade Ally Network: Trained trade ally energy advisors will provide energy assessments to business customers with less than 400 kW peak demand and to multifamily and non-profit buildings. The program implementer will issue an annual Request for Qualification (RFQ) to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses and provide training to SBES trade allies on the program process, with an emphasis on improving energy efficiency sales.

Energy Assessment: Trade allies will walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They will provide an energy assessment report that will detail customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally will then review the report with the customer, presenting the program benefits and process, while addressing any questions.

Initial Measures, Products and Services

The program will have two types of measures provided. The first are measures that will be installed at no cost to the customer. They will include but are not limited to the following:

- Smart Wi-Fi-enabled thermostats
- Programmable thermostats
- Program the programmable thermostats
- Faucet aerators

The second types of measures require the customer to pay a portion of the labor and materials. These measures include (LEDs are not GSL):

- Interior LED lighting (replacing incandescent, high bays and linear fluorescents)
- Delamping
- Exterior LED lighting
- Interior Lighting Controls
- Advanced Rooftop Controls
- EC Motors
- Anti-sweat heater controls
- Pre rinse sprayers
- Refrigerated LED
- Refrigerated Case Cover
- Vending Machine Control
- Economizer Repair
- Refrigerant Charge
- Weatherstripping
- Air Conditioner Tune-Up

Incentive Strategy

In addition to the no-cost measures identified during the audit, the program will also pay a cash incentive on every recommended improvement identified through the assessment. Incentive rates may change over time and vary with special initiatives.

Program Delivery

CEI South will oversee the program partner Resource Innovations to deliver the program.

Integration with CEI South Gas

CEI South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory.

Evaluation, Measurement and Verification

On-site verification will be provided for the first three projects completed by each trade ally, in addition to the program standard 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure the trade allies are providing high-quality customer services and the incentivized equipment satisfies program requirements. A third-party evaluator will evaluate the program using standard EM&V protocols.

O. Building Optimization

Program Description

The Building Optimization Program targets customers who are seeking a detailed list of energy saving opportunities in their facilities, outside the scope of savings measures that can be implemented through our other programs. The program is designed to create building optimization awareness and identify solutions for improving building performance. Through a partially incentivized study performed by qualified trade allies, customers gain clarity on where to prioritize operational and capital funds, along with the expected return on such investments. When applying for the study incentive, customers commit to implement energy measures within 90 days following the study. Additional custom and/or prescriptive incentives are paid to the customer following measurement and verification of implemented energy measures (performed by HEAPY as the program implementer). HEAPY intends to work in-step with CenterPoint's additional C&I program implementer to maximize incentive opportunities across multiple C&I offerings.

Table 26: Building Optimization Budget & Energy Savings Targets

Market	Program	2025	2026	2027	Total Program
Commercial	**Building Optimization**				
	Number of Participants	10	10	10	30
	Energy Savings kWh	1,500,000	1,500,000	1,500,000	4,500,000
	Peak Demand kW	20	20	20	60
	Total Program Budget $	$309,955	$310,504	$311,072	$931,531
	Per Participant Avg. Energy Savings kWh	150,000	150,000	150,000	150,000
	Per Participant Avg. Demand Savings kW	2.000	2.000	2.000	2.000
	Weighted Avg. Measure Life				15
	Net to Gross Ratio				100%

Eligible Customers

Any participating commercial or industrial customer receiving electric service from CEI South.

Marketing Plan

Proposed marketing efforts include individualized outreach to large C&I customers through a variety of channels and coordination with key account managers to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, marketing campaigns and bonuses, trade ally meetings, and educational seminars could also be used to promote the program.

Barriers/Theory

Customers will need to be utilizing a sophisticated building automation system with trending capability to be eligible for the program.

Initial Measures, Products and Services

Measures will be implemented to focus on Building Optimization and Retro-Commissioning, such as:

- Building Systems Controls
- Chilled/Hot Water Plant Optimizations
- Economizer Adjustments
- Hydronic System Operations
- Mechanical Air Handling
- Supply Air Static Pressure Resets
- Supply Air Temperature Resets
- Supply and Return Fan Control
- Underfloor Plenum Pressure Adjustments
- VFD Installations and Sequencing
- Zone-level Setpoint Adjustments
- Zone Terminal Units

Implementation & Delivery Strategy

The implementation partner will work collaboratively with CEI South staff to recruit and screen customers. The implementation partner will then contact customers from the target list through phone call and email correspondence, providing that customer with clarity on the eligibility of the building(s). The implementation partner will also work with the customer to understand the detailed terms and conditions. Upon approval, the implementation partner will then send a pre-approval letter to the customer. The next phase of implementation after acceptance is to complete a building optimization study, reviewing mechanical and electrical systems with the goal of identifying potential energy saving measures. The results will be compiled in a formal study report including results on building optimization and retro-commissioning energy savings solutions. Upon completion of the study, a copy of the study report will be shared with the customer and CEI South so that a mutually agreed project and timeline can be finalized. The implementation partner will maintain regular correspondence with the customer and study provider during the implementation phase to ensure timely results.

Upon completion of implementation, the implementation partner will perform measurement and verification (M&V) to estimate measures savings, primarily using building controls system trending. Then energy calculation assumptions made in the study report will be compared to actual operating parameters verified in the collected trend data.

Incentive Strategy

Incentives will be delivered by the implementation partner by check to the customer at the end of the project. The amount of the incentive check will be determined by the verified project savings stipulated in the final M&V report at $0.04/kWh, capped at 100% of measure implementation costs.

The program will include a two-part incentive. The first incentive, Customer Study Incentive, is to support the preliminary costs of a formal study performed by a qualified study provider. The second incentive, Customer Implementation Incentive, is to support implementation costs of the energy saving measures.

a. The Customer Study Incentive is based on a $0.11 per kWh study cost ratio. This ratio will vary based on complexity of the building. For each application, HEAPY will input the savings target and the study cost into a project evaluation tool to evaluate the cost per kWh savings and approve the study cost.
    i. The program will incentivize up to 75% of the total study cost. The first 50% will be paid upon implementation completion. The remaining 25% will be paid after M&V is completed.
    ii. If the study does not identify measures at least 90% of the savings goal stated on the project application, the study cost will be adjusted downward to the study cost per kWh established during the Application.
b. The Customer Implementation Incentive is based on $0.04 of verified kWh savings, capped at 100% of the implementation cost. Electric incentives will be limited to $300,000 per project and $500,000 per premise per calendar year.

Program Delivery

CEI South will oversee the program and partner with HEAPY Engineering to deliver the program.

Evaluation, Measurement and Verification

Standard EM&V protocols will be used for the third-party evaluation of the program.

8. Program Administration

As in previous years, CEI South will continue to serve as the program administrator for the 2025-2027 Plan. CEI South will utilize third-party program implementers to deliver specific programs or program components where specialty expertise is required. Contracting directly with specialty vendors avoids an unnecessary layer of management, oversight and expense that occurs when utilizing a third-party administration approach.

Program administration costs are allocated at the program level and include costs associated with program support and internal labor. Program support includes costs associated with outside consulting and annual license and maintenance fees for DSMore, Data Management, and Esource. Based upon the EE and DR programs proposed in the 2025 - 2027 Plan, CEI South is proposing to maintain the staffing levels that were previously approved to support the portfolio. The major responsibilities associated with these FTEs are as follows:

- **Portfolio Management and Implementation** - Oversees the overall portfolio and staff necessary to support program administration. Serves as primary contact for regulatory and oversight of programs.
- **Reporting and Analysis** - Responsible for all aspects of program reporting including, budget analysis/reporting, scorecards and filings.
- **Outreach and Education** - Serves as contact to trade allies regarding program awareness. Also serves as point of contact for residential and commercial/industrial customers to assist with responding to program inquiries.
- **Research and Evaluation** - Works with the selected EM&V Administrator and facilitates measurement and verification efforts, assists with program reporting/tracking.

9. Support Services

Support services are considered indirect costs which support the entire portfolio and include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

Table 27: Portfolio Level Costs by Year

Indirect Portfolio Level Costs	2025	2026	2027
Contact Center	$69,842	$71,239	$72,664
Online Audit	$47,571	$48,523	$49,493
Outreach & Education	$561,116	$572,338	$583,785
Evaluation	$645,452	$700,691	$741,254
Total Indirect Portfolio Level Costs	**$1,323,981**	**$1,392,791**	**$1,447,196**

A. Contact Center

The CenterPoint Contact Center, called the Energy Efficiency Advisory Team, fields referrals from the company's general call center and serves as a resource for interested customers. A toll-free number is provided on all outreach and education materials. Direct calls are initial contacts from customers or market providers coming through the dedicated toll-free number printed on all CEI South's energy efficiency materials. Transferred calls are customers that have spoken with a CenterPoint Contact Center representative and have either asked or been offered a transfer to an Energy Efficiency Advisor who is trained to respond to energy efficiency questions or conduct the on-line energy audit.

These customer communication channels provide support mechanisms for CEI South customers to receive the following services:

- Provide general guidance on energy saving behaviors and investments using customer specific billing data via the on-line tool (bill analyzer and energy audit).
- Respond to questions about the residential and general service programs.
- Facilitate the completion of and provide a hard copy report from the online audit tool for customers without internet access or who have difficulty understanding how to use the tool.
- Respond to inquiries about rebate fulfillment status.

B. Online Audit

The Online Energy Audit tool is a customer engagement and messaging tool that uses actual billing data from a customer's energy bills to pinpoint ways to save energy in their home. Data collected drives account messaging through providing tips and rebates relevant to that customer's situation. Additionally, data collected from the online energy audit is used to validate neighbor comparison data, which illustrates how the customer's monthly energy use compares to their neighbors and is designed to inspire customers to try and save more energy than their efficient neighbors. The Online Energy Audit tool provides the means to educate customers about energy efficiency and CenterPoint's energy efficiency programs through cross-promotion and personalized suggestions, tips and advice on energy usage. The budget for the Online Audit tool is shared across CenterPoint's Indiana Gas DSM, Electric DSM and CenterPoint Energy Ohio, Inc. (CEOH) DSM portfolios.

C. Outreach & Education

CEI South's Customer Outreach and Education program serves to raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program includes the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate elementary students and their families;
- Educate customers on how to manage their energy costs and reduce their usage;
- Communicate support of customer EE needs; and
- Drive participation in the EE and DR programs.

The marketing approach includes paid media as well as web-based tools to help analyze bills, energy audit tools, EE and DSM program education and information. Informational guides and sales promotion materials for specific programs are included in this budget.

This effort is the key to achieving greater energy savings by influencing the families and businesses making housing/facility, appliance and equipment investments to opt for greater EE. The first step in convincing the public and businesses to invest in EE is to raise their awareness.

It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but also prime them for participation in the various EE and DR programs.

CEI South will oversee outreach and education for the programs and work closely with implementation partners to provide consistent messaging across different program outreach and education efforts. CEI South will utilize the services of communication and EE experts to deliver the EE and DR message.

The Outreach budget also includes funds for program development and staff training. Examples of these costs include memberships to EE related organizations, outreach for home/trade shows and travel and training related to EE associated staff development.

Another outreach opportunity that CEI South has employed is a jointly facilitated Industrial Energy Efficiency Workshop. CEI South first offered this workshop in June 2019 to share resources available for commercial and industrial customers. There were 25 total attendees, with 10 customers represented (6 opt-out and 4 opt-in). The workshop featured speakers from the Midwest Energy Efficiency Alliance (MEEA), Department of Energy (DOE) ENERGY STAR® division, Nexant and CEI, and included a bonus incentive for companies who attended in an effort to increase program participation. The workshop was well received and CEI South plans to continue offering this resource during the 2025-2027 Plan period.

D. Evaluation

CEI South will work with an independent third-party evaluator, selected by the OSB, to conduct an evaluation of DSM programs approved as part of its 2025-2027 Plan. The evaluation will include standard EM&V analyses, such as a process, impact, and/or market effects evaluation of CEI South's portfolio of DSM programs. Gas impacts will be calculated for all of CEI South's integrated gas programs. EM&V costs are based on 5% of the budget and allocated at the portfolio level.

10. Other Costs

Other costs being requested in the 2025-2027 filed plan include a Market Potential Study and funding for Emerging Markets.

Table 28: Other Costs by Year

Other Costs	2025	2026	2027
Emerging Markets	$200,000	$200,000	$200,000
Market Potential Study	$300,000	$0	$0
Total	**$500,000**	**$200,000**	**$200,000**

A. Emerging Markets

The Emerging Markets funding allows CenterPoint's DSM portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the CEI South territory. The budget will be $200,000 each year for 2025-2027 and will not be used to support existing programs, but rather support new program development or new measures within an existing program.

Incentives promoted through this program may range from innovative rebate offerings to engineering and trade ally assistance to demand-control services that encourage early adoption of new, efficient technologies in high-impact market sectors. Depending on the development of certain technologies and growth areas in the service territory, a wide variety of projects and services are eligible.

To offset the risks of oversaturation of common prescriptive measures and redefined prescriptive baselines, this program will bring to market next generation technologies and energy-saving strategies that have significant savings and cost-effectiveness potential. As new technologies develop towards lower costs and higher efficiency, their market penetration and energy-savings potential will increase. This program will allow CenterPoint to be on the forefront of emerging technologies to understand the market disruption a new product may cause, test strategies for capturing their energy-saving opportunities, and plan for future program savings growth. This offering will supplement the other DSM programs that do not easily fit into other program offerings. Additionally, growing segments of CEI South electric customers may require tailored offerings to accommodate their needs in order to participate.

This program will focus on innovative new approaches and leading the DSM market, so the exact list of measures cannot be set at this time. However, potential measures and services include: new technologies, such as Advanced Lighting Controls; new strategies for achieving significant energy savings, such as midstream incentives, contractor bids to provide energy efficiency projects, and targeting high-impact

market sectors; and integrated DSM (iDSM) approaches, such as demand response, combined energy efficiency and demand response measures, and load shifting.

Emerging technologies and measures will be reviewed and may be offered using this funding as long as they do not fall into a current program offering. Innovative engagement and incentivizing approaches may also be used as a tool to provide reduced costs to new systems, equipment and/or services to help reduce peak demand and electric usage. This program also allows CenterPoint to take steps toward an integrated Demand Side Management approach to address both energy efficiency and demand response together.

B. Market Potential Study

CEI South is requesting $300,000 to complete a refresh and Market Potential Study (MPS) in 2025 for program years 2026 - 2030. The new MPS is necessary to support future EE filings. CEI South will issue a Request for Quote to select a consultant to perform this work.

11. Conclusion

CEI South has developed a 2025-2027 Electric Energy Efficiency Plan that is aligned with the 2022 Integrated Resource Plan and is reasonably achievable and cost effective. The cost effectiveness analysis was performed for 2025-2027 using the DSMore model – a nationally recognized economic analysis tool that is specifically designed to evaluate the cost effectiveness of implementing energy efficiency and demand response programs.

Program costs were determined by referencing current program delivery costs, based on prior contracts and performance in the field and consultation with the program vendors that will deliver the DSM Plan. Energy and demand savings were primarily determined by using recent EM&V results and the IN TRM version 2.2. For measures that were not addressed in the IN TRM or EM&V, CEI South used Technical Resource Manual resources from nearby states or vendor input. CEI South utilized the avoided costs from 2022 IRP[1] adjusted down for fixed capacity.

Based on this information, CEI South requests IURC approval of this 2025-2027 DSM Plan as well as the costs associated with Emerging Markets and the Market Potential study for 2025 and beyond.

[1] Avoided costs aligned with CEI South's 2022 IRP, with an adjustment down to fixed capacity cost assumptions.

12. Appendix A: Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

Appendix B: Program Measure Detail

Type	Program	Measure	Measure Life	NTG	Avg. kWh/Unit	Avg. kW/Unit	2025 Participation	2026 Participation	2027 Participation	Incentive/ Unit	IMC/Unit	2025 KWH	2026 KWH	2027 KWH	2025 KW	2026 KW	2027 KW
Residential	Residential Prescriptive	AC Tune Up	3	53%	135	0.044	250	250	300	$ 25.00	$ 82.00	33,863	33,863	40,635	11.075	11.075	13.290
Residential	Residential Prescriptive	Aeroseal - Electric	15	100%						$ 1,500.00	$ 2,500.00	-	-	-	-	-	-
Residential	Residential Prescriptive	Air Purifier	9	75%	426	0.049	10	10	10	$ 50.00	$ 41.90	4,260	4,260	4,260	0.490	0.490	0.490
Residential	Residential Prescriptive	ASHP Tune Up	3	62%	316	0.044	15	15	15	$ 50.00	$ 82.00	4,745	4,745	4,745	0.665	0.665	0.665
Residential	Residential Prescriptive	Attic Insulation - South (Dual - Gas & Electric)	20	67%	429	0.359	80	80	80	$ 360.00	$ 750.00	34,299	34,299	34,299	28.758	28.758	28.758
Residential	Residential Prescriptive	Attic Insulation - South (Electric Only)	20	67%	1,787	0.200	10	10	10	$ 450.00	$ 1,500.00	17,870	17,870	17,870	1.995	1.995	1.995
Residential	Residential Prescriptive	Clothes Dryer	16	75%	160	0.022	280	280	280	$ 50.00	$ 152.00	44,923	44,923	44,923	6.031	6.031	6.031
Residential	Residential Prescriptive	Clothes Washer	14	75%	140	0.018	375	375	375	$ 50.00	$ 87.00	52,350	52,350	52,350	6.750	6.750	6.750
Residential	Residential Prescriptive	CoolSaver Tune Up (Electric)	3	95%						$ 325.00	$ 325.00	-	-	-	-	-	-
Residential	Residential Prescriptive	Dehumidifier	12	75%	134	0.030	5	5	5	$ 35.00	$ 10.00	670	670	670	0.150	0.150	0.150
Residential	Residential Prescriptive	Duct Sealing - South (Dual)	20	100%	125	0.079	1	1	1	$ 125.00	$ 110.00	125	125	125	0.079	0.079	0.079
Residential	Residential Prescriptive	Duct Sealing - South (Electric Only)	20	100%	353	0.079	1	1	1	$ 250.00	$ 450.00	353	353	353	0.079	0.079	0.079
Residential	Residential Prescriptive	Heat Pump Water Heater	15	75%	1,852	0.088	10	15	20	$ 500.00	$ 1,030.00	18,517	27,775	37,034	0.877	1.316	1.754
Residential	Residential Prescriptive	Pool Heater (COP >= 6.0)	15	75%	1,492	0.022	2	2	2	$ 800.00	$ 1,916.00	2,984	2,984	2,984	0.044	0.044	0.044
Residential	Residential Prescriptive	Pool Heater (COP 5.5-5.9)	15	75%	1,351	0.020	5	5	5	$ 350.00	$ 1,916.00	6,755	6,755	6,755	0.100	0.100	0.100
Residential	Residential Prescriptive	Smart Programmable Thermostat - South (Dual - Gas & Electric)	11	78%	248	0.162	450	500	500	$ 40.00	$ 30.00	111,780	124,200	124,200	72.900	81.000	81.000
Residential	Residential Prescriptive	Smart Programmable Thermostat - South (Electric Only)	11	78%	206	0.000	85	100	120	$ 50.00	$ 30.00	17,527	20,620	24,744	-	-	-
Residential	Residential Prescriptive	Wifi Thermostat - South (Dual - Gas & Electric)	11	78%	244	0.165	349	149	-	$ 24.00	$ 79.00	85,121	36,341	-	57.585	24.585	-
Residential	Residential Prescriptive	Wifi Thermostat - South (Electric Only)	11	78%	758	0.147	50	20	-	$ 30.00	$ 79.00	37,900	15,160	-	7.360	2.944	-
Residential	**Total Residential Other Prescriptive**		**13**	**74%**			**1,978**	**1,818**	**1,724**			**474,041**	**427,293**	**395,946**	**195**	**166**	**141**
Residential	Home Energy Assessment	HEA - Tier 1 (Dual - Electric)	10	100%	900	0.047	400	500	600	$ 342.75	$ 100.00	359,993	449,991	539,990	18.906	23.633	28.359
Residential	Home Energy Assessment	HEA - Tier 1 (Electric Only)	10	100%	1,523	0.113	2	2	2	$ 437.19	$ 228.00	3,047	3,047	3,047	0.227	0.227	0.227
Residential	Home Energy Assessment	HEA - Tier 2 (Dual - Electric)	20	100%	240	0.149	50	75	100	$ 520.00	$ 650.00	12,008	18,011	24,015	7.427	11.140	14.853
Residential	Home Energy Assessment	HEA - Tier 2 (Electric Only)	20	100%	729	0.149	1	1	1	$ 650.00	$ 100.00	729	729	729	0.149	0.149	0.149
Residential	Home Energy Assessment	HEA - Virtual Assessment (Dual - Electric)	1	100%	68	0.001	20	25	40	$ 80.00	$ 32.00	1,369	1,711	2,738	0.028	0.035	0.056
Residential	Home Energy Assessment	HEA - Virtual Assessment (Electric Only)	1	100%	75	0.001	5	5	5	$ 100.00	$ -	375	375	375	0.005	0.005	0.005
Residential	**Total Home Energy Assessment**		**10**	**100%**			**478**	**608**	**748**			**377,520**	**473,865**	**570,893**	**27**	**35**	**44**
Residential	Residential Midstream	Air Source Heat Pump 14 SEER2	16	51%	0.000	0.000	-	-	-	$ 200.00	$ 303.00	-	-	-	-	-	-
Residential	Residential Midstream	Air Source Heat Pump 15 SEER2	16	51%	1,224	0.276	155	155	160	$ 250.00	$ 438.00	189,714	189,714	195,834	42.718	42.718	44.096
Residential	Residential Midstream	Air Source Heat Pump 16 SEER2	16	51%	1,333	0.276	20	22	25	$ 300.00	$ 724.00	26,661	29,328	33,327	5.512	6.063	6.890
Residential	Residential Midstream	Air Source Heat Pump 17 SEER2	16	51%	1,376	0.276	140	140	140	$ 400.00	$ 933.00	192,583	192,583	192,583	38.584	38.584	38.584
Residential	Residential Midstream	Central Air Conditioner 14 SEER2	18	53%	370	0.270	180	100	-	$ 200.00	$ 108.00	66,640	37,022	-	48.600	27.000	-
Residential	Residential Midstream	Central Air Conditioner 15 SEER2	18	53%	514	0.315	700	750	800	$ 250.00	$ 221.00	359,450	385,125	410,800	220.500	236.250	252.000
Residential	Residential Midstream	Central Air Conditioner 16 SEER2	18	53%	514	0.315	120	135	160	$ 300.00	$ 620.00	61,620	69,323	82,160	37.800	42.525	50.400
Residential	Residential Midstream	Central Air Conditioner 17 SEER2	18	53%	912	0.449	325	340	365	$ 400.00	$ 620.00	296,400	310,080	332,880	145.925	152.660	163.885
Residential	Residential Midstream	Ductless Heat Pump 18 SEER2 8.6 HSPF2	16	38%	2,235	0.230	15	15	15	$ 250.00	$ 1,443.00	33,524	33,524	33,524	3.455	3.455	3.455
Residential	Residential Midstream	Ductless Heat Pump 19 SEER2 8.6 HSPF2	16	38%	5,477	0.256	10	10	10	$ 250.00	$ 1,443.00	54,772	54,772	54,772	2.558	2.558	2.558
Residential	Residential Midstream	Ductless Heat Pump 20 SEER2 8.6 HSPF2	16	38%	5,477	0.278	30	30	30	$ 350.00	$ 1,443.00	164,316	164,316	164,316	8.325	8.325	8.325
Residential	Residential Midstream	Ductless Heat Pump 21 SEER2 8.6 HSPF2	16	38%	5,525	0.296	15	15	15	$ 500.00	$ 1,443.00	82,868	82,868	82,868	4.439	4.439	4.439
Residential	Residential Midstream	Ductless Heat Pump 22 SEER2 8.6 HSPF2	16	38%	5,525	0.311	12	12	12	$ 500.00	$ 1,443.00	66,294	66,294	66,294	3.733	3.733	3.733
Residential	Residential Midstream	Ductless Heat Pump 23 SEER2 8.6 HSPF2	16	38%	4,319	0.324	55	55	55	$ 500.00	$ 1,443.00	237,534	237,534	237,534	17.798	17.798	17.798
Residential	Residential Midstream	Heat Pump Water Heater	15	75%	1,851	0.088	5	5	5	$ 500.00	$ 1,030.00	9,255	9,255	9,255	0.439	0.439	0.439
Residential	Residential Midstream	Wifi Thermostat - Electric	11	95%	244	0.165	1	1	1	$ 20.00		244	244	244	0.165	0.165	0.165
Residential	**Total Residential Midstream**		**17**	**48%**			**1,783**	**1,785**	**1,793**			**1,841,874**	**1,861,980**	**1,896,389**	**581**	**587**	**597**
Residential	In Store Discount	Advanced Power Strip	7	100%	32	0.004	500	750	1,000	$ 6.00	$ 10.00	15,950	23,925	31,900	1.800	2.700	3.600
Residential	In Store Discount	Air Filter	1	100%	78	0.000	1,000	1,000	1,000	$ 1.00	$ 11.50	78,230	78,230	78,230	-	-	-
Residential	In Store Discount	Air Purifier	9	100%	426	0.049	75	100	125	$ 25.00	$ 41.90	31,950	42,600	53,250	3.675	4.900	6.125
Residential	In Store Discount	Bathroom Vent Fan	19	100%	60	0.007	100	150	200	$ 25.00	$ 43.50	5,970	8,955	11,940	0.705	1.058	1.410
Residential	In Store Discount	Dehumidifier	12	100%	134	0.030	50	50	50	$ 25.00	$ 10.00	6,700	6,700	6,700	1.500	1.500	1.500
Residential	In Store Discount	Door and Window Weather Stripping	20	100%	105	0.001	500	750	1,000	$ 1.00	$ 10.47	52,315	78,473	104,630	0.530	0.795	1.060
Residential	In Store Discount	Door Sweep	20	100%	94	0.002	500	750	1,000	$ 3.00	$ 5.47	47,155	70,733	94,310	1.245	1.867	2.489
Residential	In Store Discount	Domestic Hot Water Pipewrap 6ft	5	100%	281	0.032	750	750	750	$ 1.00	$ 6.00	211,050	211,050	211,050	24.093	24.093	24.093
Residential	In Store Discount	ENERGY STAR Room AC	12	100%	27	0.021	100	125	150	$ 25.00	$ 40.00	2,673	3,341	4,010	2.120	2.650	3.180
Residential	In Store Discount	Spray Foam	20	100%	6	0.000	1,000	1,500	2,000	$ 1.00	$ 4.38	5,900	8,850	11,800	-	-	-
Residential	**Total In Store Discount**		**10**	**100%**			**4,575**	**5,925**	**7,275**			**457,893**	**532,856**	**607,820**	**36**	**40**	**43**
Residential	**Total Home Energy Solutions**						**8,814**	**10,136**	**11,540**			**3,151,328**	**3,295,993**	**3,471,049**	**838**	**828**	**825**
Residential	Multi-Family Energy Solutions	MFES - Res DI Tier 1 (Dual - Electric)	12	100%	9,047	0.233	16	16	16	$ 2,906.25	$ 2,042.81	144,751	144,751	144,751	3.732	3.732	3.732
Residential	Multi-Family Energy Solutions	MFES - Res DI Tier 1 (Electric Only)	10	100%	22,426	2.147	10	10	10	$ 2,681.25	$ 650.00	224,264	224,264	224,264	21.472	21.472	21.472
Residential	Multi-Family Energy Solutions	MFES - Res DI Tier 2 (Dual - Electric)	20	100%			-	-	-	$ -	$ 2,831.25	-	-	-	-	-	-
Residential	Multi-Family Energy Solutions	MFES - Res DI Tier 2 (Electric Only)	20	100%			-	-	-	$ -	$ 650.00	-	-	-	-	-	-
Residential	**Total Multi-Family Energy Solutions**		**11**	**100%**			**26**	**26**	**26**			**369,015**	**369,015**	**369,015**	**25**	**25**	**25**
Residential	Community Connections	Door and Window Weather Stripping	20	100%	66	0.001	5,000	5,000	5,000	$ -	$ 10.47	329,600	329,600	329,600	3.340	3.340	3.340
Residential	Community Connections	Door Sweep	20	100%	53	0.001	5,000	5,000	5,000	$ -	$ 5.47	264,050	264,050	264,050	6.970	6.970	6.970
Residential	Community Connections	LED Nightlight	8	100%	17	0.000	5,000	5,000	5,000	$ -	$ 3.35	84,350	84,350	84,350	-	-	-
Residential	Community Connections	Outlet Gaskets	20	100%	3	0.000	30,000	30,000	30,000	$ -	$ 2.93	100,800	100,800	100,800	11.400	11.400	11.400
Residential	**Total Community Connections**		**19**	**100%**			**45,000**	**45,000**	**45,000**	**$ -**		**778,800**	**778,800**	**778,800**	**22**	**22**	**22**

Type	Program	Measure	Measure Life	NTG	Avg. kWh/Unit	Avg. kW/Unit	2025 Participation	2026 Participation	2027 Participation	Incentive/ Unit	IMC/Unit	2025 KWH	2026 KWH	2027 KWH	2025 KW	2026 KW	2027 KW
Residential	Income Qualified Weatherization	Air Source Heat Pump 15 SEER2	16	100%	1,224	0.276	1	1	1	$ 5,400.00	$ 100.00	1,224	1,224	1,224	0.276	0.276	0.276
Residential	Income Qualified Weatherization	Attic Insulation - Electric Resistance Heated	20	100%	1,787	0.200	1	1	1	$ 1,412.60	$ 259.31	1,787	1,787	1,787	0.200	0.200	0.200
Residential	Income Qualified Weatherization	Attic Insulation - Gas Heated (Electric)	20	100%	401	0.378	40	40	40	$ 706.30	$ 650.00	16,027	16,027	16,027	15.118	15.118	15.118
Residential	Income Qualified Weatherization	Central Air Conditioner 15 SEER2	18	100%	514	0.315	25	25	25	$ 3,500.00	$ 50.00	12,838	12,838	12,838	7.875	7.875	7.875
Residential	Income Qualified Weatherization	Central Air Conditioner Tune Up	3	100%	135	0.044	125	125	125	$ 75.00	$ 447.45	16,931	16,931	16,931	5.538	5.538	5.538
Residential	Income Qualified Weatherization	Heat Pump Tune Up	3	100%	316	0.044	10	10	10	$ 250.00	$ 520.00	3,163	3,163	3,163	0.443	0.443	0.443
Residential	Income Qualified Weatherization	NWP - Tier 1 (Dual - Electric)	10	100%	955	0.047	700	700	700	$ 367.45	$ 8,500.00	668,365	668,365	668,365	33.086	33.086	33.086
Residential	Income Qualified Weatherization	NWP - Tier 1 (Electric Only)	10	100%	1,737	0.119	5	5	5	$ 458.06	$ 1,412.60	8,684	8,684	8,684	0.596	0.596	0.596
Residential	Income Qualified Weatherization	NWP - Tier 2 (Dual - Electric)	20	100%	240	0.149	100	125	150	$ 520.00	$ 706.30	24,015	30,019	36,023	14.853	18.567	22.280
Residential	Income Qualified Weatherization	NWP - Tier 2 (Electric Only)	20	100%	729	0.149	2	2	2	$ 650.00	$ 221.00	1,457	1,457	1,457	0.297	0.297	0.297
Residential	Income Qualified Weatherization	NWP - Virtual Assessment (Dual - Electric)	1	100%	68	0.001	25	35	45	$ 50.00	$ 225.00	1,711	2,396	3,080	0.035	0.049	0.063
Residential	Income Qualified Weatherization	NWP - Virtual Assessment (Electric Only)	1	100%	75	0.001	5	5	5	$ 100.00	$ 225.00	375	375	375	0.005	0.005	0.005
Residential	Income Qualified Weatherization	NWP - Whole Home (Dual - Gas & Electric)					-	-	-	$ -	$ -	-	-	-	-	-	-
Residential	Income Qualified Weatherization	NWP - Whole Home (Electric Only)					-	-	-	$ -	$ -	-	-	-	-	-	-
Residential	Income Qualified Weatherization	Refrigerator Replacement	15	100%	209	0.031	20	15	10	$ 580.00	$ 580.00	4,170	3,128	2,085	0.628	0.471	0.314
Residential	Income Qualified Weatherization	Wall Insulation - Dual (gas heated)	20	100%	260	0.200	15	15	15	$ 877.00	$ 877.00	3,902	3,902	3,902	2.994	2.994	2.994
Residential	Income Qualified Weatherization	Wall Insulation - Electric Only	20	100%	2,939	0.196	5	5	5	$ 877.00	$ 877.00	14,694	14,694	14,694	0.980	0.980	0.980
Residential	**Total Income Qualified & Weatherization**		**11**	**100%**			**837**	**872**	**907**			**779,346**	**784,991**	**790,637**	**83**	**86**	**90**
Residential	Residential New Construction	Central AC (15+ SEER2)	18	53%	370	0.280	70	70	70	$ 100.00	$ 108.00	25,915	25,915	25,915	19.600	19.600	19.600
Residential	Residential New Construction	Heat Pump - Tier 1	16	51%	504	0.182	3	3	3	$ 275.00	$ 8,185.00	1,512	1,512	1,512	0.545	0.545	0.545
Residential	Residential New Construction	Heat Pump - Tier 2	16	51%	842	0.182	3	3	3	$ 500.00	$ 8,185.00	2,526	2,526	2,526	0.545	0.545	0.545
Residential	Residential New Construction	Heat Pump Water Heater	15	69%	1,852	0.088	5	5	5	$ 500.00	$ 1,030.00	9,258	9,258	9,258	0.439	0.439	0.439
Residential	Residential New Construction	Smart Tstat - Gas Furn + CAC	11	78%	315	0.150	5	5	5	$ 40.00	$ 30.00	1,576	1,576	1,576	0.750	0.750	0.750
Residential	Residential New Construction	Smart Tstat - Heat Pump	11	78%	510	0.000	1	1	1	$ 50.00	$ 30.00	510	510	510	-	-	-
Residential	Residential New Construction	Sub-52 HERS Kicker - Gas Heat + CAC	20	100%	1,523	0.000	12	12	12	$ 160.00		18,276	18,276	18,276	-	-	-
Residential	Residential New Construction	Whole Home - BOP 1 - Gas Heat + CAC	20	40%	315	0.150	38	38	38	$ 95.00		11,974	11,974	11,974	5.700	5.700	5.700
Residential	Residential New Construction	Whole Home - BOP 1 - Heat Pump	20	78%	1,013	0.280	1	1	1	$ 375.00		1,013	1,013	1,013	0.280	0.280	0.280
Residential	Residential New Construction	Whole Home - BOP 2 - Gas Heat + CAC	20	40%	315	0.150	15	15	15	$ 180.00		4,727	4,727	4,727	2.250	2.250	2.250
Residential	Residential New Construction	Whole Home - BOP 2 - Heat Pump	20	78%	1,351	0.160	1	1	1	$ 600.00		1,351	1,351	1,351	0.160	0.160	0.160
Residential	**Total Residential New Construction**		**18**	**64%**			**154**	**154**	**154**			**78,637**	**78,637**	**78,637**	**30**	**30**	**30**
Residential	Residential Marketplace	Air Purifier	9	100%	61	0.007	374	392	409	$ 75.00		22,691	23,783	24,814	2.591	2.715	2.833
Residential	Residential Marketplace	Bathroom Aerator (Dual)	10	100%	35	0.049	1,071	1,122	1,173	$ 0.98		38,016	39,827	41,637	52.273	54.762	57.251
Residential	Residential Marketplace	Dehumidifier	12	100%	98	0.022	37	39	40	$ 35.00		3,644	3,841	3,939	0.816	0.860	0.882
Residential	Residential Marketplace	Deluxe (5) Window Insulation Kit	1	100%	3	0.001	68	72	75	$ 3.04		204	216	225	0.053	0.057	0.059
Residential	Residential Marketplace	EE KIT		100%			-	-	-	$ -		-	-	-	-	-	-
Residential	Residential Marketplace	High Efficiency Showerhead, Fixed	5	100%	321	0.031	137	143	150	$ 2.50		43,997	45,924	48,172	4.277	4.464	4.682
Residential	Residential Marketplace	High Efficiency Showerhead, Handheld	5	100%	321	0.031	137	143	150	$ 10.00		43,997	45,924	48,172	4.277	4.464	4.682
Residential	Residential Marketplace	Kitchen Aerator (Dual)	10	100%	141	0.028	37	39	40	$ 2.50		5,227	5,510	5,651	1.027	1.082	1.110
Residential	Residential Marketplace	LED Exterior Fixtures	15	100%			-	-	-	$ 20.00		-	-	-	-	-	-
Residential	Residential Marketplace	LED Interior Fixtures	15	100%			-	-	-	$ 12.00		-	-	-	-	-	-
Residential	Residential Marketplace	Night Light	6	100%	13	0.000	235	246	258	$ 2.00		3,088	3,232	3,390	-	-	-
Residential	Residential Marketplace	Pipe Insulation	15	100%	334	0.038	687	719	752	$ 2.00		229,588	240,282	251,310	25.986	27.197	28.445
Residential	Residential Marketplace	Showerstart TSV	10	100%	14	0.001	35	36	38	$ 29.99		482	496	523	0.033	0.033	0.035
Residential	Residential Marketplace	Smart Power Strips	4	100%	22	0.002	242	253	265	$ 10.00		5,319	5,561	5,824	0.601	0.629	0.659
Residential	Residential Marketplace	Smart Thermostat - South (Dual - Gas & Electric)	15	100%	199	0.090	2,491	2,609	2,728	$ 100.00		496,694	520,223	543,951	225.125	235.789	246.544
Residential	Residential Marketplace	Smart Thermostat - South (Electric Only)	15	100%	742	0.297	957	1,002	1,048	$ 100.00		710,227	743,624	777,762	284.187	297.550	311.210
Residential	Residential Marketplace	Switch and Outlet Sealing Gaskets, (10) pieces each	20	100%	17	0.005	35	36	38	$ 3.31		581	597	630	0.174	0.179	0.189
Residential	Residential Marketplace	T8 Bulbs	15	100%	116	0.013	105	110	115	$ 5.00		12,203	12,784	13,365	1.380	1.446	1.511
Residential	Residential Marketplace	Weatherstripping	15	100%	5	0.001	561	587	614	$ 3.00		2,615	2,736	2,862	0.432	0.452	0.473
Residential	**Total Residential Marketplace**		**15**	**100%**	**225**	**0.084**	**7,209**	**7,548**	**7,893**			**1,618,571**	**1,694,556**	**1,772,227**	**603**	**632**	**661**
Residential	**Residential Behavorial**		**1**	**100%**	**86**	**0.037**	**49,700**	**49,700**	**49,700**			**3,925,117**	**3,925,117**	**4,925,117**	**1,850**	**1,850**	**1,850**
Residential	**Smart Cycle (DLC Change Out)**		**15**	**100%**	**492**	**1.100**	**3,000**	**3,000**	**3,000**	**$ 67.50**		**1,477,053**	**1,477,053**	**1,477,053**	**3,300**	**3,300**	**3,300**
Residential	**BYOT (Bring Your Own Thermostat**		**15**	**100%**	**-**	**1.100**	**1,300**	**1,300**	**1,300**	**$ 75.00**					**1,430**	**1,430**	**1,430**
Residential	**CVR - Residential**		**15**	**100%**	**261**	**0.198**		**5,097**					**1,328,231**			**1,011**	
Residential	**Total Residential**				**110**	**0.072**	**116,040**	**122,833**	**119,520**			**12,177,867**	**13,732,395**	**13,662,535**	**8,181**	**9,214**	**8,233**

Type	Program	Measure	Measure Life	NTG	Avg. kWh/Unit	Avg. kW/Unit	2025 Participation	2026 Participation	2027 Participation	Incentive/ Unit	IMC/Unit	2025 KWH	2026 KWH	2027 KWH	2025 KW	2026 KW	2027 KW
Commercial	Commercial Prescriptive	Advanced Lighting Controls	10	84%	22,063	6.464	48	47	48	$ 3,225.00	$ 27,524.68	1,059,024	1,036,961	1,059,024	310.271	303.807	310.271
Commercial	Commercial Prescriptive	Advanced Rooftop Controls	10	84%	13,479	1.260	10	38	38	$ 2,575.00	$ 3,525.00	134,790	512,202	512,202	12.600	47.880	47.880
Commercial	Commercial Prescriptive	Electric Steam Trap Replacement	10	84%	177,021	15.169	2	2	4	$ 200.00	$ 2,800.00	354,041	354,041	708,082	30.337	30.337	60.675
Commercial	Commercial Prescriptive	Agriculture - Automatic Milker Take Off	15	84%	100	0.030	-	1	1	$ 1.67	$ 3,444.00	-	100	100	-	0.030	0.030
Commercial	Commercial Prescriptive	Agriculture - Dairy Plate Cooler	15	84%	76	0.016	-	1	1	$ 1.00	$ 447.00	-	76	76	-	0.016	0.016
Commercial	Commercial Prescriptive	Agriculture - HE Diary Scroll Compressor	5	84%	576	0.069	-	1	1	$ 16.67	$ 225.00	-	576	576	-	0.069	0.069
Commercial	Commercial Prescriptive	Agriculture - Heat Mat	15	84%	255	0.000	-	-	1	$ 21.67	$ 4,353.00	-	-	255	-	-	-
Commercial	Commercial Prescriptive	Agriculture - Heat Reclaimer	7	84%	88	0.000	-	1	1	$ 1.67	$ 150.00	-	88	88	-	-	-
Commercial	Commercial Prescriptive	Agriculture - High Speed Fans	10	84%	625	0.198	-	1	1	$ 25.00	$ 4,180.00	-	625	625	-	0.198	0.198
Commercial	Commercial Prescriptive	Agriculture - High Volume Low Speed Fans	10	84%	8,543	3.100	-	1	1	$ 250.00	$ 787.50	-	8,543	8,543	-	3.100	3.100
Commercial	Commercial Prescriptive	Agriculture - Livestock Waterer	15	84%	1,593	0.000	-	1	1	$ 66.67	$ 5,048.00	-	1,593	1,593	-	-	-
Commercial	Commercial Prescriptive	Agriculture - VSD Milk Pump	13	84%	34	0.000	-	1	1	$ 1.67	$ 17,541.04	-	34	34	-	-	-
Commercial	Commercial Prescriptive	Air Compressor	3	84%	78,517	9.772	1	1	2	$ 7,500.00	$ 500.00	78,517	78,517	157,033	9.772	9.772	19.545
Commercial	Commercial Prescriptive	Air Conditioner Tune-Up	15	84%	314	0.251	-	1	1	$ 100.00	$ 200.00	-	314	314	-	0.251	0.251
Commercial	Commercial Prescriptive	Air Conditioners	10	84%	2,879	1.865	48	52	53	$ 379.00	$ 83.26	138,209	149,726	152,606	89.496	96.954	98.819
Commercial	Commercial Prescriptive	Anti-Sweat Heater Control	5	84%	679	0.037	72	71	71	$ 66.67	$ -	48,908	48,229	48,229	2.642	2.606	2.606
Commercial	Commercial Prescriptive	Barrel Wrap Insulation	1	84%	360	0.068	-	1	1	$ 30.00	$ -	-	360	360	-	0.068	0.068
Commercial	Commercial Prescriptive	Behavioral-Based Measures	10	63%	1,000	0.240	25	25	25	$ 100.00	$ 681.34	25,000	25,000	25,000	6.000	6.000	6.000
Commercial	Commercial Prescriptive	Chilled Water Reset Control	23	84%	16,536	3.059	2	2	3	$ 700.00	$ 38,000.00	33,072	33,072	49,608	6.118	6.118	9.177
Commercial	Commercial Prescriptive	Chiller	5	84%	191,454	8.245	3	5	6	$ 20,000.00	$ -	574,386	957,259	1,148,710	24.734	41.224	49.468
Commercial	Commercial Prescriptive	Chiller Tune-Up	12	84%	34,339	7.204	28	38	39	$ 5,165.00	$ 2,125.00	961,492	1,304,882	1,339,221	201.720	273.763	280.967
Commercial	Commercial Prescriptive	Combination Oven	16	84%	14,041	1.400	2	2	2	$ 2,000.00	$ 616.25	28,082	28,082	28,082	2.800	2.800	2.800
Commercial	Commercial Prescriptive	Commercial Dishwasher	2	84%	3,822	0.250	7	7	7	$ 442.00	$ 8,000.00	26,754	26,754	26,754	1.750	1.750	1.750
Commercial	Commercial Prescriptive	Compressed Air Leak Study	15	84%	249,982	29.258	4	4	4	$ 10,000.00	$ 50.00	999,927	999,927	999,927	117.033	117.033	117.033
Commercial	Commercial Prescriptive	Compressed Air Nozzles	5	84%	888	0.337	1	9	9	$ 25.00	$ 100.00	888	7,994	7,984	0.337	3.034	3.034
Commercial	Commercial Prescriptive	Compressed Air Setpoint Reduction	12	84%	2,184	0.340	-	4	4	$ 100.00	$ 1,000.00	-	8,735	8,735	-	1.360	1.360
Commercial	Commercial Prescriptive	Convection Oven	15	84%			-	-	-	$ 500.00	$ 304.59	-	-	-	-	-	-
Commercial	Commercial Prescriptive	EC Motors	5	84%	1,586	0.181	120	119	119	$ 100.00	$ 250.00	190,320	188,734	188,734	21.720	21.539	21.539
Commercial	Commercial Prescriptive	Economizer Repair & Optimization	6	84%	250	0.000	-	4	4	$ 3.00	$ 418.00	-	999	999	-	-	-
Commercial	Commercial Prescriptive	Exterior LED	15	84%	1,560	0.000	822	804	804	$ 225.00	$ 270.24	1,281,849	1,254,030	1,253,782	-	-	-
Commercial	Commercial Prescriptive	Freezer	12	84%	1,398	0.163	3	3	3	$ 120.00	$ 154.00	4,195	4,195	4,195	0.488	0.488	0.488
Commercial	Commercial Prescriptive	Fryer	12	84%	2,986	0.260	2	2	2	$ 500.00	$ 1,000.00	5,972	5,972	5,972	0.520	0.520	0.520
Commercial	Commercial Prescriptive	Griddle	12	84%	2,597	0.260	2	2	2	$ 400.00	$ 2,090.00	5,194	5,194	5,194	0.520	0.520	0.520
Commercial	Commercial Prescriptive	Heat Pump	16	84%	1,323	0.770	114	124	124	$ 356.28	$ 143.64	150,868	164,102	164,102	87.780	95.480	95.480
Commercial	Commercial Prescriptive	Heat Pump Water Heater	15	84%	1,486	0.210	-	2	2	$ 500.00	$ 1,797.00	-	2,972	2,972	-	0.420	0.420
Commercial	Commercial Prescriptive	Hot Food Holding Cabinet	12	84%	3,800	0.450	7	7	7	$ 420.00	$ 1,110.00	26,602	26,602	26,602	3.150	3.150	3.150
Commercial	Commercial Prescriptive	Ice Machine	9	84%	924	4.360	2	2	2	$ 170.00	$ 1,333.60	1,849	1,849	1,849	8.720	8.720	8.720
Commercial	Commercial Prescriptive	Interior LED - High-Bay	15	84%	1,143	0.217	877	872	864	$ 100.00	$ 113.54	1,002,631	996,915	987,769	190.221	189.137	187.402
Commercial	Commercial Prescriptive	Interior LED - Low-Bay	15	84%	254	0.047	9,980	9,873	9,821	$ 44.00	$ 78.04	2,534,041	2,506,872	2,493,669	469.060	464.031	461.587
Commercial	Commercial Prescriptive	Kitchen Hood Demand Control Ventilation	20	84%	12,912	1.770	3	2	3	$ 457.00	$ 1,180.00	38,735	25,823	38,735	5.310	3.540	5.310
Commercial	Commercial Prescriptive	Lighting Control	10	84%	341	0.010	363	361	368	$ 30.00	$ 56.32	123,755	123,073	125,460	3.775	3.754	3.827
Commercial	Commercial Prescriptive	Lighting Power Density Reduction	15	84%	32,738	4.709	6	6	7	$ 3,928.53	$ -	196,427	196,427	229,164	28.257	28.257	32.966
Commercial	Commercial Prescriptive	Low Flow Pre-Rinse Sprayer	5	84%			-	-	-	$ 10.00	$ -	-	-	-	-	-	-
Commercial	Commercial Prescriptive	No-Loss Condensate Drains	10	84%	1,970	0.300	2	8	8	$ 200.00	$ 244.00	3,939	15,757	15,757	0.600	2.400	2.400
Commercial	Commercial Prescriptive	Packaged Rooftop Unit Sealing	5	84%			-	-	-	$ 7.00	$ 194.49	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Pellet Dryer Duct Insulation	5	84%			-	-	-	$ 30.00	$ -	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Plug Load Occupancy Sensor	7	84%			-	-	-	$ 5.00	$ 9.00	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Programmable Thermostat	11	84%	716	0.000	205	204	204	$ 50.00	$ 35.00	146,686	145,971	145,971	-	-	-
Commercial	Commercial Prescriptive	Refrigerant Charge	3	84%			-	-	-	$ 40.00	$ 500.00	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Refrigerated Case Cover	5	84%			-	-	-	$ 10.00	$ 42.00	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Refrigerated LED	8	84%			-	-	-	$ 16.00	$ 35.89	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Refrigerator	12	84%	834	0.093	5	5	5	$ 26.67	$ 146.50	4,168	4,168	4,168	0.465	0.465	0.465
Commercial	Commercial Prescriptive	Remote Condensing Unit Tune-Up	3	84%	345	0.083	14	14	14	$ 35.62	$ -	4,833	4,833	4,833	1.158	1.158	1.158
Commercial	Commercial Prescriptive	Self-Contained Unit Tune-Up	3	84%	300	0.046	4	6	6	$ 35.62	$ -	1,201	1,801	1,801	0.184	0.276	0.276
Commercial	Commercial Prescriptive	Showerheads	10	84%	7,130	0.000	1	-	1	$ 5.00	$ -	7,130	-	7,130	-	-	-
Commercial	Commercial Prescriptive	Smart Strip Plug Outlet	7	84%			-	-	-	$ 8.00	$ 15.00	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Steam Cooker	12	84%			-	-	-	$ 200.00	$ 2,490.00	-	-	-	-	-	-
Commercial	Commercial Prescriptive	Vending Machine Control	5	84%	384	0.000	2	2	2	$ 41.67	$ 245.00	769	769	769	-	-	-
Commercial	Commercial Prescriptive	VFD-Fan	15	84%	28,435	5.271	6	10	11	$ 3,000.00	$ 4,059.57	170,607	284,345	312,780	31.628	52.714	57.985
Commercial	Commercial Prescriptive	VFD-Pump	15	84%	34,153	6.182	6	9	10	$ 3,000.00	$ 2,472.38	204,915	307,373	341,525	37.092	55.637	61.819
Commercial	Commercial Prescriptive	Water Heater Recirculating Pump Control	15	84%	1,103	0.000	1	1	1	$ -	$ 2,210.00	1,103	1,103	1,103	-	-	-
Commercial	Commercial Prescriptive	Wifi-Enabled Thermostat	11	84%	716	0.000	240	238	230	$ 100.00	$ 250.00	171,730	170,299	164,575	-	-	-
Commercial	Commercial Prescriptive	Window Air Conditioner & PTAC	8	84%	554	0.150	4	4	4	$ 46.85	$ 84.00	2,216	2,216	2,216	0.600	0.600	0.600
Commercial	Commercial Prescriptive	Window Film	10	84%	2,305	0.597	3	3	4	$ 395.83	$ 3,870.67	6,914	6,914	9,219	1.790	1.790	2.387
Commercial	**Total Commercial Prescriptive**		**13**	**84%**			**13,047**	**13,004**	**12,958**			**10,751,737**	**12,032,995**	**12,824,803**	**1,709**	**1,883**	**1,964**

Type	Program	Measure	Measure Life	NTG	Avg. kWh/Unit	Avg. kW/Unit	2025 Participation	2026 Participation	2027 Participation	Incentive/ Unit	IMC/Unit	2025 KWH	2026 KWH	2027 KWH	2025 KW	2026 KW	2027 KW
Commercial	Commercial Midstream	Air Conditioners	15	84%	2,879	1.865	2	2	2	$ 379.00		5,759	5,759	5,759	3.729	3.729	3.729
Commercial	Commercial Midstream	Anti-Sweat Heater Control	10	84%	679	0.037	3	3	3	$ 66.67		2,038	2,038	2,038	0.110	0.110	0.110
Commercial	Commercial Midstream	Chiller	23	84%	191,454	8.245	1	1	2	$ 20,000.00		191,462	191,452	382,903	8.245	8.245	16.489
Commercial	Commercial Midstream	Combination Oven	12	84%	14,041	1.400	2	1	1	$ 2,000.00		28,082	14,041	14,041	2.800	1.400	1.400
Commercial	Commercial Midstream	Convection Oven	12	84%	2,025	0.200	1	1	-	$ 500.00		2,025	2,025	-	0.200	0.200	-
Commercial	Commercial Midstream	EC Motors	15	84%	1,586	0.181	5	5	6	$ 100.00		7,930	7,930	9,516	0.905	0.905	1.086
Commercial	Commercial Midstream	Freezer	12	84%	1,398	0.163	1	1	1	$ 120.00		1,398	1,398	1,398	0.163	0.163	0.163
Commercial	Commercial Midstream	Fryer	12	84%	2,986	0.260	3	1	1	$ 500.00		8,958	2,986	2,986	0.780	0.260	0.260
Commercial	Commercial Midstream	Griddle	12	84%	2,597	0.260	2	2	1	$ 400.00		5,194	5,194	2,597	0.520	0.520	0.260
Commercial	Commercial Midstream	Heat Pump	16	84%	1,323	0.770	2	5	5	$ 356.28		2,647	6,617	6,617	1.540	3.850	3.850
Commercial	Commercial Midstream	Hot Food Holding Cabinet	12	84%	3,800	0.450	1	1	-	$ 420.00		3,800	3,800	-	0.450	0.450	-
Commercial	Commercial Midstream	Ice Machine	9	84%	924	4.360	-	1	-	$ 170.00		-	924	-	-	4.360	-
Commercial	Commercial Midstream	Kitchen Hood Demand Control Ventilation	20	84%	12,912	1.770	2	3	2	$ 457.00		25,823	38,735	25,823	3.540	5.310	3.540
Commercial	Commercial Midstream	Refrigerated Case Cover	5	84%	0.00	0.000	-	-	-	$ 10.00		-	-	-	-	-	-
Commercial	Commercial Midstream	Refrigerator	12	84%	0.00	0.000	-	-	-	$ 26.67		-	-	-	-	-	-
Commercial	Commercial Midstream	Steam Cooker	12	84%	4,769	0.952	2	1	1	$ 200.00		9,538	4,769	4,769	1.904	0.952	0.952
Commercial	Commercial Midstream	Vending Machine Control	5	84%	0.00	0.000	-	-	-	$ 41.67		-	-	-	-	-	-
Commercial	Commercial Midstream	VFD-Fan	15	84%	28,435	5.271	3	5	4	$ 3,000.00		85,304	142,173	113,738	15.814	26.357	21.086
Commercial	Commercial Midstream	VFD-Pump	15	84%	34,153	6.182	2	4	3	$ 3,000.00		68,305	136,610	102,458	12.364	24.728	18.546
Commercial	Commercial Midstream	Window Air Conditioner & PTAC	8	84%	554	0.150	-	1	1	$ 46.85		-	554	554	-	0.150	0.150
Commercial	**Total Commercial Midstream**		**18**	**84%**			**32**	**38**	**33**			**448,263**	**567,005**	**675,197**	**53**	**82**	**72**
Commercial	Small Business Energy Solutions	Advanced Rooftop Controls	10	84%	13,479	1.260	10	10	10	$ 3,000.00	$ 3,525.00	134,793	134,793	134,793	12.600	12.600	12.600
Commercial	Small Business Energy Solutions	Air Conditioner Tune-Up	3	84%	314	0.251	1	1	1	$ 100.00	$ 500.00	314	314	314	0.251	0.251	0.251
Commercial	Small Business Energy Solutions	Anti-Sweat Heater Control	10	84%	679	0.037	1	1	1	$ 170.00	$ 83.26	679	679	679	0.037	0.037	0.037
Commercial	Small Business Energy Solutions	EC Motors	15	84%	1,586	0.181	9	9	9	$ 225.00	$ 304.59	14,274	14,274	14,274	1.629	1.629	1.629
Commercial	Small Business Energy Solutions	Economizer Repair & Optimization	5	84%	250	0.000	1	1	1	$ 50.00	$ 250.00	250	250	250	-	-	-
Commercial	Small Business Energy Solutions	Exterior LED	15	84%	1,584	0.000	1,091	1,091	1,091	$ 350.00	$ 181.64	1,728,144	1,728,144	1,728,144	-	-	-
Commercial	Small Business Energy Solutions	Faucet Aerator	10	84%	114	0.036	1	1	1	$ 15.00	$ 8.00	114	114	114	0.036	0.036	0.036
Commercial	Small Business Energy Solutions	Interior LED	15	84%	184	0.036	12,468	12,468	12,468	$ 50.00	$ 131.43	2,290,748	2,290,748	2,290,748	449.532	449.532	449.532
Commercial	Small Business Energy Solutions	Lighting Control	10	84%	137	0.026	188	188	188	$ 35.00	$ 56.69	25,691	25,691	25,691	4.963	4.963	4.963
Commercial	Small Business Energy Solutions	Low Flow Pre-Rinse Sprayer	5	84%	713	0.000	2	2	2	$ 60.00	$ -	1,426	1,426	1,426	-	-	-
Commercial	Small Business Energy Solutions	Packaged Rooftop Unit Sealing	5	84%	232	0.190	1	1	1	$ 50.00	$ 194.49	232	232	232	0.190	0.190	0.190
Commercial	Small Business Energy Solutions	Program the Programmable Thermostat	15	84%	716	0.000	1	1	1	$ 25.00	$ 25.00	716	716	716	-	-	-
Commercial	Small Business Energy Solutions	Program the Programmable Thermostat	15	84%	737	0.000	11	11	11	$ 18.75	$ 25.00	8,102	8,102	8,102	-	-	-
Commercial	Small Business Energy Solutions	Programmable Thermostat	11	84%	1,380	0.000	8	8	8	$ 225.00	$ 35.00	11,039	11,039	11,039	-	-	-
Commercial	Small Business Energy Solutions	Programmable Thermostat	11	84%	1,380	0.000	7	7	7	$ 175.00	$ 35.00	9,659	9,659	9,659	-	-	-
Commercial	Small Business Energy Solutions	Refrigerant Charge	3	84%	335	0.269	1	1	1	$ 125.00	$ 500.00	335	335	335	0.269	0.269	0.269
Commercial	Small Business Energy Solutions	Refrigerated Case Cover	5	84%	158	0.000	15	15	15	$ 30.00	$ 42.00	2,363	2,363	2,363	-	-	-
Commercial	Small Business Energy Solutions	Refrigerated LED	8	84%	529	0.091	3	3	3	$ 75.00	$ 100.00	1,588	1,588	1,588	0.274	0.274	0.274
Commercial	Small Business Energy Solutions	Vending Machine Control	5	84%	384	0.000	5	5	5	$ 150.00	$ 245.00	1,921	1,921	1,921	-	-	-
Commercial	Small Business Energy Solutions	Weather Stripping - Exterior Door	5	84%			-	-	-	$ -	$ 16.50	-	-	-	-	-	-
Commercial	Small Business Energy Solutions	Wifi-Enabled Thermostat	11	84%	1,380	0.000	6	6	6	$ 400.00	$ 250.00	8,279	8,279	8,279	-	-	-
Commercial	Small Business Energy Solutions	Wifi-Enabled Thermostat	11	84%	1,380	0.000	43	43	43	$ 350.00	$ 250.00	59,334	59,334	59,334	-	-	-
Commercial	**Total Small Business Energy Solutions**		**15**	**84%**			**13,873**	**13,873**	**13,873**			**4,300,000**	**4,300,000**	**4,300,000**	**470**	**470**	**470**
Commercial	Commercial Custom	Building Tune-Up (Electric)	7	84%	68,750	0.050	8	12	12	$ 5,000.00	$ 6,000.00	400,000	900,000	900,000	0.400	0.600	0.600
Commercial	Commercial Custom	Custom Electric	17	84%	56,687	9.342	75	75	75	$ 7,936.19	$ 15,345.24	4,251,533	4,251,533	4,251,533	700.683	700.683	700.683
Commercial	Commercial Custom	EDA Design Team Incentives	15	84%	0.00	0.000	10	10	10	$ 2,000.00	$ 4,000.00	-	-	-	-	-	-
Commercial	Commercial Custom	EDA Lighting Power Density Reduction	15	84%	10,140	2.300	2	2	2	$ 1,135.60	$ 4,000.00	20,280	20,280	20,280	4.600	4.600	4.600
Commercial	Commercial Custom	EDA Non-Lighting (Electric)	13	84%	28,187	18.000	1	1	1	$ 3,946.21	$ 4,000.00	28,187	28,187	28,187	18.000	18.000	18.000
Commercial	Commercial Custom	SEM Electric	13	84%	300,000	10.000	3	3	3	$ 60,000.00	$ 35,000.00	900,000	900,000	900,000	30.000	30.000	30.000
Commercial	**Total C&I Custom**		**15**	**84%**			**89**	**93**	**93**			**5,600,000**	**6,100,000**	**6,100,000**	**754**	**754**	**754**
Commercial	**Building Optimization**		**15**	**100%**	**150,000**	**2.000**	**10**	**10**	**10**			**1,500,000**	**1,500,000**	**1,500,000**	**20**	**20**	**20**
Commercial	**CVR - Commercial**		**15**	**100%**	**778**	**0.422**		**674**					**524,327**			**284**	
Commercial	**Total Commercial & Industrial**		**1**	**100%**	**894**	**0.120**	**27,051**	**27,692**	**26,967**			**22,600,000**	**25,024,327**	**25,400,000**	**3,005**	**3,492**	**3,279**
	Total Residential & C&I				**256**	**0.080**	**143,091**	**150,525**	**146,487**			**34,777,868**	**38,756,721**	**39,062,535**	**11,186**	**12,706**	**11,512**

Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)

SEE ATTACHMENT: CONFIDENTIAL - Attachment 3.5 Gas Pipeline Cost Estimates

Attachment 3.6 2025 DSM Market Potential Study



GDS Associates, Inc.
ENGINEERS & CONSULTANTS

MARKET POTENTIAL STUDY

CENTERPOINT ENERGY

December 03, 2025

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Georgia · Alabama · California · Maine · New Hampshire · Texas · Washington · Wisconsin

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01 INTRODUCTION

1.1 BACKGROUND AND STUDY SCOPE

This Market Potential Study was conducted by GDS to support the Integrated Resource Plan ("IRP") and DSM planning for CenterPoint Energy in Indiana ("CenterPoint"). The study included a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. Separate estimates of electric energy efficiency ("EE") and demand response potential were developed. The GDS Team worked collaboratively alongside CenterPoint and the CenterPoint Oversight Board to produce estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates.

In addition to providing an estimate of achievable potential which informed the IRP, GDS developed a DSM Action Plan for the years 2028-2033. This Action Plan was developed to help CenterPoint utilize the results of the potential study in creating its own future DSM Operating Plans. The Action Plan is described in Chapters 5 and 6 of this document.

1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test ("UCT") to assess cost-effectiveness.
- **Achievable Potential** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and Evaluation, Measurement & Verification ("EM&V"); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate ("WTP") in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated three achievable potential scenarios:
  - **Maximum Achievable Potential ("MAP")** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
  - **Realistic Achievable Potential ("RAP")** estimates achievable potential with CenterPoint paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
  - **Enhanced RAP** estimates achievable potential achievable potential by adjusting incentive levels in the RAP scenario to increase participation beyond the RAP scenario while also considering implications related to cost-effectiveness. For this scenario, a maximum incentive was calculated to either cover a sector-specific lifetime cost per MWh or 100% of the measure cost, whichever was less. There was also an incentive floor of 10% of measure cost. Effectively, it is a scenario that has savings and costs greater than the RAP scenario, but less than the MAP scenario.

1.3 APPROACH SUMMARY

The purpose of this market potential study is to provide a foundation for the continuation of utility-administered energy efficiency and demand response programs in the CenterPoint Energy service area, to determine the remaining opportunities for cost-effective energy and demand savings. This study has examined a full array of technologies, programs, and energy efficient building practices that are technically achievable.

The GDS Team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial sectors, the GDS team utilized a top-down modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness and then applied cost-effective measure savings to all applicable shares of electric energy load.

1.4 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency and demand response measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures
- Projections of electric avoided costs
- Future known changes to codes and standards
- CenterPoint load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data, there are often reasonable alternative assumptions which would yield slightly different results.

1.5 POTENTIAL SAVINGS OVERVIEW

The following three sub-sections provide a high-level summary of the results of the residential and C&I energy efficiency potential as well as summary demand response potential. Chapters 3 and 4 of this report provide additional summary data and methodological considerations and descriptions.

1.5.1 Residential Energy Efficiency Potential

Figure 1-1 provides the technical, economic, MAP, RAP and Enhanced RAP results for the 3-year, 6-year, and 18-year timeframes. The cumulative annual 3-year technical and economic potential is 10% of forecasted sales. The cumulative annual 3-year MAP is 4.0%, the RAP is 2.8%, and the Enhanced RAP is 3.2% of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 32% and 30% of forecasted sales, respectively. The MAP, RAP and Enhanced RAP increased to 21.1%, 15.0% and 17.5% of forecasted sales respectively, over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential. The Enhanced RAP is greater than RAP as a result of higher incentive levels.

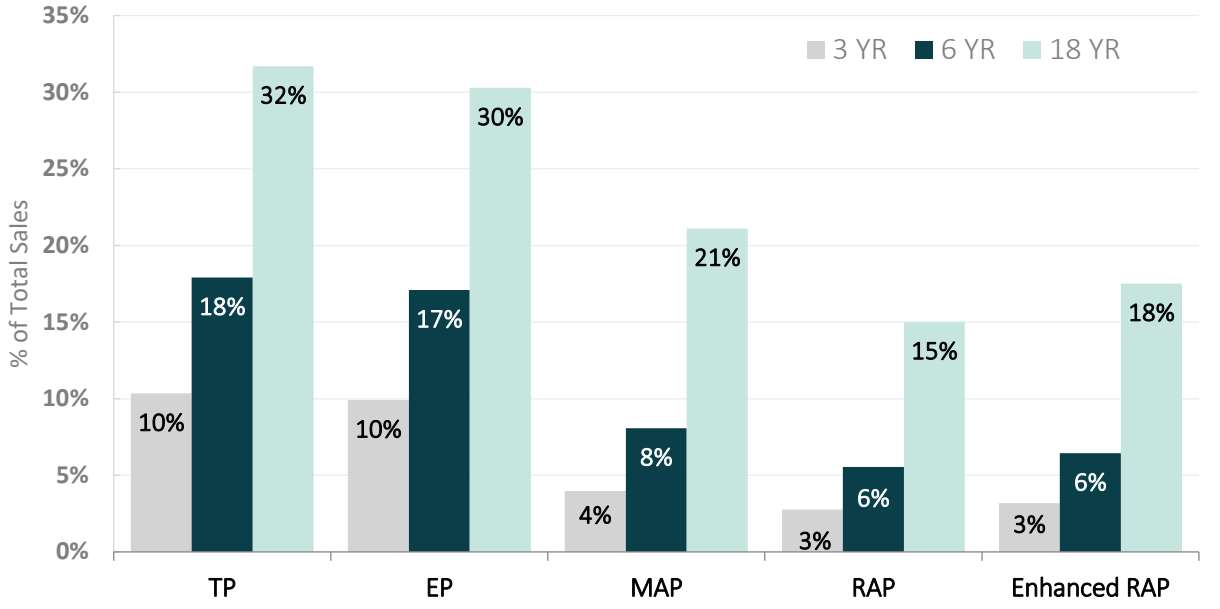


FIGURE 1-1: RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF RESIDENTIAL SALES)

Table 1-1 provides the incremental annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.1% to 1.5% per year over the next six years, while the Enhanced RAP ranges from 1.2% to 1.7%.

TABLE 1-1: RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2028	2029	2030	2031	2032	2033
Energy (MWh)						
Technical	59,102	59,548	59,106	58,577	58,062	57,519
Economic	56,894	57,386	56,987	56,499	56,023	55,519
MAP	20,652	23,274	25,503	27,311	28,764	30,098
RAP	15,299	17,166	18,908	20,394	21,568	22,549
Enhanced RAP	16,984	19,210	21,180	22,811	24,157	25,381
Technical	4.1%	4.1%	4.1%	4.0%	3.9%	3.9%
Economic	4.0%	4.0%	3.9%	3.9%	3.8%	3.7%
MAP	1.4%	1.6%	1.8%	1.9%	1.9%	2.0%
RAP	1.1%	1.2%	1.3%	1.4%	1.5%	1.5%
Enhanced RAP	1.2%	1.3%	1.5%	1.6%	1.6%	1.7%
Demand (MW)						
Technical	13.9	13.9	13.8	13.7	13.6	13.5
Economic	13.6	13.6	13.5	13.4	13.3	13.2
MAP	4.5	5.1	5.6	6.1	6.3	6.5
RAP	2.8	3.2	3.5	3.7	3.9	4.0
Enhanced RAP	3.2	3.6	4.0	4.3	4.5	4.6

1.5.2 Commercial and Industrial Energy Efficiency Potential

Figure 1-2 provides the technical, economic, MAP, RAP and Enhanced RAP results for the 3-year, 6-year, and 18-year timeframes. The cumulative annual 3-year technical and economic potential is 6% of forecasted sales. The cumulative annual 3-year MAP is 4.8%, the RAP is 4.0%, and the Enhanced RAP is 4.2% of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 27% of forecasted sales, respectively. The MAP, RAP and Enhanced RAP increased to 17.9%, 15.9% and 16.5% of forecasted sales respectively, over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential. The Enhanced RAP is greater than RAP as a result of higher incentive levels.

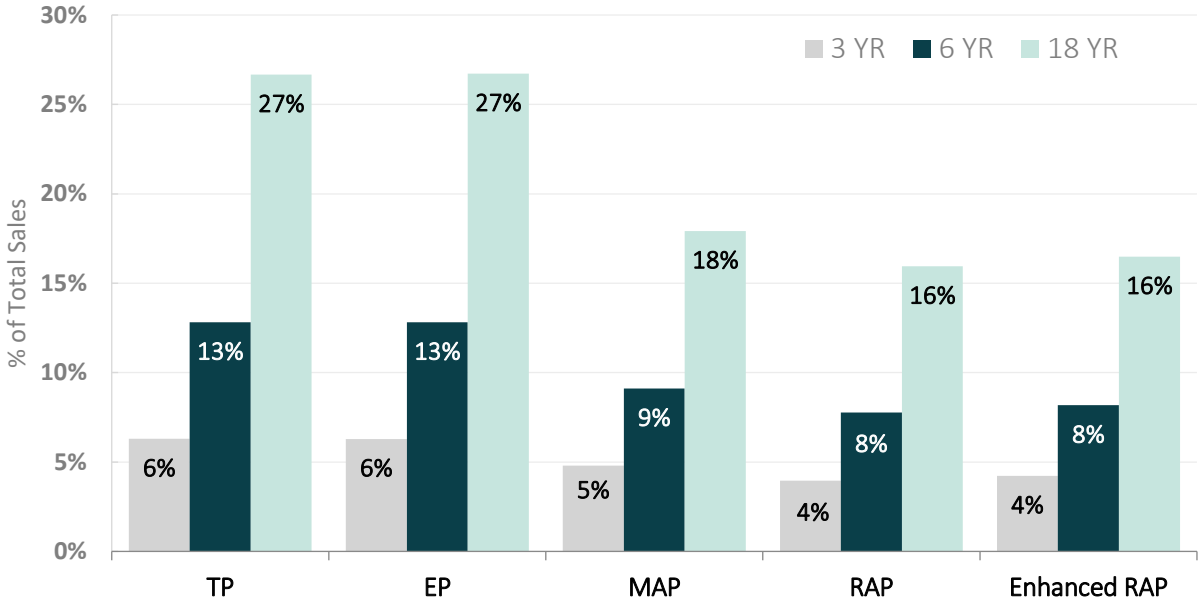


FIGURE 1-2: C&I ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERICAL AND INDUSTRIAL SALES)

Table 1-2 provides the incremental annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.3% to 1.4% per year over the next six years, while the Enhanced RAP ranges from 1.4% to 1.5%.

TABLE 1-2: C&I INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2028	2029	2030	2031	2032	2033
Energy (MWh)						
Technical	35,864	37,997	39,463	41,560	41,543	41,379
Economic	35,858	37,992	39,459	41,556	41,538	41,370
MAP	28,697	28,985	28,679	29,120	27,899	25,750
RAP	22,911	23,939	24,329	25,387	24,726	23,714
Enhanced RAP	24,899	25,553	25,627	26,380	25,517	24,052
Energy Savings (as% of Sector Sales Forecast)						
Technical	2.0%	2.1%	2.2%	2.3%	2.3%	2.3%
Economic	2.0%	2.1%	2.2%	2.3%	2.3%	2.3%

	2028	2029	2030	2031	2032	2033
MAP	1.6%	1.6%	1.6%	1.6%	1.5%	1.4%
RAP	1.3%	1.3%	1.4%	1.4%	1.4%	1.3%
Enhanced RAP	1.4%	1.4%	1.4%	1.5%	1.4%	1.3%
Demand (MW)						
Technical	5.2	5.5	5.6	5.9	5.8	5.8
Economic	5.2	5.5	5.6	5.9	5.8	5.8
MAP	4.4	4.4	4.2	4.2	4.0	3.6
RAP	3.3	3.4	3.4	3.5	3.4	3.3
Enhanced RAP	3.7	3.7	3.6	3.8	3.6	3.3

1.5.3 Demand Response Potential

Figure 1-3 shows the cumulative annual RAP (MW) by program in the residential sector. The two DLC Thermostat options provide the greatest amount of potential, with the Time of Use + Critical Peak Pricing and DLC Grid-Enabled Water Heater program options growing over time as well. Overall, the residential RAP grows from 26.9 MW in 2028 to 39 MW in 2045.

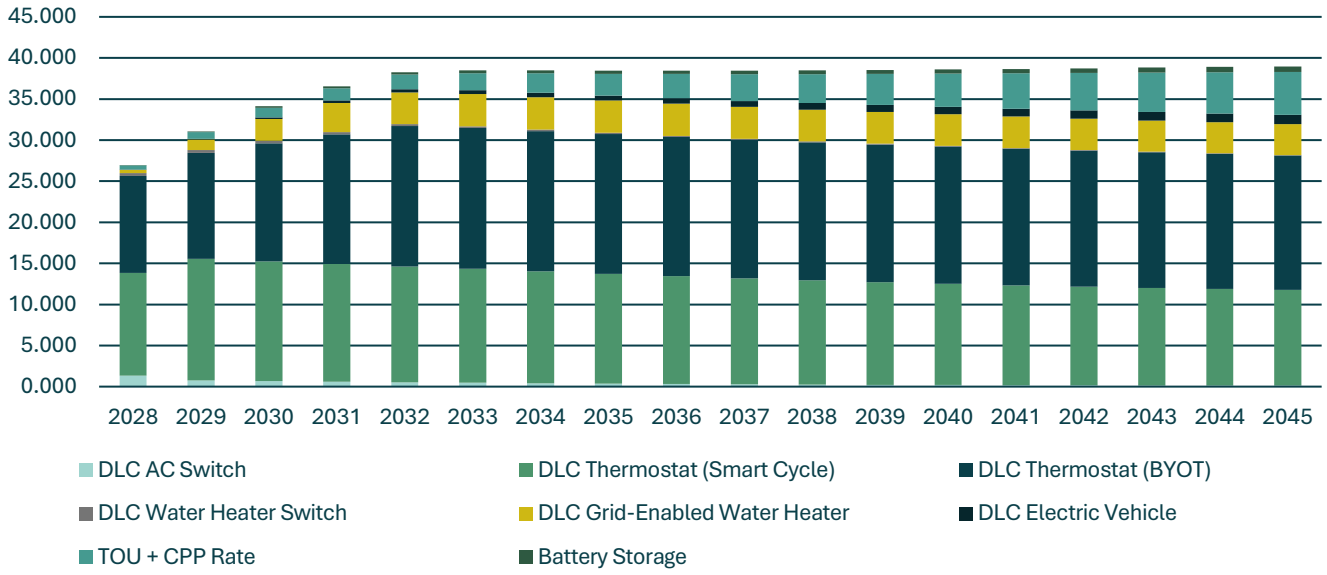


FIGURE 1-3 RESIDENTIAL SECTOR DEMAND RESPONSE RAP – BY PROGRAM

Figure 1-4 shows the cumulative annual RAP (MW) by program in the commercial sector. The DLC Thermostat option provides the greatest amount of potential, with the DLC Grid-Enabled Water Heater and Time of Use + Critical Peak Pricing options growing significantly over time as well. Overall, the commercial RAP grows from 1 MW in 2028 to 8 MW in 2045.

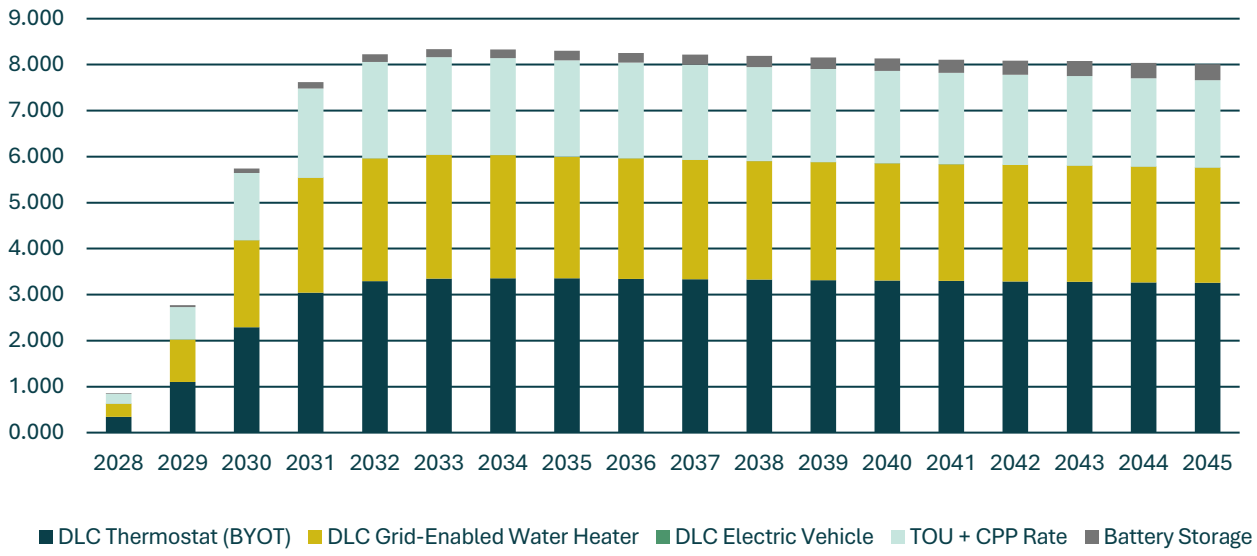


FIGURE 1-4 COMMERCIAL SECTOR DEMAND RESPONSE RAP – BY PROGRAM

02 BASELINE FORECAST

The load forecast is a critical input into CenterPoint's 2025 DSM Market Potential Study, having various uses in estimation of residential and business sector potential. Therefore, the GDS Team took considerable time and effort to review CenterPoint's most recently completed load forecast models and documentation to produce the various forecast components necessary as inputs into this analysis. The chapter describes the various ways in which the forecast is used for this study, presents the baseline and disaggregated forecasts, and describes the methodology and data sources used by GDS for the purposes of generating the load forecasts that were used in the potential analysis.

2.1 CENTERPOINT LOAD FORECASTING SYSTEM

CenterPoint employs a sophisticated load forecasting system that uses econometric and Statistically Adjusted End-Use ("SAE") models to project number of consumers, average consumption per consumer, and total energy sales by class. Residential, Commercial, and Industrial consumers are projected using traditional econometric techniques. Residential average usage and commercial energy sales are projected using SAE model specifications. Industrial energy sales are projected using econometric techniques.

A residential SAE model specification takes end-use data drawn from utility, regional, and even national sources and develops monthly end-use indices designed to predict average household consumption. The end-use data includes market shares of key electric consuming appliances, average device efficiency trends, average building shell efficiency trends, price elasticity of demand, income elasticity of demand, and elasticity associated with the average number of people per household. A cooling index is developed to represent space cooling load and is further modified by Cooling Degree Days to incorporate summer weather into the model. Likewise, a heating index representing space heating is modified by Heating Degree Days. Finally, a base index is developed to represent consumption of all other end-uses in the home.

A commercial SAE model specification is very similar to a residential specification, except end-use energy intensity indices are developed for each commercial building type based on area employment in various industry codes. National and regional commercial data is used to estimate end-use consumption for various industries (for example, restaurants will have higher cooking usage shares than offices).

CenterPoint also projects the impacts of DSM programs it has run in the past. The DSM impacts included in the load forecast based on the evaluated results of CenterPoint DSM programs.

2.2 ADJUSTMENTS TO THE CENTERPOINT LOAD FORECAST

Before assessing the future potential for energy efficiency and demand response in the CenterPoint service area, a few modifications to CenterPoint's forecast were necessary to create an adjusted baseline forecast. These modifications are addressed in more detail below.

2.2.1 Reclassification of Load

The CenterPoint C&I sector customer database designated commercial and industrial ("C&I") rate code based on current tariff definition. When only using the account type/tariff definition to classify customers as either commercial or industrial, there were several manufacturing type premises classified as commercial, as well as several customers that GDS typically classifies as commercial classified as industrial, (i.e., a retail service building coded as an industrial account).

Additionally, the dataset also identified each business by North American Industry Classification System ("NAICS") code. To reclassify CenterPoint C&I sector data, GDS mapped industry codes to a specified building type and classified the building type as either commercial or industrial. Customers with a building type classified as "Industrial Manufacturing" were coded as Industrial customers, while all other building types were coded as Commercial. While the goal for this

analysis is to determine the actual amount of energy sales attributable to the commercial and industrial customer classes as a whole, it is only achievable by analyzing individual customer data. The result of this reclassification was a shift of approximately 12% of industrial sector sales, or roughly 280,000 MWh, to the commercial sector. This 12% shift was then applied to the CenterPoint case forecasted sales for the commercial and industrial classes. It is important to have accurate energy sales by customer class so that specific DSM/EE programs have the correct amount of energy sales eligible for savings.

2.2.2 Adjustments for Large C&I Opt Out Customers

The CenterPoint business sector customer database containing usage and demographic data for all C&I customers, with indication for large customer opt-out of DSM/EE programs status was utilized to determine how to adjust for opt-out customers. The number of customers and total energy use was calculated both including and excluding opt-out customers. The load forecast for the C&I sector was adjusted down by the percentage of load attributed to opt-out customers from the customer database, in effect excluding from the potential analysis any load of opt-out customers. The opt-out adjustment was held constant for all years of the load forecast. In total, GDS removed approximately 15% of commercial energy sales and 71% of industrial energy sales due to large customer opt-out.

2.3 LOAD FORECAST DISAGGREGATION

The baseline forecasts represent projected total energy sales by class. For the potential studies, it is useful to have the class forecasts disaggregated in several different ways. This section presents the forecast disaggregation scenarios used by GDS to determine intensity by end-use.

2.3.1 Residential Sector

The residential electric calibration effort led to an end-use breakdown of consumption by home type (single-family vs multifamily) as shown below in Figure 2-1. Overall, we estimated per home consumption to be 10,680 kWh per year for 2028. Among home types, both SF and MF homes use Heating for 17% of their total electricity consumption. Appliances (12% and 11% for SF and MF, respectively) and Other[1] (10% for both SF and MF) had similar end-use consumption profiles across housing types. SF homes use relatively more for Cooling than MF homes (17% vs 12%) and less for Water Heating (13% for SF vs 28% for MF).

[1] The “Other” end use consists of common loads such as Lighting, Cooking, Electronics, and Pools. The “Miscellaneous” end use consists of other less common plug loads such as EVs.

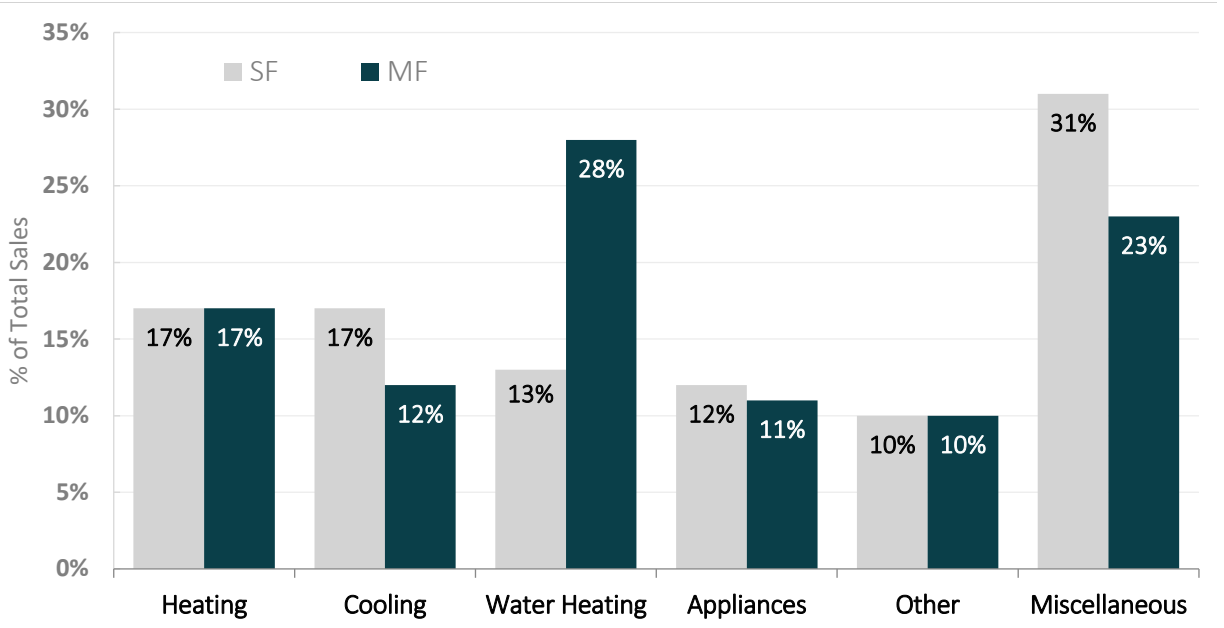


FIGURE 2-1. RESIDENTIAL ELECTRIC END-USE BREAKDOWN BY HOME TYPE

2.3.2 C&I Sector

In the C&I sector, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS received a base case sales forecast from CenterPoint for the residential, commercial, and industrial sectors. As noted above, the C&I forecast was adjusted from the base case by using NAICS information from CenterPoint to reclassify usage as commercial or industrial. NAICS information from CenterPoint, along with Commercial Buildings Energy Consumption Survey ("CBECS") building type consumption tables, was then used to segment the forecast into building types. The forecast was further segmented into end-uses by building type using regional specifical projections of end-use consumption contained within Energy Information Administration's ("EIA") Annual Energy Outlook supporting workpapers. Figure 2-2 provides a breakdown of commercial electric sales, excluding opt-outs, by building type.[2]

2 "Other" commercial building types include buildings that engage in several different activities, a majority of which are commercial (e.g., retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

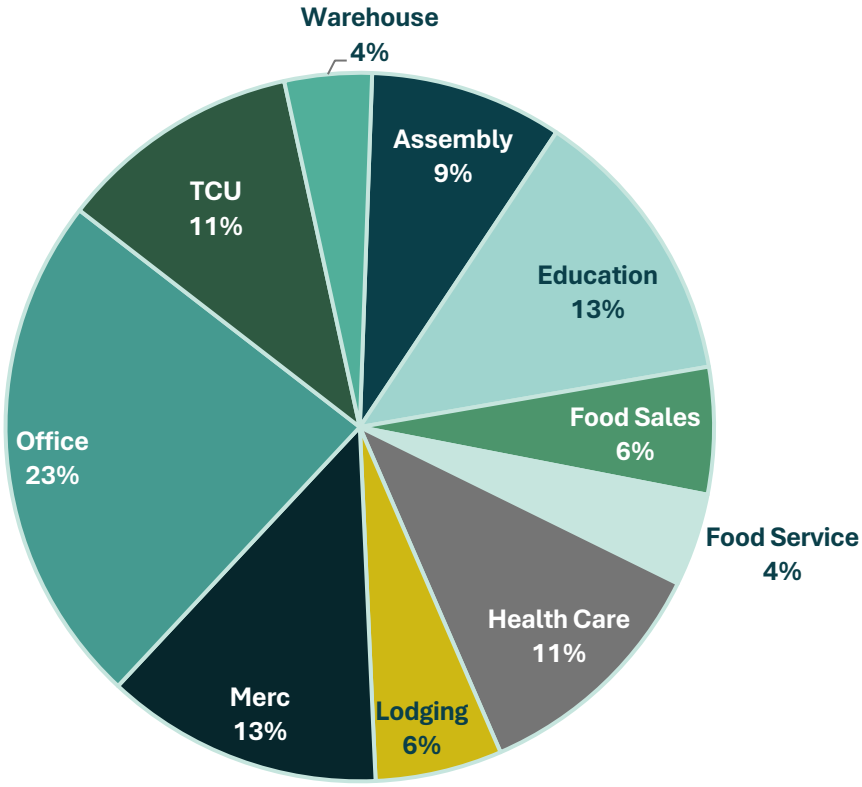


FIGURE 2-2. COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

Figure 2-4 provides an illustration of the leading end-uses across all building types in the commercial sector. Lighting, space cooling, and ventilation are the primary end-uses with a significant share of load across most building types. Shares of refrigeration and office/computing are often dependent on the type of building, with refrigeration loads greatest in food sales and food service while office/computing loads are greatest in offices and education. Miscellaneous plug load is also a significant share of load in some building types, indicating that various small electric devices are becoming more common in commercial buildings.

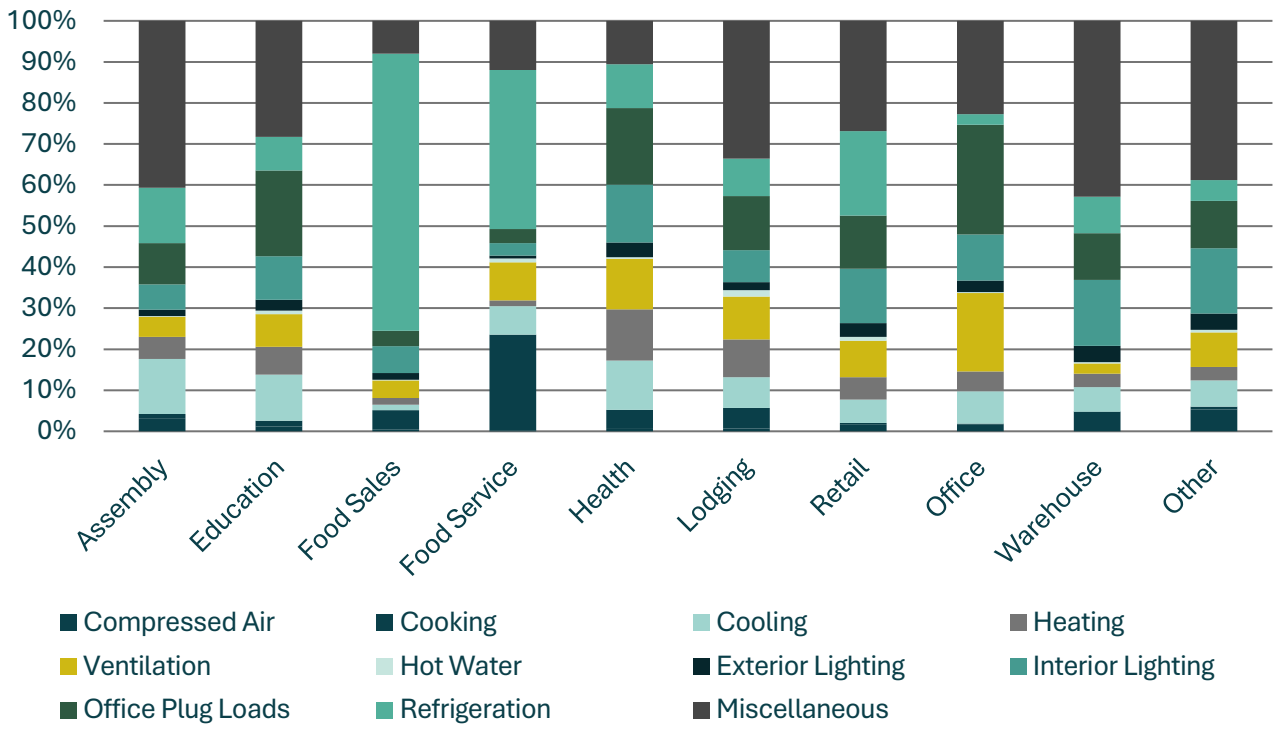


FIGURE 2-3. COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE

Industrial sales were also segmented by end-use based on the overall distribution of sales by industry type and EIA Manufacturing Energy Consumption Survey ("MECS") data on end-use consumption by industrial segment. Figure 2-4 provides a breakdown of the sales by end-use. Overall, the weighted average industrial sales by end-use in the CenterPoint service area was roughly 42% Machine Drive, 12% Process Heat, 10% HVAC, 8% Process Other, 8% Compressed Air, and 7% for both Process Refrigeration and Lighting. The remaining 6% was split between water-wastewater and other process loads.

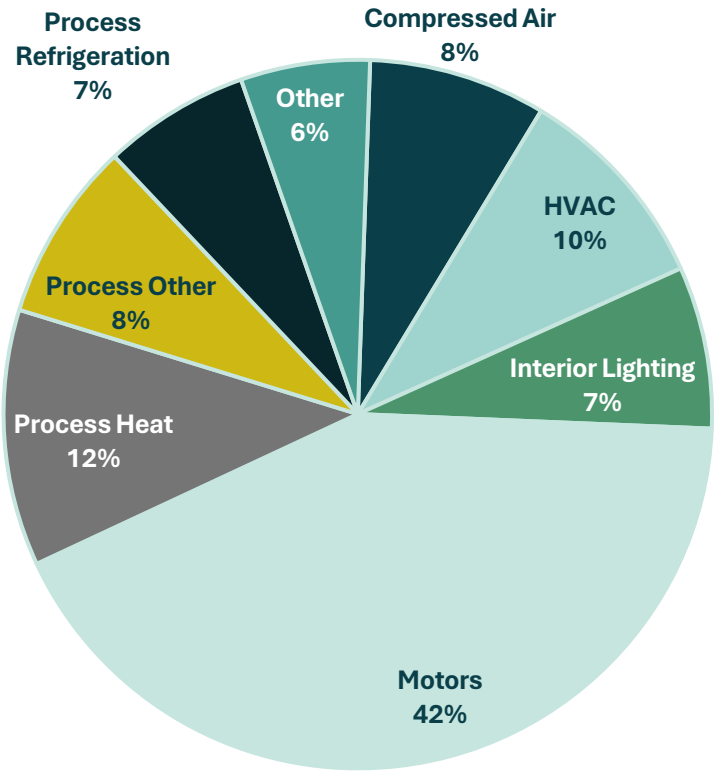


FIGURE 2-4. COMMERCIAL ELECTRIC SALES BY END-USE

03 ENERGY EFFICIENY POTENTIAL ANALYSIS

This chapter describes the overall methodology utilized to assess the electric energy efficiency potential in the CenterPoint service area. The main objectives of this demand-side management ("DSM") market potential study ("MPS", or "study") were to estimate the technical, economic, maximum, and realistic potential savings from energy efficiency ("EE") in the CenterPoint service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency and demand response ("DR") potential (see Chapter 4 for details on the DR analysis).

Energy efficiency potential studies involve several analytical steps to produce estimates of each type of energy efficiency potential. This study utilizes benefit/cost screening tools for the residential and non-residential sectors to assess the cost-effectiveness of energy efficiency measures. These cost effectiveness screening tools are built-in to Excel-based models that integrate technology-specific impacts and costs, customer characteristics, and utility avoided cost forecasts. The modeling platform provides transparency to the estimation process. The major analytical steps and an overview of the potential savings are summarized below, and specific changes in methodology from one sector to another have been noted throughout this section.

3.1 OVERVIEW OF APPROACH

For the residential sector, GDS utilized a bottom-up approach to the modeling of energy efficiency potential, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, taking into consideration incentives and estimates of annual adoption rates. For the C&I sector, GDS employed a bottom-up modeling approach to first estimate measure-level savings, costs, and cost-effectiveness, and then applied measure savings to all applicable shares of energy load.

3.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments in the CenterPoint service area. The GDS team coordinated with CenterPoint to gather utility sales and customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data, and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and non-residential sectors.

3.2.1 Forecast Disaggregation

Through the development of the baseline forecasts, the GDS Team produced disaggregated forecasts by sector and end-use. The resulting aggregate baseline forecasts were disaggregated by sector and then further segmented as follows:

- **Residential.** The residential forecast was broken out by housing type as well as existing vs. new construction.
- **Commercial.** Typically based on major EIA CBECS business types: retail, warehouse, food sales, office, lodging, health, food service, education, and miscellaneous.
- **Industrial.** As determined by actual load consumption shares and major industry types as defined by EIA's MECS data.

The segmentation analysis was performed by applying CenterPoint-specific segment and end-use consumption shares, derived from CenterPoint's customer database and NAICS code analysis (building segmentation), and by EIA CBECS and MECS data (end-use segmentation) to forecast year sales. Within the residential, commercial, and industrial market segments, the sector level disaggregated forecasts were further segmented by the major end uses shown in Table 3-1.

TABLE 3-1: ELECTRIC END-USE LOADS

Residential	Commercial	Industrial
Heating	Interior Lighting	Lighting
Cooling	Exterior Lighting	HVAC
Water Heating	Refrigeration	Machine Drive
Cooking	Space Cooling	Process Heat
Refrigerator	Space Heating	Process Cool / Refrigeration
Freezer	Ventilation	Other Process
Dishwasher	Water Heating	Process – Machine Drive
Clothes Washer	Plug Loads / Office Equipment	Other Facility
Dryer	Cooking	Compressed Air
TV	Other	
Light	Whole Building / Behavioral	
Miscellaneous		

3.2.2 Eligible Opt-Out Customers

In Indiana, individual commercial, or industrial customer sites with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the CenterPoint service area, approximately 15% of total reclassified retail commercial sales have opted out of utility-funded electric energy efficiency programs, while roughly 71% of total reclassified retail industrial sales have opted out.

Figure 3-1 shows the total sales for the C&I sectors, as well as the sales, by sector, which have currently opted out of paying the rate of utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e., does not meet the 1 MW peak demand requirement) as well as eligible load that has not yet opted out.

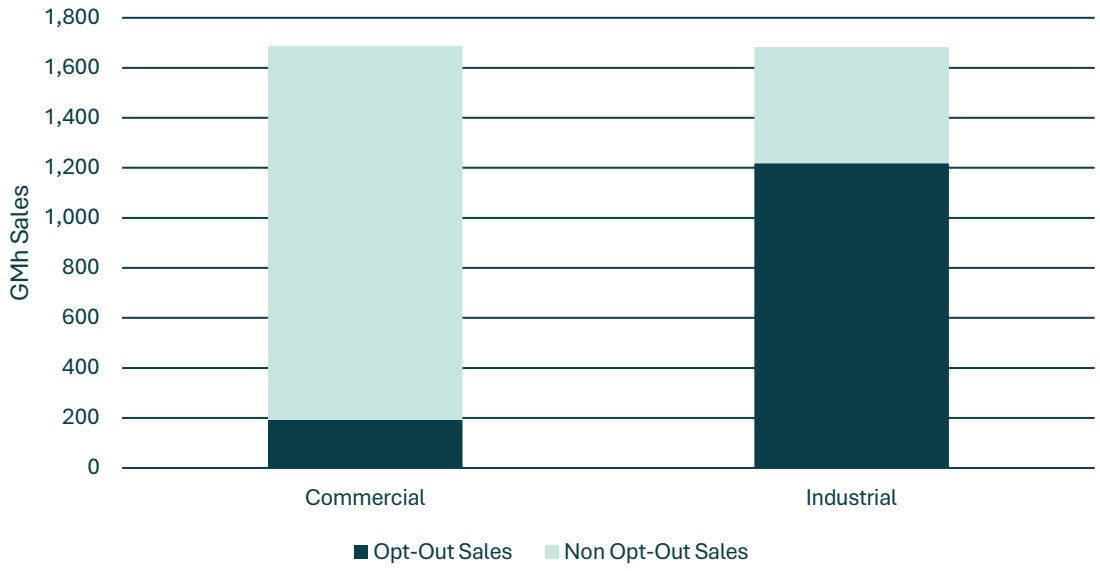


FIGURE 3-1 OPT-OUT SALES BY C&I SECTOR

GDS removed the sales from opt-out GDS also examined the full potential in the C&I sector if these customers were no longer able to opt-out of utility-funded electric energy efficiency programs. These results are included in the appendices of this report.

3.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

3.2.3.1 Residential Sector

For the residential sector, GDS relied on a 2025 Residential Energy Efficiency Baseline Survey conducted by CenterPoint and other historical research efforts. Other data sources included ENERGY STAR unit shipment data, CenterPoint evaluation reports, and EIA Residential Energy Consumption Survey data. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

3.2.3.2 C&I Sector

For the commercial sector, building stock and equipment saturation data was informed from a combination of the CenterPoint customer database as well as other available regional or national data. The customer database helped inform sales by building type while the regional data helped inform the disaggregation of the end-use sales forecast further into measure groups consistent with the measures included in the potential analysis as well as saturation of energy efficient equipment.

For the industrial sector, the analysis employed a top-down analysis at the end-use level. Accordingly, it was not critical to disaggregate the industrial sales at a measure-level. Instead, measures were developed to estimate savings at a total end-use level.

3.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. In this study, two key adjustments were made in order to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation.

First, while a percentage of installed measures may already be efficient, some customers may backslide (i.e., revert to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences). For example, customers who purchased efficient HVAC equipment in the past may not want to pay the full cost for an efficient piece of equipment again due to price increases in recent years.

For most measures categorized as market opportunity (i.e., replace-on-burnout/time of sale), the study assumes that 40% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This adjustment assumes that 60% of the market is transformed, and no future savings potential exists, whereas the remaining 40% of the market is not transformed and could backslide without the intervention of a CenterPoint program and an incentive. Similarly, for retrofit measures and a few select market opportunities measures, the study assumes that only 15% of the already efficient measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. The uncertainty in these assumptions is appropriate, as they factor in a key component of natural customer decision making.

Second, for measures that are installed in the early years of the analysis, but reach the end of their useful life, the study assumed that a portion of those measures would also be transformed and not occur again as incremental annual savings. The percentage of measures that would not be included again for incremental annual savings was typically small (15%) and was informed by historical net to gross (NTG) ratios3. However, for select measures such as commercial LED lighting fixtures, second life re-upping for purposes of calculating incremental annual savings (and costs) was restricted so that 85% of the measures would not be included for re-upping to reflect the expectation that significant market transformation is occurring as well as the limitations in technological improvements that could produce additional future savings at the existing levels.

3.3 MEASURE CHARACTERIZATION

Measure characterization involves defining a set of measures for the study, and developing a set of cost, savings, and useful life assumptions to help determine measure-level cost-effectiveness. This section provides an overview of that process.

3.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Illinois Technical Reference Manual ("TRM"), current CenterPoint program offerings, measures included in other recent Indiana utility market potential studies, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with CenterPoint and stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 322 measure types for this study. Several measures were included with multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. In total, GDS developed 2,030 measure permutations for this study. Each permutation was screened for cost-effectiveness under the UCT cost test. The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 3.4.3.

TABLE 3-2: NUMBER OF MEASURES EVALUATED

	# of Measures	Total # of Measure Permutations
Residential	154	677
Commercial	164	1,353
Total	***318***	***2,030***

3.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart/connected technologies, energy recovery ventilators, nanoinsulation, ultrasonic and heat pump dryers and smart vents/sensors. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include several commercial behavioral options, triple pane windows, energy recovery ventilators, data center hot/cold aisle configuration, advanced lighting controls, and server virtualization. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

[3] The study's estimates of cumulative annual savings were not impacted by this second lifetime adjustment to incremental annual savings.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

3.3.3 Assumptions & Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to CenterPoint when it was available and current. GDS used the most recent CenterPoint evaluation report findings (as well as CenterPoint program planning documents), the Illinois TRM, and the Michigan Energy Measures Database ("MEMD"), and EIA data for a large amount of the data requirements. Additional source documents included American Council for an Energy-Efficient Economy ("ACEEE") research reports covering topics like emerging technologies.

Measure Savings: GDS relied on existing CenterPoint evaluation report findings and the Illinois TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the Illinois TRM, GDS estimated savings from a variety of sources, including:

- MEMD, IN TRM, and other regional/state TRMs
- Secondary sources such as the ACEEE, Department of Energy ("DOE"), EIA, ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates primarily from CenterPoint evaluation report findings and the Illinois TRM. GDS also used the following supplementary data sources:

- MEMD, IN, and other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and NREL

Costs and savings for new construction and replace on burnout measures were calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach was utilized because the consumer must select an efficiency level that is at least the code minimum equipment when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the CenterPoint evaluation report findings and the Illinois TRM:

- MEMD, IN TRM, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in the Appendices volume of this report.

3.3.4 Treatment of Codes & Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does attempt to reflect the latest legislated improvements to federal codes and standards. Where possible, improvements to baseline equipment standards can typically be met with incremental improvements to efficient equipment standards. However, in select cases, such as screw-in lighting improvements to the baseline standard effectively were expected to eliminate the efficient technology from future consideration.

3.3.5 Net to Gross (NTG)

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities but never receive a program incentive) were considered in the development of DSM Inputs into CenterPoint's IRP.

3.4 ENERGY EFFICIENCY POTENTIAL

This section provides a definition of the types of potential, followed by an overview and additional information regarding each type of potential.

3.4.1 Types of Potential

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 3-2 illustrates the types of energy efficiency potential considered in this analysis.

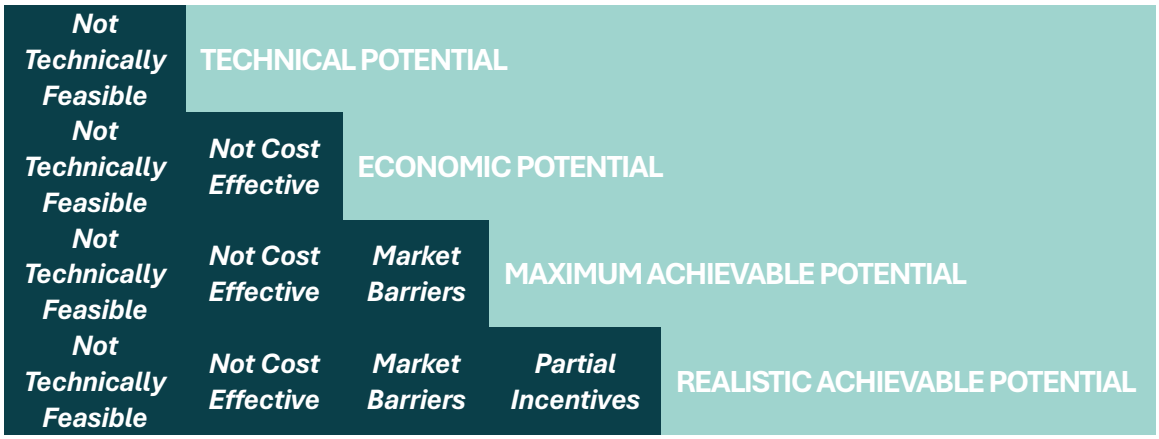


FIGURE 3-2 TYPES OF ENERGY EFFICIENCY POTENTIAL

3.4.2 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.

Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Figure 3-3 below. The C&I sector employs a similar analytical approach.



FIGURE 3-3 CORE EQUATION FOR RESIDENTIAL ENERGY EFFICIENCY TECHNICAL POTENTIAL

- **Base Case Equipment End-Use Intensity** = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.
- **Saturation Share** = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.
- **Remaining Factor =** the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.
- **Feasibility Factor** = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).
- **Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

3.4.2.1 Measure Competition and Interactive Effects

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

- **Baseline Saturation Adjustment.** Competing measure shares are factored into the baseline saturation estimates. For example, nearly all homes can receive insulation. To account for this, GDS' analysis used multiple measure permutations that account for varying impacts of different heating/cooling combinations and baseline saturations were applied to reflect the proportions of households with each heating/cooling combination.
- **Applicability Factor Adjustment.** Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat and a smart thermostat for the same zone. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.
- **Interactive Savings Adjustment.** As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the

savings from building shell upgrades are adjusted down to reflect the efficiency gains of installing an efficient HVAC equipment.

3.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the UCT) as compared to conventional supply-side energy resources.

3.4.3.1 Utility Cost Test & Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the UCT at the measure level. In the CenterPoint territory, the UCT considers electric energy, capacity, and transmission & distribution ("T&D") savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency ("NAPEE"), the measure level economic screening does not consider non-incentive/measure delivery costs (e.g., admin, marketing, evaluation etc.) in determining cost-effectiveness.[4]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. GDS relied on the prior CenterPoint DSM plan estimates and historical CenterPoint evaluation reports files, and current rebate applications to map current measure offerings to their historical incentive levels.

- In the residential sector, incentives by program ranged from 40% to 100% and averaged 72%.
- In the non-residential sector, prescriptive incentives averaged approximately 45% of the measure cost for in the RAP scenarios.
- Custom measures received incentives equal to $0.14 per first-year kWh saved.
- In the MAP scenario, incentives were increased up to 100% of the incremental measure cost.[5]

3.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided T&D were provided by CenterPoint as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

CenterPoint provided the GDS team with annual on and off-peak avoided energy costs. GDS used this data to create 8,760 avoided cost values for each forecast year. GDS then applied these avoided costs to the 8,760 savings from each measure based on assigned end-use load shapes[6] to determine the value of measures that save more energy during peak periods than those that might saving during off-peak periods. In addition, the avoided capacity and T&D avoided costs were applied to the estimated coincident peak demand savings for each measure.

[4] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. Note: Non-incentive delivery costs are included in the assessment of achievable potential.
[5] The GDS team lowered MAP incentives to less than 100% of measure incremental cost in some cases if 100% incentives would preclude the measure from being cost-effective. MAP incentives were lowered to either 75% or 50% of the incremental measure cost if either of those incentive levels would allow for a measure to remain cost-effective.
[6] End-use load shapes were derived from building energy simulation models created by housing type and building type, specific to the CenterPoint service area.

3.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- **MAP** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- **RAP** estimates achievable potential with CenterPoint paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- **Enhanced RAP** estimates achievable potential achievable potential by adjusting incentive levels in the RAP scenario to increase participation beyond the RAP scenario while also considering implications related to cost-effectiveness. For this scenario, a maximum incentive was calculated to either cover a sector-specific lifetime cost per MWh or 100% of the measure cost, whichever was less. There was also an incentive floor of 10% of measure cost. Effectively, it is a scenario that has savings and costs greater than the RAP scenario, but less than the MAP scenario.

3.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on a combination of CenterPoint-specific WTP research (conducted for the prior CenterPoint MPS) and more recent WTP surveys conducted in neighboring Indiana utility service areas.

The CenterPoint-specific research included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive/payback performance levels. One caveat to this approach is that the WTP adoption score is generally a simple function of incentive levels and/or payback performance. There are other factors (both as barriers and motivations) that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. The secondary WTP research conducted in neighboring jurisdictions included additional questions related to these barriers and motivations factors, and the general impact of these additional elements were layered onto the initial CenterPoint-specific research to be able to update and refine the original long-term adoption rates. The WTP approach and results were provided to the CenterPoint Oversight Board during a discussion of draft methodology and results.

GDS utilized likelihood and WTP data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios. Table 3-3 presents the long-term market adoption rates at varied incentive levels used for the residential sector. Most end-uses are based on the WTP primary market research. Behavior was set to 100% to reflect that the program design is typically opt-out and participation levels are dictated by the utility.

TABLE 3-3 RESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

End Use/Housing Type/Income	0% Incentive	25% Incentive	50% Incentive	75% Incentive	100% Incentive
Water Heating	20%	37%	49%	65%	93%
HVAC Equipment	22%	36%	43%	60%	89%
Appliances	21%	37%	53%	68%	95%
Building Shell	20%	35%	48%	64%	91%
Behavior	100%	100%	100%	100%	100%

Table 3-4 presents the long-term market adoption rates used in the nonresidential sector. The C&I adoption rates were consistent with the prior CenterPoint MPS and informed by a combination of CenterPoint-specific WTP research and more recent WTP surveys conducted in neighboring Indiana utility service areas. GDS also included a custom project opportunity adjustment of 75% to reflect the difficulty in raising awareness levels for all potential custom project opportunities compared to the discrete energy efficient opportunities included in the WTP survey research. This adjustment was applied to all measures mapped to the Custom Program.

TABLE 3-4 NONRESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE PAYBACK INTERVALS

End-Use	20 Year Payback Period	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
EE Lighting	19%	28%	47%	71%	88%	95%
EE Prescriptive (Non-Lighting	24%	36%	59%	77%	84%	88%
Custom EE	18%	27%	44%	58%	63%	66%

GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2028 annual potential to recent historical levels achieved by CenterPoint's current DSM portfolio. Although this calibration ensured that near-term savings indicated in the MPS demonstrated achievable incremental increases relative to recent historical levels, the near-term adjustment had little impact on the long-term potential. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

3.4.4.2 Non-Incentive Costs

Consistent with (NAPEE) guidelines[7], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the RAP scenario. Program non-incentive costs were calibrated to recent projected levels (using the 2026 Operating Plan) and set at:

- $0.078 per Behavioral program participant
- $0.183 per first year kWh saved for the Residential Prescriptive program.
- $0.117 per first year kWh saved for the Home Energy Assessment program measures.
- $1.265 per first year kWh saved for the Income-Qualified program measures.
- $0.274 per first year kWh saved for the Residential Midstream program measures.

[7] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.

- $0.135 per first year kWh saved for the In Store Discount program measures.
- $0.113 per first year kWh saved for the Multi-Family Energy Solutions program measures.
- $0.408 per first year kWh saved for the Community Connections program measures.
- $0.661 per first year kWh saved for the Residential New Construction program measures.
- $0.136 per first year kWh saved for the Residential Marketplace program measures.
- $0.084 per first year kWh saved for prescriptive C&I measures.
- $0.105 per first year kWh saved for C&I customs measures and small business direct install measures.

In addition, an indirect/cross-cutting cost of $0.045 per first year kWh saved was added to address those costs are not directly attributed at the program level. Non-incentive costs were then escalated annually to account for inflationary factors.[8]

3.5 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

3.5.1 Scope of Measures & End Uses Analyzed

There were 157 total unique residential electric measures included in the analysis. Table 3-5 provides the number of unique measures by end-use. The measure list was developed based on a review of current CenterPoint programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 3-5: RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Appliances	22
Behavior	2
HVAC	48
Lighting	9
New Construction	5
Pool/Pump	3
Plug Loads	5
Shell	48
Water Heating	12
Total	**154**

3.5.2 Summary of Residential Electric Potential

Figure 3-11 provides the technical, economic, MAP, RAP and Enhanced RAP results for the 3-year, 6-year, and 18-year timeframes. The cumulative annual 3-year technical and economic potential is 10% of forecasted sales. The cumulative annual 3-year MAP is 4.0%, the RAP is 2.8%, and the Enhanced RAP is 3.2% of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 32% and 30% of forecasted sales, respectively. The MAP, RAP and Enhanced RAP increased to 21.1%, 15.0% and 17.5% of forecasted sales respectively, over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program

[8] Measure costs and utility incentives were not escalated over analysis timeframe to keep those costs constant in nominal dollars.

participants, both financial and non-financial, to achieving the full amount of economic potential. The Enhanced RAP is greater than RAP as a result of higher incentive levels.

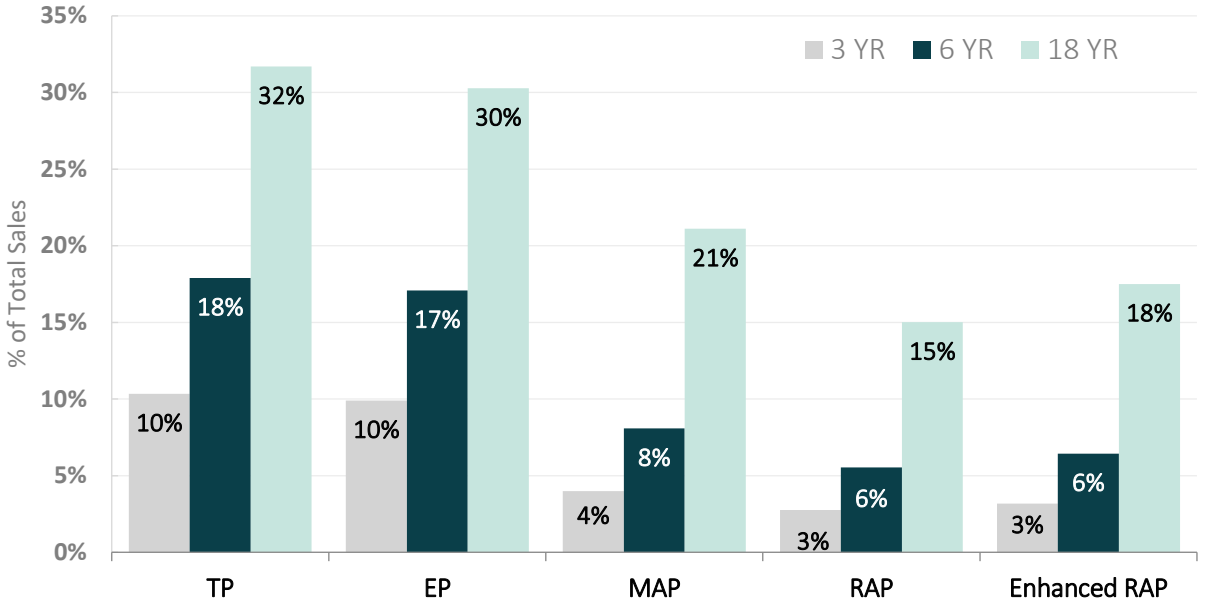


FIGURE 3-4: RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERICAL AND INDUSTRIAL SALES)

Table 3-11 provides additional detail regarding the cumulative annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast over 3-yr, 6-yr and 18-yr timeframes. The associated MW of demand savings are also provided.

TABLE 3-6: RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	3 YR	6 YR	18 YR
Energy (MWh)			
Technical	150,598	265,102	519,114
Economic	144,247	253,086	496,038
MAP	58,059	119,610	345,708
RAP	40,296	82,079	245,817
Enhanced RAP	46,245	95,411	286,802
Technical	10.3%	17.9%	31.7%
Economic	9.9%	17.1%	30.3%
MAP	4.0%	8.1%	21.1%
RAP	2.8%	5.5%	15.0%
Enhanced RAP	3.2%	6.4%	17.5%
Demand (MW)			
Technical	38	65	113
Economic	37	63	109
MAP	14	29	78

	3 YR	6 YR	18 YR
RAP	8	17	45
Enhanced RAP	10	20	52

Table 3-12 provides the incremental annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.1% to 1.5% per year over the next six years, while the Enhanced RAP ranges from 1.2% to 1.7%.

TABLE 3-7: RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2028	2029	2030	2031	2032	2033
Energy (MWh)						
Technical	59,102	59,548	59,106	58,577	58,062	57,519
Economic	56,894	57,386	56,987	56,499	56,023	55,519
MAP	20,652	23,274	25,503	27,311	28,764	30,098
RAP	15,299	17,166	18,908	20,394	21,568	22,549
Enhanced RAP	16,984	19,210	21,180	22,811	24,157	25,381
Technical	4.1%	4.1%	4.1%	4.0%	3.9%	3.9%
Economic	4.0%	4.0%	3.9%	3.9%	3.8%	3.7%
MAP	1.4%	1.6%	1.8%	1.9%	1.9%	2.0%
RAP	1.1%	1.2%	1.3%	1.4%	1.5%	1.5%
Enhanced RAP	1.2%	1.3%	1.5%	1.6%	1.6%	1.7%
Demand (MW)						
Technical	13.9	13.9	13.8	13.7	13.6	13.5
Economic	13.6	13.6	13.5	13.4	13.3	13.2
MAP	4.5	5.1	5.6	6.1	6.3	6.5
RAP	2.8	3.2	3.5	3.7	3.9	4.0
Enhanced RAP	3.2	3.6	4.0	4.3	4.5	4.6

3.5.3 Residential Technical, Economic and Achievable Potential Summary and Detail by End-Use

Figure 3-12 provides additional annual savings data for the technical and economic potential. The incremental annual technical and economic potential starts off at approximately 59,000 MWh and 57,000 MWh in 2028, respectively, and slowly decline and flatten out by 2045. The cumulative annual technical and economic potential rise to 32% and 30% of forecasted sector sales, respectively, by 2045.

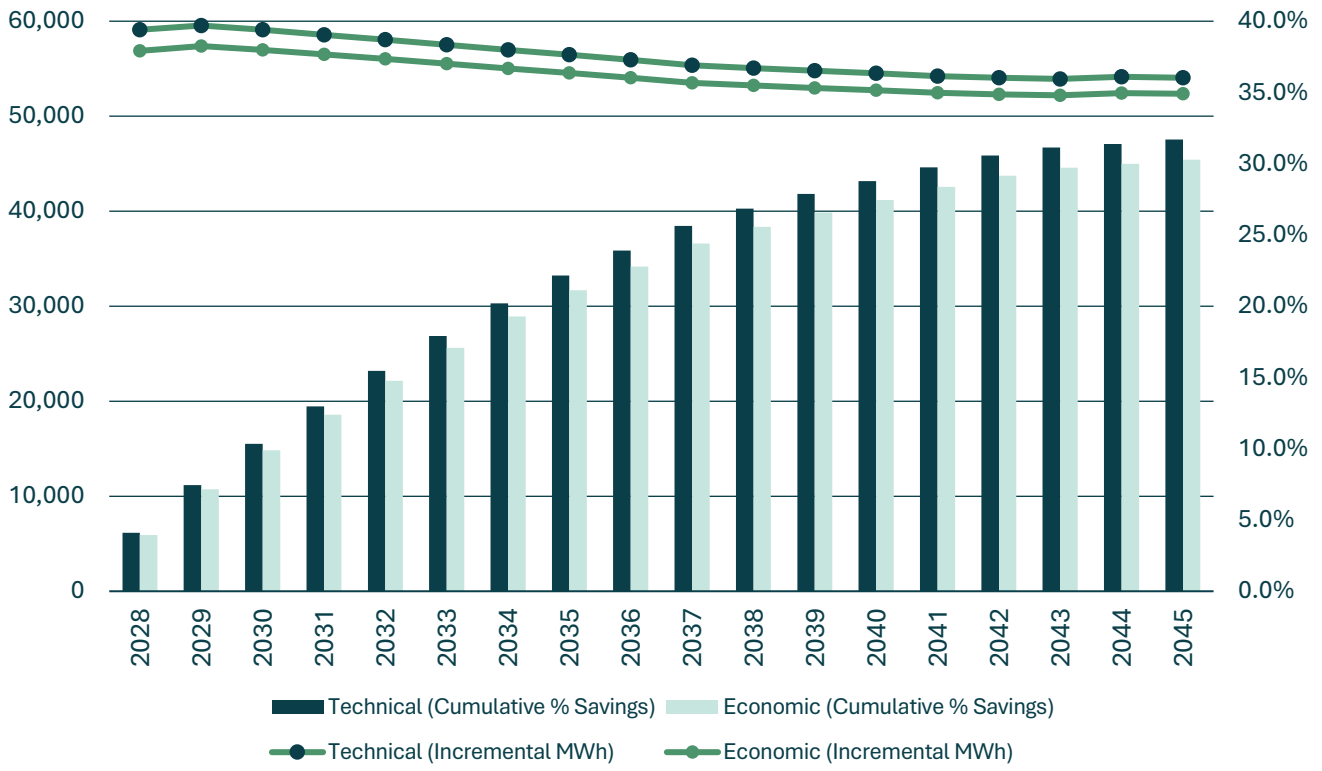


FIGURE 3-5: RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERICAL AND INDUSTRIAL SALES)

Figure 3-13 provides the MAP, RAP and Enhanced RAP across the 18-yr timeframe of the study. The lines provide the respective incremental annual MAP, RAP and Enhanced RAP in MWh per year energy savings. The corresponding bars provide the cumulative annual MAP, RAP and Enhanced RAP as a percentage of forecasted annual sector sales. The incremental RAP ranges from approximately 15,000 to 23,000 MWh. The incremental Enhanced RAP ranges from approximately 17,000 to 25,000 MWh, with a corresponding 15.0% and 17.5% in cumulative annual savings for RAP and Enhanced RAP, respectively.

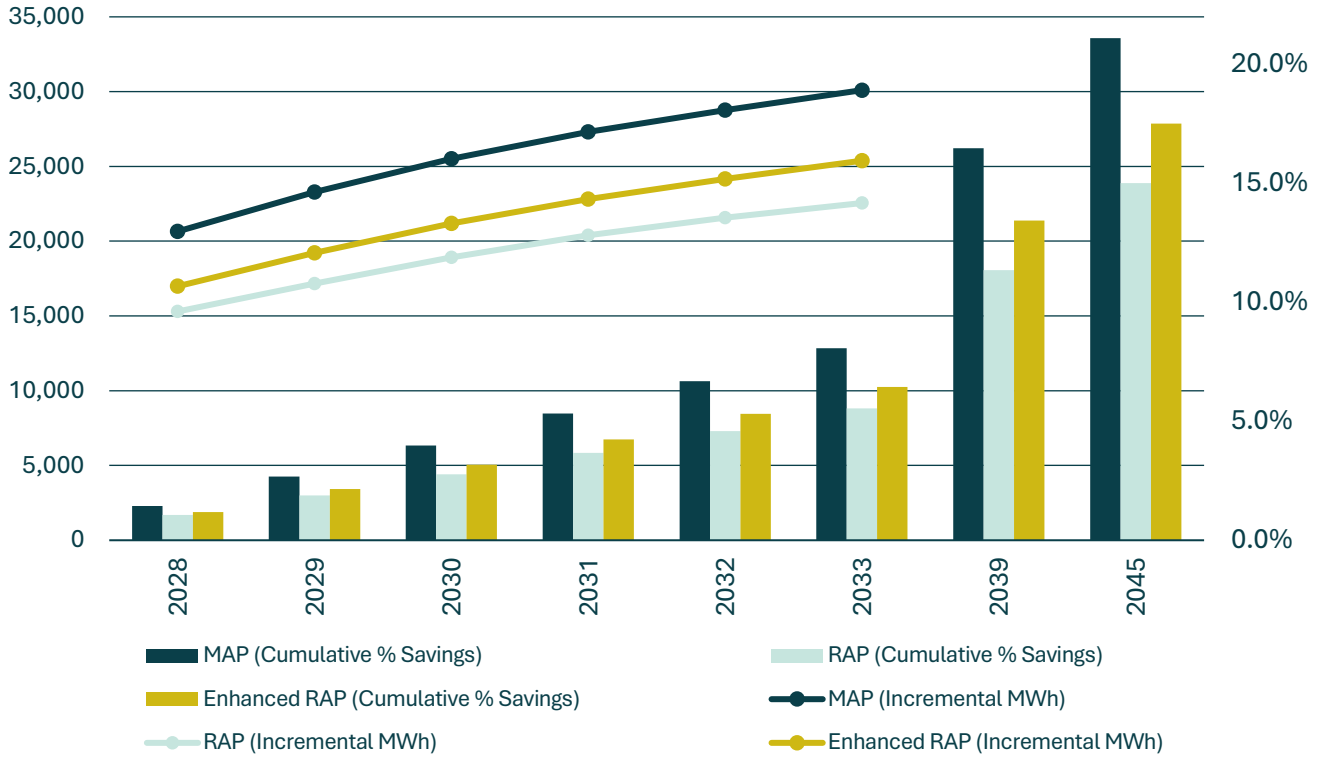


FIGURE 3-6: RESIDENTIAL ANNUAL ACHIEVABLE POTENTIAL

Figure 3-7 provides a breakdown of the residential achievable potential by end use. HVAC (37%), Shell (23%), and Water Heating (21%), combine to account for more than 80% of the residential achievable potential.

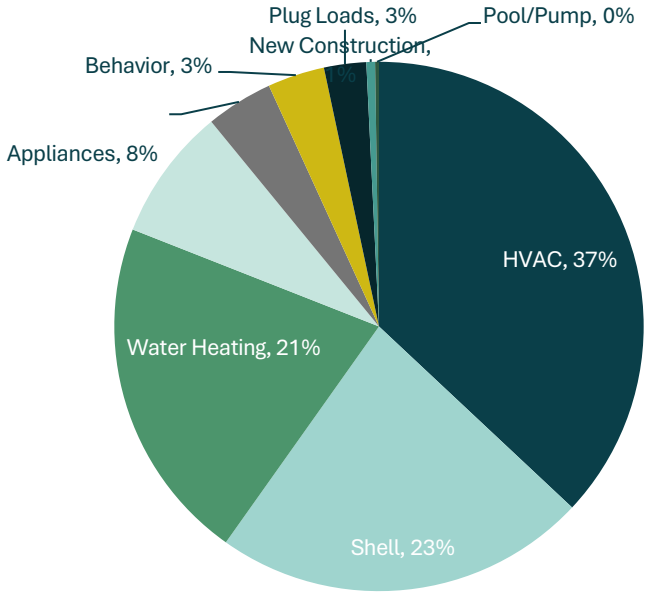


FIGURE 3-7: RESIDENTIAL POTENTIAL BY END-USE (SHARES OF ACHIEVABLE POTENTIAL)

Table 3-9 below provides additional annual detail by end use in the MAP, RAP and Enhanced RAP scenarios over the first six years of the study (2028-2033).

TABLE 3-8: RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2028	2029	2030	2031	2032	2033
MAP						
Lighting	769	1,052	1,234	1,405	1,602	1,911
Whole Building	4,999	5,684	6,307	6,847	7,297	7,663
Refrigeration	5,524	6,523	7,351	8,145	8,548	8,800
HVAC	565	840	945	1,026	1,142	1,422
Plug Loads	36	47	63	73	83	92
Miscellaneous	6	15	24	35	46	61
Motors	616	773	937	1,093	1,219	1,297
Process	3,209	3,211	3,207	3,200	3,190	3,178
Compressed Air	4,927	5,128	5,435	5,488	5,636	5,674
Total	**20,652**	**23,274**	**25,503**	**27,311**	**28,764**	**30,098**
RAP						
Lighting	492	638	747	852	968	1,127
Whole Building	4,999	5,684	6,306	6,845	7,296	7,660
Refrigeration	4,328	5,075	5,716	6,334	6,644	6,828
HVAC	170	250	285	315	356	440
Plug Loads	36	47	63	73	83	92
Miscellaneous	2	5	8	12	16	21
Motors	272	341	413	483	541	578
Process	2,267	2,282	2,294	2,303	2,310	2,316
Compressed Air	2,733	2,844	3,075	3,177	3,355	3,487
Total	**15,299**	**17,166**	**18,908**	**20,394**	**21,568**	**22,549**
Enhanced RAP						
Lighting	659	882	1,026	1,159	1,311	1,549
Whole Building	4,999	5,684	6,306	6,845	7,296	7,660
Refrigeration	4,460	5,250	5,912	6,543	6,865	7,068
HVAC	398	590	664	722	804	1,001
Plug Loads	36	47	63	73	83	92
Miscellaneous	2	5	9	12	16	21
Motors	498	625	757	883	986	1,050
Process	2,278	2,292	2,304	2,313	2,320	2,325
Compressed Air	3,654	3,833	4,139	4,261	4,476	4,613
Total	**16,984**	**19,210**	**21,180**	**22,811**	**24,157**	**25,381**

Figure 3-8 provides the top 20 measures in the residential sector. Together, these 20 measures account for more than 80% of the residential achievable potential over the next 18 years. Heat pump water heaters, ductless and air source heat pumps, smart thermostats and nanoinsulation account for more than 50% of the achievable potential.

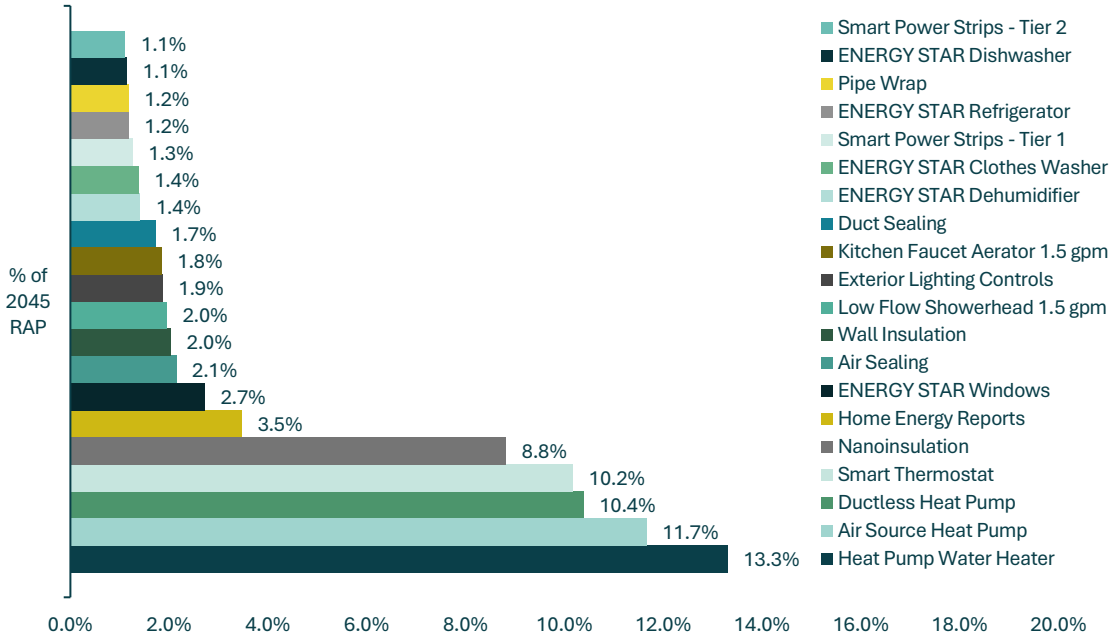


FIGURE 3-8: RESIDENTIAL TOP 20 MEASURES

Figure 3-9 provides the share of potential in the residential sector by housing and income type. Single-family non-IQ homes account for nearly 75% of the potential over the next 18 years.

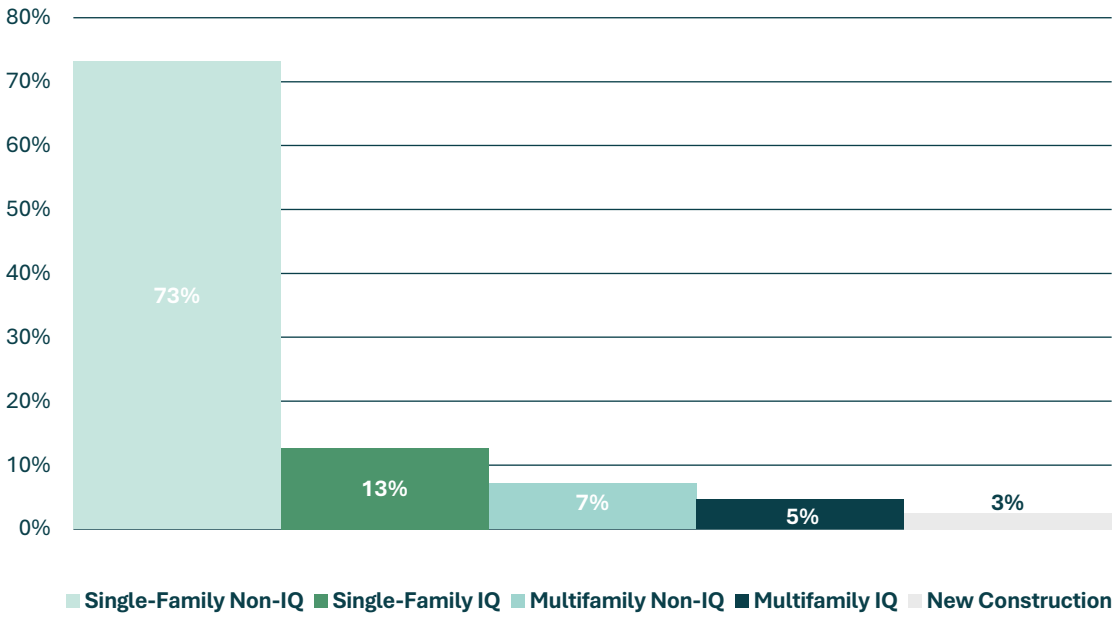


FIGURE 3-9: RESIDENTIAL ACHIEVABLE POTENTIAL BY BUILDING TYPE

3.5.4 Residential Achievable Potential Benefits & Costs

Table 3-14 shows the annual budgets associated with the MAP, RAP and Enhanced RAP scenarios in the residential sector. The figure also shows a breakdown of the RAP budgets by incentives and admin costs each year. The MAP budgets range from about $12 million to $35 million over the timeframe of the study. The RAP budgets range from $7 million to $22 million. The Enhanced RAP budgets range from $8 million to $26 million, with about 37% of spending on incentives and the remaining 63% on non-incentive costs at the outset of the study timeframe.

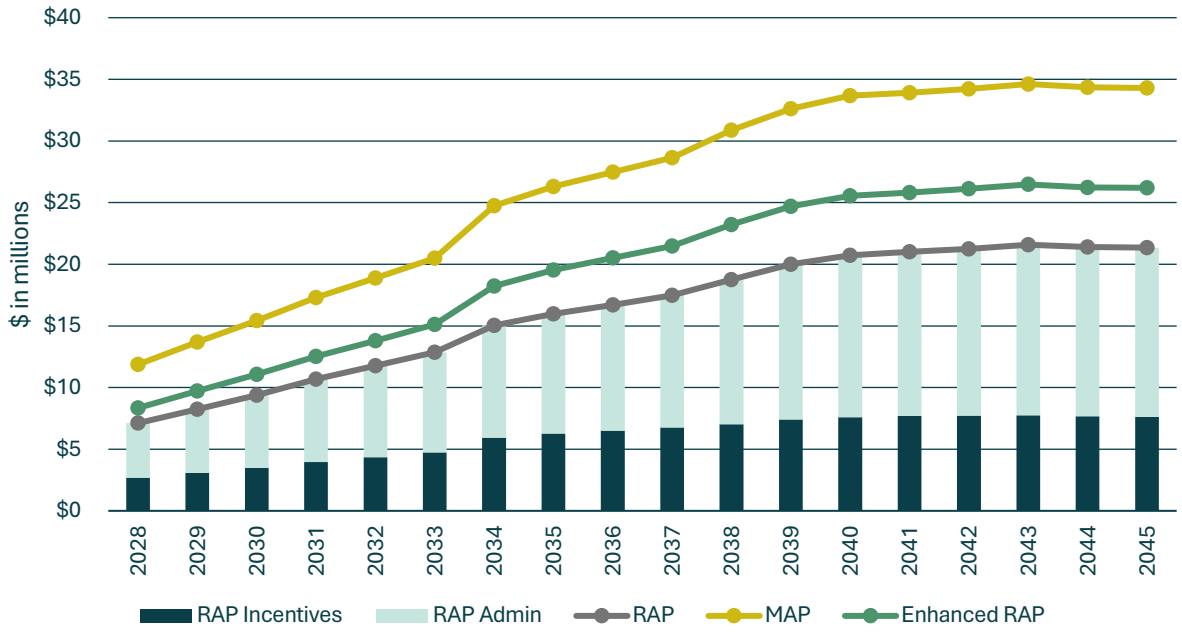


FIGURE 3-10: RESIDENTIAL ANNUAL BUDGETS – ACHIEVABLE POTENTIAL SCENARIOS

Table 3-14 provides the net present value (NPV) benefits and cost, as calculated using the UCT, across the 2028-2045 timeframe for the MAP, RAP and Enhanced RAP scenarios. The overall UCT ratio in the RAP scenario is 0.89. The overall UCT ratio in the MAP scenario is 0.87, and the Enhanced RAP UCT ratio is 0.80. The UCT ratios in the residential sector fall below 1.0 due to the inclusion of income-qualified measures, which do not have to pass a cost-effectiveness screening criterion. Non-IQ measures must pass the cost-effectiveness test at a 1.0 UCT ratio to be included in the achievable potential.

TABLE 3-9: RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

End Use	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$258,179,577	$298,345,225	-$40,165,648	0.87
RAP	$163,777,465	$183,316,995	-$19,539,531	0.89
Enhanced RAP	$177,856,921	$222,400,924	-$44,544,003	0.80

3.6 COMMERCIAL AND INDUSTRIAL ENERGY EFFICIENCY POTENTIAL

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

3.6.1 Scope of Measures & End Uses Analyzed

There were 164 total unique commercial and industrial (C&I) electric measures included in the analysis. Table 3-10 provides the number of unique measures by end-use. The measure list was developed based on a review of current CenterPoint programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 3-10: COMMERCIAL AND INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Lighting	34
Whole Building	20
Refrigeration	28
HVAC	31
Plug Loads	10
Miscellaneous	6
Motors	6
Process	9
Compressed Air	8
Cooking	9
Hot Water	3
Total	**164**

3.6.2 Summary of Commercial and Industrial Electric Potential

Figure 3-11 provides the technical, economic, MAP, RAP and Enhanced RAP results for the 3-year, 6-year, and 18-year timeframes. The cumulative annual 3-year technical and economic potential is 6% of forecasted sales. The cumulative annual 3-year MAP is 4.8%, the RAP is 4.0%, and the Enhanced RAP is 4.2% of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 27% of forecasted sales, respectively. The MAP, RAP and Enhanced RAP increased to 17.9%, 15.9% and 16.5% of forecasted sales respectively, over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential. The Enhanced RAP is greater than RAP as a result of higher incentive levels.

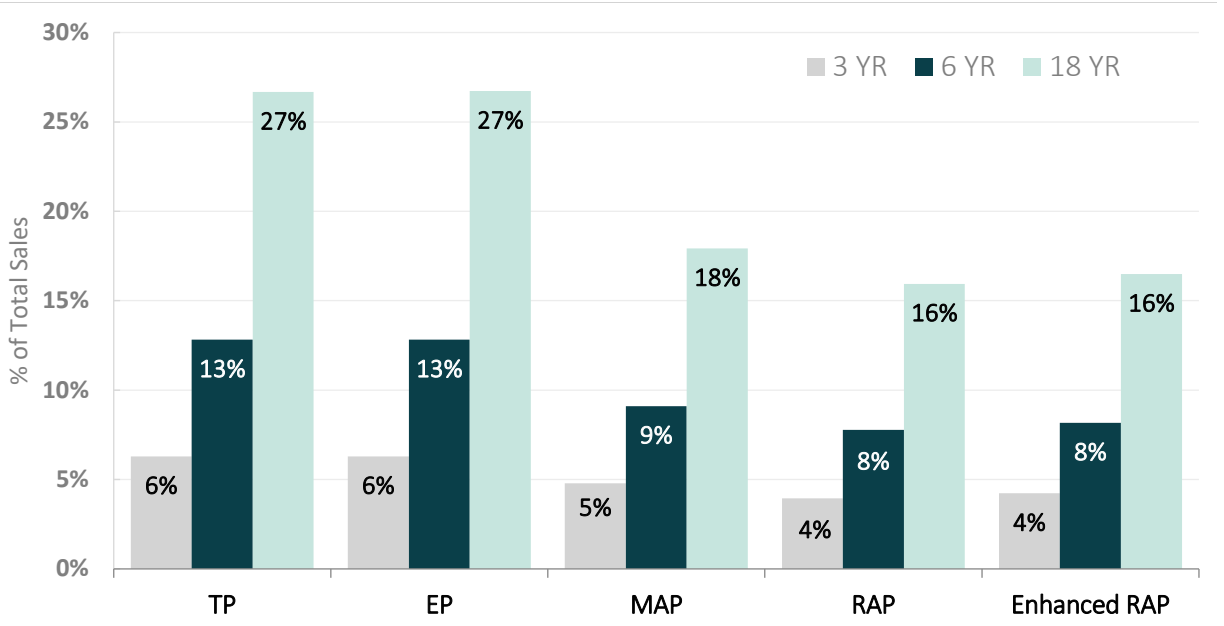


FIGURE 3-11: C&I ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERICAL AND INDUSTRIAL SALES)

Table 3-11 provides additional detail regarding the cumulative annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast over 3-yr, 6-yr and 18-yr timeframes. The associated MW of demand savings are also provided.

TABLE 3-11: C&I CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	3 YR	6 YR	18 YR
Energy (MWh)			
Technical	113,298	230,494	487,239
Economic	113,282	230,467	488,252
MAP	86,350	163,815	327,474
RAP	71,168	139,749	291,351
Enhanced RAP	76,066	146,951	301,277
Energy Savings (as% of Sector Sales Forecast)			
Technical	6.3%	12.8%	26.7%
Economic	6.3%	12.8%	26.7%
MAP	4.8%	9.1%	17.9%
RAP	4.0%	7.8%	15.9%
Enhanced RAP	4.2%	8.2%	16.5%
Demand (MW)			
Technical	16	56	81
Economic	16	56	81
MAP	13	39	56
RAP	10	33	48

	3 YR	6 YR	18 YR
Enhanced RAP	22	65	86

Table 3-12 provides the incremental annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.3% to 1.4% per year over the next six years, while the Enhanced RAP ranges from 1.4% to 1.5%.

TABLE 3-12: C&I INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2028	2029	2030	2031	2032	2033
Energy (MWh)						
Technical	35,864	37,997	39,463	41,560	41,543	41,379
Economic	35,858	37,992	39,459	41,556	41,538	41,370
MAP	28,697	28,985	28,679	29,120	27,899	25,750
RAP	22,911	23,939	24,329	25,387	24,726	23,714
Enhanced RAP	24,899	25,553	25,627	26,380	25,517	24,052
Energy Savings (as% of Sector Sales Forecast)						
Technical	2.0%	2.1%	2.2%	2.3%	2.3%	2.3%
Economic	2.0%	2.1%	2.2%	2.3%	2.3%	2.3%
MAP	1.6%	1.6%	1.6%	1.6%	1.5%	1.4%
RAP	1.3%	1.3%	1.4%	1.4%	1.4%	1.3%
Enhanced RAP	1.4%	1.4%	1.4%	1.5%	1.4%	1.3%
Demand (MW)						
Technical	12.2	12.4	12.5	12.6	12.3	11.9
Economic	12.2	12.4	12.5	12.6	12.3	11.9
MAP	8.0	8.1	8.0	8.0	7.8	7.2
RAP	6.6	6.8	6.9	7.1	6.9	6.7
Enhanced RAP	7.1	7.2	7.2	7.3	7.1	6.7

3.6.3 Commercial and Industrial Technical, Economic and Achievable Potential

Figure 3-12 provides additional annual savings data for the technical and economic potential. The incremental annual technical and economic potential starts off at nearly 36,000 MWh in 2028 and rises to more than 50,000 MWh by 2045. The cumulative annual economic potential rises to nearly 27% of forecasted sector sales by 2045.

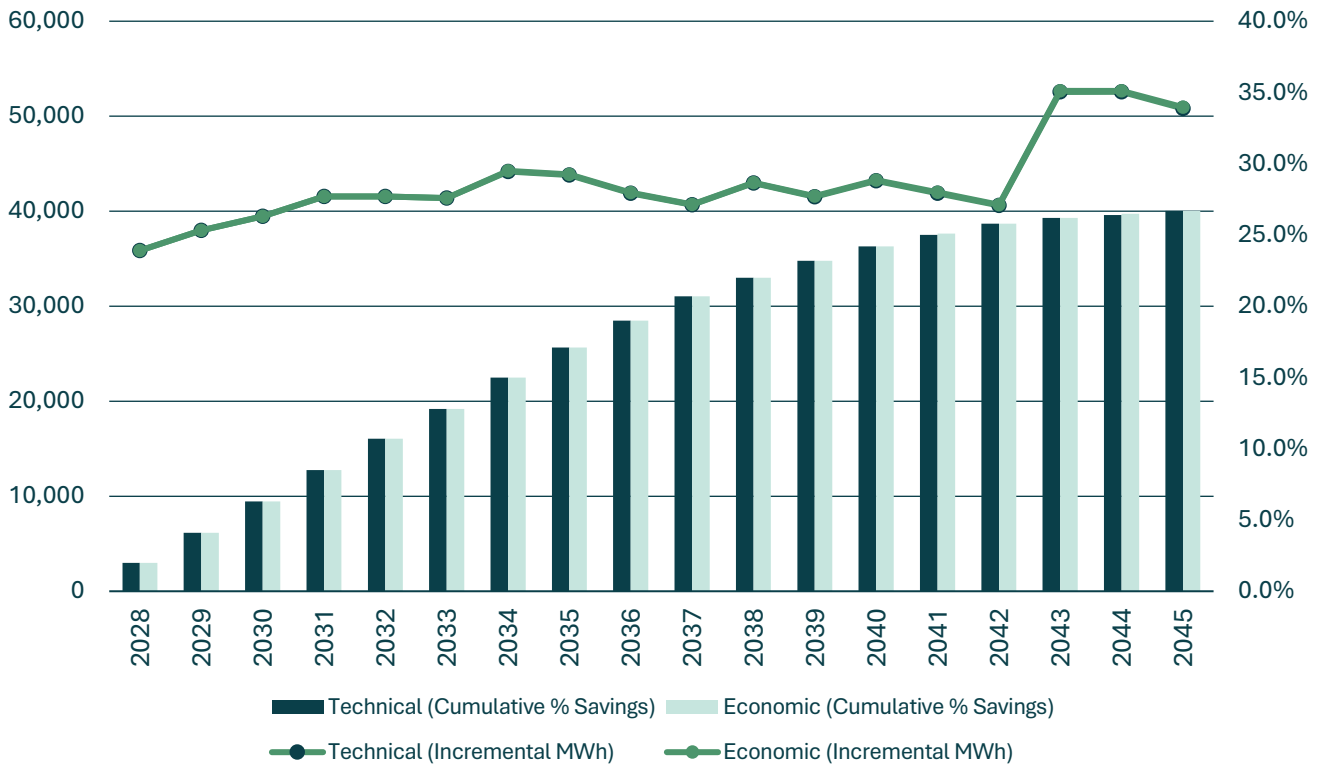


FIGURE 3-12: C&I ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERICAL AND INDUSTRIAL SALES)

Figure 3-13 provides the MAP, RAP and Enhanced RAP across the 18-yr timeframe of the study. The lines provide the respective incremental annual MAP, RAP and Enhanced RAP in MWh per year energy savings. The corresponding bars provide the cumulative annual MAP, RAP and Enhanced RAP as a percentage of forecasted annual sector sales. The incremental RAP ranges from approximately 23,000 to 25,000 MWh. The incremental Enhanced RAP ranges from approximately 25,000 to 26,000 MWh, with a corresponding 15.9% and 16.5% in cumulative annual savings for RAP and Enhanced RAP, respectively.

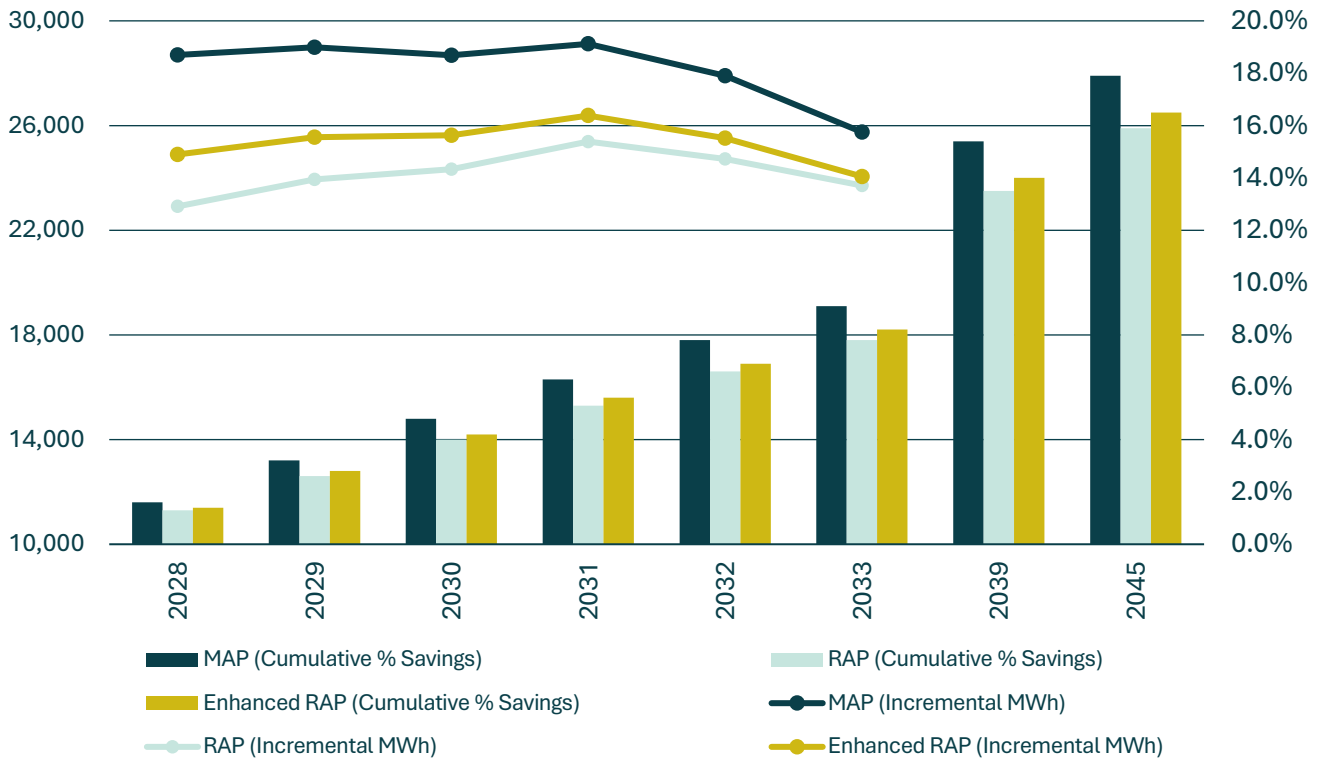


FIGURE 3-13: C&I ANNUAL ACHIEVABLE POTENTIAL

Figure 3-7 provides a breakdown of the C&I achievable potential by end use. Lighting (25%), Whole Building (21%), Refrigeration (13%), and HVAC (10%) combine to account for nearly three-quarters of the C&I achievable potential.

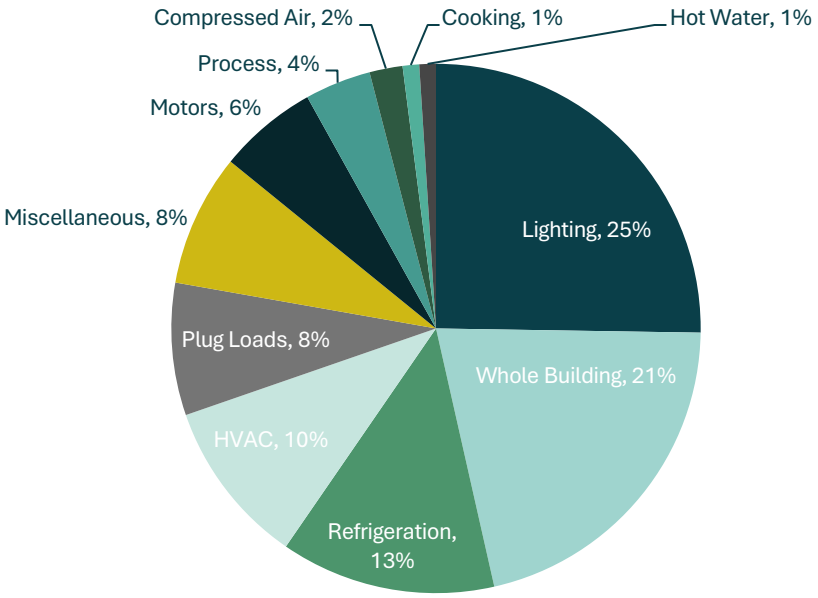


FIGURE 3-14: C&I POTENTIAL BY END-USE (SHARES OF ACHIEVABLE POTENTIAL)

Table 3-9 below provides additional annual detail by end use in the MAP, RAP and Enhanced RAP scenarios over the first six years of the study (2028-2033).

TABLE 3-13: C&I CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2028	2029	2030	2031	2032	2033
MAP						
Lighting	13,678	12,249	10,788	9,440	8,158	5,875
Whole Building	2,660	3,143	3,390	4,161	4,167	4,143
Refrigeration	4,225	4,416	4,442	4,335	4,137	4,030
HVAC	2,497	2,747	2,964	3,303	3,338	3,627
Plug Loads	1,908	2,133	2,302	2,392	2,392	2,298
Miscellaneous	1,688	2,019	2,326	2,569	2,705	2,714
Motors	847	957	1,046	1,354	1,402	1,410
Process	462	521	569	709	734	738
Compressed Air	515	559	583	855	846	916
Cooking	117	142	168	195	222	248
Hot Water	99	100	104	106	119	170
Total	**28,697**	**28,985**	**28,681**	**29,418**	**28,219**	**26,170**
RAP						
Lighting	9,572	8,963	8,229	7,493	6,707	5,499
Whole Building	2,222	2,703	2,979	3,804	3,853	3,861
Refrigeration	3,679	3,885	3,944	3,883	3,737	3,677
HVAC	2,193	2,417	2,603	2,893	2,927	3,213
Plug Loads	1,831	2,046	2,208	2,293	2,291	2,198
Miscellaneous	1,477	1,766	2,035	2,248	2,368	2,377
Motors	841	950	1,037	1,345	1,391	1,399
Process	427	481	525	662	683	686
Compressed Air	472	508	525	791	777	837
Cooking	102	124	147	171	196	219
Hot Water	96	96	100	101	114	164
Total	**22,911**	**23,939**	**24,331**	**25,683**	**25,044**	**24,131**
Enhanced RAP						
Lighting	11,198	10,187	9,121	8,122	7,140	5,490
Whole Building	2,234	2,723	2,997	3,791	3,841	3,859
Refrigeration	3,814	4,013	4,061	3,985	3,821	3,745
HVAC	2,346	2,580	2,776	3,070	3,101	3,367
Plug Loads	1,804	2,016	2,175	2,259	2,258	2,169
Miscellaneous	1,573	1,880	2,165	2,391	2,518	2,528
Motors	811	917	1,002	1,297	1,344	1,352
Process	440	496	542	676	699	703
Compressed Air	475	514	534	790	780	844
Cooking	109	133	157	182	208	233
Hot Water	96	96	100	101	114	164

	2028	2029	2030	2031	2032	2033
Total	**24,899**	**25,553**	**25,629**	**26,665**	**25,824**	**24,454**

Figure 3-8 provides the top 20 measures in the C&I sector. Together, these 20 measures account for 51% of the C&I achievable potential. Custom measures, whole building retrofits, and luminaire-level lighting controls account for close to 20% of the achievable potential.

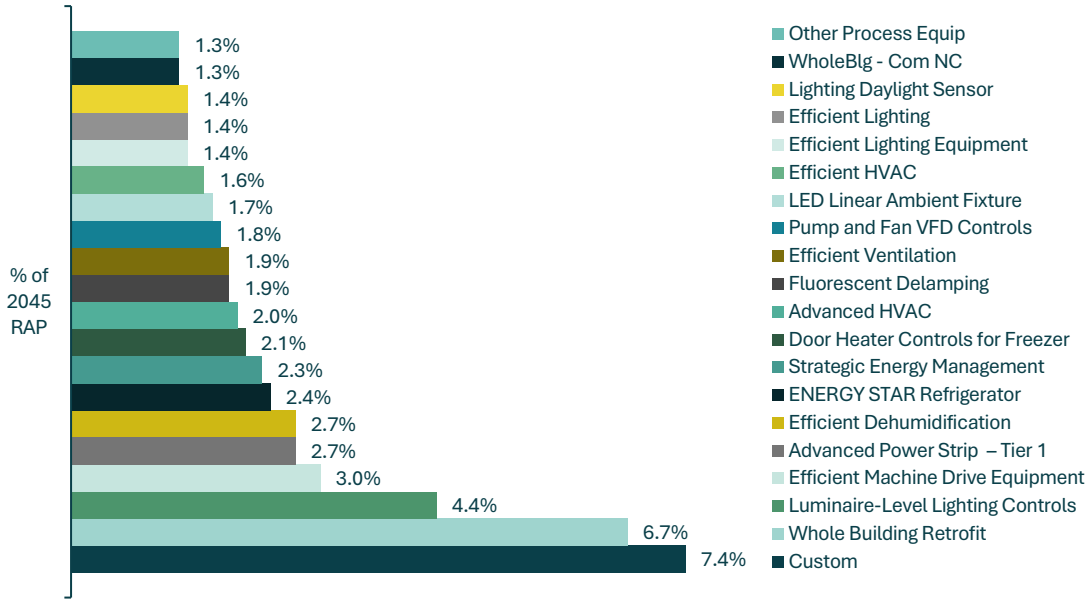


FIGURE 3-15: C&I TOP 20 MEASURES

Figure 3-9 provides the share of potential in the C&I sector by building type. Office buildings (16%) and Industrial buildings (14%) have the most potential among all building types.

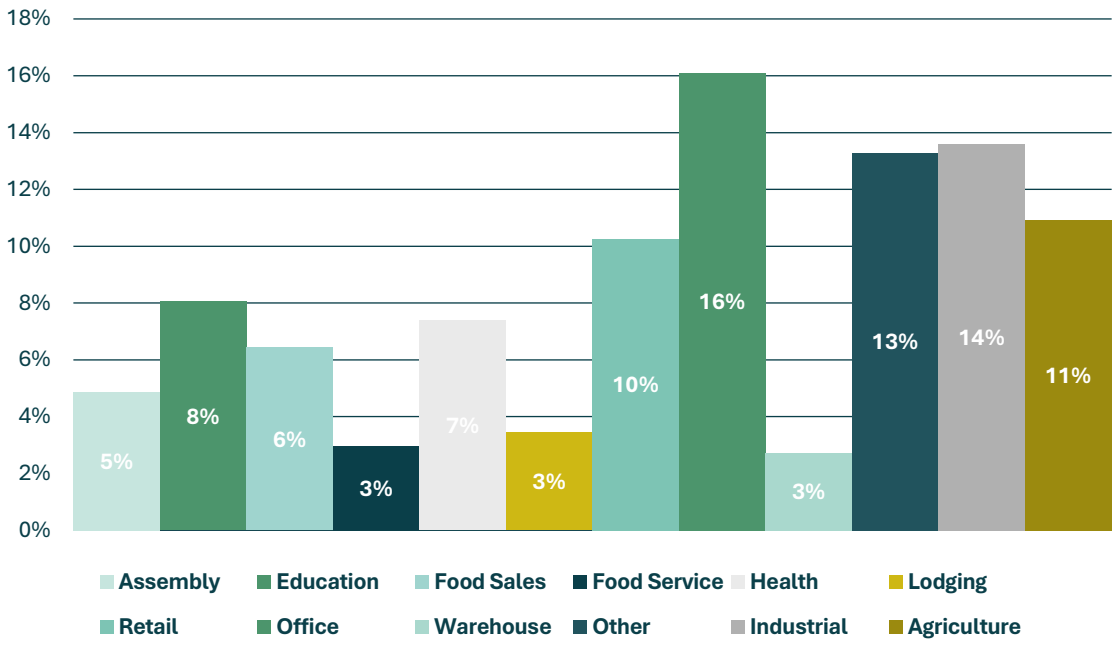


FIGURE 3-16: C&I ACHIEVABLE POTENTIAL BY BUILDING TYPE

3.6.4 Commercial and Industrial Achievable Potential Benefits & Costs

Table 3-14 shows the annual budgets associated with the MAP, RAP and Enhanced RAP scenarios in the C&I sector. The figure also shows a breakdown of the RAP budgets by incentives and admin costs each year. The MAP budgets range from about $9 million to $12 million over the timeframe of the study. The RAP budgets range from $5.7 million to $7.3 million. The Enhanced RAP budgets range from $7.6 million to $8.4 million, with about 50% of spending on incentives and the remaining 50% on non-incentive costs at the outset of the study timeframe.

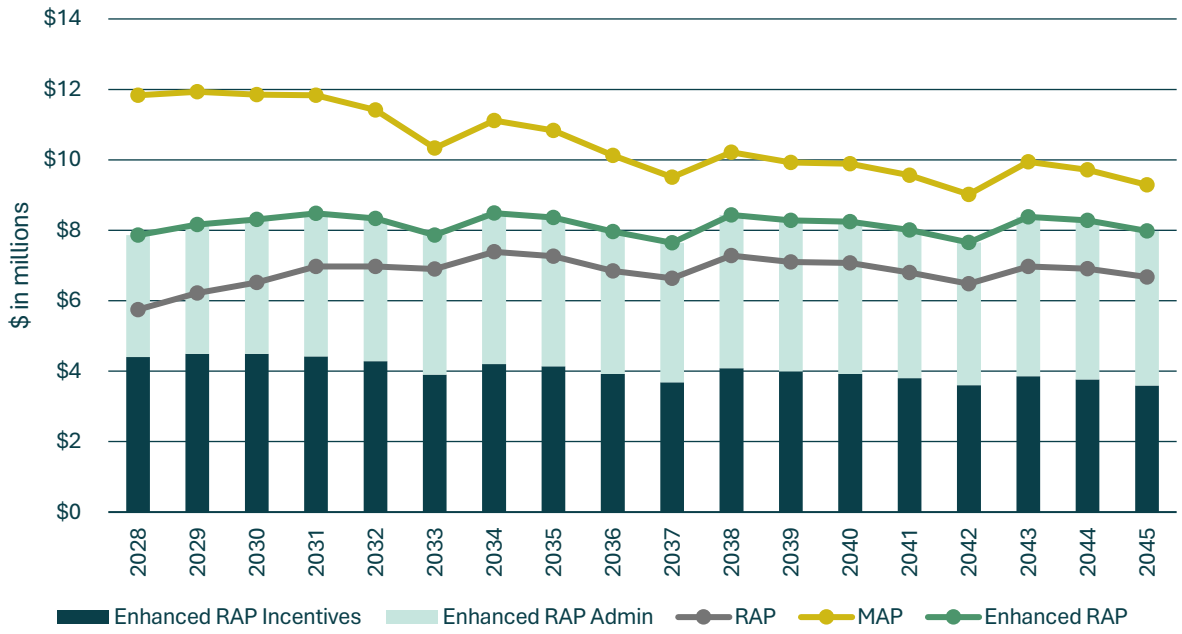


FIGURE 3-17: C&I ELECTRIC ANNUAL BUDGETS – ACHIEVABLE POTENTIAL SCENARIOS

Table 3-14 provides the net present value (NPV) benefits and cost, as calculated using the UCT, across the 2028-2045 timeframe for the MAP, RAP and Enhanced RAP scenarios. The overall UCT ratio in the RAP scenario is 2.93. The overall UCT ratio in the MAP scenario is 2.16 due to higher assumed incentive costs. Similarly, the savings and costs in the Enhanced RAP are higher due to the increased incentives compared to the RAP scenario, and the Enhanced RAP UCT ratio is 2.55.

TABLE 3-14: C&I CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

End Use	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$265,546,074	$122,869,296	$142,676,778	2.16
RAP	$227,024,997	$77,530,833	$149,494,164	2.93
Enhanced RAP	$238,734,940	$93,460,665	$145,274,275	2.55

04 DEMAND RESPONSE POTENTIAL

This chapter provides the results of the MAP and RAP potential for the demand response analysis. Results are broken down by sector and program. The cost-effectiveness results and budgets for the MAP and RAP scenarios are also provided. Section 4.1 provides a description of the demand response methodology.

4.1 DEMAND RESPONSE PROGRAM OPTIONS

Table 4-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC) and rate design options.

TABLE 4-1 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

Demand Response Program Option	Program Description	Eligible Markets
DLC AC Switch	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle).	Residential and C&I Customers
DLC Thermostat (BYOT & Smart Cycle)	The system operator can remotely change the HVAC's thermostat set point during peak load conditions, lowering HVAC load. GDS looked at the two options CenterPoint currently has: the BYOT option, where the customer brings an existing thermostat and is only given an annual incentive and the Smart Cycle option where AC switch participants are being transitioned to thermostats.	Residential and C&I Customers
DLC Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential Customers
DLC Water Heater Switch	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and C&I Customers
DLC Grid-Enabled Water Heaters	The grid-enabled water heater is equipped with a smart controller that allows the utility to remotely shut off the water heater for periods normally ranging from 2 to 4 hours.	Residential and C&I Customers
DLC Electric Vehicle	DLC of electric vehicles relies on communication (i.e., "dispatch") signals originating from a utility or aggregator and sent to a vehicle or charger to control charging in a predetermined manner. Can be events-based to control load during a limited number of events in a given time period (season or annually) or use continuous management to control load when the vehicle is connected to the charger.	Residential and C&I Customers

Demand Response Program Option	Program Description	Eligible Markets
Time of Use + Critical Peak Pricing Rate	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. An extra-high price for electricity is provided during critical periods of the year.	Residential and C&I Customers
Battery Storage	Uses the battery to reduce a home or facility's demand during peak or DR event hours, without requiring the customer to curtail their power. Instead of turning off equipment, the battery discharges power to offset load—or shifts charging to off-peak periods—so the utility sees a drop in grid demand.	Residential and C&I Customers

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control (DLC) program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. One cannot save a kW of load in a specific hour more than once. In general, the hierarchy of demand response programs is accounted for by subtracting the number participants in a higher priority program from the eligible market for a lower priority program. Table 4-2 shows the hierarchy for each sector, with 1 being the top priority. Note that only cost-effective programs are included in the hierarchy.

TABLE 4-2 DR HIERARCHY FOR EACH SECTOR

Order	Residential Hierarchy	C&I Hierarchy
1	Direct Load Control	Direct Load Control
2	Time of Use + Critical Peak Pricing Rate	Time of Use + Critical Peak Pricing Rate

4.1.1 Demand Response Potential Assessment Approach Overview

The analysis of demand response, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[9] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[10] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

Direct load control and rate programs demand response analysis was conducted using the GDS Demand Response Model. GDS determined the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. A modeling approach that considers numerous required inputs for each program was used, including expected life, coincident peak (CP) kW load reductions, proposed incentive levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses.

[9] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[10] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

The UCT was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions, and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum achievable potential (MAP) and realistic achievable potential (RAP) in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 18-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 18-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

4.1.2 Avoided Costs

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by CenterPoint. The primary benefit of demand response is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy-related benefits. If the demand response option is considered "load shifting," such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

4.1.3 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis.

4.1.3.1 Direct Load Control Program Assumptions

Load Reduction: Demand reductions were based on load reductions found in CenterPoint's existing demand response programs, and various secondary data sources including other industry reports and evaluations or demand response potential studies that conducted primary research. DLC and thermostat-based demand response options were typically calculated based on a per-unit kW demand reduction.

Useful Life: The useful life of a smart thermostat is assumed to be 11 years. Load control switches have a useful life of 10 years. This life was used for all direct load control measures in this study.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost,

with evaluation cost for existing programs already being included in the administration costs. It was assumed that there would be a cost of $50 per new participant for marketing for the DLC programs for RAP. Marketing costs are assumed to be 20% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

Saturation: For direct load control programs that control a specific end use, a saturation was applied to determine the number of eligible customers. For example, only customers with electric water heaters can participate in the water heating control program. Saturations from CenterPoint's 2025 market research were used.

Program Adoption Levels: Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility demand response programs. As noted earlier in this section, for direct load control programs, MAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels.

For the existing residential DLC AC switch and DLC water heater switch programs that are planned to be phased out over time, it was assumed that 80% of the current switches would be phased out or transitioned to other technologies, and the remaining 20% of switches would continue in the program until the switch or equipment fails.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 4-1). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

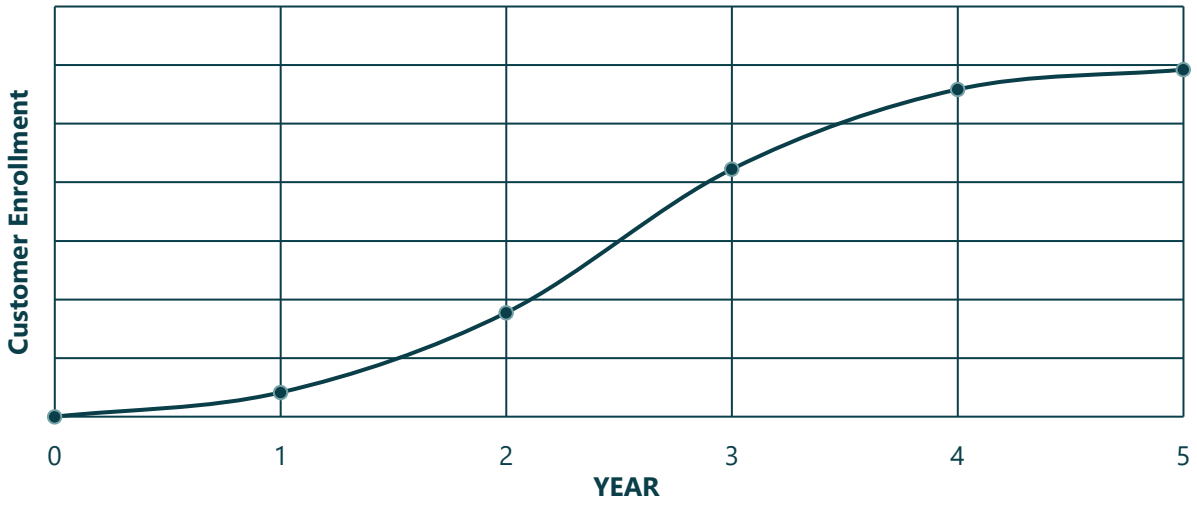


FIGURE 4-1: ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE

4.1.3.2 Rate Program Assumptions

Load Reduction: Demand reductions were based on various secondary data sources including other industry reports and evaluations or demand response potential studies that conducted primary research. Rate-based demand response options were typically assumed to reduce a percentage of the total facility coincident peak load.

Useful Life: The only equipment needed for rate programs is a smart meter. The life of a smart meter was assumed to be 20 years.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost, with evaluation cost for existing programs already being included in the administration costs. It was assumed that there would be a cost of $50 per new participant for marketing for the DLC programs. Marketing costs are assumed to be 20% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

4.2 TOTAL DEMAND RESPONSE POTENTIAL

Figure 4-2 provides the technical and economic demand response potential across the 3-year, 6-year, and 18-year timeframes. The technical potential ranges from 366 MW to 373 MW, whereas the economic potential ranges from 302 MW to 310 MW, which indicates that most technical potential is cost-effective.

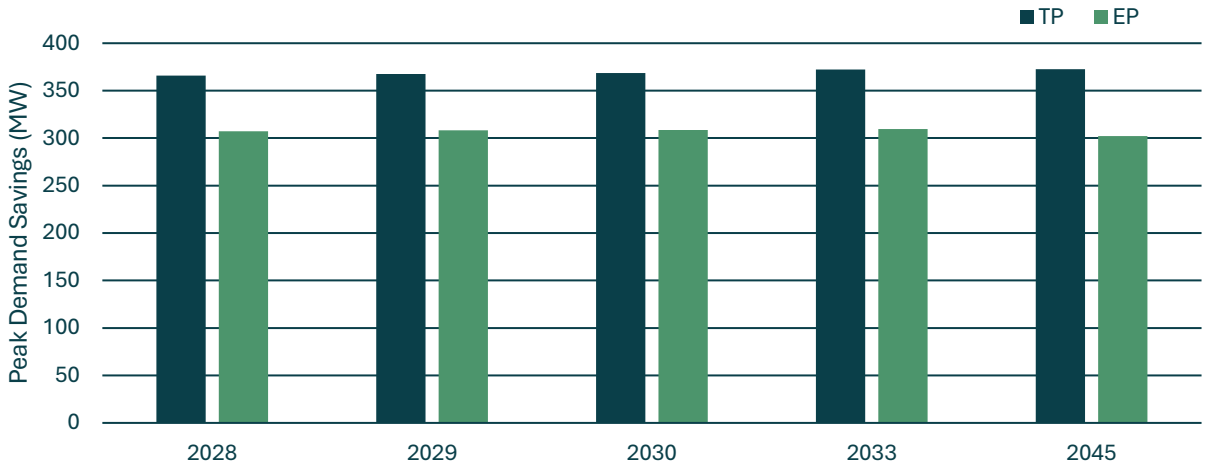


FIGURE 4-2: RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF SECTOR SALES)

Table 4-3 and Table 4-4 show the cumulative annual MAP and RAP savings for across the first six years of the study timeframe (2028-2033). These values are at the customer meter. The MAP assumes the maximum participation that would happen in the real-world, while the RAP considers additional barriers to program implementation that could limit the amount of savings achieved. The DLC Thermostat program options provide the most potential in both the residential and commercial sectors. Overall, the MAP ranges from 29.8 MW to 63.3 MW over the next six years, and the RAP ranges from 27.8 MW to 46.8 MW over the next six years.

TABLE 4-3: MAP SAVINGS BY PROGRAM AND SECTOR

Sector	Program	2028	2029	2030	2031	2032	2033
Residential	DLC AC Switch	1.3	0.8	0.7	0.6	0.5	0.5
	DLC Thermostat (Smart Cycle)	12.5	14.6	14.3	14.0	13.7	13.4
	DLC Thermostat (BYOT)	12.5	14.4	16.5	18.5	20.3	22.1
	DLC Water Heater Switch	0.4	0.3	0.3	0.3	0.2	0.2
	DLC Grid-Enabled Water Heater	0.8	2.5	5.3	7.0	7.5	7.6
	DLC Electric Vehicle	0.0	0.1	0.3	0.4	0.5	0.6

Sector	Program	2028	2029	2030	2031	2032	2033
	TOU + CPP Rate	0.7	1.1	1.6	2.1	2.5	3.0
	Battery Storage	0.0	0.1	0.2	0.3	0.4	0.4
	Residential Total	**28.2**	**34.0**	**39.1**	**43.1**	**45.7**	**47.8**
Commercial	DLC Thermostat (BYOT)	0.7	2.3	4.7	6.3	6.8	6.9
	DLC Grid-Enabled Water Heater	0.6	1.8	3.8	4.9	5.3	5.3
	DLC Electric Vehicle	0.0	0.0	0.0	0.0	0.0	0.0
	TOU + CPP Rate	0.3	1.1	2.2	2.9	3.1	3.2
	Battery Storage	0.0	0.1	0.1	0.2	0.2	0.2
	Commercial Total	**1.6**	**5.2**	**10.8**	**14.3**	**15.4**	**15.5**
All Sectors Combined		**29.8**	**39.2**	**49.9**	**57.4**	**61.1**	**63.3**

TABLE 4-4 RAP SAVINGS BY PROGRAM AND SECTOR

Sector	Program	2028	2029	2030	2031	2032	2033
Residential	DLC AC Switch	1.3	0.8	0.7	0.6	0.5	0.5
	DLC Thermostat (Smart Cycle)	12.5	14.8	14.6	14.3	14.1	13.9
	DLC Thermostat (BYOT)	11.8	12.9	14.4	15.8	17.1	17.1
	DLC Water Heater Switch	0.4	0.3	0.3	0.3	0.2	0.2
	DLC Grid-Enabled Water Heater	0.4	1.3	2.7	3.6	3.8	3.9
	DLC Electric Vehicle	0.0	0.1	0.2	0.3	0.4	0.5
	TOU + CPP Rate	0.5	0.8	1.2	1.5	1.8	2.1
	Battery Storage	0.0	0.1	0.2	0.3	0.3	0.3
	Residential Total	**26.9**	**31.1**	**34.1**	**36.6**	**38.3**	**38.5**
Commercial	DLC Thermostat (BYOT)	0.3	1.1	2.3	3.0	3.3	3.4
	DLC Grid-Enabled Water Heater	0.3	0.9	1.9	2.5	2.7	2.7
	DLC Electric Vehicle	0.0	0.0	0.0	0.0	0.0	0.0
	TOU + CPP Rate	0.2	0.7	1.5	1.9	2.1	2.1
	Battery Storage	0.0	0.0	0.1	0.1	0.2	0.2
	Commercial Total	**0.9**	**2.8**	**5.7**	**7.6**	**8.2**	**8.3**
All Sectors Combined		**27.8**	**33.8**	**39.9**	**44.2**	**46.5**	**46.8**

Figure 4-3 shows the cumulative annual RAP (MW) by program in the residential sector. The two DLC Thermostat options provide the greatest amount of potential, with the Time of Use + Critical Peak Pricing and DLC Grid-Enabled Water Heater program options growing over time as well. Overall, the residential RAP grows from 26.9 MW in 2028 to 39 MW in 2045.

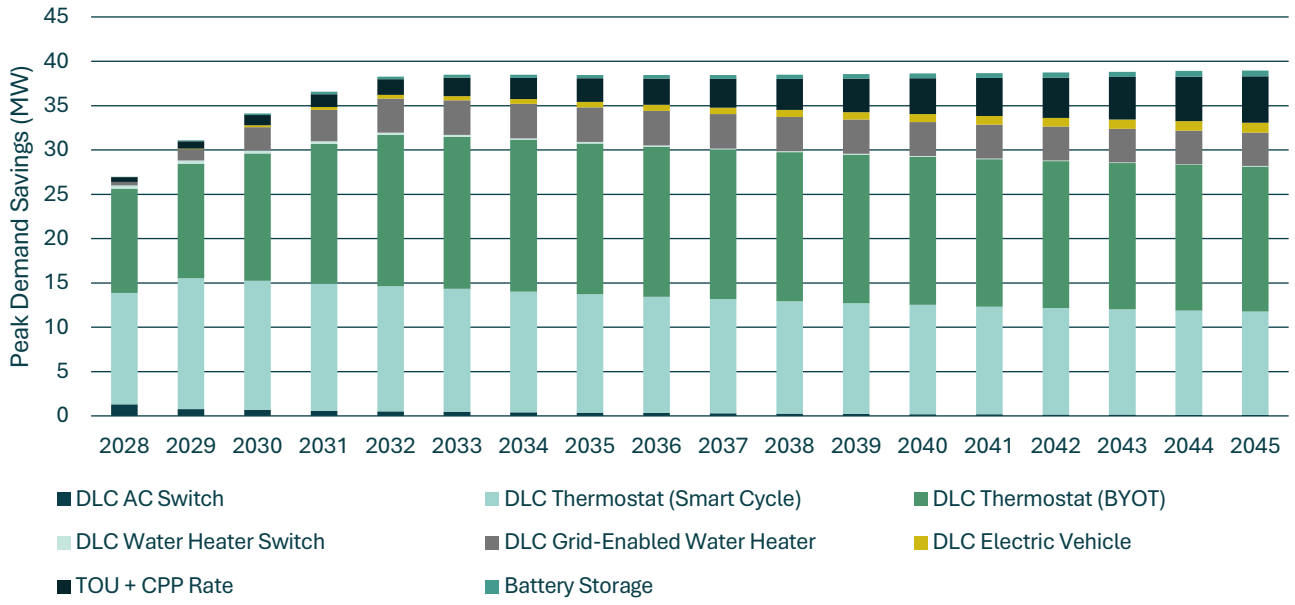


FIGURE 4-3 RESIDENTIAL SECTOR DEMAND RESPONSE RAP – BY PROGRAM

Figure 4-4 shows the cumulative annual RAP (MW) by program in the commercial sector. The DLC Thermostat option provides the greatest amount of potential, with the DLC Grid-Enabled Water Heater and Time of Use + Critical Peak Pricing program options growing significantly over time as well. Overall, the commercial RAP grows from 1 MW in 2028 to 8 MW in 2045.

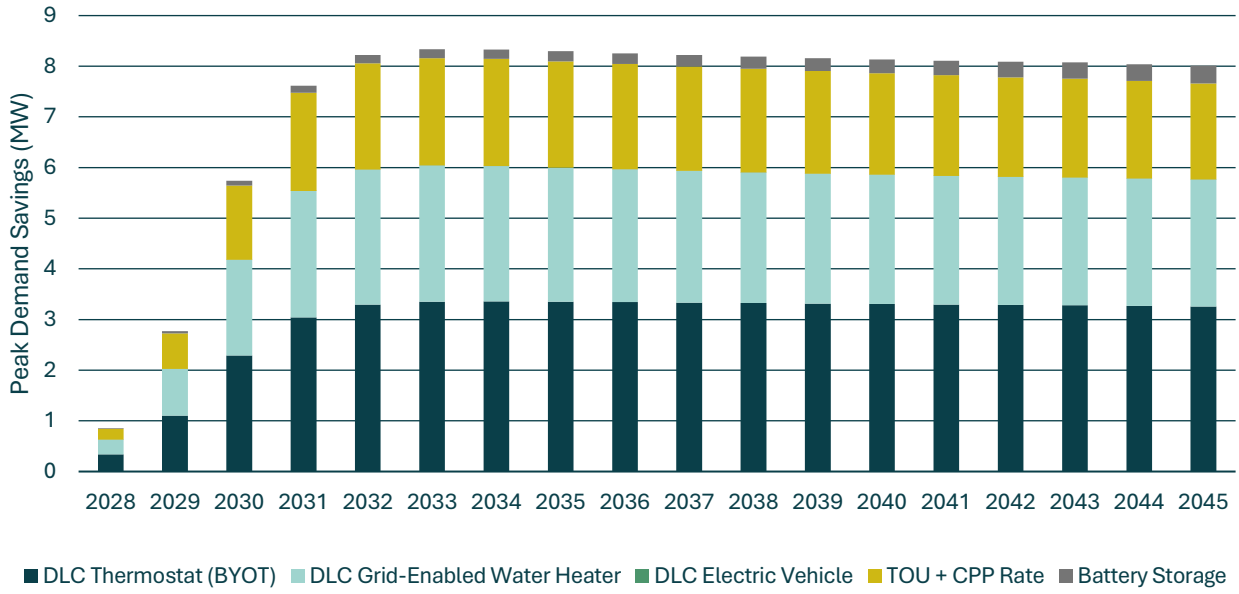


FIGURE 4-4 COMMERCIAL SECTOR DEMAND RESPONSE RAP – BY PROGRAM

4.3 BENEFITS & COSTS

Figure 4-5 provides the budget for the MAP and RAP scenarios, with a breakout shown for the residential and commercial sectors. For the MAP scenario, the budget ranges from $7.5 million to $14.5 million. For the RAP scenario, the budget ranges from $6.2 million to $9.6 million. The residential sector accounts for 91% of the total RAP budget and 90% of the total MAP budget.

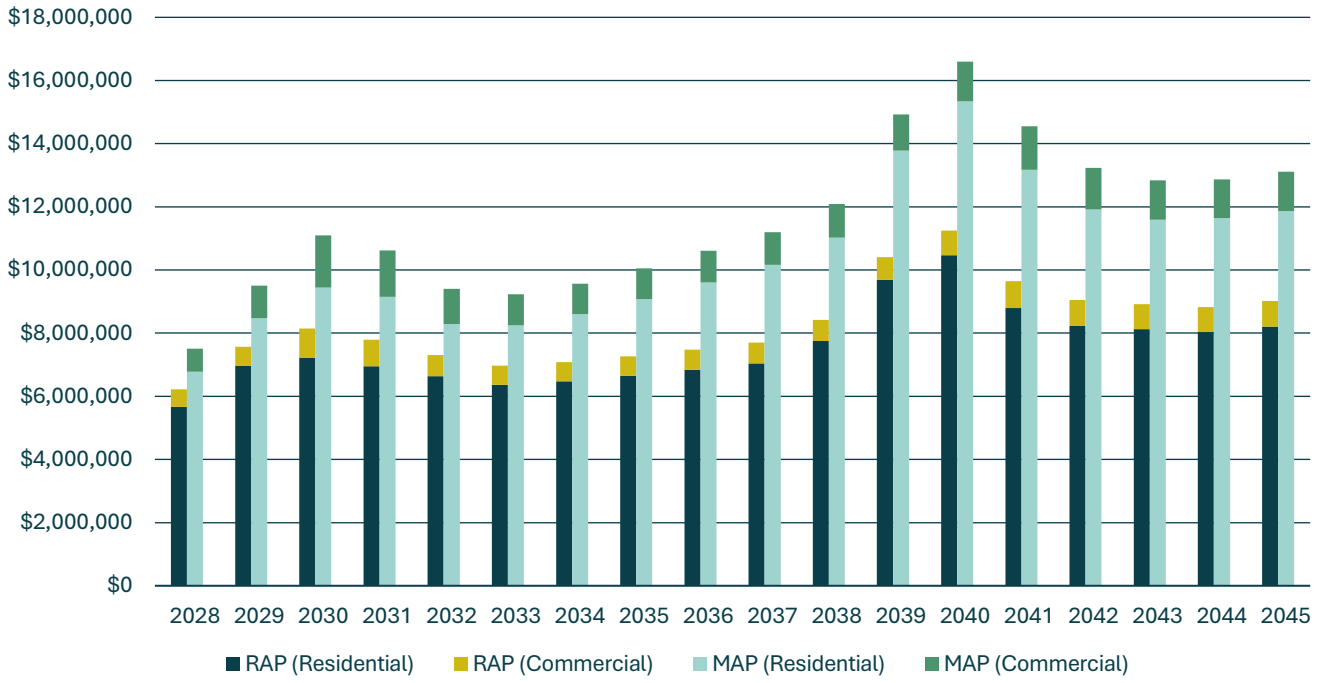


FIGURE 4-5: DEMAND RESPONSE ANNUAL BUDGETS – MAP AND RAP

Table 4-5 and Table 4-6 show the MAP and RAP residential NPVs of the total benefits, costs, and savings, along with the UCT ratio for each program for the length of the study.

TABLE 4-5 MAP NPV BENEFITS, COSTS, AND TRC RATIOS FOR EACH DEMAND RESPONSE PROGRAM

Sector	Program	MAP NPV Benefits	MAP NPV Costs	MAP UCT
Residential	DLC AC Switch	$1,306,809	$2,261,277	0.58
	DLC Thermostat (Smart Cycle)	$37,690,984	$30,708,879	1.23
	DLC Thermostat (BYOT)	$67,153,482	$63,331,695	1.47
	DLC Water Heater Switch	$541,476	$2,563,830	0.21
	DLC Grid-Enabled Water Heater	$19,036,235	$34,169,464	0.73
	DLC Electric Vehicle	$2,202,987	$7,556,272	0.67
	TOU + CPP Rate	$10,886,779	$1,606,725	6.78
	Battery Storage	$1,305,987	$1,791,468	0.73
Commercial	DLC Thermostat (BYOT)	$17,418,605	$9,645,507	3.21
	DLC Grid-Enabled Water Heater	$13,259,124	$5,636,904	2.81
	DLC Electric Vehicle	$1,986	$776,278	0.00

	TOU + CPP Rate	$7,303,437	$859,263	8.50
	Battery Storage	$717,468	$1,305,604	0.55

TABLE 4-6 RAP NPV BENEFITS, COSTS, AND TRC RATIOS FOR EACH DEMAND RESPONSE PROGRAM

Sector	Program	RAP NPV Benefits	RAP NPV Costs	RAP UCT
Residential	DLC AC Switch	$1,347,718	$2,257,653	0.60
	DLC Thermostat (Smart Cycle)	$39,577,520	$30,632,231	1.29
	DLC Thermostat (BYOT)	$47,814,104	$39,685,013	1.62
	DLC Water Heater Switch	$556,119	$2,563,830	0.22
	DLC Grid-Enabled Water Heater	$9,950,648	$17,356,000	0.75
	DLC Electric Vehicle	$1,762,422	$6,170,917	0.64
	TOU + CPP Rate	$7,659,804	$1,195,505	6.41
	Battery Storage	$1,142,866	$1,617,649	0.71
Commercial	DLC Thermostat (BYOT)	$8,545,967	$4,667,475	3.26
	DLC Grid-Enabled Water Heater	$6,747,318	$3,165,732	2.49
	DLC Electric Vehicle	$990	$772,336	0.00
	TOU + CPP Rate	$4,918,339	$785,756	6.26
	Battery Storage	$604,182	$1,231,826	0.49

05 ACTION PLAN SUMMARY

5.1 DEVELOPMENT OF DSM ACTION PLAN

The Market Potential Study serves as the basis for developing CenterPoint Indiana's DSM Action Plan. The DSM Action Plan is designed to extract the insights and data from the Market Potential Study and translate them into opportunities to deliver to customers. The DSM Action Plan provides guidance to mobilize the results of the Market Potential Study findings to provide a pathway to advance efforts that are reasonable and relevant in developing CenterPoint Indiana's portfolio in future years. The following section lays out the process, principles, and elements of CenterPoint Indiana's portfolio of programs. A summary of the results for the proposed portfolio is also provided.

5.2 DSM ACTION PLAN – GUIDING PRINCIPLES AND FRAMEWORK

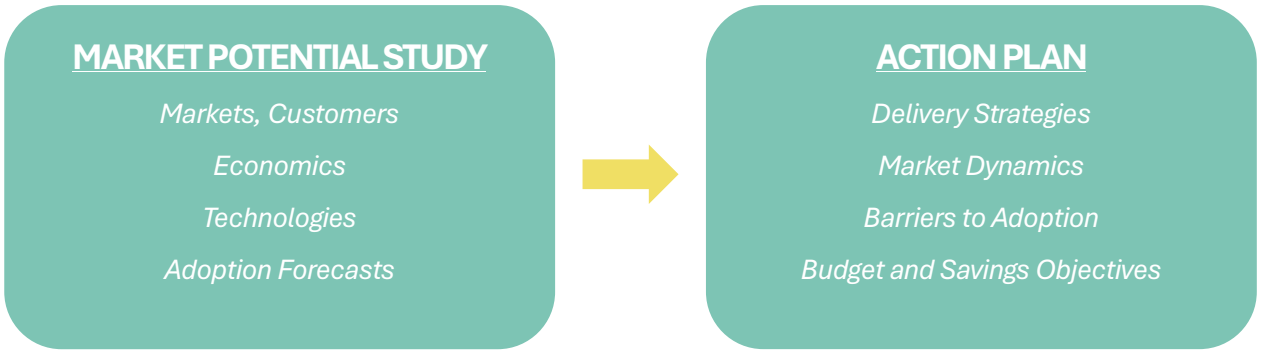
CenterPoint Indiana's DSM Action Plan was developed in accordance with a number of guiding principles and considerations. The process was built on using the most recent Market Potential Study as the foundation, and was then designed to incorporate industry best standards, implementer experiences, and projected changes in the market (such as codes and standards) in order to translate the insights and knowledge from the Market Potential Study into actionable energy efficiency programs for CenterPoint Indiana's planning purposes and customers.11 Key planning guidelines and considerations used to frame the Action Plan are listed in Table 5-1 below.

TABLE 5-1: RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

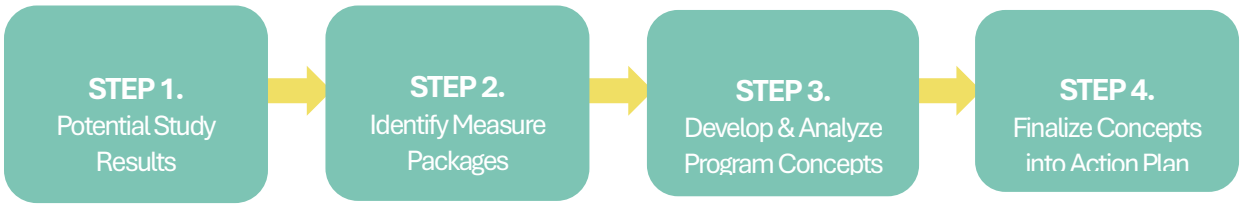
Plan Consideration	Description
Market Coverage	Consideration was given to crafting a portfolio of programs that offers opportunities for savings across all CenterPoint Indiana's customer groups.
Market Potential Study	The Action Plan is linked to the Market Potential Study.
Current Program Efforts	The Action Plan leverages current CenterPoint Indiana offerings to take advantage of market and trade ally understanding, to utilize existing market relationships, retain the relevant elements of programs already working well, and to continue promotional efforts.
Cost Effectiveness Analysis	All programs were screened for cost-effectiveness using the TRC test (except for the Income Qualified program)
Income-Qualified Programs	Program funding is linked to the Market Potential Study.
Program Costs and Budgets	A budget that characterizes the estimated costs for delivering programs to customers is presented for each program. The costs include all participant incentive, implementation, admin, and evaluation costs for each year of program operation.

The development of the Action Plan is designed to translate the insights and information from the broader Market Potential Study analysis into discrete and specific offerings for CenterPoint Indiana's customers. The Market Potential Study and the Action Plan are related and share common values, but the Action Plan provides more detail, specificity, and mobilization strategies. The Action Plan outlines recommended electric programs for 2028-2033, a shorter timeframe than the potential research. The Action Plan lays out how to achieve the savings identified in the potential study research, shifting the broad and high-level forecast of savings opportunities in the Market Potential Study results into specific and actionable savings opportunities. An illustrative view between the Market Potential Study and the Action Plan elements follows:

[11] The DSM Action Plan represents modified versions of the RAP from the MPS. The residential sector includes minor modifications to better align program measure mapping with current CenterPoint Indiana offerings. The C&I sector has slightly higher costs over the DSM Action Plan timeframe.



The effort to develop CenterPoint Indiana's energy efficiency programs follows a grounded and sequential process. The process was built on applying the recent market potential analytics as a starting point and, from there, developing program offerings that cost-effectively meet CenterPoint Indiana's planning and program objectives. An illustrative review of the process follows.



5.3 DSM ACTION PLAN – PORTFOLIO SUMMARY

Figure 5-1 below provides an overview of the savings and budgets. The annual savings range from approximately 32,000 MWh to 36,000 MWh with annual budgets ranging from $17 million to $20 million.

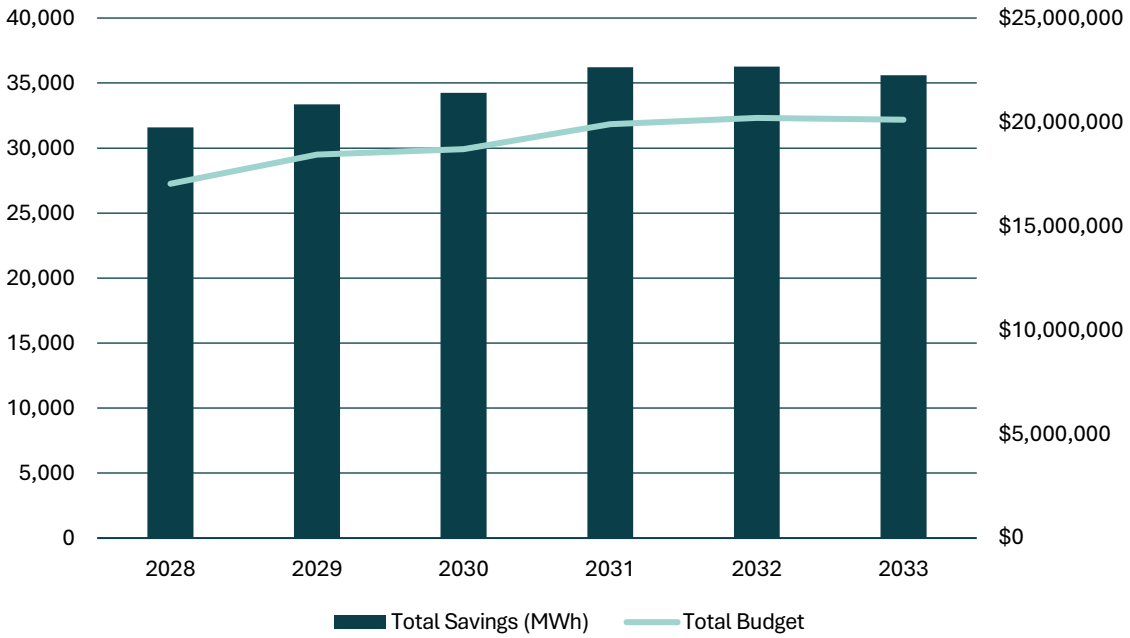


FIGURE 5-1: ANNUAL SAVINGS (MWH) AND BUDGET (2028-2033)

Table 5-2 below provides additional savings and budget detail by sector, as well as detailed indirect costs.[12] The residential sector accounts for approximately 33% of total savings and 50% of total spending.

TABLE 5-2: ANNUAL SAVINGS AND BUDGET DETAIL BY SECTOR (2028-2033)

	2028	2029	2030	2031	2032	2033
Residential Savings (MWh)	10,683	11,902	12,721	14,075	14,841	15,407
C&I Savings (MWh)	20,908	21,457	21,519	22,152	21,428	20,198
Total Savings (MWh)	***31,591***	***33,359***	***34,240***	***36,226***	***36,269***	***35,605***
Residential Budget	$8,229,275	$9,632,867	$9,677,086	$10,340,765	$11,222,641	$11,693,478
C&I Budget	$7,032,474	$7,307,997	$7,483,086	$7,547,478	$7,343,516	$6,812,014
Outreach & Education	$71,378	$75,373	$77,363	$81,852	$81,948	$80,449
Contact Center	$48,617	$51,338	$52,694	$55,751	$55,816	$54,796
Online Audit	$573,453	$605,551	$621,540	$657,599	$658,370	$646,331
Evaluation	$728,135	$768,891	$789,193	$834,978	$835,957	$820,671
Market Potential Study	$350,000	$0	$0	$375,000	$0	$0
Total Budget	***$17,033,332***	***$18,442,018***	***$18,700,963***	***$19,893,422***	***$20,198,248***	***$20,107,739***

Table 5-3 below provides additional savings and budget detail by sector. Annual budgets range from $17.0 million to $20.2 from 2028-2033. Incentives are the greatest expenditure by category, followed by delivery and implementation, administrative and indirect costs. Refer to Chapter 6 for additional detail.

TABLE 5-3: ANNUAL BUDGET DETAIL BY SECTOR AND SPENDING CATEGORY (2028-2033)

	2028	2029	2030	2031	2032	2033
Residential						
Incentives	$3,124,539	$3,673,645	$4,097,202	$4,529,397	$4,951,566	$5,266,900
Delivery & Implementation	$3,465,264	$4,121,451	$3,722,575	$3,838,454	$4,183,754	$4,360,214
Admin	$1,639,472	$1,837,771	$1,857,309	$1,972,914	$2,087,321	$2,066,364
Residential Budget	**$8,229,275**	**$9,632,867**	**$9,677,086**	**$10,340,765**	**$11,222,641**	**$11,693,478**
Commercial						
Incentives	$4,659,160	$4,723,701	$4,730,146	$4,646,868	$4,494,342	$4,038,782
Delivery & Implementation	$1,891,861	$2,046,642	$2,160,149	$2,267,428	$2,223,671	$2,161,541
Admin	$481,453	$537,654	$592,791	$633,181	$625,503	$611,691
Commercial Budget	**$7,032,474**	**$7,307,997**	**$7,483,086**	**$7,547,478**	**$7,343,516**	**$6,812,014**
All Sectors						
Incentives	$7,783,700	$8,397,346	$8,827,348	$9,176,265	$9,445,908	$9,305,682
Delivery & Implementation	$5,357,125	$6,168,094	$5,882,724	$6,105,882	$6,407,426	$6,521,755
Admin	$2,120,925	$2,375,425	$2,450,100	$2,606,095	$2,712,824	$2,678,055
Indirect	$1,771,583	$1,501,154	$1,540,791	$2,005,180	$1,632,090	$1,602,247
Total Budget	**$17,033,332**	**$18,442,018**	**$18,700,963**	**$19,893,422**	**$20,198,248**	**$20,107,739**

[12] Indirect costs include outreach and education, contact center, online audit, and evaluation.

5.4 PORTFOLIO TARGETS BY YEAR

TABLE 5-4: 2028 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	921	235,269	68.9	$138,559	$32,403	$13,388	$184,351
Home Energy Assessment	2,374	402,429	99.7	$72,784	$101,135	$46,935	$220,855
Residential Midstream	2,128	1,620,551	249.1	$460,605	$513,594	$55,671	$1,029,870
In Store Discount	4,272	365,798	120.0	$52,443	$36,500	$12,731	$101,674
Multi-Family Energy Solutions	1,709	307,351	61.7	$34,186	$25,835	$17,673	$77,694
Community Connections	8,296	884,155	116.1	$72,283	$277,194	$0	$349,477
Income Qualified Weatherization	1,732	557,071	112.7	$437,641	$613,935	$0	$1,051,576
Residential New Construction	244	124,213	21.9	$48,292	$56,181	$7,805	$112,278
Residential Marketplace	8,316	1,187,694	333.4	$59,968	$205,683	$231,588	$497,239
Residential Behavioral	40,638	4,998,443	570.6	$0	$222,797	$2,133	$224,930
Smart Cycle	13,352	0	12,528.9	$901,260	$1,181,917	$733,422	$2,816,599
Bring Your Own Thermostat	12,541	0	11,767.9	$846,518	$198,090	$518,126	$1,562,733
CVR – Residential	0	0	0.0	$0	$0	$0	$0
Residential Subtotal	***96,522***	***10,682,974***	***26,050.9***	***$3,124,539***	***$3,465,264***	***$1,639,472***	***$8,229,275***
Commercial & Industrial							
Commercial Prescriptive	31,632	10,940,025	1,700.9	$1,995,931	$893,762	$223,440	$3,113,133
Commercial Custom	155	7,774,104	1,003.3	$1,664,963	$778,114	$194,528	$2,637,606
Small Business Energy Solutions	6,174	2,193,629	417.4	$986,453	$193,735	$48,434	$1,228,622
Bring Your Own Thermostat	175	0	339.9	$11,813	$26,250	$15,050	$53,113
CVR - Commercial	0	0	0.0	$0	$0	$0	$0
Commercial & Industrial Subtotal	**38,136**	**20,907,758**	**3,461.5**	**$4,659,160**	**$1,891,861**	**$481,453**	**$7,032,474**
Indirect Costs							
Contact Center							$71,378
Online Audit							$48,617
Outreach & Education							$573,453
Evaluation							$728,135
Indirect Costs Subtotal							***$1,421,583***
Other Costs							
Market Potential Study							$350,000
Unallocated Budget							$0
Other Costs Subtotal							***$350,000***
DSM Portfolio Totals	**134,658**	**31,590,732**	**29,512.3**	**$7,783,700**	**$5,357,125**	**$2,120,925**	**$17,033,332**

TABLE 5-5: 2029 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	1,261	306,994	91.3	$154,224	$43,170	$17,837	$215,231
Home Energy Assessment	2,592	420,414	101.1	$76,699	$108,373	$50,294	$235,366
Residential Midstream	2,365	1,828,370	271.9	$539,024	$599,468	$64,980	$1,203,472
In Store Discount	5,162	430,965	138.8	$62,482	$44,006	$15,349	$121,837
Multi-Family Energy Solutions	1,001	174,038	39.4	$28,914	$16,731	$11,445	$57,089
Community Connections	8,819	1,011,664	130.6	$81,707	$324,923	$0	$406,630
Income Qualified Weatherization	2,050	661,703	125.4	$540,541	$747,412	$0	$1,287,953
Residential New Construction	283	143,917	25.4	$56,081	$66,743	$9,273	$132,097
Residential Marketplace	8,534	1,242,392	355.5	$67,577	$224,421	$252,686	$544,683
Residential Behavioral	46,194	5,681,824	648.6	$0	$259,083	$2,480	$261,563
Smart Cycle	15,958	0	14,771.3	$1,101,940	$1,476,462	$826,111	$3,404,513
Bring Your Own Thermostat	13,967	0	12,928.3	$964,456	$210,659	$587,317	$1,762,432
CVR – Residential	0	0	0.0	$0	$0	$0	$0
Residential Subtotal	***108,186***	***11,902,280***	***29,627.6***	***$3,673,645***	***$4,121,451***	***$1,837,771***	***$9,632,867***
Commercial & Industrial							
Commercial Prescriptive	29,618	10,790,182	1,634.2	$1,941,129	$910,060	$227,515	$3,078,704
Commercial Custom	177	8,798,340	1,139.2	$1,912,457	$905,042	$226,261	$3,043,760
Small Business Energy Solutions	5,186	1,868,172	349.1	$830,824	$171,081	$42,770	$1,044,675
Bring Your Own Thermostat	569	0	1,101.9	$39,291	$60,459	$41,108	$140,858
CVR - Commercial	0	0	0.0	$0	$0	$0	$0
Commercial & Industrial Subtotal	**35,550**	**21,456,694**	**4,224.3**	**$4,723,701**	**$2,046,642**	**$537,654**	**$7,307,997**
Indirect Costs							
Contact Center							$75,373
Online Audit							$51,338
Outreach & Education							$605,551
Evaluation							$768,891
Indirect Costs Subtotal							***$1,501,154***
Other Costs							
Market Potential Study							$0
Unallocated Budget							$0
Other Costs Subtotal							***$0***
DSM Portfolio Totals	**143,736**	**33,358,974**	**33,851.9**	**$8,397,346**	**$6,168,094**	**$2,375,425**	**$18,442,018**

TABLE 5-6: 2030 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	1,537	359,685	101.9	$169,531	$52,098	$21,526	$243,155
Home Energy Assessment	2,791	435,446	100.6	$80,465	$115,144	$53,436	$249,046
Residential Midstream	2,128	1,620,551	249.1	$615,534	$682,673	$73,999	$1,372,206
In Store Discount	6,046	492,770	155.1	$71,895	$51,492	$17,961	$141,348
Multi-Family Energy Solutions	877	147,891	31.2	$26,850	$15,188	$10,389	$52,427
Community Connections	9,311	1,131,166	144.1	$90,558	$372,128	$0	$462,686
Income Qualified Weatherization	2,395	779,417	137.9	$659,805	$902,236	$0	$1,562,041
Residential New Construction	330	167,322	29.5	$65,373	$79,591	$11,058	$156,021
Residential Marketplace	9,036	1,284,002	368.2	$75,407	$238,260	$268,267	$581,934
Residential Behavioral	51,240	6,302,523	719.5	$0	$293,995	$2,814	$296,810
Smart Cycle	15,958	0	14,556.0	$1,127,284	$670,419	$708,749	$2,506,452
Bring Your Own Thermostat	15,777	0	14,390.9	$1,114,498	$249,351	$689,110	$2,052,960
CVR – Residential	0	0	0.0	$0	$0	$0	$0
Residential Subtotal	***117,427***	***12,720,772***	***30,984.0***	***$4,097,202***	***$3,722,575***	***$1,857,309***	***$9,677,086***
Commercial & Industrial							
Commercial Prescriptive	27,268	10,489,289	1,551.5	$1,889,867	$914,302	$228,576	$3,032,745
Commercial Custom	194	9,471,904	1,224.4	$2,065,733	$1,000,893	$250,223	$3,316,849
Small Business Energy Solutions	4,266	1,557,827	287.0	$690,766	$148,097	$37,024	$875,888
Bring Your Own Thermostat	1,186	0	2,289.3	$83,780	$96,856	$76,968	$257,604
CVR - Commercial	0	0	0.0	$0	$0	$0	$0
Commercial & Industrial Subtotal	**32,914**	**21,519,020**	**5,352.2**	**$4,730,146**	**$2,160,149**	**$592,791**	**$7,483,086**
Indirect Costs							
Contact Center							$77,363
Online Audit							$52,694
Outreach & Education							$621,540
Evaluation							$789,193
Indirect Costs Subtotal							***$1,540,791***
Other Costs							
Market Potential Study							$0
Unallocated Budget							$0
Other Costs Subtotal							***$0***
DSM Portfolio Totals	**150,341**	**34,239,792**	**36,336.3**	**$8,827,348**	**$5,882,724**	**$2,450,100**	**$18,700,963**

TABLE 5-7: 2031 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	1,886	417,748	115.1	$187,956	$62,653	$25,887	$276,497
Home Energy Assessment	2,919	441,014	98.3	$83,759	$119,654	$55,529	$258,941
Residential Midstream	2,706	2,155,011	297.4	$686,820	$760,512	$82,436	$1,529,768
In Store Discount	6,835	545,426	166.9	$79,532	$58,326	$20,344	$158,203
Multi-Family Energy Solutions	371	55,190	5.8	$7,175	$4,249	$2,907	$14,332
Community Connections	9,699	1,225,018	154.7	$97,547	$412,779	$0	$510,326
Income Qualified Weatherization	3,087	947,671	180.7	$816,059	$1,124,110	$0	$1,940,169
Residential New Construction	339	171,341	30.3	$67,135	$83,617	$11,617	$162,369
Residential Marketplace	9,211	1,275,790	364.8	$81,510	$243,487	$274,153	$599,150
Residential Behavioral	55,613	6,840,346	780.9	$0	$326,422	$3,125	$329,547
Smart Cycle	15,958	0	14,331.5	$1,153,212	$390,353	$725,050	$2,268,615
Bring Your Own Thermostat	17,556	0	15,766.7	$1,268,692	$252,291	$771,866	$2,292,849
CVR – Residential	0	0	0.0	$0	$0	$0	$0
Residential Subtotal	***126,180***	***14,074,555***	***32,293.1***	***$4,529,397***	***$3,838,454***	***$1,972,914***	***$10,340,765***
Commercial & Industrial							
Commercial Prescriptive	24,923	10,179,104	1,476.7	$1,835,766	$916,620	$229,155	$2,981,540
Commercial Custom	203	10,698,611	1,405.4	$2,128,383	$1,161,211	$290,303	$3,579,896
Small Business Energy Solutions	3,447	1,273,947	232.2	$568,323	$125,843	$31,461	$725,628
Bring Your Own Thermostat	1,583	0	3,045.2	$114,396	$63,754	$82,263	$260,413
CVR - Commercial	0	0	0.0	$0	$0	$0	$0
Commercial & Industrial Subtotal	**30,156**	**22,151,662**	**6,159.4**	**$4,646,868**	**$2,267,428**	**$633,181**	**$7,547,478**
Indirect Costs							
Contact Center							$81,852
Online Audit							$55,751
Outreach & Education							$657,599
Evaluation							$834,978
Indirect Costs Subtotal							***$1,630,180***
Other Costs							
Market Potential Study							$375,000
Unallocated Budget							$0
Other Costs Subtotal							***$375,000***
DSM Portfolio Totals	**156,336**	**36,226,217**	**38,452.6**	**$9,176,265**	**$6,105,882**	**$2,606,095**	**$19,893,422**

TABLE 5-8: 2032 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	2,206	476,458	127.4	$206,129	$73,703	$30,453	$310,285
Home Energy Assessment	3,010	441,169	94.5	$86,585	$122,839	$57,007	$266,432
Residential Midstream	2,813	2,267,113	301.4	$750,471	$831,673	$90,149	$1,672,294
In Store Discount	7,426	583,120	172.7	$84,350	$63,813	$22,258	$170,421
Multi-Family Energy Solutions	315	31,025	3.0	$4,140	$2,473	$1,692	$8,305
Community Connections	9,915	1,276,219	160.5	$101,429	$440,510	$0	$541,939
Income Qualified Weatherization	3,468	1,078,290	191.6	$958,191	$1,310,542	$0	$2,268,733
Residential New Construction	342	172,470	30.5	$67,785	$86,368	$11,999	$166,152
Residential Marketplace	9,109	1,226,012	347.8	$85,210	$240,885	$271,223	$597,318
Residential Behavioral	59,260	7,288,938	832.1	$0	$355,829	$3,406	$359,236
Smart Cycle	15,958	0	14,106.4	$1,179,736	$399,331	$741,727	$2,320,793
Bring Your Own Thermostat	19,310	0	17,069.5	$1,427,541	$255,787	$857,406	$2,540,735
CVR – Residential	0	0	0.0	$0	$0	$0	$0
Residential Subtotal	***133,130***	***14,840,813***	***33,437.3***	***$4,951,566***	***$4,183,754***	***$2,087,321***	***$11,222,641***
Commercial & Industrial							
Commercial Prescriptive	22,449	9,638,378	1,382.4	$1,756,550	$896,236	$224,059	$2,876,845
Commercial Custom	207	10,761,249	1,414.4	$2,147,152	$1,199,600	$299,900	$3,646,652
Small Business Energy Solutions	2,753	1,028,235	186.2	$463,632	$105,657	$26,414	$595,703
Bring Your Own Thermostat	1,718	0	3,292.9	$127,008	$22,178	$75,130	$224,316
CVR - Commercial	0	0	0.0	$0	$0	$0	$0
Commercial & Industrial Subtotal	**27,128**	**21,427,862**	**6,275.9**	**$4,494,342**	**$2,223,671**	**$625,503**	**$7,343,516**
Indirect Costs							
Contact Center							$81,948
Online Audit							$55,816
Outreach & Education							$658,370
Evaluation							$835,957
Indirect Costs Subtotal							***$1,632,090***
Other Costs							
Market Potential Study							$0
Unallocated Budget							$0
Other Costs Subtotal							***$0***
DSM Portfolio Totals	**160,257**	**36,268,674**	**39,713.2**	**$9,445,908**	**$6,407,426**	**$2,712,824**	**$20,198,248**

TABLE 5-9: 2033 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	2,648	565,628	152.3	$230,141	$90,010	$37,190	$357,340
Home Energy Assessment	3,022	431,249	89.5	$89,316	$123,302	$57,222	$269,841
Residential Midstream	2,886	2,347,133	301.5	$805,088	$895,719	$97,092	$1,797,899
In Store Discount	7,727	600,631	171.8	$85,663	$67,264	$23,462	$176,390
Multi-Family Energy Solutions	280	26,213	2.5	$4,091	$2,158	$1,476	$7,725
Community Connections	9,915	1,274,103	160.1	$101,429	$450,642	$0	$552,071
Income Qualified Weatherization	3,787	1,196,333	197.8	$1,102,262	$1,489,892	$0	$2,592,154
Residential New Construction	340	171,035	30.3	$67,439	$87,903	$12,212	$167,554
Residential Marketplace	8,762	1,143,119	320.0	$86,018	$231,324	$260,458	$577,800
Residential Behavioral	62,210	7,651,781	873.5	$0	$382,134	$3,658	$385,792
Smart Cycle	15,958	0	13,881.6	$1,206,870	$408,516	$758,786	$2,374,172
Bring Your Own Thermostat	19,683	0	17,122.0	$1,488,584	$131,350	$814,807	$2,434,741
CVR – Residential	0	0	0.0	$0	$0	$0	$0
Residential Subtotal	***137,218***	***15,407,224***	***33,303.0***	***$5,266,900***	***$4,360,214***	***$2,066,364***	***$11,693,478***
Commercial & Industrial							
Commercial Prescriptive	18,554	8,679,105	1,200.4	$1,519,879	$832,946	$208,237	$2,561,062
Commercial Custom	207	10,946,638	1,451.3	$2,169,009	$1,256,608	$314,152	$3,739,769
Small Business Energy Solutions	1,415	572,523	85.4	$217,167	$65,768	$16,442	$299,378
Bring Your Own Thermostat	1,755	0	3,350.8	$132,727	$6,218	$72,860	$211,806
CVR - Commercial	0	0	0.0	$0	$0	$0	$0
Commercial & Industrial Subtotal	**21,932**	**20,198,266**	**6,087.9**	**$4,038,782**	**$2,161,541**	**$611,691**	**$6,812,014**
Indirect Costs							
Contact Center							$80,449
Online Audit							$54,796
Outreach & Education							$646,331
Evaluation							$820,671
Indirect Costs Subtotal							***$1,602,247***
Other Costs							
Market Potential Study							$0
Unallocated Budget							$0
Other Costs Subtotal							***$0***
DSM Portfolio Totals	**159,150**	**35,605,491**	**39,390.8**	**$9,305,682**	**$6,521,755**	**$2,678,055**	**$20,107,739**

06 ACTION PLAN PROGRAM DETAIL

6.1 RESIDENTIAL PRESCRIPTIVE PROGRAM

Program Description: The Residential Prescriptive Program is a cash-back rebate program that helps CenterPoint Energy residential customers afford high efficiency equipment options when replacing space heating and cooling equipment through the Residential Prescriptive Program channel. The equipment rebates help to educate customers about the energy savings and non-energy benefits associated with higher efficiency equipment that reduces energy consumption. The Insulation channel of the Residential Prescriptive Program offers home weatherization rebates to residential customers for attic insulation.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-1: RESIDENTIAL PRESCRIPTIVE PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
AC Tune Up	$25.00	97.3	0.10
ASHP Tune Up	$50.00	301.3	0.10
Attic Fan	$37.50	82.3	0.17
Attic Insulation - Inadequate Insulation - Electric furnace	$750.00	923.0	0.16
Attic Insulation - Inadequate Insulation - Gas Heating	$750.00	290.6	0.11
Attic Insulation - Inadequate Insulation - Heat pump	$750.00	592.7	0.10
CEE Advanced Tier Clothes Washer	$50.00	157.7	0.02
CEE Tier 2 Clothes Washer	$50.00	141.0	0.02
ENERGY STAR Air Purifier	$25.00	298.0	0.03
ENERGY STAR Clothes Dryer (Electric)	$50.00	159.9	0.02
ENERGY STAR Clothes Washer	$50.00	78.5	0.01
ENERGY STAR Dehumidifier	$10.00	157.0	0.04
ENERGY STAR Dishwasher	$7.50	67.0	0.00
ENERGY STAR Freezer - Chest	$1.25	27.2	0.00
ENERGY STAR Freezer - Compact Upright	$1.25	27.3	0.00
ENERGY STAR Most Efficient Dehumidifier	$10.00	230.0	0.05
ENERGY STAR Windows - Electric furnace	$502.25	2,901.2	0.49
ENERGY STAR Windows - Gas Heating	$502.25	271.8	0.10
ENERGY STAR Windows - Heat pump	$502.25	1,689.6	0.29
Heat Pump Swimming Pool Heater (COP >=6.0)	$800.00	1,594.3	0.00
Heat Pump Swimming Pool Heater (COP 5.5-5.9)	$350.00	1,005.2	0.00
Heat Pump Water Heater-electric resistance heat	$500.00	1,708.2	0.08
Heat Pump Water Heater-gas heat	$500.00	1,723.1	0.08
Heat Pump Water Heater-heat pump heat	$500.00	1,715.0	0.08
Smart Thermostat - Furnace baseline	$30.00	934.3	0.17
Smart Thermostat - Gas/CAC baseline	$19.20	169.8	0.18
Smart Thermostat - Heat pump baseline	$30.00	522.2	0.18

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units.

Marketing: The marketing plan includes program specific marketing materials that will target contractors and trade allies in the Heating, Ventilation and Air Conditioning (HVAC) industry. The HVAC industry will be marketed by using targeted direct marketing, direct contact by the program vendor personnel, trade shows and trade association outreach. The program will be promoted through trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets. CenterPoint Indiana will also use web banners, bill inserts, and mass market advertising. Program marketing directs customers and contractors to the CenterPoint Indiana website or call center for information.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor. Vendors will work with local contractors to deliver the program.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-2: RESIDENTIAL PRESCRIPTIVE PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
AC Tune Up						
Participation	55	59	65	122	142	163
Incentive Budget	$1,379	$1,477	$1,627	$3,056	$3,559	$4,072
Projected kWh Savings	2,860	3,059	3,362	6,305	7,328	8,371
Projected kW Savings	3.0	3.2	3.5	6.7	7.7	8.8
ASHP Tune Up						
Participation	32	36	45	78	89	103
Incentive Budget	$1,621	$1,785	$2,234	$3,905	$4,469	$5,150
Projected kWh Savings	6,092	6,696	8,364	14,592	16,670	19,178
Projected kW Savings	2.0	2.1	2.7	4.7	5.4	6.2
Attic Fan						
Participation	8	13	14	15	17	21
Incentive Budget	$313	$472	$527	$567	$626	$783
Projected kWh Savings	524	781	865	921	1,006	1,245
Projected kW Savings	1.1	1.6	1.8	1.9	2.1	2.6
Attic Insulation - Inadequate Insulation - Electric furnace						
Participation	59	59	59	59	59	59
Incentive Budget	$44,157	$44,157	$44,157	$44,157	$44,157	$44,157
Projected kWh Savings	37,027	36,803	36,559	36,298	36,025	35,737
Projected kW Savings	6.3	6.3	6.2	6.2	6.1	6.1
Attic Insulation - Inadequate Insulation - Gas Heating						
Participation	32	32	32	32	32	32
Incentive Budget	$23,971	$23,971	$23,971	$23,971	$23,971	$23,971

Measure	2028	2029	2030	2031	2032	2033
Projected kWh Savings	6,329	6,291	6,249	6,205	6,158	6,109
Projected kW Savings	2.3	2.3	2.3	2.3	2.3	2.2
Attic Insulation - Inadequate Insulation - Heat pump						
Participation	42	42	42	42	42	42
Incentive Budget	$31,540	$31,540	$31,540	$31,540	$31,540	$31,540
Projected kWh Savings	16,985	16,882	16,770	16,650	16,525	16,393
Projected kW Savings	2.9	2.9	2.9	2.8	2.8	2.8
CEE Advanced Tier Clothes Washer						
Participation	3	8	13	18	24	32
Incentive Budget	$154	$386	$645	$919	$1,218	$1,592
Projected kWh Savings	365	913	1,526	2,173	2,882	3,767
Projected kW Savings	0.1	0.1	0.2	0.3	0.4	0.5
CEE Tier 2 Clothes Washer						
Participation	3	8	13	18	24	32
Incentive Budget	$155	$388	$649	$923	$1,224	$1,600
Projected kWh Savings	328	820	1,372	1,953	2,589	3,384
Projected kW Savings	0.0	0.1	0.2	0.3	0.4	0.5
ENERGY STAR Air Purifier						
Participation	3	6	11	15	20	26
Incentive Budget	$63	$159	$265	$378	$502	$657
Projected kWh Savings	567	1,419	2,369	3,378	4,486	5,872
Projected kW Savings	0.1	0.2	0.3	0.4	0.5	0.7
ENERGY STAR Clothes Dryer (Electric)						
Participation	35	88	147	209	278	363
Incentive Budget	$1,757	$4,398	$7,356	$10,472	$13,887	$18,146
Projected kWh Savings	4,216	10,555	17,652	25,126	33,311	43,520
Projected kW Savings	0.6	1.4	2.4	3.4	4.5	5.8
ENERGY STAR Clothes Washer						
Participation	17	23	31	40	50	62
Incentive Budget	$874	$1,174	$1,550	$1,998	$2,516	$3,094
Projected kWh Savings	1,029	1,382	1,825	2,352	2,963	3,643
Projected kW Savings	0.1	0.2	0.3	0.3	0.4	0.5
ENERGY STAR Dehumidifier						
Participation	30	38	47	57	66	75
Incentive Budget	$300	$381	$471	$565	$660	$750
Projected kWh Savings	3,534	4,486	5,549	6,659	7,769	8,830
Projected kW Savings	0.8	1.0	1.3	1.5	1.8	2.0
ENERGY STAR Dishwasher						
Participation	206	254	305	355	403	446
Incentive Budget	$1,548	$1,906	$2,284	$2,662	$3,020	$3,343
Projected kWh Savings	10,234	12,600	15,101	17,597	19,964	22,101
Projected kW Savings	0.8	0.9	1.1	1.3	1.5	1.6

Measure	2028	2029	2030	2031	2032	2033
ENERGY STAR Freezer - Chest						
Participation	11	28	46	66	87	114
Incentive Budget	$14	$34	$58	$82	$109	$143
Projected kWh Savings	222	555	927	1,321	1,754	2,295
Projected kW Savings	0.0	0.1	0.1	0.2	0.3	0.4
ENERGY STAR Freezer - Compact Upright						
Participation	13	33	55	78	104	136
Incentive Budget	$16	$41	$68	$98	$130	$170
Projected kWh Savings	265	663	1,106	1,578	2,098	2,747
Projected kW Savings	0.0	0.1	0.2	0.3	0.3	0.4
ENERGY STAR Most Efficient Dehumidifier						
Participation	54	69	85	102	120	136
Incentive Budget	$545	$691	$854	$1,025	$1,195	$1,358
Projected kWh Savings	9,400	11,921	14,734	17,676	20,618	23,428
Projected kW Savings	2.1	2.7	3.3	4.0	4.7	5.3
ENERGY STAR Windows - Electric furnace						
Participation	18	18	18	18	18	18
Incentive Budget	$9,205	$9,205	$9,205	$9,205	$9,205	$9,205
Projected kWh Savings	40,014	39,773	39,508	39,226	38,932	38,620
Projected kW Savings	6.8	6.8	6.7	6.7	6.6	6.6
ENERGY STAR Windows - Gas Heating						
Participation	12	12	12	12	12	12
Incentive Budget	$6,246	$6,246	$6,246	$6,246	$6,246	$6,246
Projected kWh Savings	2,544	2,529	2,512	2,494	2,475	2,455
Projected kW Savings	0.9	0.9	0.9	0.9	0.9	0.9
ENERGY STAR Windows - Heat pump						
Participation	7	7	7	7	7	7
Incentive Budget	$3,287	$3,287	$3,287	$3,287	$3,287	$3,287
Projected kWh Savings	8,323	8,273	8,218	8,159	8,098	8,033
Projected kW Savings	1.4	1.4	1.4	1.4	1.4	1.4
Heat Pump Swimming Pool Heater (COP >=6.0)						
Participation	0	1	1	1	2	2
Incentive Budget	$191	$478	$798	$1,138	$1,511	$1,976
Projected kWh Savings	285	714	1,193	1,701	2,258	2,954
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Heat Pump Swimming Pool Heater (COP 5.5-5.9)						
Participation	0	0	1	1	1	2
Incentive Budget	$56	$140	$233	$332	$441	$577
Projected kWh Savings	120	300	502	715	950	1,243
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Heat Pump Water Heater-electric resistance heat						

Measure	2028	2029	2030	2031	2032	2033
Participation	5	14	23	32	43	56
Incentive Budget	$2,708	$6,769	$11,282	$16,117	$21,441	$28,104
Projected kWh Savings	7,355	18,139	29,758	41,762	54,486	69,933
Projected kW Savings	0.3	0.9	1.4	2.0	2.6	3.3
Heat Pump Water Heater-gas heat						
Participation	1	3	4	6	8	11
Incentive Budget	$516	$1,289	$2,149	$3,070	$4,084	$5,353
Projected kWh Savings	1,413	3,485	5,718	8,024	10,469	13,437
Projected kW Savings	0.1	0.2	0.3	0.4	0.5	0.6
Heat Pump Water Heater-heat pump heat						
Participation	4	10	16	23	31	40
Incentive Budget	$1,934	$4,835	$8,058	$11,512	$15,315	$20,075
Projected kWh Savings	5,275	13,009	21,341	29,949	39,074	50,152
Projected kW Savings	0.2	0.6	1.0	1.4	1.9	2.4
Smart Thermostat - Furnace baseline						
Participation	38	58	64	68	75	94
Incentive Budget	$1,150	$1,725	$1,917	$2,054	$2,262	$2,831
Projected kWh Savings	27,939	41,909	46,566	49,892	54,937	68,759
Projected kW Savings	5.1	7.7	8.6	9.2	10.1	12.6
Smart Thermostat - Gas/CAC baseline						
Participation	187	280	311	334	367	460
Incentive Budget	$3,587	$5,380	$5,978	$6,405	$7,052	$8,827
Projected kWh Savings	24,737	37,106	41,229	44,173	48,640	60,878
Projected kW Savings	25.9	38.8	43.1	46.2	50.9	63.7
Smart Thermostat - Heat pump baseline						
Participation	42	64	71	76	83	104
Incentive Budget	$1,273	$1,910	$2,122	$2,274	$2,504	$3,133
Projected kWh Savings	17,287	25,931	28,812	30,870	33,992	42,544
Projected kW Savings	5.8	8.7	9.7	10.4	11.5	14.3
Total						
Participation	921	1,261	1,537	1,886	2,206	2,648
Incentive Budget	$138,559	$154,224	$169,531	$187,956	$206,129	$230,141
Projected kWh Savings	235,269	306,994	359,685	417,748	476,458	565,628
Projected kW Savings	68.9	91.3	101.9	115.1	127.4	152.3

TABLE 6-3: RESIDENTIAL PRESCRIPTIVE PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$138,559	$154,224	$169,531	$187,956	$206,129	$230,141
Delivery & Implementation	$32,403	$43,170	$52,098	$62,653	$73,703	$90,010
Admin	$13,388	$17,837	$21,526	$25,887	$30,453	$37,190
Total Budget	**$184,351**	**$215,231**	**$243,155**	**$276,497**	**$310,285**	**$357,340**
Participation	921	1,261	1,537	1,886	2,206	2,648
Energy Savings (kWh)	235,269	306,994	359,685	417,748	476,458	565,628
Demand Savings (kW)	68.9	91.3	101.9	115.1	127.4	152.3
Weighted Program EUL	18.5	17.2	16.7	16.0	15.6	15.2
NTG	0.73	0.73	0.74	0.73	0.74	0.74

6.2 HOME ENERGY ASSESSMENT PROGRAM

Program Description: The Home Energy Assessment program is designed to produce long term energy and demand savings in the residential market through in-home and virtual energy assessments for market rate customers. The program will provide direct installation of energy-saving measures and educate consumers on ways to reduce energy consumption through additional weatherization measures such as air sealing, duct sealing, and insulation.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-4: HOME ENERGY ASSESSMENT PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Sealing - Inadequate Sealing - Gas Heating	$90.67	352.2	0.13
Air Sealing Inadequate Sealing - Electric furnace	$200.00	1,457.9	0.26
Air Sealing Inadequate Sealing - Heat pump	$200.00	957.9	0.17
Audit Recommendations	$75.00	82.0	0.01
Bathroom Aerator 1.0 gpm	$1.00	48.6	0.07
Door and Window Weather Stripping	$0.00	0.0	0.00
Duct Sealing - Inadequate Sealing - Electric furnace	$450.00	1,633.5	0.29
Duct Sealing - Inadequate Sealing - Gas Heating	$214.29	333.8	0.12
Duct Sealing - Inadequate Sealing - Heat pump	$450.00	1,080.8	0.19
Kitchen Faucet Aerator 1.5 gpm	$1.00	195.4	0.05
LED Nightlights	$1.00	13.6	0.00
Low Flow Showerhead 1.5 gpm	$5.00	254.4	0.03
Outlet Gaskets	$0.00	0.0	0.00
Pipe Wrap	$0.00	0.0	0.00
Smart Power Strips - Tier 2	$10.00	136.1	0.02
Smart Thermostat - Furnace baseline	$111.93	923.8	0.17
Smart Thermostat - Heat pump baseline	$125.00	527.1	0.18
Thermostatic Restrictor Shower Valve	$5.00	77.9	0.00
Water Heater Temperature Setback	$1.25	120.7	0.01

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory.

Marketing: The marketing plan includes program specific marketing materials that will target contractors and trade allies in the Heating, Ventilation and Air Conditioning (HVAC) industry. The HVAC industry will be marketed by using targeted direct marketing, direct contact by the program vendor personnel, trade shows and trade association outreach. The program will be promoted through trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets. CenterPoint Indiana will also use web banners, bill inserts, and mass market advertising. Program marketing directs customers and contractors to the CenterPoint Indiana website or call center for information.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor. Vendors will work with local contractors to deliver the program

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-5: HOME ENERGY ASSESSMENT PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Air Sealing - Inadequate Sealing - Gas Heating						
Participation	81	81	81	81	81	81
Incentive Budget	$7,313	$7,313	$7,313	$7,313	$7,313	$7,313
Projected kWh Savings	28,890	28,716	28,525	28,322	28,109	27,884
Projected kW Savings	10.5	10.5	10.4	10.3	10.3	10.2
Air Sealing Inadequate Sealing - Electric furnace						
Participation	30	30	30	30	30	30
Incentive Budget	$5,943	$5,943	$5,943	$5,943	$5,943	$5,943
Projected kWh Savings	44,059	43,793	43,502	43,191	42,867	42,524
Projected kW Savings	7.9	7.9	7.8	7.8	7.7	7.6
Air Sealing Inadequate Sealing - Heat pump						
Participation	21	21	21	21	21	21
Incentive Budget	$4,245	$4,245	$4,245	$4,245	$4,245	$4,245
Projected kWh Savings	20,677	20,552	20,416	20,270	20,118	19,957
Projected kW Savings	3.7	3.7	3.7	3.6	3.6	3.6
Audit Recommendations						
Participation	19	47	78	111	148	194
Incentive Budget	$1,400	$3,499	$5,832	$8,332	$11,084	$14,529
Projected kWh Savings	1,530	3,826	6,377	9,110	12,119	15,885
Projected kW Savings	0.2	0.4	0.7	1.0	1.4	1.8
Bathroom Aerator 1.0 gpm						
Participation	422	399	360	309	255	204
Incentive Budget	$422	$399	$360	$309	$255	$204
Projected kWh Savings	20,470	19,393	17,456	15,002	12,389	9,898
Projected kW Savings	28.1	26.7	24.0	20.6	17.0	13.6

Measure	2028	2029	2030	2031	2032	2033
Door and Window Weather Stripping[13]						
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Duct Sealing - Inadequate Sealing - Electric furnace						
Participation	30	30	30	30	30	30
Incentive Budget	$13,372	$13,372	$13,372	$13,372	$13,372	$13,372
Projected kWh Savings	49,365	49,067	48,741	48,393	48,030	47,645
Projected kW Savings	8.9	8.8	8.8	8.7	8.6	8.6
Duct Sealing - Inadequate Sealing - Gas Heating						
Participation	81	81	81	81	81	81
Incentive Budget	$17,284	$17,284	$17,284	$17,284	$17,284	$17,284
Projected kWh Savings	27,381	27,216	27,035	26,842	26,641	26,428
Projected kW Savings	10.0	9.9	9.9	9.8	9.7	9.6
Duct Sealing - Inadequate Sealing - Heat pump						
Participation	21	21	21	21	21	21
Incentive Budget	$9,551	$9,551	$9,551	$9,551	$9,551	$9,551
Projected kWh Savings	23,329	23,188	23,034	22,870	22,698	22,517
Projected kW Savings	4.2	4.2	4.1	4.1	4.1	4.0
Kitchen Faucet Aerator 1.5 gpm						
Participation	18	20	20	18	17	14
Incentive Budget	$18	$20	$20	$18	$17	$14
Projected kWh Savings	3,613	3,814	3,814	3,613	3,252	2,795
Projected kW Savings	0.9	0.9	0.9	0.9	0.8	0.7
LED Nightlights						
Participation	709	784	849	903	945	978
Incentive Budget	$709	$784	$849	$903	$945	$978
Projected kWh Savings	9,645	10,668	11,548	12,275	12,855	13,307
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Low Flow Showerhead 1.5 gpm						
Participation	198	180	156	130	105	82
Incentive Budget	$991	$902	$782	$652	$524	$411
Projected kWh Savings	50,681	45,971	39,796	33,079	26,577	20,774
Projected kW Savings	5.1	4.6	4.0	3.3	2.7	2.1
Outlet Gaskets						
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Wrap						

[13] For measures showing zero participation, these measures can still be offered by CenterPoint as they are currently part of the program. In these cases, the Action Plan forecasts that any participation for these measures will be attributable to other programs which offer the same measure.

Measure	2028	2029	2030	2031	2032	2033
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Smart Power Strips - Tier 2						
Participation	403	488	567	630	665	665
Incentive Budget	$4,026	$4,876	$5,673	$6,303	$6,653	$6,653
Projected kWh Savings	54,798	66,356	77,210	85,781	90,542	90,542
Projected kW Savings	10.0	12.1	14.1	15.7	16.5	16.5
Smart Thermostat - Furnace baseline						
Participation	42	46	49	49	46	42
Incentive Budget	$4,674	$5,193	$5,481	$5,481	$5,193	$4,674
Projected kWh Savings	38,579	42,861	45,240	45,240	42,861	38,579
Projected kW Savings	7.1	7.9	8.3	8.3	7.9	7.1
Smart Thermostat - Heat pump baseline						
Participation	12	13	14	14	13	12
Incentive Budget	$1,470	$1,633	$1,723	$1,723	$1,633	$1,470
Projected kWh Savings	6,197	6,885	7,267	7,267	6,885	6,197
Projected kW Savings	2.1	2.3	2.4	2.4	2.3	2.1
Thermostatic Restrictor Shower Valve						
Participation	268	332	398	457	502	524
Incentive Budget	$1,340	$1,661	$1,990	$2,287	$2,510	$2,621
Projected kWh Savings	20,766	25,787	30,947	35,645	39,207	41,018
Projected kW Savings	1.0	1.2	1.5	1.7	1.9	1.9
Water Heater Temperature Setback						
Participation	20	19	38	34	50	44
Incentive Budget	$25	$24	$47	$43	$62	$55
Projected kWh Savings	2,449	2,320	4,537	4,115	6,020	5,299
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Total						
Participation	2,374	2,592	2,791	2,919	3,010	3,022
Incentive Budget	$72,784	$76,699	$80,465	$83,759	$86,585	$89,316
Projected kWh Savings	402,429	420,414	435,446	441,014	441,169	431,249
Projected kW Savings	99.7	101.1	100.6	98.3	94.5	89.5

TABLE 6-6: HOME ENERGY ASSESSMENT PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$72,784	$76,699	$80,465	$83,759	$86,585	$89,316
Delivery & Implementation	$101,135	$108,373	$115,144	$119,654	$122,839	$123,302
Admin	$46,935	$50,294	$53,436	$55,529	$57,007	$57,222
Total Budget	**$220,855**	**$235,366**	**$249,046**	**$258,941**	**$266,432**	**$269,841**
Participation	2,374	2,592	2,791	2,919	3,010	3,022
Energy Savings (kWh)	402,429	420,414	435,446	441,014	441,169	431,249

	2028	2029	2030	2031	2032	2033
Demand Savings (kW)	99.7	101.1	100.6	98.3	94.5	89.5
Weighted Program EUL	14.4	14.0	13.7	13.5	13.4	13.3
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.3 RESIDENTIAL MIDSTREAM PROGRAM

Program Description: The Residential Midstream Program is very similar to the Residential Prescriptive Program, though it targets a smaller group of participating partners rather than focusing on end-use customers. By working with participating partners (Distributors and Contractors), the burden of the administrative paperwork is taken off end-use customers and absorbed through the partner. To help compensate participating partners for the administrative work, they receive a spiff for each piece of equipment submitted through the program.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-7: RESIDENTIAL MIDSTREAM PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	$200.00	7,171.3	0.11
Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	$200.00	599.7	0.11
Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	$275.00	7,626.0	0.22
Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	$275.00	1,058.7	0.23
Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	$300.00	8,138.4	0.31
Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	$300.00	1,575.7	0.32
Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	$400.00	8,443.0	0.40
Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	$400.00	1,883.3	0.40
Central Air Conditioner 15.2 SEER	$100.00	108.7	0.11
Central Air Conditioner 16.2 SEER	$200.00	213.0	0.23
Central Air Conditioner 17.2 SEER	$320.66	301.0	0.32
Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	$500.00	6,990.6	0.32
Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline	$500.00	6,954.5	0.31
Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	$500.00	1,613.4	0.31
Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	$500.00	7,327.2	0.41
Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline	$500.00	7,291.2	0.40
Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	$500.00	1,933.9	0.39
Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	$250.00	5,963.8	0.11
Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline	$250.00	5,934.8	0.11
Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	$250.00	615.9	0.11
Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	$350.00	6,441.2	0.23
Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline	$350.00	6,407.9	0.23
Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	$350.00	1,083.5	0.22
Heat Pump Water Heater-electric resistance heat	$500.00	1,732.3	0.08
Heat Pump Water Heater-gas heat	$500.00	1,747.4	0.08
Heat Pump Water Heater-heat pump heat	$500.00	1,739.2	0.08
Smart Thermostat - Furnace baseline	$30.00	948.2	0.17
Smart Thermostat - Gas/CAC baseline	$111.52	154.1	0.14
Smart Thermostat - Heat pump baseline	$30.00	495.2	0.17

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory.

Marketing: The Midstream marketing plan will target distributors and large contractors through direct outreach to contractor trade networks. Co-branded materials will be available to participating distributors to draw attention to, and provide education on, the HVAC measures within the program. Fact Sheets will also be created to keep the program top of mind.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor. Vendors will work with local contractors to deliver the program

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-8: RESIDENTIAL MIDSTREAM PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline						
Participation	34	39	43	47	50	52
Incentive Budget	$6,882	$7,802	$8,630	$9,342	$9,930	$10,399
Projected kWh Savings	126,478	143,127	158,023	170,737	181,156	189,384
Projected kW Savings	2.0	2.3	2.5	2.7	2.9	3.0
Air Source Heat Pump 15.2 SEER2 - Heat pump baseline						
Participation	20	22	24	26	28	29
Incentive Budget	$3,901	$4,422	$4,892	$5,295	$5,628	$5,895
Projected kWh Savings	5,995	6,784	7,490	8,093	8,587	8,977
Projected kW Savings	1.1	1.3	1.4	1.5	1.6	1.7
Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline						
Participation	28	32	35	38	41	42
Incentive Budget	$7,731	$8,765	$9,696	$10,495	$11,156	$11,683
Projected kWh Savings	109,897	124,363	137,306	148,353	157,406	164,556
Projected kW Savings	3.2	3.7	4.0	4.4	4.6	4.8
Air Source Heat Pump 16.2 SEER2 - Heat pump baseline						
Participation	16	18	20	22	23	24
Incentive Budget	$4,382	$4,968	$5,496	$5,949	$6,323	$6,622
Projected kWh Savings	8,648	9,787	10,805	11,674	12,387	12,949
Projected kW Savings	1.8	2.1	2.3	2.5	2.6	2.8
Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline						
Participation	26	30	33	36	38	40
Incentive Budget	$7,890	$8,945	$9,894	$10,710	$11,384	$11,922
Projected kWh Savings	109,705	124,147	137,067	148,095	157,132	164,269
Projected kW Savings	4.2	4.8	5.3	5.7	6.0	6.3
Air Source Heat Pump 17.1 SEER2 - Heat pump baseline						
Participation	15	17	19	20	22	23
Incentive Budget	$4,472	$5,070	$5,608	$6,071	$6,453	$6,758

Measure	2028	2029	2030	2031	2032	2033
Projected kWh Savings	12,040	13,625	15,043	16,253	17,245	18,028
Projected kW Savings	2.4	2.7	3.0	3.3	3.5	3.6
Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline						
Participation	26	30	33	36	38	40
Incentive Budget	$10,502	$11,906	$13,170	$14,257	$15,154	$15,870
Projected kWh Savings	113,624	128,581	141,963	153,385	162,745	170,137
Projected kW Savings	5.4	6.1	6.8	7.3	7.7	8.1
Air Source Heat Pump 18.1 SEER2 - Heat pump baseline						
Participation	15	17	19	20	21	22
Incentive Budget	$5,953	$6,749	$7,465	$8,081	$8,589	$8,996
Projected kWh Savings	14,366	16,257	17,949	19,393	20,577	21,512
Projected kW Savings	3.1	3.5	3.9	4.2	4.4	4.6
Central Air Conditioner 15.2 SEER						
Participation	298	330	357	380	398	412
Incentive Budget	$29,849	$33,017	$35,740	$37,989	$39,786	$41,184
Projected kWh Savings	17,282	19,082	20,616	21,873	22,866	23,627
Projected kW Savings	18.2	20.1	21.7	23.1	24.1	24.9
Central Air Conditioner 16.2 SEER						
Participation	292	342	390	434	472	504
Incentive Budget	$58,338	$68,344	$77,957	$86,730	$94,368	$100,749
Projected kWh Savings	33,122	38,723	44,077	48,937	53,142	56,625
Projected kW Savings	35.0	41.0	46.6	51.8	56.2	59.9
Central Air Conditioner 17.2 SEER						
Participation	176	210	244	276	305	329
Incentive Budget	$56,442	$67,353	$78,215	$88,462	$97,653	$105,529
Projected kWh Savings	28,152	33,569	38,948	44,008	48,532	52,386
Projected kW Savings	29.9	35.7	41.4	46.8	51.6	55.7
Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline						
Participation	3	4	4	4	5	5
Incentive Budget	$1,547	$1,758	$1,949	$2,114	$2,251	$2,363
Projected kWh Savings	8,260	9,368	10,369	11,223	11,933	12,503
Projected kW Savings	0.4	0.4	0.5	0.5	0.5	0.6
Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline						
Participation	9	10	11	12	13	14
Incentive Budget	$4,473	$5,087	$5,648	$6,129	$6,535	$6,867
Projected kWh Savings	23,760	26,972	29,890	32,379	34,459	36,143
Projected kW Savings	1.1	1.2	1.4	1.5	1.6	1.6
Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline						
Participation	5	5	6	7	7	7
Incentive Budget	$2,414	$2,743	$3,043	$3,301	$3,517	$3,692
Projected kWh Savings	2,975	3,375	3,736	4,045	4,302	4,509
Projected kW Savings	0.6	0.6	0.7	0.8	0.8	0.9
Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline						
Participation	3	3	4	4	4	4
Incentive Budget	$1,447	$1,644	$1,823	$1,977	$2,106	$2,211
Projected kWh Savings	8,098	9,184	10,166	11,004	11,701	12,260

Measure	2028	2029	2030	2031	2032	2033
Projected kW Savings	0.4	0.5	0.6	0.6	0.6	0.7
Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline						
Participation	8	10	11	11	12	13
Incentive Budget	$4,177	$4,750	$5,275	$5,725	$6,104	$6,414
Projected kWh Savings	23,262	26,408	29,267	31,706	33,745	35,396
Projected kW Savings	1.3	1.5	1.6	1.8	1.9	2.0
Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline						
Participation	4	5	6	6	7	7
Incentive Budget	$2,234	$2,539	$2,816	$3,055	$3,255	$3,418
Projected kWh Savings	3,300	3,743	4,145	4,488	4,773	5,003
Projected kW Savings	0.7	0.8	0.8	0.9	1.0	1.0
Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline						
Participation	4	4	5	5	6	6
Incentive Budget	$961	$1,092	$1,211	$1,313	$1,398	$1,467
Projected kWh Savings	8,756	9,929	10,988	11,892	12,643	13,245
Projected kW Savings	0.2	0.2	0.2	0.2	0.2	0.3
Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline						
Participation	11	13	14	15	16	17
Incentive Budget	$2,774	$3,154	$3,501	$3,799	$4,050	$4,255
Projected kWh Savings	25,148	28,543	31,624	34,253	36,447	38,222
Projected kW Savings	0.5	0.5	0.6	0.7	0.7	0.7
Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline						
Participation	6	7	7	8	9	9
Incentive Budget	$1,484	$1,687	$1,871	$2,029	$2,161	$2,269
Projected kWh Savings	1,397	1,584	1,754	1,899	2,019	2,116
Projected kW Savings	0.3	0.3	0.3	0.3	0.4	0.4
Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline						
Participation	3	4	4	4	5	5
Incentive Budget	$1,096	$1,245	$1,381	$1,497	$1,595	$1,674
Projected kWh Savings	7,701	8,734	9,667	10,464	11,126	11,657
Projected kW Savings	0.3	0.3	0.3	0.4	0.4	0.4
Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline						
Participation	9	10	11	12	13	14
Incentive Budget	$3,169	$3,603	$4,001	$4,342	$4,629	$4,864
Projected kWh Savings	22,156	25,151	27,872	30,193	32,132	33,702
Projected kW Savings	0.8	0.9	1.0	1.1	1.1	1.2
Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline						
Participation	5	6	6	7	7	7
Incentive Budget	$1,712	$1,945	$2,158	$2,341	$2,494	$2,618
Projected kWh Savings	2,024	2,296	2,542	2,752	2,927	3,067
Projected kW Savings	0.4	0.5	0.5	0.6	0.6	0.6
Heat Pump Water Heater-electric resistance heat						
Participation	200	246	294	343	389	430
Incentive Budget	$100,118	$123,040	$147,233	$171,426	$194,347	$214,978
Projected kWh Savings	272,893	330,837	389,681	445,707	495,559	536,760

Measure	2028	2029	2030	2031	2032	2033
Projected kW Savings	12.9	15.7	18.5	21.1	23.5	25.4
Heat Pump Water Heater-gas heat						
Participation	38	47	56	65	74	82
Incentive Budget	$19,070	$23,436	$28,044	$32,653	$37,018	$40,948
Projected kWh Savings	52,434	63,568	74,874	85,639	95,217	103,134
Projected kW Savings	2.5	3.0	3.5	4.1	4.5	4.9
Heat Pump Water Heater-heat pump heat						
Participation	143	176	210	245	278	307
Incentive Budget	$71,513	$87,885	$105,166	$122,447	$138,819	$153,556
Projected kWh Savings	195,704	237,258	279,458	319,636	355,388	384,935
Projected kW Savings	9.3	11.2	13.2	15.1	16.8	18.2
Smart Thermostat - Furnace baseline						
Participation	316	316	300	270	232	191
Incentive Budget	$9,485	$9,485	$8,986	$8,088	$6,951	$5,741
Projected kWh Savings	284,790	284,790	269,816	242,858	208,716	172,363
Projected kW Savings	52.3	52.3	49.6	44.6	38.4	31.7
Smart Thermostat - Gas/CAC baseline						
Participation	297	297	281	253	217	179
Incentive Budget	$33,073	$33,073	$31,334	$28,204	$24,239	$20,017
Projected kWh Savings	43,430	43,430	41,146	37,035	31,829	26,285
Projected kW Savings	40.0	40.0	37.9	34.1	29.3	24.2
Smart Thermostat - Heat pump baseline						
Participation	117	117	111	100	86	71
Incentive Budget	$3,517	$3,517	$3,333	$3,000	$2,578	$2,129
Projected kWh Savings	55,155	55,155	52,255	47,034	40,422	33,381
Projected kW Savings	18.7	18.7	17.7	16.0	13.7	11.3
Total						
Participation	2,128	2,365	2,559	2,706	2,813	2,886
Incentive Budget	$460,605	$539,024	$615,534	$686,820	$750,471	$805,088
Projected kWh Savings	1,620,551	1,828,370	2,008,538	2,155,011	2,267,113	2,347,133
Projected kW Savings	249.1	271.9	288.0	297.4	301.4	301.5

TABLE 6-9: RESIDENTIAL MIDSTREAM PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$460,605	$539,024	$615,534	$686,820	$750,471	$805,088
Delivery & Implementation	$513,594	$599,468	$682,673	$760,512	$831,673	$895,719
Admin	$55,671	$64,980	$73,999	$82,436	$90,149	$97,092
Total Budget	**$1,029,870**	**$1,203,472**	**$1,372,206**	**$1,529,768**	**$1,672,294**	**$1,797,899**
Participation	2,128	2,365	2,559	2,706	2,813	2,886
Energy Savings (kWh)	1,620,551	1,828,370	2,008,538	2,155,011	2,267,113	2,347,133
Demand Savings (kW)	249.1	271.9	288.0	297.4	301.4	301.5
Weighted Program EUL	15.1	15.1	15.2	15.3	15.4	15.5
NTG	0.63	0.62	0.62	0.61	0.61	0.61

6.4 IN STORE DISCOUNT PROGRAM

Program Description: The Residential In-Store Discount Program is a market-based residential energy efficiency program designed to reach residential customers through retail outlets. The program consists of a buy-down strategy that provides incentives to consumers to facilitate the purchase of energy efficient products. The overall program goal is to increase the penetration of energy efficient products by influencing customers' purchase decisions at the point of purchase.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-10: IN STORE DISCOUNT PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Filter	$1.00	78.4	0.00
Bathroom Aerator 1.0 gpm	$1.00	39.8	0.04
Can Foam	$0.00	0.0	0.00
Caulk	$1.25	15.6	0.00
Door and Window Weather Stripping	$0.00	0.0	0.00
ENERGY STAR Air Purifier	$25.00	298.0	0.03
ENERGY STAR Bath Vent Fan	$25.00	38.1	0.05
ENERGY STAR Dehumidifier	$10.00	157.0	0.04
ENERGY STAR Most Efficient Dehumidifier	$10.00	230.0	0.05
ENERGY STAR Room Air Conditioner	$25.00	75.3	0.08
Kitchen Faucet Aerator 1.5 gpm	$1.00	232.2	0.05
Low Flow Showerhead 1.5 gpm	$5.00	192.6	0.02
Pipe Wrap	$0.00	0.0	0.00
Smart Power Strips - Tier 1	$6.00	56.6	0.01
Smart Thermostat - Gas/CAC baseline	$70.76	169.2	0.18

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory.

Marketing: The marketing plan includes program specific marketing materials that will target contractors and trade allies in the Heating, Ventilation and Air Conditioning (HVAC) industry. The HVAC industry will be marketed by using targeted direct marketing, direct contact by the program vendor personnel, trade shows and trade association outreach. The program will be promoted through trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets. CenterPoint Indiana will also use web banners, bill inserts, and mass market advertising. Program marketing directs customers and contractors to the CenterPoint Indiana website or call center for information.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor. Vendors will work with local contractors to deliver the program

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-11: IN STORE DISCOUNT PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Air Filter						
Participation	75	139	192	234	267	293
Incentive Budget	$75	$139	$192	$234	$267	$293
Projected kWh Savings	5,896	10,943	15,092	18,389	20,938	22,866
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Bathroom Aerator 1.0 gpm						
Participation	66	73	78	78	73	66
Incentive Budget	$66	$73	$78	$78	$73	$66
Projected kWh Savings	2,630	2,922	3,084	3,084	2,922	2,630
Projected kW Savings	2.4	2.7	2.8	2.8	2.7	2.4
Can Foam						
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Caulk						
Participation	256	256	256	256	256	256
Incentive Budget	$320	$320	$320	$320	$320	$320
Projected kWh Savings	4,049	4,024	3,997	3,969	3,939	3,908
Projected kW Savings	0.7	0.7	0.7	0.7	0.7	0.6
Door and Window Weather Stripping						
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
ENERGY STAR Air Purifier						
Participation	118	146	175	204	231	256
Incentive Budget	$2,960	$3,645	$4,371	$5,094	$5,780	$6,399
Projected kWh Savings	35,283	43,453	52,097	60,718	68,892	76,280
Projected kW Savings	4.0	5.0	6.0	6.9	7.9	8.7
ENERGY STAR Bath Vent Fan						
Participation	214	260	303	337	356	357
Incentive Budget	$5,360	$6,502	$7,579	$8,429	$8,908	$8,924
Projected kWh Savings	8,380	10,075	11,633	12,811	13,400	13,280
Projected kW Savings	10.0	12.0	13.9	15.3	16.0	15.8
ENERGY STAR Dehumidifier						
Participation	97	101	104	106	108	109
Incentive Budget	$973	$1,011	$1,041	$1,064	$1,082	$1,086
Projected kWh Savings	15,277	15,868	16,344	16,707	16,991	17,058
Projected kW Savings	3.5	3.6	3.7	3.8	3.9	3.9
ENERGY STAR Most Efficient Dehumidifier						
Participation	177	184	189	193	196	197
Incentive Budget	$1,768	$1,835	$1,890	$1,931	$1,963	$1,970
Projected kWh Savings	40,661	42,216	43,463	44,411	45,149	45,305

Measure	2028	2029	2030	2031	2032	2033
Projected kW Savings	9.2	9.6	9.9	10.1	10.3	10.3
ENERGY STAR Room Air Conditioner						
Participation	178	208	237	262	284	303
Incentive Budget	$4,460	$5,205	$5,916	$6,555	$7,106	$7,566
Projected kWh Savings	13,438	15,685	17,827	19,751	21,411	22,798
Projected kW Savings	14.4	16.8	19.1	21.1	22.9	24.4
Kitchen Faucet Aerator 1.5 gpm						
Participation	157	160	154	141	123	104
Incentive Budget	$157	$160	$154	$141	$123	$104
Projected kWh Savings	36,766	37,220	35,755	32,662	28,493	23,868
Projected kW Savings	7.4	7.5	7.2	6.6	5.8	4.9
Low Flow Showerhead 1.5 gpm						
Participation	36	36	34	30	26	22
Incentive Budget	$178	$178	$169	$152	$131	$108
Projected kWh Savings	6,869	6,869	6,508	5,858	5,034	4,157
Projected kW Savings	0.8	0.8	0.8	0.7	0.6	0.5
Pipe Wrap						
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Smart Power Strips - Tier 1						
Participation	2,607	3,263	3,951	4,598	5,108	5,391
Incentive Budget	$15,643	$19,578	$23,707	$27,586	$30,648	$32,349
Projected kWh Savings	147,563	184,688	223,640	260,224	289,109	305,154
Projected kW Savings	16.6	20.7	25.1	29.2	32.4	34.2
Smart Thermostat - Gas/CAC baseline						
Participation	289	337	374	395	395	374
Incentive Budget	$20,483	$23,833	$26,479	$27,949	$27,949	$26,479
Projected kWh Savings	48,987	57,001	63,328	66,842	66,842	63,328
Projected kW Savings	51.0	59.4	66.0	69.7	69.7	66.0
Total						
Participation	4,272	5,162	6,046	6,835	7,426	7,727
Incentive Budget	$52,443	$62,482	$71,895	$79,532	$84,350	$85,663
Projected kWh Savings	365,798	430,965	492,770	545,426	583,120	600,631
Projected kW Savings	120.0	138.8	155.1	166.9	172.7	171.8

TABLE 6-12: IN STORE DISCOUNT PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$52,443	$62,482	$71,895	$79,532	$84,350	$85,663
Delivery & Implementation	$36,500	$44,006	$51,492	$58,326	$63,813	$67,264
Admin	$12,731	$15,349	$17,961	$20,344	$22,258	$23,462
Total Budget	**$101,674**	**$121,837**	**$141,348**	**$158,203**	**$170,421**	**$176,390**
Participation	4,272	5,162	6,046	6,835	7,426	7,727
Energy Savings (kWh)	365,798	430,965	492,770	545,426	583,120	600,631

	2028	2029	2030	2031	2032	2033
Demand Savings (kW)	120.0	138.8	155.1	166.9	172.7	171.8
Weighted Program EUL	10.0	9.7	9.5	9.3	9.2	9.1
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.5 MULTI-FAMILY ENERGY SOLUTIONS PROGRAM

Program Description: The Multi-family Energy Solutions program is designed to produce long term energy savings within multifamily properties. The program provides customers with information on energy best practices and promotes energy efficiency through the installation of energy efficient technologies including high efficiency showerheads, aerators, door and window weatherstripping, door sweeps and Smart Thermostats. In addition, the program will begin offering weatherization services such as air and duct sealing. Additional measures may be available to properties that also have electric service from CenterPoint. The program is open for, and promoted to, owners and managers of multi-family properties. The program will educate consumers on ways to reduce energy consumption and cross-promote other programs to increase overall awareness.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-13: MULTI-FAMILY ENERGY SOLUTIONS PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Filter	$6.00	78.5	0.00
Air Sealing - Inadequate Sealing - Gas Heating	$72.53	167.9	0.06
Air Sealing Inadequate Sealing - Electric furnace	$200.00	697.9	0.06
Air Sealing Inadequate Sealing - Heat pump	$200.00	456.9	0.04
Audit Recommendations	$75.00	82.0	0.01
Bathroom Aerator 1.0 gpm	$1.00	39.8	0.04
Door and Window Weather Stripping	$8.20	102.7	0.01
Door Sweep	$2.68	91.9	0.02
Duct Sealing - Inadequate Sealing - Electric furnace	$450.00	1,068.5	0.09
Duct Sealing - Inadequate Sealing - Gas Heating	$214.29	204.2	0.08
Duct Sealing - Inadequate Sealing - Heat pump	$450.00	707.5	0.06
Kitchen Faucet Aerator 1.5 gpm	$1.00	195.4	0.05
LED Nightlights	$1.00	13.6	0.00
Low Flow Showerhead 1.5 gpm	$5.00	192.6	0.02
Multifamily Whole Building Aerosol Sealing - Electric furnace	$450.00	1,261.1	0.11
Multifamily Whole Building Aerosol Sealing - Gas Heating / CAC	$214.29	0.0	0.00
Multifamily Whole Building Aerosol Sealing - Heat pump	$450.00	724.8	0.06
Pipe Wrap	$3.00	246.7	0.03
Programmable Thermostat - Furnace baseline	$5.00	471.1	0.00
Programmable Thermostat - Gas/CAC baseline	$5.00	0.0	0.00
Programmable Thermostat - Heat pump baseline	$5.00	214.2	0.00
Smart Thermostat - Furnace baseline	$125.00	762.1	0.14
Smart Thermostat - Gas/CAC baseline	$74.94	154.1	0.14
Smart Thermostat - Heat pump baseline	$125.00	409.9	0.14
Water Heater Temperature Setback	$1.25	120.7	0.01

Eligible Customers: The program is available to multifamily properties located in the CenterPoint Indiana electric service territory.

Marketing: The Multifamily Energy Solutions Program will be marketed to multifamily property ownership and property management organizations, as well as through direct outreach to property managers.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-14: MULTI-FAMILY ENERGY SOLUTIONS PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Air Filter						
Participation	60	60	60	60	60	60
Incentive Budget	$358	$358	$358	$358	$358	$358
Projected kWh Savings	4,700	4,692	4,683	4,674	4,666	4,657
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Air Sealing - Inadequate Sealing - Gas Heating						
Participation	2	2	2	0	0	0
Incentive Budget	$144	$144	$144	$0	$0	$0
Projected kWh Savings	336	334	332	0	0	0
Projected kW Savings	0.1	0.1	0.1	0.0	0.0	0.0
Air Sealing Inadequate Sealing - Electric furnace						
Participation	1	1	1	1	1	1
Incentive Budget	$293	$293	$293	$293	$293	$293
Projected kWh Savings	1,040	1,034	1,027	1,020	1,012	1,004
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Air Sealing Inadequate Sealing - Heat pump						
Participation	3	3	3	3	3	3
Incentive Budget	$524	$524	$524	$524	$524	$524
Projected kWh Savings	1,216	1,209	1,201	1,192	1,183	1,174
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Audit Recommendations						
Participation	17	33	49	0	0	0
Incentive Budget	$1,238	$2,476	$3,649	$0	$0	$0
Projected kWh Savings	1,354	2,707	3,990	0	0	0
Projected kW Savings	0.2	0.3	0.5	0.0	0.0	0.0
Bathroom Aerator 1.0 gpm						
Participation	281	211	156	0	0	0
Incentive Budget	$281	$211	$156	$0	$0	$0
Projected kWh Savings	11,177	8,386	6,217	0	0	0
Projected kW Savings	10.2	7.7	5.7	0.0	0.0	0.0

Measure	2028	2029	2030	2031	2032	2033
Door and Window Weather Stripping						
Participation	70	70	70	70	70	70
Incentive Budget	$570	$570	$570	$570	$570	$570
Projected kWh Savings	7,262	7,218	7,170	7,119	7,066	7,009
Projected kW Savings	0.6	0.6	0.6	0.6	0.6	0.6
Door Sweep						
Participation	70	70	70	70	70	70
Incentive Budget	$187	$187	$187	$187	$187	$187
Projected kWh Savings	6,527	6,488	6,445	6,398	6,350	6,300
Projected kW Savings	1.2	1.2	1.2	1.2	1.1	1.1
Duct Sealing - Inadequate Sealing - Electric furnace						
Participation	3	3	3	3	3	3
Incentive Budget	$1,289	$1,289	$1,289	$1,289	$1,289	$1,289
Projected kWh Savings	3,114	3,095	3,074	3,053	3,030	3,005
Projected kW Savings	0.3	0.3	0.3	0.3	0.3	0.3
Duct Sealing - Inadequate Sealing - Gas Heating						
Participation	1	1	1	0	0	0
Incentive Budget	$213	$213	$213	$0	$0	$0
Projected kWh Savings	204	203	202	0	0	0
Projected kW Savings	0.1	0.1	0.1	0.0	0.0	0.0
Duct Sealing - Inadequate Sealing - Heat pump						
Participation	2	2	2	0	0	0
Incentive Budget	$921	$921	$921	$0	$0	$0
Projected kWh Savings	1,457	1,448	1,439	0	0	0
Projected kW Savings	0.1	0.1	0.1	0.0	0.0	0.0
Kitchen Faucet Aerator 1.5 gpm						
Participation	278	209	155	0	0	0
Incentive Budget	$278	$209	$155	$0	$0	$0
Projected kWh Savings	54,325	40,757	30,217	0	0	0
Projected kW Savings	13.0	9.7	7.2	0.0	0.0	0.0
LED Nightlights						
Participation	61	61	61	61	61	61
Incentive Budget	$61	$61	$61	$61	$61	$61
Projected kWh Savings	830	830	830	830	830	830
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Low Flow Showerhead 1.5 gpm						
Participation	475	0	0	0	0	0
Incentive Budget	$2,375	$0	$0	$0	$0	$0
Projected kWh Savings	91,471	0	0	0	0	0
Projected kW Savings	10.8	0.0	0.0	0.0	0.0	0.0
Multifamily Whole Building Aerosol Sealing - Electric furnace						
Participation	16	16	16	0	0	0
Incentive Budget	$7,328	$7,328	$7,328	$0	$0	$0
Projected kWh Savings	20,666	20,541	20,405	0	0	0
Projected kW Savings	1.8	1.8	1.8	0.0	0.0	0.0

Measure	2028	2029	2030	2031	2032	2033
Multifamily Whole Building Aerosol Sealing - Gas Heating / CAC						
Participation	4	4	4	4	4	4
Incentive Budget	$782	$782	$782	$782	$782	$782
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Multifamily Whole Building Aerosol Sealing - Heat pump						
Participation	1	1	1	0	0	0
Incentive Budget	$654	$654	$654	$0	$0	$0
Projected kWh Savings	1,060	1,054	1,047	0	0	0
Projected kW Savings	0.1	0.1	0.1	0.0	0.0	0.0
Pipe Wrap						
Participation	34	27	21	16	12	9
Incentive Budget	$103	$82	$64	$49	$37	$27
Projected kWh Savings	8,474	6,771	5,268	4,015	3,013	2,234
Projected kW Savings	1.0	0.8	0.6	0.5	0.3	0.3
Programmable Thermostat - Furnace baseline						
Participation	24	18	14	10	0	0
Incentive Budget	$119	$90	$68	$50	$0	$0
Projected kWh Savings	11,174	8,517	6,390	4,737	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Programmable Thermostat - Gas/CAC baseline						
Participation	64	49	37	27	0	0
Incentive Budget	$322	$245	$184	$136	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Programmable Thermostat - Heat pump baseline						
Participation	59	45	34	25	0	0
Incentive Budget	$297	$226	$170	$126	$0	$0
Projected kWh Savings	12,701	9,681	7,263	5,385	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Smart Thermostat - Furnace baseline						
Participation	52	40	30	22	0	0
Incentive Budget	$6,487	$4,944	$3,710	$2,750	$0	$0
Projected kWh Savings	39,548	30,143	22,615	16,766	0	0
Projected kW Savings	7.4	5.6	4.2	3.1	0.0	0.0
Smart Thermostat - Gas/CAC baseline						
Participation	63	48	36	0	0	0
Incentive Budget	$4,688	$3,573	$2,681	$0	$0	$0
Projected kWh Savings	9,643	7,350	5,514	0	0	0
Projected kW Savings	8.9	6.8	5.1	0.0	0.0	0.0
Smart Thermostat - Heat pump baseline						
Participation	37	28	21	0	0	0
Incentive Budget	$4,634	$3,532	$2,650	$0	$0	$0
Projected kWh Savings	15,194	11,580	8,688	0	0	0
Projected kW Savings	5.3	4.0	3.0	0.0	0.0	0.0

Measure	2028	2029	2030	2031	2032	2033
Water Heater Temperature Setback						
Participation	32	0	32	0	32	0
Incentive Budget	$40	$0	$40	$0	$40	$0
Projected kWh Savings	3,875	0	3,875	0	3,875	0
Projected kW Savings	0.4	0.0	0.4	0.0	0.4	0.0
Total						
Participation	1,709	1,001	877	371	315	280
Incentive Budget	$34,186	$28,914	$26,850	$7,175	$4,140	$4,091
Projected kWh Savings	307,351	174,038	147,891	55,190	31,025	26,213
Projected kW Savings	61.7	39.4	31.2	5.8	3.0	2.5

TABLE 6-15: MULTI-FAMILY ENERGY SOLUTIONS PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$34,186	$28,914	$26,850	$7,175	$4,140	$4,091
Delivery & Implementation	$25,835	$16,731	$15,188	$4,249	$2,473	$2,158
Admin	$17,673	$11,445	$10,389	$2,907	$1,692	$1,476
Total Budget	**$77,694**	**$57,089**	**$52,427**	**$14,332**	**$8,305**	**$7,725**
Participation	1,709	1,001	877	371	315	280
Energy Savings (kWh)	307,351	174,038	147,891	55,190	31,025	26,213
Demand Savings (kW)	61.7	39.4	31.2	5.8	3.0	2.5
Weighted Program EUL	11.8	13.0	13.0	14.2	13.8	15.6
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.6 COMMUNITY CONNECTIONS PROGRAM

Program Description: The Community Connections program is designed to provide energy efficient products to low-income customers who receive assistance from local food banks, township trustees, and additional community-assistance organizations. The program is intended to educate low-income customers on the benefits of energy efficient measures and provide them with products which would otherwise be unaffordable.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-16: COMMUNITY CONNECTIONS PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Can Foam	$3.00	5.9	0.00
Door and Window Weather Stripping	$5.47	102.7	0.02
Door Sweep	$5.47	91.9	0.01
Outlet Gaskets	$5.47	2.9	0.00
Pipe Wrap	$18.00	246.7	0.03

Eligible Customers: The Community Connections program targets local food banks, township trustees, and additional community-assistance organizations who serve low-income homeowners and tenants within CenterPoint electric service territory.

Marketing: Marketing materials will be created to educate product recipients on the benefits of energy efficiency products.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-17: COMMUNITY CONNECTIONS PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Can Foam						
Participation	1,700	1,700	1,700	1,700	1,700	1,700
Incentive Budget	$5,099	$5,099	$5,099	$5,099	$5,099	$5,099
Projected kWh Savings	10,145	10,084	10,017	9,945	9,870	9,792
Projected kW Savings	1.7	1.7	1.7	1.7	1.6	1.6
Door and Window Weather Stripping						
Participation	1,169	1,169	1,169	1,169	1,169	1,169
Incentive Budget	$6,395	$6,395	$6,395	$6,395	$6,395	$6,395
Projected kWh Savings	122,098	121,361	120,555	119,694	118,796	117,845
Projected kW Savings	21.3	21.2	21.0	20.9	20.7	20.5
Door Sweep						
Participation	1,445	1,445	1,445	1,445	1,445	1,445
Incentive Budget	$7,903	$7,903	$7,903	$7,903	$7,903	$7,903
Projected kWh Savings	135,096	134,281	133,389	132,436	131,442	130,391
Projected kW Savings	21.6	21.5	21.3	21.2	21.0	20.8
Outlet Gaskets						
Participation	1,500	1,500	1,500	1,500	1,500	1,500
Incentive Budget	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203
Projected kWh Savings	4,475	4,448	4,419	4,387	4,354	4,319
Projected kW Savings	1.7	1.7	1.6	1.6	1.6	1.6
Pipe Wrap						
Participation	2,482	3,006	3,498	3,886	4,102	4,102
Incentive Budget	$44,683	$54,107	$62,957	$69,946	$73,828	$73,828
Projected kWh Savings	612,342	741,491	862,786	958,556	1,011,756	1,011,756
Projected kW Savings	69.9	84.6	98.5	109.4	115.5	115.5
Total						
Participation	8,296	8,819	9,311	9,699	9,915	9,915
Incentive Budget	$72,283	$81,707	$90,558	$97,547	$101,429	$101,429
Projected kWh Savings	884,155	1,011,664	1,131,166	1,225,018	1,276,219	1,274,103
Projected kW Savings	116.1	130.6	144.1	154.7	160.5	160.1

TABLE 6-18: COMMUNITY CONNECTIONS PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$72,283	$81,707	$90,558	$97,547	$101,429	$101,429
Delivery & Implementation	$277,194	$324,923	$372,128	$412,779	$440,510	$450,642
Admin	$0	$0	$0	$0	$0	$0
Total Budget	**$349,477**	**$406,630**	**$462,686**	**$510,326**	**$541,939**	**$552,071**
Participation	8,296	8,819	9,311	9,699	9,915	9,915
Energy Savings (kWh)	884,155	1,011,664	1,131,166	1,225,018	1,276,219	1,274,103
Demand Savings (kW)	116.1	130.6	144.1	154.7	160.5	160.1
Weighted Program EUL	14.5	14.1	13.9	13.7	13.7	13.6
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.7 INCOME QUALIFIED WEATHERIZATION PROGRAM

Program Description: The Income Qualified Weatherization (IQW) program is designed to produce long-term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Customers eligible through the Income Qualified Weatherization Program will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, air infiltration reduction and installation of new central air conditioner or air source heat pump.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. CenterPoint committed to finding innovative solutions to these areas. A health and safety (H&S) budget has been established, and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-19: INCOME QUALIFIED WEATHERIZATION PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
AC Tune Up	$75.00	93.0	0.10
Air Filter	$6.00	78.4	0.00
Air Sealing - Inadequate Sealing - Gas Heating	$123.58	302.4	0.11
Air Sealing Inadequate Sealing - Electric furnace	$200.00	1,254.6	0.21
Air Sealing Inadequate Sealing - Heat pump	$200.00	823.8	0.14
Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	$5,400.00	7,022.0	0.11
Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	$5,400.00	581.1	0.11
Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	$5,400.00	7,466.5	0.22
Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	$5,400.00	1,025.7	0.22
Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	$5,400.00	7,967.6	0.31
Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	$5,400.00	1,526.7	0.31
Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	$5,400.00	8,265.3	0.39
Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	$5,400.00	1,824.4	0.39
ASHP Tune Up	$75.00	290.6	0.09
Attic Insulation - Inadequate Insulation - Electric furnace	$750.00	914.5	0.14

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Attic Insulation - Inadequate Insulation - Gas Heating	$157.15	277.3	0.10
Attic Insulation - Inadequate Insulation - Heat pump	$750.00	587.3	0.09
Audit Recommendations	$75.00	82.0	0.01
Bathroom Aerator 1.0 gpm	$1.00	46.9	0.06
Central Air Conditioner 15.2 SEER	$3,500.00	103.8	0.11
Door and Window Weather Stripping	$10.00	102.7	0.01
Door Sweep	$5.00	91.9	0.01
Duct Sealing - Inadequate Sealing - Electric furnace	$450.00	1,398.1	0.21
Duct Sealing - Inadequate Sealing - Gas Heating	$126.95	298.6	0.11
Duct Sealing - Inadequate Sealing - Heat pump	$450.00	922.1	0.14
ENERGY STAR Refrigerator	$580.00	209.0	0.03
Kitchen Faucet Aerator 1.5 gpm	$1.00	234.8	0.05
LED Nightlights	$1.00	7.3	0.00
Low Flow Showerhead 1.5 gpm	$5.00	244.3	0.03
Pipe Wrap	$3.00	246.7	0.03
Smart Power Strips - Tier 2	$10.00	136.1	0.02
Smart Thermostat - Furnace baseline	$125.00	935.6	0.17
Smart Thermostat - Gas/CAC baseline	$70.76	163.2	0.16
Smart Thermostat - Heat pump baseline	$125.00	492.1	0.17
Wall Insulation - Electric furnace	$877.00	1,787.3	0.31
Wall Insulation - Gas Heating	$446.63	266.3	0.10
Wall Insulation - Heat pump	$877.00	1,111.1	0.19
Water Heater Temperature Setback	$1.25	120.7	0.01

Eligible Customers: This program is available to residential customer who receive either electric only or gas and electric service from where CenterPoint is the homes primary heat source. Homes must be at least 5 years or older and have not received an audit within the last three years; and is owner occupied or authorized non-owner occupied where occupants have the service in their name. Eligible homes must be less than 4 total units, and units, and should not be stacked.

Marketing: CenterPoint will provide a list to the implementation contractor of customers who have received Energy Assistance Program (EAP) funds within the past 12 months to help prioritize those customers who will benefit most from the program. This will also help in any direct marketing activities to specifically target those customers. In addition to utilizing the EAP List, the program will utilize census data to target low-income areas within CenterPoint territory. CenterPoint uses door-to-door canvassing for obtaining most of the appointments. The program is marketed to the public as "Neighborhood Weatherization" at various community events.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-20: INCOME QUALIFIED WEATHERIZATION PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
AC Tune Up						
Participation	256	256	243	475	444	398
Incentive Budget	$19,229	$19,229	$18,218	$35,627	$33,322	$29,856
Projected kWh Savings	23,973	23,929	22,628	44,168	41,237	36,881
Projected kW Savings	25.6	25.6	24.2	47.2	44.1	39.4
Air Filter						
Participation	112	237	369	500	625	737
Incentive Budget	$674	$1,422	$2,212	$3,002	$3,751	$4,424
Projected kWh Savings	8,855	18,659	28,970	39,243	48,939	57,626
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Air Sealing - Inadequate Sealing - Gas Heating						
Participation	12	12	12	12	12	12
Incentive Budget	$1,532	$1,532	$1,532	$1,532	$1,532	$1,532
Projected kWh Savings	3,812	3,789	3,764	3,737	3,709	3,679
Projected kW Savings	1.4	1.4	1.4	1.4	1.4	1.3
Air Sealing Inadequate Sealing - Electric furnace						
Participation	5	5	5	5	5	5
Incentive Budget	$913	$913	$913	$913	$913	$913
Projected kWh Savings	5,826	5,791	5,753	5,712	5,669	5,623
Projected kW Savings	1.0	1.0	1.0	0.9	0.9	0.9
Air Sealing Inadequate Sealing - Heat pump						
Participation	3	3	3	3	3	3
Incentive Budget	$652	$652	$652	$652	$652	$652
Projected kWh Savings	2,733	2,716	2,698	2,679	2,659	2,638
Projected kW Savings	0.5	0.5	0.4	0.4	0.4	0.4
Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline						
Participation	7	8	11	13	16	18
Incentive Budget	$35,553	$45,761	$57,638	$70,833	$84,761	$98,689
Projected kWh Savings	46,494	59,733	75,095	92,116	110,031	127,882
Projected kW Savings	0.7	0.9	1.2	1.5	1.7	2.0
Air Source Heat Pump 15.2 SEER2 - Heat pump baseline						
Participation	5	6	8	9	11	13
Incentive Budget	$25,395	$32,686	$41,170	$50,595	$60,544	$70,492
Projected kWh Savings	2,748	3,531	4,439	5,445	6,504	7,559
Projected kW Savings	0.5	0.7	0.8	1.0	1.2	1.4
Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline						
Participation	7	8	11	13	16	18
Incentive Budget	$35,553	$45,761	$57,638	$70,833	$84,761	$98,689
Projected kWh Savings	49,437	63,515	79,849	97,947	116,997	135,978
Projected kW Savings	1.5	1.9	2.3	2.9	3.4	4.0
Air Source Heat Pump 16.2 SEER2 - Heat pump baseline						
Participation	5	6	8	9	11	13
Incentive Budget	$25,395	$32,686	$41,170	$50,595	$60,544	$70,492
Projected kWh Savings	4,851	6,232	7,835	9,610	11,480	13,342
Projected kW Savings	1.0	1.3	1.7	2.1	2.5	2.9

Measure	2028	2029	2030	2031	2032	2033
Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline						
Participation	7	8	11	13	16	18
Incentive Budget	$35,553	$45,761	$57,638	$70,833	$84,761	$98,689
Projected kWh Savings	52,755	67,777	85,208	104,520	124,848	145,103
Projected kW Savings	2.0	2.6	3.3	4.0	4.8	5.6
Air Source Heat Pump 17.1 SEER2 - Heat pump baseline						
Participation	5	6	8	9	11	13
Incentive Budget	$25,395	$32,686	$41,170	$50,595	$60,544	$70,492
Projected kWh Savings	7,220	9,277	11,662	14,305	17,088	19,860
Projected kW Savings	1.5	1.9	2.3	2.9	3.4	4.0
Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline						
Participation	7	8	11	13	16	18
Incentive Budget	$35,553	$45,761	$57,638	$70,833	$84,761	$98,689
Projected kWh Savings	54,726	70,310	88,392	108,426	129,514	150,525
Projected kW Savings	2.6	3.3	4.2	5.2	6.2	7.2
Air Source Heat Pump 18.1 SEER2 - Heat pump baseline						
Participation	5	6	8	9	11	13
Incentive Budget	$25,395	$32,686	$41,170	$50,595	$60,544	$70,492
Projected kWh Savings	8,629	11,085	13,936	17,095	20,420	23,733
Projected kW Savings	1.9	2.4	3.0	3.7	4.4	5.1
ASHP Tune Up						
Participation	48	45	41	83	74	64
Incentive Budget	$3,587	$3,398	$3,059	$6,216	$5,569	$4,794
Projected kWh Savings	13,973	13,214	11,871	24,079	21,536	18,502
Projected kW Savings	4.5	4.3	3.8	7.8	6.9	6.0
Attic Insulation - Inadequate Insulation - Electric furnace						
Participation	20	20	20	20	20	20
Incentive Budget	$15,102	$15,102	$15,102	$15,102	$15,102	$15,102
Projected kWh Savings	18,728	18,615	18,492	18,359	18,222	18,076
Projected kW Savings	2.9	2.9	2.9	2.9	2.9	2.8
Attic Insulation - Inadequate Insulation - Gas Heating						
Participation	55	55	55	55	55	55
Incentive Budget	$8,589	$8,589	$8,589	$8,589	$8,589	$8,589
Projected kWh Savings	15,411	15,318	15,216	15,107	14,994	14,874
Projected kW Savings	5.7	5.6	5.6	5.5	5.5	5.5
Attic Insulation - Inadequate Insulation - Heat pump						
Participation	14	14	14	14	14	14
Incentive Budget	$10,787	$10,787	$10,787	$10,787	$10,787	$10,787
Projected kWh Savings	8,591	8,539	8,482	8,422	8,359	8,292
Projected kW Savings	1.3	1.3	1.3	1.3	1.3	1.3
Audit Recommendations						
Participation	36	90	149	213	284	372
Incentive Budget	$2,689	$6,722	$11,204	$16,005	$21,292	$27,910
Projected kWh Savings	2,940	7,350	12,249	17,499	23,280	30,515
Projected kW Savings	0.3	0.8	1.4	2.0	2.7	3.5

Measure	2028	2029	2030	2031	2032	2033
Bathroom Aerator 1.0 gpm						
Participation	31	35	38	39	38	35
Incentive Budget	$31	$35	$38	$39	$38	$35
Projected kWh Savings	1,487	1,671	1,789	1,818	1,755	1,611
Projected kW Savings	2.0	2.2	2.3	2.4	2.3	2.1
Central Air Conditioner 15.2 SEER						
Participation	17	23	30	39	49	60
Incentive Budget	$60,391	$80,340	$105,308	$135,542	$170,722	$209,808
Projected kWh Savings	1,801	2,392	3,129	4,020	5,054	6,200
Projected kW Savings	1.9	2.6	3.3	4.3	5.4	6.6
Door and Window Weather Stripping						
Participation	70	70	70	70	70	70
Incentive Budget	$695	$695	$695	$695	$695	$695
Projected kWh Savings	7,264	7,220	7,172	7,121	7,067	7,011
Projected kW Savings	0.6	0.6	0.6	0.6	0.6	0.6
Door Sweep						
Participation	68	68	68	68	68	68
Incentive Budget	$342	$342	$342	$342	$342	$342
Projected kWh Savings	6,396	6,358	6,315	6,270	6,223	6,173
Projected kW Savings	0.6	0.6	0.6	0.6	0.6	0.5
Duct Sealing - Inadequate Sealing - Electric furnace						
Participation	3	3	3	3	3	3
Incentive Budget	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
Projected kWh Savings	4,076	4,051	4,024	3,996	3,966	3,934
Projected kW Savings	0.6	0.6	0.6	0.6	0.6	0.6
Duct Sealing - Inadequate Sealing - Gas Heating						
Participation	6	6	6	6	6	6
Incentive Budget	$787	$787	$787	$787	$787	$787
Projected kWh Savings	1,882	1,870	1,858	1,845	1,831	1,816
Projected kW Savings	0.7	0.7	0.7	0.7	0.7	0.7
Duct Sealing - Inadequate Sealing - Heat pump						
Participation	2	2	2	2	2	2
Incentive Budget	$921	$921	$921	$921	$921	$921
Projected kWh Savings	1,920	1,909	1,896	1,882	1,868	1,853
Projected kW Savings	0.3	0.3	0.3	0.3	0.3	0.3
ENERGY STAR Refrigerator						
Participation	29	36	43	50	57	63
Incentive Budget	$16,989	$20,878	$24,984	$29,089	$32,978	$36,479
Projected kWh Savings	6,122	7,523	9,003	10,482	11,884	13,145
Projected kW Savings	0.9	1.1	1.4	1.6	1.8	2.0
Kitchen Faucet Aerator 1.5 gpm						
Participation	67	75	79	80	77	70
Incentive Budget	$67	$75	$79	$80	$77	$70
Projected kWh Savings	15,697	17,547	18,661	18,829	18,021	16,398
Projected kW Savings	3.1	3.5	3.7	3.8	3.6	3.3

Measure	2028	2029	2030	2031	2032	2033
LED Nightlights						
Participation	137	164	191	217	240	260
Incentive Budget	$137	$164	$191	$217	$240	$260
Projected kWh Savings	1,009	1,207	1,406	1,594	1,763	1,908
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Low Flow Showerhead 1.5 gpm						
Participation	57	61	62	60	55	48
Incentive Budget	$284	$305	$310	$299	$274	$240
Projected kWh Savings	13,997	14,963	15,174	14,586	13,318	11,600
Projected kW Savings	1.4	1.5	1.6	1.5	1.4	1.2
Pipe Wrap						
Participation	9	10	11	14	17	19
Incentive Budget	$28	$30	$33	$41	$50	$58
Projected kWh Savings	2,277	2,440	2,686	3,362	4,071	4,738
Projected kW Savings	0.3	0.3	0.3	0.4	0.5	0.5
Smart Power Strips - Tier 2						
Participation	398	426	469	587	711	827
Incentive Budget	$3,976	$4,260	$4,691	$5,872	$7,110	$8,273
Projected kWh Savings	54,119	57,985	63,849	79,912	96,766	112,596
Projected kW Savings	9.9	10.6	11.7	14.6	17.7	20.6
Smart Thermostat - Furnace baseline						
Participation	36	45	55	64	71	75
Incentive Budget	$4,541	$5,684	$6,883	$8,008	$8,897	$9,391
Projected kWh Savings	33,990	42,542	51,515	59,941	66,595	70,291
Projected kW Savings	6.3	7.8	9.5	11.0	12.3	12.9
Smart Thermostat - Gas/CAC baseline						
Participation	85	106	128	149	166	175
Incentive Budget	$5,991	$7,498	$9,079	$10,564	$11,737	$12,388
Projected kWh Savings	13,815	17,290	20,937	24,362	27,066	28,568
Projected kW Savings	13.8	17.2	20.9	24.3	27.0	28.5
Smart Thermostat - Heat pump baseline						
Participation	47	59	71	83	92	97
Incentive Budget	$5,868	$7,344	$8,893	$10,347	$11,496	$12,134
Projected kWh Savings	23,097	28,908	35,006	40,732	45,253	47,765
Projected kW Savings	7.8	9.8	11.9	13.8	15.4	16.2
Wall Insulation - Electric furnace						
Participation	10	10	10	10	10	10
Incentive Budget	$8,956	$8,956	$8,956	$8,956	$8,956	$8,956
Projected kWh Savings	18,562	18,450	18,328	18,197	18,060	17,916
Projected kW Savings	3.2	3.2	3.2	3.1	3.1	3.1
Wall Insulation - Gas Heating						
Participation	28	28	28	28	28	28
Incentive Budget	$12,380	$12,380	$12,380	$12,380	$12,380	$12,380
Projected kWh Savings	7,506	7,461	7,411	7,358	7,303	7,245
Projected kW Savings	2.7	2.7	2.7	2.7	2.7	2.7

Measure	2028	2029	2030	2031	2032	2033
Wall Insulation - Heat pump						
Participation	7	7	7	7	7	7
Incentive Budget	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397
Projected kWh Savings	8,242	8,193	8,138	8,080	8,020	7,955
Projected kW Savings	1.4	1.4	1.4	1.4	1.4	1.4
Water Heater Temperature Setback						
Participation	17	19	38	40	57	57
Incentive Budget	$22	$24	$47	$50	$72	$72
Projected kWh Savings	2,108	2,342	4,580	4,814	6,922	6,922
Projected kW Savings	0.2	0.3	0.5	0.5	0.8	0.8
Total						
Participation	1,732	2,050	2,395	3,087	3,468	3,787
Incentive Budget	$437,641	$540,541	$659,805	$816,059	$958,191	$1,102,262
Projected kWh Savings	557,071	661,703	779,417	947,671	1,078,290	1,196,333
Projected kW Savings	112.7	125.4	137.9	180.7	191.6	197.8

TABLE 6-21: INCOME QUALIFIED WEATHERIZATION PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$437,641	$540,541	$659,805	$816,059	$958,191	$1,102,262
Delivery & Implementation	$613,935	$747,412	$902,236	$1,124,110	$1,310,542	$1,489,892
Admin	$0	$0	$0	$0	$0	$0
Total Budget	**$1,051,576**	**$1,287,953**	**$1,562,041**	**$1,940,169**	**$2,268,733**	**$2,592,154**
Participation	1,732	2,050	2,395	3,087	3,468	3,787
Energy Savings (kWh)	557,071	661,703	779,417	947,671	1,078,290	1,196,333
Demand Savings (kW)	112.7	125.4	137.9	180.7	191.6	197.8
Weighted Program EUL	15.0	14.7	14.4	13.7	13.6	13.6
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.8 RESIDENTIAL NEW CONSTRUCTION PROGRAM

Program Description: The Residential New Construction (RNC) program produces long-term energy savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall. The program will incentivize builders and help improve cost effectiveness.

The Residential New Construction program allows builders to individually select high-efficiency measures at a tiered approach, which improves flexibility enhancing the ability to meet participant demand. This approach also helps encourage a more energy efficiency focus at the measure level. Structuring this program around specific measures allows CenterPoint to analyze specific measures, add or remove measures and ensure the program is cost-effective.

The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-22: RESIDENTIAL NEW CONSTRUCTION PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	$275.00	7,202.6	0.11
Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	$275.00	597.0	0.11
Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	$500.00	7,659.5	0.23
Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	$500.00	1,053.9	0.23
Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	$500.00	8,174.2	0.31
Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	$500.00	1,568.6	0.31
Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	$500.00	8,480.3	0.40
Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	$500.00	1,874.7	0.40
Central Air Conditioner 15.2 SEER	$108.00	107.5	0.11
Central Air Conditioner 16.2 SEER	$108.00	212.9	0.23
Central Air Conditioner 17.2 SEER	$108.00	306.0	0.32
Heat Pump Water Heater-electric resistance heat	$500.00	1,746.2	0.08
Heat Pump Water Heater-gas heat	$500.00	1,761.5	0.08
Heat Pump Water Heater-heat pump heat	$500.00	1,753.2	0.08
Smart Thermostat - Furnace baseline	$30.00	936.5	0.17
Smart Thermostat - Gas/CAC baseline	$7.61	167.4	0.17
Smart Thermostat - Heat pump baseline	$30.00	509.5	0.17
Sub-52 HERS Kicker - Gas Heat + CAC	$66.12	1,523.0	0.17
Whole Home - BOP 1 - Gas Heat + CAC	$228.02	315.1	0.04
Whole Home - BOP 1 - Heat Pump	$375.00	1,013.0	0.12
Whole Home - BOP 2 - Gas Heat + CAC	$348.88	315.1	0.04
Whole Home - BOP 2 - Heat Pump	$600.00	1,351.1	0.15

Eligible Customers: Any customer or home builder constructing a home to the program specifications in the CenterPoint electric service territory are eligible to participate.

Marketing: In order to move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-23: RESIDENTIAL NEW CONSTRUCTION PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$217	$252	$293	$301	$304	$302
Projected kWh Savings	2,907	3,370	3,921	4,019	4,051	4,023
Projected kW Savings	0.0	0.1	0.1	0.1	0.1	0.1
Air Source Heat Pump 15.2 SEER2 - Heat pump baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$155	$180	$209	$215	$217	$216
Projected kWh Savings	172	200	232	238	240	238
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$394	$457	$533	$547	$553	$550
Projected kWh Savings	3,092	3,584	4,170	4,274	4,308	4,278
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Air Source Heat Pump 16.2 SEER2 - Heat pump baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$281	$327	$381	$391	$395	$393
Projected kWh Savings	304	352	410	420	423	420
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$357	$414	$483	$496	$501	$498
Projected kWh Savings	2,988	3,464	4,030	4,131	4,163	4,135
Projected kW Savings	0.1	0.1	0.2	0.2	0.2	0.2
Air Source Heat Pump 17.1 SEER2 - Heat pump baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$255	$296	$345	$354	$358	$356
Projected kWh Savings	410	475	552	566	571	567
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline						
Participation	1	1	1	1	1	1
Incentive Budget	$332	$386	$450	$462	$466	$464
Projected kWh Savings	2,889	3,349	3,896	3,994	4,025	3,997
Projected kW Savings	0.1	0.2	0.2	0.2	0.2	0.2
Air Source Heat Pump 18.1 SEER2 - Heat pump baseline						
Participation	0	1	1	1	1	1
Incentive Budget	$237	$276	$321	$330	$333	$331
Projected kWh Savings	456	529	615	631	636	631
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Central Air Conditioner 15.2 SEER						
Participation	24	28	32	33	34	33
Incentive Budget	$2,582	$2,999	$3,496	$3,590	$3,625	$3,606
Projected kWh Savings	1,369	1,587	1,846	1,892	1,907	1,894
Projected kW Savings	1.4	1.7	2.0	2.0	2.0	2.0

Measure	2028	2029	2030	2031	2032	2033
Central Air Conditioner 16.2 SEER						
Participation	11	12	14	15	15	15
Incentive Budget	$1,150	$1,336	$1,557	$1,599	$1,614	$1,606
Projected kWh Savings	1,207	1,400	1,628	1,669	1,682	1,671
Projected kW Savings	1.3	1.5	1.7	1.8	1.8	1.8
Central Air Conditioner 17.2 SEER						
Participation	10	11	13	14	14	14
Incentive Budget	$1,068	$1,240	$1,445	$1,484	$1,499	$1,491
Projected kWh Savings	1,611	1,868	2,173	2,228	2,245	2,230
Projected kW Savings	1.7	2.0	2.3	2.4	2.4	2.4
Heat Pump Water Heater-electric resistance heat						
Participation	8	9	11	11	11	11
Incentive Budget	$3,914	$4,545	$5,299	$5,441	$5,494	$5,466
Projected kWh Savings	9,850	11,284	12,947	13,062	12,934	12,600
Projected kW Savings	0.5	0.5	0.6	0.6	0.6	0.6
Heat Pump Water Heater-gas heat						
Participation	1	2	2	2	2	2
Incentive Budget	$746	$866	$1,009	$1,036	$1,046	$1,041
Projected kWh Savings	1,893	2,168	2,488	2,510	2,485	2,421
Projected kW Savings	0.1	0.1	0.1	0.1	0.1	0.1
Heat Pump Water Heater-heat pump heat						
Participation	6	6	8	8	8	8
Incentive Budget	$2,796	$3,247	$3,785	$3,887	$3,924	$3,904
Projected kWh Savings	7,064	8,092	9,285	9,367	9,276	9,036
Projected kW Savings	0.3	0.4	0.4	0.4	0.4	0.4
Smart Thermostat - Furnace baseline						
Participation	17	20	24	24	25	24
Incentive Budget	$524	$609	$709	$728	$736	$732
Projected kWh Savings	12,759	14,818	17,273	17,738	17,910	17,818
Projected kW Savings	2.3	2.7	3.2	3.3	3.3	3.3
Smart Thermostat - Gas/CAC baseline						
Participation	32	37	43	44	45	45
Incentive Budget	$243	$282	$329	$338	$341	$339
Projected kWh Savings	4,172	4,844	5,647	5,799	5,855	5,826
Projected kW Savings	4.3	5.0	5.8	6.0	6.0	6.0
Smart Thermostat - Heat pump baseline						
Participation	12	14	17	17	18	17
Incentive Budget	$374	$435	$507	$520	$525	$523
Projected kWh Savings	4,958	5,758	6,712	6,893	6,960	6,924
Projected kW Savings	1.7	1.9	2.3	2.3	2.4	2.3
Sub-52 HERS Kicker - Gas Heat + CAC						
Participation	19	23	26	27	27	27
Incentive Budget	$1,284	$1,491	$1,738	$1,785	$1,803	$1,793
Projected kWh Savings	29,579	34,350	40,041	41,121	41,519	41,307
Projected kW Savings	3.4	3.9	4.6	4.7	4.7	4.7

Measure	2028	2029	2030	2031	2032	2033
Whole Home - BOP 1 - Gas Heat + CAC						
Participation	43	50	58	59	60	60
Incentive Budget	$9,749	$11,321	$13,197	$13,553	$13,684	$13,614
Projected kWh Savings	5,389	6,258	7,295	7,491	7,564	7,525
Projected kW Savings	0.6	0.7	0.8	0.9	0.9	0.9
Whole Home - BOP 1 - Heat Pump						
Participation	27	31	37	38	38	38
Incentive Budget	$10,126	$11,759	$13,708	$14,077	$14,213	$14,141
Projected kWh Savings	21,336	24,777	28,883	29,661	29,948	29,795
Projected kW Savings	2.4	2.8	3.3	3.4	3.4	3.4
Whole Home - BOP 2 - Gas Heat + CAC						
Participation	21	25	29	30	30	30
Incentive Budget	$7,458	$8,661	$10,096	$10,368	$10,469	$10,415
Projected kWh Savings	2,694	3,129	3,647	3,746	3,782	3,763
Projected kW Savings	0.3	0.4	0.4	0.4	0.4	0.4
Whole Home - BOP 2 - Heat Pump						
Participation	7	8	9	9	9	9
Incentive Budget	$4,050	$4,704	$5,483	$5,631	$5,685	$5,656
Projected kWh Savings	7,114	8,262	9,631	9,890	9,986	9,935
Projected kW Savings	0.8	0.9	1.1	1.1	1.1	1.1
Total						
Participation	244	283	330	339	342	340
Incentive Budget	$48,292	$56,081	$65,373	$67,135	$67,785	$67,439
Projected kWh Savings	124,213	143,917	167,322	171,341	172,470	171,035
Projected kW Savings	21.9	25.4	29.5	30.3	30.5	30.3

TABLE 6-24: RESIDENTIAL NEW CONSTRUCTION PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$48,292	$56,081	$65,373	$67,135	$67,785	$67,439
Delivery & Implementation	$56,181	$66,743	$79,591	$83,617	$86,368	$87,903
Admin	$7,805	$9,273	$11,058	$11,617	$11,999	$12,212
Total Budget	**$112,278**	**$132,097**	**$156,021**	**$162,369**	**$166,152**	**$167,554**
Participation	244	283	330	339	342	340
Energy Savings (kWh)	124,213	143,917	167,322	171,341	172,470	171,035
Demand Savings (kW)	21.9	25.4	29.5	30.3	30.5	30.3
Weighted Program EUL	18.3	18.3	18.3	18.4	18.4	18.4
NTG	0.71	0.71	0.71	0.71	0.71	0.71

6.9 RESIDENTIAL MARKETPLACE PROGRAM

Program Description: The online marketplace program encourages customers to purchase products online where an instant rebate is applied.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-25: RESIDENTIAL MARKETPLACE PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Bathroom Aerator 1.0 gpm	$2.50	48.3	0.07
ENERGY STAR Air Purifier	$75.00	298.0	0.03
ENERGY STAR Dehumidifier	$35.00	157.0	0.04
ENERGY STAR Most Efficient Dehumidifier	$35.00	230.0	0.05
Exterior Lighting Controls	$0.75	86.4	0.00
Kitchen Faucet Aerator 1.5 gpm	$2.50	238.7	0.05
LED Nightlights	$2.00	13.6	0.00
Linear LED	$2.50	18.1	0.00
Low Flow Showerhead 1.5 gpm	$2.50	267.5	0.03
Occupancy Sensor	$7.50	89.4	0.01
Outlet Gaskets	$0.00	0.0	0.00
Pipe Wrap	$0.00	0.0	0.00
Shower Timer	$1.36	90.8	0.03
Smart Outlets	$2.25	50.4	0.01
Smart Power Strips - Tier 1	$10.00	56.6	0.01
Smart Power Strips - Tier 2	$10.00	136.1	0.02
Smart Thermostat - Furnace baseline	$100.00	925.4	0.17
Smart Thermostat - Gas/CAC baseline	$80.00	167.4	0.17
Smart Thermostat - Heat pump baseline	$100.00	512.3	0.17
Window Insulation	$3.04	44.3	0.01

Eligible Customers: Residential customers who receive electric service from CenterPoint are eligible to participate in this integrated natural gas and electric EE program.

Marketing: Proposed marketing effort is include utilizing direct mailers, email blasts, CenterPoint online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Program Delivery Channels: CenterPoint will oversee the program and will partner with an implementation contractor to deliver the program.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-26: RESIDENTIAL MARKETPLACE PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Bathroom Aerator 1.0 gpm						
Participation	2,329	2,470	2,485	2,370	2,149	1,865
Incentive Budget	$5,823	$6,176	$6,213	$5,924	$5,373	$4,663
Projected kWh Savings	112,549	119,314	119,959	114,303	103,592	89,828
Projected kW Savings	153.6	162.7	163.5	155.6	140.9	122.0

Measure	2028	2029	2030	2031	2032	2033
ENERGY STAR Air Purifier						
Participation	13	16	20	24	27	31
Incentive Budget	$948	$1,198	$1,475	$1,767	$2,058	$2,336
Projected kWh Savings	3,768	4,759	5,861	7,020	8,179	9,280
Projected kW Savings	0.4	0.5	0.7	0.8	0.9	1.1
ENERGY STAR Dehumidifier						
Participation	93	98	102	104	107	109
Incentive Budget	$3,252	$3,418	$3,553	$3,656	$3,737	$3,803
Projected kWh Savings	14,589	15,332	15,936	16,401	16,764	17,058
Projected kW Savings	3.3	3.5	3.6	3.7	3.8	3.9
ENERGY STAR Most Efficient Dehumidifier						
Participation	279	293	305	313	320	326
Incentive Budget	$9,757	$10,254	$10,658	$10,969	$11,212	$11,408
Projected kWh Savings	64,116	67,383	70,038	72,080	73,676	74,967
Projected kW Savings	14.6	15.3	15.9	16.4	16.7	17.0
Exterior Lighting Controls						
Participation	497	603	703	782	826	828
Incentive Budget	$373	$452	$527	$586	$620	$621
Projected kWh Savings	42,902	52,062	60,704	67,533	71,386	71,542
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Kitchen Faucet Aerator 1.5 gpm						
Participation	1,310	1,387	1,393	1,326	1,200	1,039
Incentive Budget	$3,275	$3,468	$3,483	$3,315	$3,000	$2,598
Projected kWh Savings	312,943	331,342	332,642	316,429	286,272	247,812
Projected kW Savings	61.6	65.2	65.5	62.3	56.4	48.8
LED Nightlights						
Participation	225	266	305	340	371	398
Incentive Budget	$450	$531	$610	$681	$743	$797
Projected kWh Savings	3,059	3,611	4,150	4,630	5,051	5,419
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Linear LED						
Participation	346	375	400	420	436	448
Incentive Budget	$863	$937	$998	$1,048	$1,087	$1,118
Projected kWh Savings	6,260	6,794	7,243	7,602	7,885	8,109
Projected kW Savings	0.5	0.6	0.6	0.7	0.7	0.7
Low Flow Showerhead 1.5 gpm						
Participation	1,569	1,577	1,504	1,363	1,181	987
Incentive Budget	$3,923	$3,943	$3,759	$3,406	$2,952	$2,466
Projected kWh Savings	420,430	422,294	402,356	364,340	315,527	263,463
Projected kW Savings	41.1	41.3	39.4	35.7	30.9	25.8
Occupancy Sensor						
Participation	211	256	298	332	351	352
Incentive Budget	$1,582	$1,919	$2,238	$2,490	$2,632	$2,638
Projected kWh Savings	18,844	22,867	26,663	29,663	31,355	31,423
Projected kW Savings	1.6	2.0	2.3	2.6	2.7	2.7
Outlet Gaskets						

Measure	2028	2029	2030	2031	2032	2033
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Wrap						
Participation	0	0	0	0	0	0
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	0	0	0	0	0	0
Projected kW Savings	0.0	0.0	0.0	0.0	0.0	0.0
Shower Timer						
Participation	20	29	52	65	92	114
Incentive Budget	$27	$40	$71	$88	$125	$155
Projected kWh Savings	1,774	2,666	4,761	5,875	8,320	10,324
Projected kW Savings	0.6	0.9	1.7	2.0	2.9	3.6
Smart Outlets						
Participation	499	79	119	159	198	238
Incentive Budget	$1,122	$241	$362	$482	$603	$723
Projected kWh Savings	25,139	3,568	5,317	7,038	8,732	10,394
Projected kW Savings	3.5	0.6	0.9	1.2	1.5	1.7
Smart Power Strips - Tier 1						
Participation	359	396	496	601	699	777
Incentive Budget	$3,595	$3,962	$4,962	$6,010	$6,994	$7,773
Projected kWh Savings	20,346	22,424	28,083	34,015	39,588	43,997
Projected kW Savings	2.3	2.5	3.2	3.8	4.4	4.9
Smart Power Strips - Tier 2						
Participation	277	306	382	463	539	599
Incentive Budget	$2,774	$3,055	$3,825	$4,632	$5,390	$5,989
Projected kWh Savings	37,748	41,580	52,055	63,041	73,360	81,514
Projected kW Savings	6.9	7.6	9.5	11.5	13.4	14.9
Smart Thermostat - Furnace baseline						
Participation	58	70	81	90	95	95
Incentive Budget	$5,772	$6,989	$8,133	$9,036	$9,537	$9,537
Projected kWh Savings	53,413	64,678	75,258	83,612	88,253	88,253
Projected kW Savings	9.8	11.9	13.9	15.4	16.2	16.2
Smart Thermostat - Gas/CAC baseline						
Participation	147	178	207	230	242	242
Incentive Budget	$11,733	$14,208	$16,532	$18,367	$19,387	$19,387
Projected kWh Savings	24,557	29,736	34,601	38,441	40,575	40,575
Projected kW Savings	25.3	30.6	35.6	39.6	41.7	41.7
Smart Thermostat - Heat pump baseline						
Participation	46	55	65	72	76	76
Incentive Budget	$4,580	$5,546	$6,453	$7,170	$7,568	$7,568
Projected kWh Savings	23,462	28,411	33,058	36,728	38,766	38,766
Projected kW Savings	7.9	9.6	11.2	12.4	13.1	13.1
Window Insulation						

Measure	2028	2029	2030	2031	2032	2033
Participation	40	79	119	159	198	238
Incentive Budget	$121	$241	$362	$482	$603	$723
Projected kWh Savings	1,795	3,568	5,317	7,038	8,732	10,394
Projected kW Savings	0.3	0.6	0.9	1.2	1.5	1.7
Total						
Participation	8,316	8,534	9,036	9,211	9,109	8,762
Incentive Budget	$59,968	$66,579	$74,214	$80,108	$83,620	$84,302
Projected kWh Savings	1,187,694	1,242,392	1,284,002	1,275,790	1,226,012	1,143,119
Projected kW Savings	333.4	355.5	368.2	364.8	347.8	320.0

TABLE 6-27: RESIDENTIAL MARKETPLACE PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$59,968	$67,577	$75,407	$81,510	$85,210	$86,018
Delivery & Implementation	$205,683	$224,421	$238,260	$243,487	$240,885	$231,324
Admin	$231,588	$252,686	$268,267	$274,153	$271,223	$260,458
Total Budget	**$497,239**	**$544,683**	**$581,934**	**$599,150**	**$597,318**	**$577,800**
Participation	8,316	8,534	9,036	9,211	9,109	8,762
Energy Savings (kWh)	1,187,694	1,242,392	1,284,002	1,275,790	1,226,012	1,143,119
Demand Savings (kW)	333.4	355.5	368.2	364.8	347.8	320.0
Weighted Program EUL	10.3	10.3	10.2	10.2	10.1	10.1
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.10 RESIDENTIAL BEHAVIORAL SAVINGS PROGRAM

Program Description: The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The reports and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of other customers with similar home size and demographics. Customers can view the past 12 months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. The main delivery channel will be targeted mail and email with the addition of specific tips provided to the low-income customer segment.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-28: RESIDENTIAL BEHAVIORAL PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Home Energy Reports	$0.00	123.0	0.01

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory.

Marketing: N/A

Program Delivery Channels: CenterPoint will oversee the program and partner with and implementation contractor to deliver the program.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-29: RESIDENTIAL BEHAVIORAL PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Home Energy Reports						
Participation	40,638	46,194	51,240	55,613	59,260	62,210
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	4,998,443	5,681,824	6,302,523	6,840,346	7,288,938	7,651,781
Projected kW Savings	570.6	648.6	719.5	780.9	832.1	873.5
Total						
Participation	40,638	46,194	51,240	55,613	59,260	62,210
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	4,998,443	5,681,824	6,302,523	6,840,346	7,288,938	7,651,781
Projected kW Savings	570.6	648.6	719.5	780.9	832.1	873.5

TABLE 6-30: RESIDENTIAL BEHAVIORAL PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$0	$0	$0	$0	$0	$0
Delivery & Implementation	$222,797	$259,083	$293,995	$326,422	$355,829	$382,134
Admin	$2,133	$2,480	$2,814	$3,125	$3,406	$3,658
Total Budget	**$224,930**	**$261,563**	**$296,810**	**$329,547**	**$359,236**	**$385,792**
Participation	40,638	46,194	51,240	55,613	59,260	62,210
Energy Savings (kWh)	4,998,443	5,681,824	6,302,523	6,840,346	7,288,938	7,651,781
Demand Savings (kW)	570.6	648.6	719.5	780.9	832.1	873.5
Weighted Program EUL	1.0	1.0	1.0	1.0	1.0	1.0
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.11 SMART CYCLE PROGRAM

Program Description: Until recently, Direct Load Control (DLC) switches have been the default choice for residential load control programs. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, CenterPoint began replacing DLC switches with smart thermostats. Smart thermostats provide an alternative to traditional residential load control switches as well as enhance the way customers manage and understand their home energy use.

CenterPoint will continue to replace DLC switches with smart thermostats. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while utilities can learn from occupant behavior/preference, adjusting heating, ventilation, and air conditioning (HVAC) settings. Evaluation results are showing significantly more load reduction delivered by smart thermostats.

Eligible Customers: The Smart Cycle (DLC Change Out) Program will focus on residential single-family homes and apartment dwellers that have access to a Wi-Fi network and are currently direct load control switch customers participating in the DLC program.

Marketing: Proposed marketing efforts include utilizing direct mailers, email blasts, online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-31: SMART CYCLE PROGRAM BUDGET SUMMARY

Smart Cycle	2028	2029	2030	2031	2032	2033
Incentives	$901,260	$1,101,940	$1,127,284	$1,153,212	$1,179,736	$1,206,870
Delivery & Implementation	$1,181,917	$1,476,462	$670,419	$390,353	$399,331	$408,516
Admin	$733,422	$826,111	$708,749	$725,050	$741,727	$758,786
Total Budget	**$2,816,599**	**$3,404,513**	**$2,506,452**	**$2,268,615**	**$2,320,793**	**$2,374,172**
Participation	13,352	15,958	15,958	15,958	15,958	15,958
Energy Savings (kWh)	0	0	0	0	0	0
Demand Savings (kW)	12,529	14,771	14,556	14,332	14,106	13,882
Weighted Program EUL	15.0	15.0	15.0	15.0	15.0	15.0
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.12 BRING YOUR OWN THERMOSTAT PROGRAM – RESIDENTIAL

Program Description: The BYOT program allows customers with a compatible thermostat to participate in demand response (DR) events - utility managed load curtailing programs during periods when electricity demand is high. The BYOT program allows the utility to avoid the costs of hardware, installation, and maintenance associated with traditional load control methods. Customers choose to participate in this program by enrolling their eligible device. Upon enrolling, they receive a one-time credit. A customer actively participating in the program will also receive monthly credits during the months DR events are called.

By taking advantage of two-way communicating smart thermostats, BYOT programs can help utilities curtail load, reduce acquisition costs associated with typical load curtailment programs and improve customer satisfaction. With smart enabled thermostats, the utility can remotely verify how many customers are participating in DR events. Customers will be notified of all events and have the capability of opting out of events at any time during the actual event.

Eligible Customers: Any eligible residential customer who receives electric service from CenterPoint at a single-family residence.

Marketing: Proposed marketing efforts include utilizing direct mailers, email blasts, online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-32: BRING YOUR OWN THERMOSTAT (RESIDENTIAL) PROGRAM BUDGET SUMMARY

BYOT	2028	2029	2030	2031	2032	2033
Incentives	$846,518	$964,456	$1,114,498	$1,268,692	$1,427,541	$1,488,584
Delivery & Implementation	$198,090	$210,659	$249,351	$252,291	$255,787	$131,350
Admin	$518,126	$587,317	$689,110	$771,866	$857,406	$814,807
Total Budget	**$1,562,733**	**$1,762,432**	**$2,052,960**	**$2,292,849**	**$2,540,735**	**$2,434,741**
Participation	12,541	13,967	15,777	17,556	19,310	19,683
Energy Savings (kWh)	0	0	0	0	0	0
Demand Savings (kW)	11,768	12,928	14,391	15,767	17,069	17,122
Weighted Program EUL	15.0	15.0	15.0	15.0	15.0	15.0
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.13 COMMERCIAL PRESCRIPTIVE PROGRAM

Program Description: The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around EE. Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

The following table describes the end-uses included in this program, and an estimate of average savings per project within each end-use.

TABLE 6-33: COMMERCIAL PRESCRTIPTIVE PROGRAM MEASURES

End Use	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Compressed Air	$107 - $142	$1,333.00	0.2
Food Service / Refrigeration	$246 - $255	$2,127.00	0.2
Hot Water	$207 - $323	$10,000.00	0.9
HVAC	$2144 - $2337	$9,745.00	2.0
Lighting	$49 - $54	$294.00	0.1
Misc	$2631 - $3411	$99,658.00	1.1

Eligible Customers: Any participating commercial or industrial customer receiving electric service from CenterPoint.

Marketing: Proposed marketing efforts include trade ally outreach, trade ally meetings, direct mail, face-to-face meetings with customers, targeted marketing campaigns potential bonuses, web-based marketing, and coordination with key account managers.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-34: COMMERCIAL PRESCRTIPTIVE PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Compressed Air						
Participation	163	172	174	270	264	250
Incentive Budget	$18,142	$21,462	$24,720	$28,820	$31,523	$33,668
Projected kWh Savings	182,617	192,253	195,031	302,819	295,749	279,845
Projected kWh Savings	30.3	32.8	34.4	49.5	49.6	48.4
Food Service / Refrigeration						
Participation	1,204	1,316	1,382	1,397	1,385	1,334
Incentive Budget	$298,727	$323,729	$339,580	$345,972	$344,834	$339,968
Projected kWh Savings	2,150,823	2,351,554	2,469,273	2,496,481	2,474,107	2,382,852
Projected kW Savings	208.0	228.0	240.6	245.3	246.6	239.3
Hot Water						
Participation	6	7	8	9	11	14
Incentive Budget	$1,308	$1,736	$2,247	$2,835	$3,489	$4,195
Projected kWh Savings	52,987	59,263	67,761	78,362	90,661	118,393
Projected kW Savings	4.9	6.4	8.1	10.0	12.1	14.2
HVAC						
Participation	77	84	93	102	106	112
Incentive Budget	$179,357	$194,416	$211,966	$228,600	$231,634	$239,344
Projected kWh Savings	628,322	691,007	764,461	836,428	867,678	914,019
Projected kW Savings	129.2	145.8	164.7	183.7	196.7	211.1
Lighting						
Participation	30,177	28,032	25,603	23,134	20,674	16,835
Incentive Budget	$1,483,537	$1,381,616	$1,289,611	$1,203,927	$1,115,864	$869,029
Projected kWh Savings	7,452,396	6,922,804	6,322,796	5,713,246	5,105,618	4,157,632
Projected kW Savings	1,323.1	1,214.5	1,095.4	978.1	865.7	674.2
Misc						
Participation	6	7	8	9	10	10
Incentive Budget	$14,861	$18,171	$21,743	$25,612	$29,206	$33,675
Projected kWh Savings	472,881	573,301	669,967	751,768	804,564	826,365

Measure	2028	2029	2030	2031	2032	2033
Projected kW Savings	5.4	6.8	8.4	10.0	11.6	13.2
Total						
Participation	31,632	29,618	27,268	24,923	22,449	18,554
Incentive Budget	$1,995,931	$1,941,129	$1,889,867	$1,835,766	$1,756,550	$1,519,879
Projected kWh Savings	10,940,025	10,790,182	10,489,289	10,179,104	9,638,378	8,679,105
Projected kW Savings	1,700.9	1,634.2	1,551.5	1,476.7	1,382.4	1,200.4

TABLE 6-35: COMMERCIAL PRESCRTIPTIVE PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$1,995,931	$1,941,129	$1,889,867	$1,835,766	$1,756,550	$1,519,879
Delivery & Implementation	$893,762	$910,060	$914,302	$916,620	$896,236	$832,946
Admin	$223,440	$227,515	$228,576	$229,155	$224,059	$208,237
Total Budget	**$3,113,133**	**$3,078,704**	**$3,032,745**	**$2,981,540**	**$2,876,845**	**$2,561,062**
Participation	31,632	29,618	27,268	24,923	22,449	18,554
Energy Savings (kWh)	10,940,025	10,790,182	10,489,289	10,179,104	9,638,378	8,679,105
Demand Savings (kW)	1,701	1,634	1,551	1,477	1,382	1,200
Weighted Program EUL	13.4	13.3	13.2	13.0	12.9	12.7
NTG	0.84	0.84	0.84	0.84	0.84	0.84

6.14 COMMERCIAL CUSTOM PROGRAM

Program Description: The Custom Program promotes the implementation of customized energy-saving projects at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible.

Eligible Customers: Any participating commercial or industrial customer receiving electric service from CenterPoint.

Marketing: Proposed marketing efforts include individualized outreach to large C&I customers through a variety of channels and coordination with key account managers to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, marketing campaigns and bonuses, trade ally meetings, and educational seminars could also be used to promote the program.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-36: COMMERCIAL CUSTOM PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
Custom						
Participation	155	177	194	203	207	207
Incentive Budget	$1,568,930	$1,806,616	$1,954,869	$1,996,439	$2,020,277	$2,014,875
Projected kWh Savings	5,969,701	6,853,404	7,479,285	7,847,609	8,010,541	8,010,551
Projected kW Savings	753.6	869.5	947.6	1,003.6	1,025.8	1,031.9
RCx						
Participation	28	30	31	39	37	45
Incentive Budget	$79,345	$87,845	$92,703	$101,017	$97,143	$125,591
Projected kWh Savings	1,063,622	1,164,827	1,214,938	1,499,242	1,445,256	1,727,049
Projected kW Savings	112.2	125.0	132.7	151.0	146.4	195.1
SEM						
Participation	19	20	20	35	34	31
Incentive Budget	$16,687	$17,994	$18,158	$30,923	$29,727	$28,537
Projected kWh Savings	881,883	928,700	925,810	1,609,238	1,554,109	1,439,331
Projected kW Savings	163.6	172.2	171.7	298.5	288.3	266.9
Total						
Participation	201	228	245	277	279	283
Incentive Budget	$1,664,963	$1,912,455	$2,065,729	$2,128,380	$2,147,147	$2,169,003
Projected kWh Savings	7,915,205	8,946,932	9,620,033	10,956,089	11,009,906	11,176,931
Projected kW Savings	1,029.4	1,166.7	1,251.9	1,453.1	1,460.5	1,494.0

TABLE 6-37: COMMERCIAL CUSTOM PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$1,664,963	$1,912,457	$2,065,733	$2,128,383	$2,147,152	$2,169,009
Delivery & Implementation	$778,114	$905,042	$1,000,893	$1,161,211	$1,199,600	$1,256,608
Admin	$194,528	$226,261	$250,223	$290,303	$299,900	$314,152
Total Budget	**$2,637,606**	**$3,043,760**	**$3,316,849**	**$3,579,896**	**$3,646,652**	**$3,739,769**
Participation	155	177	194	203	207	207
Energy Savings (kWh)	7,774,104	8,798,340	9,471,904	10,698,611	10,761,249	10,946,638
Demand Savings (kW)	1,003	1,139	1,224	1,405	1,414	1,451
Weighted Program EUL	10.6	10.7	10.7	9.9	9.9	9.8
NTG	0.84	0.84	0.84	0.84	0.84	0.84

6.15 SMALL BUSINESS ENERGY SOLUTIONS PROGRAM

Program Description: The Small Business Energy Solutions Program provides value by directly installing EE products such as high efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically commutated motors, smart the1mostats and vending machine controls. The program helps small businesses, multi-family and not-for-profit customers identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

The following table indicates the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-38: SMALL BUSINESS ENERGY SOLUTIONS PROGRAM MEASURES

End Use	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
HVAC	$27 - $71	$1,594.00	0.3
Lighting	$105 - $142	$390.00	0.1
Other	$2 - $3	$500.00	0.0

Eligible Customers: Any participating CenterPoint business customer with a maximum peak energy demand of less than 400 kW or any designated non-profit, opt-in customer of any peak energy demand usage. Additionally, multifamily building owners with CenterPoint general electric service may qualify for the program, including apartment buildings, condominiums, cooperatives, duplexes, quadraplexes, townhomes, nursing homes and retirement communities.

Marketing: The SBES Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to individual customer segments (e.g., hospitality, grocery stores, and non-profit organizations) to increase participation in under-performing segments, including direct customer outreach and enhanced incentive campaigns. Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from CenterPoint staff and third-party contractors. Marketing efforts will continue to target Multi-Family, Non-Profit and Civil/Governmental sectors within this program.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-39: SMALL BUSINESS ENERGY SOLUTIONS PROGRAM SUMMARY

Measure	2028	2029	2030	2031	2032	2033
HVAC						
Participation	165	164	156	142	124	104
Incentive Budget	$4,510	$5,461	$6,355	$7,060	$7,452	$7,431
Projected kWh Savings	220,595	219,599	208,564	189,639	165,849	139,769
Projected kW Savings	38.6	38.6	36.8	33.7	29.6	25.1
Lighting						
Participation	5,961	4,984	4,082	3,290	2,618	1,276
Incentive Budget	$846,605	$692,824	$561,102	$452,187	$363,533	$134,056

Measure	2028	2029	2030	2031	2032	2033
Projected kWh Savings	1,952,851	1,632,863	1,337,327	1,077,707	857,517	417,859
Projected kW Savings	377.4	309.5	249.5	198.5	156.5	60.3
Other						
Participation	48	37	28	16	12	35
Incentive Budget	$95	$76	$59	$45	$34	$106
Projected kWh Savings	20,183	15,711	11,936	6,602	4,869	14,896
Projected kW Savings	1.3	1.0	0.7	0.0	0.0	0.0
Total						
Participation	6,174	5,186	4,266	3,447	2,753	1,415
Incentive Budget	$851,211	$698,361	$567,516	$459,292	$371,019	$141,592
Projected kWh Savings	2,193,629	1,868,172	1,557,827	1,273,947	1,028,235	572,523
Projected kW Savings	417.4	349.1	287.0	232.2	186.2	85.4

TABLE 6-40: SMALL BUSINESS ENERGY SOLUTIONS PROGRAM BUDGET SUMMARY

	2028	2029	2030	2031	2032	2033
Incentives	$986,453	$830,824	$690,766	$568,323	$463,632	$217,167
Delivery & Implementation	$193,735	$171,081	$148,097	$125,843	$105,657	$65,768
Admin	$48,434	$42,770	$37,024	$31,461	$26,414	$16,442
Total Budget	**$1,228,622**	**$1,044,675**	**$875,888**	**$725,628**	**$595,703**	**$299,378**
Participation	6,174	5,186	4,266	3,447	2,753	1,415
Energy Savings (kWh)	2,193,629	1,868,172	1,557,827	1,273,947	1,028,235	572,523
Demand Savings (kW)	417	349	287	232	186	85
Weighted Program EUL	13.6	13.5	13.4	13.3	13.3	12.3
NTG	0.84	0.84	0.84	0.84	0.84	0.84

6.16 BRING YOUR OWN THERMOSTAT PROGRAM – C&I

Program Description: The BYOT program allows customers with a compatible thermostat to participate in demand response (DR) events - utility managed load curtailing programs during periods when electricity demand is high. The BYOT program allows the utility to avoid the costs of hardware, installation, and maintenance associated with traditional load control methods. Customers choose to participate in this program by enrolling their eligible device. Upon enrolling, they receive a one-time credit. A customer actively participating in the program will also receive monthly credits during the months DR events are called.

By taking advantage of two-way communicating smart thermostats, BYOT programs can help utilities curtail load, reduce acquisition costs associated with typical load curtailment programs and improve customer satisfaction. With smart enabled thermostats, the utility can remotely verify how many customers are participating in DR events. Customers will be notified of all events and have the capability of opting out of events at any time during the actual event.

Eligible Customers: Any participating commercial or industrial customer receiving electric service from CenterPoint.

Marketing: Proposed marketing efforts include utilizing direct mailers, email blasts, online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor.

Evaluation: CenterPoint will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint will evaluate the program annually.

Estimated Participation, Savings, and Budgets:

TABLE 6-41: BRING YOUR OWN THERMOSTAT (C&I) PROGRAM BUDGET SUMMARY

BYOT	2028	2029	2030	2031	2032	2033
Incentives	$11,813	$39,291	$83,780	$114,396	$127,008	$132,727
Delivery & Implementation	$26,250	$60,459	$96,856	$63,754	$22,178	$6,218
Admin	$15,050	$41,108	$76,968	$82,263	$75,130	$72,860
Total Budget	**$53,113**	**$140,858**	**$257,604**	**$260,413**	**$224,316**	**$211,806**
Participation	175	569	1,186	1,583	1,718	1,755
Energy Savings (kWh)	0	0	0	0	0	0
Demand Savings (kW)	340	1,102	2,289	3,045	3,293	3,351
Weighted Program EUL	15.0	15.0	15.0	15.0	15.0	15.0
NTG	1.00	1.00	1.00	1.00	1.00	1.00

6.17 COST-EFFECTIVENESS

As part of the development of the DSM Action Plan, GDS evaluated the cost-effectiveness results of each program. Table 6-46 provides program-level, sector-level and overall portfolio-level cost-effectiveness results. The TRC and UCT ratios are provided, along with TRC and UCT net benefits.[14] The overall portfolio has a TRC ratio of 1.4 and a UCT ratio of 1.7.

TABLE 6-42: DSM ACTION PLAN BENEFIT-COST RATIOS – BY PROGRAM AND SECTOR

	TRC Ratio	UCT Ratio	TRC Net Benefits ($)	UCT Net Benefits ($)
Residential				
Residential Prescriptive	1.35	1.69	$703,537	$934,169
Home Energy Assessment	1.15	1.72	$363,685	$928,426
Residential Midstream	1.24	1.17	$2,595,955	$1,220,133
In Store Discount	2.75	3.53	$1,718,543	$1,878,564
Multi-Family Energy Solutions	1.88	2.03	$239,714	$208,025
Community Connections	1.87	1.87	$2,089,923	$2,089,923
Income Qualified Weatherization	0.44	0.36	-$5,670,217	-$5,772,027
Residential New Construction	1.14	1.08	$122,065	$64,868
Residential Marketplace	2.46	2.08	$4,494,473	$3,178,633
Residential Behavioral	1.41	1.41	$646,778	$646,778
Smart Cycle	1.26	1.26	$3,530,641	$3,530,641

[14] The Income Qualified Weatherization program does not need to be cost-effective.

	TRC Ratio	UCT Ratio	TRC Net Benefits ($)	UCT Net Benefits ($)
Bring Your Own Thermostat	1.11	1.68	$1,781,069	$7,358,717
Residential Sub-total	***1.20***	***1.31***	***$12,616,166***	***$16,266,849***
Commercial				
C&I Prescriptive	2.21	3.44	$24,367,237	$37,607,170
C&I Custom	1.45	2.14	$9,588,579	$19,503,462
Small Business	3.01	3.13	$7,551,381	$9,162,369
Bring Your Own Thermostat	1.23	2.76	$494,793	$1,703,930
Commercial Sub-total	***1.89***	***2.80***	***$41,507,197***	***$66,273,001***
All Sectors				
Total	***1.39***	***1.78***	***$54,123,364***	***$82,539,850***

TABLE 6-43: ANNUAL TRC RATIOS – BY PROGRAM

Annual TRC Ratios	2028	2029	2030	2031	2032	2033
Residential						
Residential Prescriptive	1.29	1.38	1.37	1.34	1.34	1.38
Home Energy Assessment	1.28	1.23	1.17	1.12	1.07	1.02
Residential Midstream	1.30	1.28	1.25	1.23	1.22	1.20
In Store Discount	3.02	2.90	2.79	2.70	2.63	2.58
Multi-Family Energy Solutions	2.51	1.71	1.43	1.09	1.40	1.41
Community Connections	1.95	1.90	1.86	1.84	1.83	1.84
Income Qualified Weatherization	0.49	0.47	0.46	0.43	0.43	0.42
Residential New Construction	1.14	1.13	1.13	1.14	1.14	1.15
Residential Marketplace	2.67	2.60	2.50	2.41	2.31	2.21
Residential Behavioral	1.55	1.53	1.40	1.36	1.33	1.33
Smart Cycle	1.00	1.00	1.37	1.52	1.49	1.46
Bring Your Own Thermostat	1.04	1.06	1.03	1.07	1.10	1.39
Residential Sub-total	***1.19***	***1.16***	***1.21***	***1.21***	***1.19***	***1.25***
Commercial						
C&I Prescriptive	2.18	2.17	2.14	2.12	2.11	2.13
C&I Custom	1.44	1.44	1.44	1.44	1.46	1.49
Small Business	3.89	3.67	3.46	3.15	3.02	2.91
Bring Your Own Thermostat	1.00	1.01	1.01	1.27	2.42	3.46
Commercial Sub-total	***1.95***	***1.89***	***1.82***	***1.79***	***1.83***	***1.84***
All Sectors						
Total	**1.43**	**1.38**	**1.38**	**1.36**	**1.36**	**1.39**

TABLE 6-44: ANNUAL UCT RATIOS – BY PROGRAM

Annual UCT Ratios	2028	2029	2030	2031	2032	2033
Residential						
Residential Prescriptive	1.53	1.69	1.70	1.69	1.71	1.79

Annual UCT Ratios	2028	2029	2030	2031	2032	2033
Home Energy Assessment	1.89	1.81	1.73	1.67	1.61	1.57
Residential Midstream	1.26	1.22	1.18	1.15	1.12	1.11
In Store Discount	3.78	3.67	3.56	3.48	3.42	3.38
Multi-Family Energy Solutions	2.46	1.91	1.68	1.46	1.70	1.72
Community Connections	1.95	1.90	1.86	1.84	1.83	1.84
Income Qualified Weatherization	0.41	0.39	0.37	0.35	0.34	0.33
Residential New Construction	1.08	1.08	1.08	1.08	1.09	1.10
Residential Marketplace	2.19	2.16	2.10	2.06	2.01	1.96
Residential Behavioral	1.55	1.53	1.40	1.36	1.33	1.33
Smart Cycle	1.00	1.00	1.37	1.52	1.49	1.46
Bring Your Own Thermostat	1.70	1.69	1.65	1.65	1.65	1.76
Residential Sub-total	***1.30***	***1.26***	***1.36***	***1.37***	***1.34***	***1.33***
Commercial						
C&I Prescriptive	3.35	3.35	3.31	3.29	3.28	3.35
C&I Custom	2.14	2.13	2.12	2.12	2.14	2.18
Small Business	4.10	3.86	3.64	3.31	3.18	3.06
Bring Your Own Thermostat	1.44	1.80	2.09	2.81	3.60	3.96
Commercial Sub-total	***2.91***	***2.82***	***2.75***	***2.71***	***2.72***	***2.71***
All Sectors						
Total	**1.85**	**1.77**	**1.81**	**1.79**	**1.75**	**1.73**

APPENDIX A. C&I OPT-OUT SCENARIO

Table A-1 provides additional detail regarding the cumulative annual technical, economic, MAP, RAP and Enhanced RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast over 3-yr, 6-yr and 18-yr timeframes. The associated MW of demand savings are also provided.

TABLE A-45: C&I CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	3 YR	6 YR	18 YR
Energy (MWh)			
Technical	182,585	367,166	781,742
Economic	182,567	367,136	782,987
MAP	131,512	248,598	506,825
RAP	111,770	216,992	456,511
Enhanced RAP	117,581	225,150	467,462
Energy Savings (as% of Sector Sales Forecast)			
Technical	5.3%	10.6%	22.2%
Economic	5.3%	10.6%	22.3%
MAP	3.8%	7.2%	14.4%
RAP	3.2%	6.3%	13.0%
Enhanced RAP	3.4%	6.5%	13.3%
Demand (MW)			
Technical	25	93	150
Economic	25	93	150
MAP	19	64	99
RAP	15	55	87
Enhanced RAP	17	58	91

Figure A-1 provides the RAP results for the 3-year, 6-year, and 18-year timeframes for both the RAP scenario and the RAP scenario including opt-out customers. The savings as a percentage of forecasted sales is slightly higher in the RAP scenario, though total MWh savings are higher in the scenario in which opt-out customers are included in the analysis.

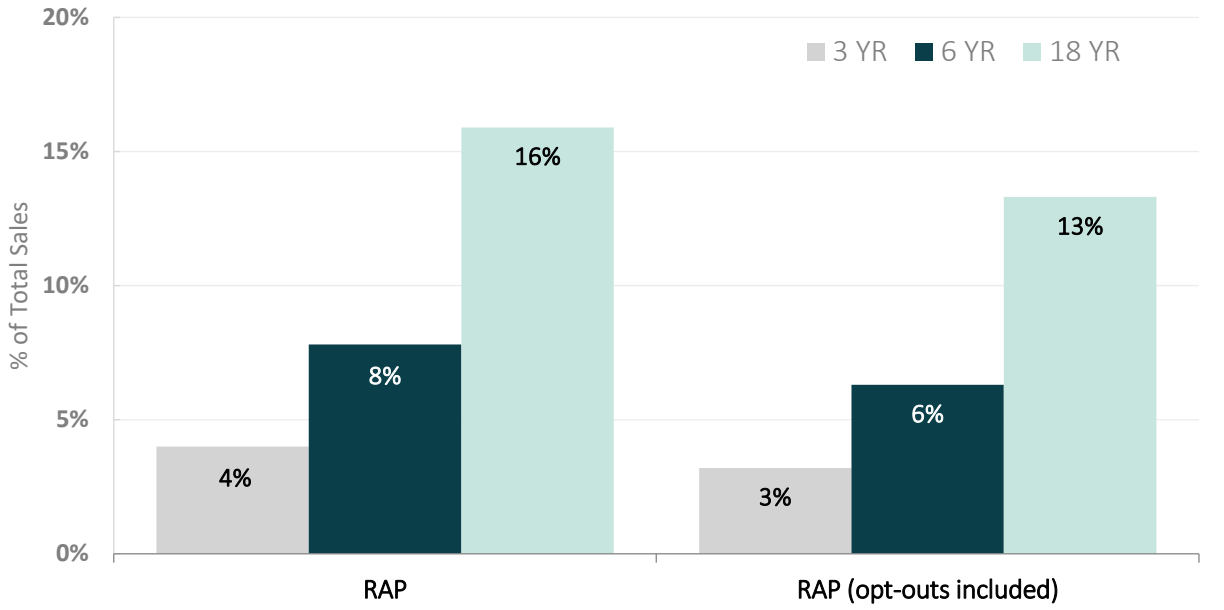


FIGURE A-1: C&I ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF C&I SALES)

Figure A-2 provides the annual budgets for commercial RAP, with and without opt-out customers. The budgets in the RAP scenario range from $6 million to $7 million, while the budgets in the RAP scenario with opt-out customers included range from $15 million to $18 million.

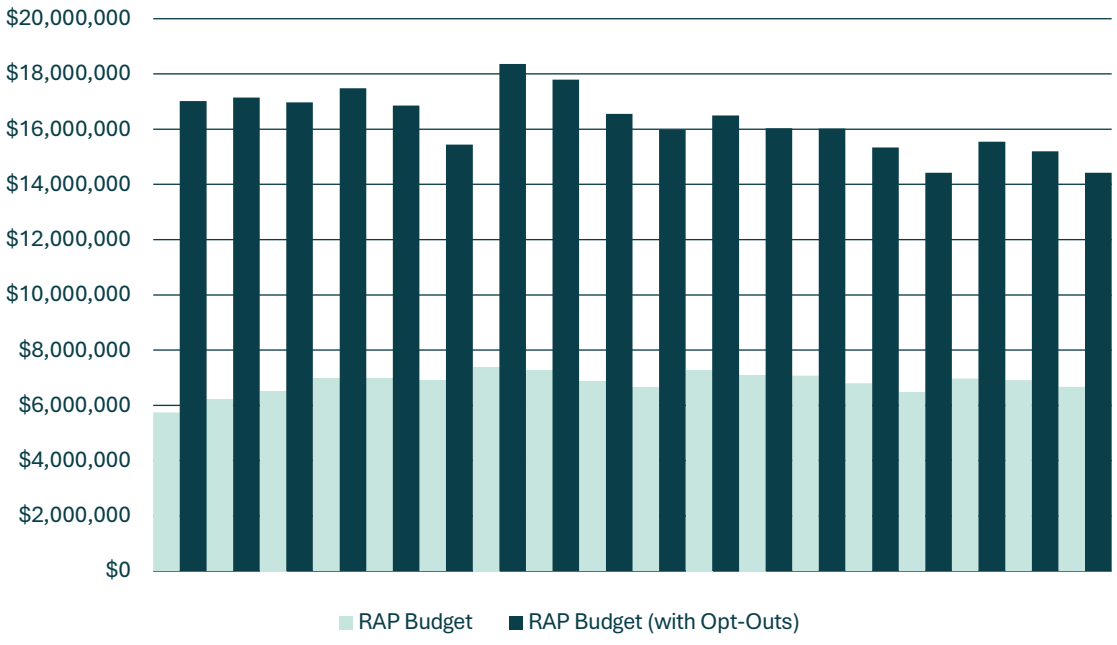


FIGURE A-2: C&I RAP BUDGETS – EXCLUDING AND INCLUDING OPT-OUT CUSTOMERS

APPENDIX B. RESIDENTIAL MEASURE DETAIL

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
1001	Appliances	ENERGY STAR Air Purifier	Residential Prescriptive	SF	MO	512	58%	298	0.03	9	$92	100%	54%	AIR PURIFIER-1	12%	36%	95.0%	55.2%	2.9
1002	Appliances	ENERGY STAR Air Purifier	Residential Prescriptive	SF	NC	512	58%	298	0.03	9	$92	100%	54%	AIR PURIFIER-2	12%	0%	95.0%	55.2%	2.9
1003	Appliances	ENERGY STAR Air Purifier	Residential Prescriptive	MF	MO	512	58%	298	0.03	9	$92	100%	54%	AIR PURIFIER-3	12%	36%	95.0%	55.2%	2.9
1004	Appliances	ENERGY STAR Air Purifier	Residential Prescriptive	MF	NC	512	58%	298	0.03	9	$92	100%	54%	AIR PURIFIER-4	12%	0%	95.0%	55.2%	2.9
1005	Appliances	ENERGY STAR Air Purifier	In Store Discount	SF	MO	512	58%	298	0.03	9	$92	100%	27%	AIR PURIFIER-1	12%	36%	95.0%	38.8%	5.9
1006	Appliances	ENERGY STAR Air Purifier	In Store Discount	SF	NC	512	58%	298	0.03	9	$92	100%	27%	AIR PURIFIER-2	12%	0%	95.0%	38.8%	5.9
1007	Appliances	ENERGY STAR Air Purifier	In Store Discount	MF	MO	512	58%	298	0.03	9	$92	100%	27%	AIR PURIFIER-3	12%	36%	95.0%	38.8%	5.9
1008	Appliances	ENERGY STAR Air Purifier	In Store Discount	MF	NC	512	58%	298	0.03	9	$92	100%	27%	AIR PURIFIER-4	12%	0%	95.0%	38.8%	5.9
1009	Appliances	ENERGY STAR Air Purifier	Residential Marketplac	SF	MO	512	58%	298	0.03	9	$92	100%	81%	AIR PURIFIER-1	12%	36%	95.0%	73.9%	2.0
1010	Appliances	ENERGY STAR Air Purifier	Residential Marketplac	SF	NC	512	58%	298	0.03	9	$92	100%	81%	AIR PURIFIER-2	12%	0%	95.0%	73.9%	2.0
1011	Appliances	ENERGY STAR Air Purifier	Residential Marketplac	MF	MO	512	58%	298	0.03	9	$92	100%	81%	AIR PURIFIER-3	12%	36%	95.0%	73.9%	2.0
1012	Appliances	ENERGY STAR Air Purifier	Residential Marketplac	MF	NC	512	58%	298	0.03	9	$92	100%	81%	AIR PURIFIER-4	12%	0%	95.0%	73.9%	2.0
1013	Appliances	ENERGY STAR Refrigerator	No Program	SF	MO	349	14%	49	0.01	15	$9	100%	25%	REFRIGERATOR-1	150%	57%	91.0%	35.0%	17.6
1014	Appliances	ENERGY STAR Refrigerator	ne Qualified Weatheriz	SF	MO	349	60%	209	0.03	15	$580	100%	100%	REFRIGERATOR-2	150%	57%	95.0%	95.0%	0.3
1015	Appliances	ENERGY STAR Refrigerator	No Program	SF	NC	349	14%	49	0.01	15	$9	100%	25%	REFRIGERATOR-3	150%	0%	91.0%	35.0%	17.6
1016	Appliances	ENERGY STAR Refrigerator	No Program	MF	MO	349	14%	49	0.01	15	$580	100%	100%	REFRIGERATOR-4	110%	57%	95.0%	95.0%	0.1
1017	Appliances	ENERGY STAR Refrigerator	ne Qualified Weatheriz	MF	MO	349	60%	209	0.03	15	$9	100%	100%	REFRIGERATOR-5	110%	57%	91.0%	91.0%	18.8
1018	Appliances	ENERGY STAR Refrigerator	No Program	MF	NC	349	14%	49	0.01	15	$9	100%	25%	REFRIGERATOR-6	110%	0%	91.0%	35.0%	17.6
1019	Appliances	CEE Tier 2 Refrigerator	No Program	SF	MO	349	19%	66	0.01	15	$26	100%	25%	REFRIGERATOR-1	150%	57%	91.0%	35.0%	8.3
1020	Appliances	CEE Tier 2 Refrigerator	No Program	SF	NC	349	19%	66	0.01	15	$26	100%	25%	REFRIGERATOR-2	150%	0%	91.0%	35.0%	8.3
1021	Appliances	CEE Tier 2 Refrigerator	No Program	MF	MO	349	19%	66	0.01	15	$26	100%	25%	REFRIGERATOR-3	110%	57%	91.0%	35.0%	8.3
1022	Appliances	CEE Tier 2 Refrigerator	No Program	MF	NC	349	19%	66	0.01	15	$26	100%	25%	REFRIGERATOR-4	110%	0%	91.0%	35.0%	8.3
1023	Appliances	CEE Tier 3 Refrigerator	No Program	SF	MO	349	24%	84	0.01	15	$135	50%	25%	REFRIGERATOR-1	150%	57%	48.0%	35.0%	2.0
1024	Appliances	CEE Tier 3 Refrigerator	No Program	SF	NC	349	24%	84	0.01	15	$135	50%	25%	REFRIGERATOR-2	150%	0%	48.0%	35.0%	2.0
1025	Appliances	CEE Tier 3 Refrigerator	No Program	MF	MO	349	24%	84	0.01	15	$135	50%	25%	REFRIGERATOR-3	110%	57%	48.0%	35.0%	2.0
1026	Appliances	CEE Tier 3 Refrigerator	No Program	MF	NC	349	24%	84	0.01	15	$135	50%	25%	REFRIGERATOR-4	110%	0%	48.0%	35.0%	2.0
1027	Appliances	Refrigerator Recycling	No Program	SF	Recycle	1,014	100%	1,014	0.15	7	$50	100%	25%	RECYCLING-1	10%	0%	91.0%	35.0%	36.2
1028	Appliances	Refrigerator Recycling	No Program	MF	Recycle	1,014	100%	1,014	0.15	7	$50	100%	25%	RECYCLING-2	2%	0%	91.0%	35.0%	36.2
1029	Appliances	Freezer Recycling	No Program	SF	Recycle	722	100%	722	0.11	7	$50	100%	25%	RECYCLING-3	6%	0%	91.0%	35.0%	25.8
1030	Appliances	Freezer Recycling	No Program	MF	Recycle	722	100%	722	0.11	7	$50	100%	25%	RECYCLING-4	1%	0%	91.0%	35.0%	25.8
1031	Appliances	Dehumidifier Recycling	No Program	SF	Recycle	1,000	100%	1,000	0.00	7	$20	100%	25%	RECYCLING-5	4%	0%	91.0%	35.0%	53.3
1032	Appliances	Dehumidifier Recycling	No Program	MF	Recycle	1,000	100%	1,000	0.00	7	$20	100%	25%	RECYCLING-6	1%	0%	91.0%	35.0%	53.3
1033	Appliances	ENERGY STAR Freezer - Chest	No Program	SF	MO	272	10%	27	0.00	21	$5	100%	25%	FREEZER-1	47%	33%	91.0%	35.0%	23.1
1034	Appliances	ENERGY STAR Freezer - Chest	No Program	SF	NC	272	10%	27	0.00	21	$5	100%	25%	FREEZER-2	47%	0%	91.0%	35.0%	23.1
1035	Appliances	ENERGY STAR Freezer - Chest	No Program	MF	MO	272	10%	27	0.00	21	$5	100%	25%	FREEZER-3	47%	33%	91.0%	35.0%	23.1
1036	Appliances	ENERGY STAR Freezer - Chest	No Program	MF	NC	272	10%	27	0.00	21	$5	100%	25%	FREEZER-4	47%	0%	91.0%	35.0%	23.1
1037	Appliances	ENERGY STAR Freezer - Compact Upright	No Program	SF	MO	273	10%	27	0.00	10	$5	100%	25%	FREEZER-1	47%	33%	91.0%	35.0%	13.4
1038	Appliances	ENERGY STAR Freezer - Compact Upright	No Program	SF	NC	273	10%	27	0.00	10	$5	100%	25%	FREEZER-2	47%	0%	91.0%	35.0%	13.4
1039	Appliances	ENERGY STAR Freezer - Compact Upright	No Program	MF	MO	273	10%	27	0.00	10	$5	100%	25%	FREEZER-3	47%	33%	91.0%	35.0%	13.4
1040	Appliances	ENERGY STAR Freezer - Compact Upright	No Program	MF	NC	273	10%	27	0.00	10	$5	100%	25%	FREEZER-4	47%	0%	91.0%	35.0%	13.4
1041	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	SF	MO	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-1	37%	89%	95.0%	95.0%	4.8
1042	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	SF	NC	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-2	37%	0%	95.0%	95.0%	4.8
1043	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	MF	MO	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-3	6%	89%	95.0%	95.0%	4.8
1044	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	MF	NC	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-4	6%	0%	95.0%	95.0%	4.8
1045	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	SF	MO	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-1	37%	89%	95.0%	95.0%	7.1
1046	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	SF	NC	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-2	37%	0%	95.0%	95.0%	7.1
1047	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	MF	MO	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-3	6%	89%	95.0%	95.0%	7.1
1048	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	MF	NC	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-4	6%	0%	95.0%	95.0%	7.1
1049	Appliances	ENERGY STAR Dehumidifier	In Store Discount	SF	MO	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-1	37%	89%	95.0%	95.0%	6.8
1050	Appliances	ENERGY STAR Dehumidifier	In Store Discount	SF	NC	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-2	37%	0%	95.0%	95.0%	6.8
1051	Appliances	ENERGY STAR Dehumidifier	In Store Discount	MF	MO	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-3	6%	89%	95.0%	95.0%	6.8
1052	Appliances	ENERGY STAR Dehumidifier	In Store Discount	MF	NC	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-4	6%	0%	95.0%	95.0%	6.8
1053	Appliances	ENERGY STAR Most Efficient Dehumidifier	In Store Discount	SF	MO	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-1	37%	89%	95.0%	95.0%	9.9
1054	Appliances	ENERGY STAR Most Efficient Dehumidifier	In Store Discount	SF	NC	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-2	37%	0%	95.0%	95.0%	9.9
1055	Appliances	ENERGY STAR Most Efficient Dehumidifier	In Store Discount	MF	MO	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-3	6%	89%	95.0%	95.0%	9.9
1056	Appliances	ENERGY STAR Most Efficient Dehumidifier	In Store Discount	MF	NC	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-4	6%	0%	95.0%	95.0%	9.9
1057	Appliances	ENERGY STAR Dehumidifier	Residential Marketplac	SF	MO	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-1	37%	89%	95.0%	95.0%	4.8
1058	Appliances	ENERGY STAR Dehumidifier	Residential Marketplac	SF	NC	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-2	37%	0%	95.0%	95.0%	4.8

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
1059	Appliances	ENERGY STAR Dehumidifier	Residential Marketplac	MF	MO	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-3	6%	89%	95.0%	95.0%	4.8
1060	Appliances	ENERGY STAR Dehumidifier	Residential Marketplac	MF	NC	1,075	15%	157	0.04	17	$9	100%	100%	DEHUMIDIFIER-4	6%	0%	95.0%	95.0%	4.8
1061	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Marketplac	SF	MO	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-1	37%	89%	95.0%	95.0%	7.1
1062	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Marketplac	SF	NC	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-2	37%	0%	95.0%	95.0%	7.1
1063	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Marketplac	MF	MO	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-3	6%	89%	95.0%	95.0%	7.1
1064	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Marketplac	MF	NC	1,075	21%	230	0.05	17	$12	100%	100%	DEHUMIDIFIER-4	6%	0%	95.0%	95.0%	7.1
1065	Appliances	ENERGY STAR Dishwasher	No Program	SF	MO	307	22%	67	0.00	11	$30	100%	25%	DISHWASHER-1	84%	90%	91.0%	35.0%	4.5
1066	Appliances	ENERGY STAR Dishwasher	No Program	SF	NC	307	22%	67	0.00	11	$30	100%	25%	DISHWASHER-2	84%	0%	91.0%	35.0%	4.5
1067	Appliances	ENERGY STAR Dishwasher	No Program	MF	MO	307	22%	67	0.00	11	$30	100%	25%	DISHWASHER-3	84%	90%	91.0%	35.0%	4.5
1068	Appliances	ENERGY STAR Dishwasher	No Program	MF	NC	307	22%	67	0.00	11	$30	100%	25%	DISHWASHER-4	84%	0%	91.0%	35.0%	4.5
1069	Appliances	ENERGY STAR Clothes Washer	Residential Prescriptive	SF	MO	612	13%	79	0.01	14	$87	57%	57%	LOTHES WASHER-	92%	57%	57.1%	57.1%	1.2
1070	Appliances	ENERGY STAR Clothes Washer	Residential Prescriptive	SF	NC	612	13%	79	0.01	14	$87	57%	57%	LOTHES WASHER-	92%	0%	57.1%	57.1%	1.2
1071	Appliances	ENERGY STAR Clothes Washer	Residential Prescriptive	MF	MO	612	13%	79	0.01	14	$87	57%	57%	LOTHES WASHER-	92%	57%	57.1%	57.1%	1.2
1072	Appliances	ENERGY STAR Clothes Washer	Residential Prescriptive	MF	NC	612	13%	79	0.01	14	$87	57%	57%	LOTHES WASHER-	92%	0%	57.1%	57.1%	1.2
1073	Appliances	CEE Tier 2 Clothes Washer	Residential Prescriptive	SF	MO	612	23%	141	0.02	14	$85	100%	59%	LOTHES WASHER-	92%	57%	95.0%	57.9%	2.1
1074	Appliances	CEE Tier 2 Clothes Washer	Residential Prescriptive	SF	NC	612	23%	141	0.02	14	$85	100%	59%	LOTHES WASHER-	92%	0%	95.0%	57.9%	2.1
1075	Appliances	CEE Tier 2 Clothes Washer	Residential Prescriptive	MF	MO	612	23%	141	0.02	14	$85	100%	59%	LOTHES WASHER-	92%	57%	95.0%	57.9%	2.1
1076	Appliances	CEE Tier 2 Clothes Washer	Residential Prescriptive	MF	NC	612	23%	141	0.02	14	$85	100%	59%	LOTHES WASHER-	92%	0%	95.0%	57.9%	2.1
1077	Appliances	CEE Advanced Tier Clothes Washer	Residential Prescriptive	SF	MO	612	26%	158	0.02	14	$99	100%	51%	LOTHES WASHER-	92%	57%	95.0%	53.3%	2.3
1078	Appliances	CEE Advanced Tier Clothes Washer	Residential Prescriptive	SF	NC	612	26%	158	0.02	14	$99	100%	51%	LOTHES WASHER-	92%	0%	95.0%	53.3%	2.3
1079	Appliances	CEE Advanced Tier Clothes Washer	Residential Prescriptive	MF	MO	612	26%	158	0.02	14	$99	100%	51%	LOTHES WASHER-	92%	57%	95.0%	53.3%	2.3
1080	Appliances	CEE Advanced Tier Clothes Washer	Residential Prescriptive	MF	NC	612	26%	158	0.02	14	$99	100%	51%	LOTHES WASHER-	92%	0%	95.0%	53.3%	2.3
1081	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	SF	MO	769	21%	160	0.02	16	$152	75%	33%	CLOTHES DRYER-1	86%	36%	68.0%	44.2%	2.6
1082	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	SF	NC	769	21%	160	0.02	16	$152	75%	33%	CLOTHES DRYER-2	86%	0%	68.0%	44.2%	2.6
1083	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	MF	MO	769	21%	160	0.02	16	$152	75%	33%	CLOTHES DRYER-3	86%	36%	68.0%	44.2%	2.6
1084	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	MF	NC	769	21%	160	0.02	16	$152	75%	33%	CLOTHES DRYER-4	86%	0%	68.0%	44.2%	2.6
1085	Appliances	Heat Pump Dryer	No Program	SF	MO	769	57%	435	0.06	16	$900	25%	25%	CLOTHES DRYER-1	86%	36%	35.0%	35.0%	1.5
1086	Appliances	Heat Pump Dryer	No Program	SF	NC	769	57%	435	0.06	16	$900	25%	25%	CLOTHES DRYER-2	86%	0%	35.0%	35.0%	1.5
1087	Appliances	Heat Pump Dryer	No Program	MF	MO	769	57%	435	0.06	16	$900	25%	25%	CLOTHES DRYER-3	86%	36%	35.0%	35.0%	1.5
1088	Appliances	Heat Pump Dryer	No Program	MF	NC	769	57%	435	0.06	16	$900	25%	25%	CLOTHES DRYER-4	86%	0%	35.0%	35.0%	1.5
1089	Appliances	Ultrasonic Clothes Dryer	No Program	SF	MO	769	10%	77	0.01	16	$150	25%	25%	CLOTHES DRYER-1	86%	0%	35.0%	35.0%	1.8
1090	Appliances	Ultrasonic Clothes Dryer	No Program	SF	NC	769	10%	77	0.01	16	$150	25%	25%	CLOTHES DRYER-2	86%	0%	35.0%	35.0%	1.8
1091	Appliances	Ultrasonic Clothes Dryer	No Program	MF	MO	769	10%	77	0.01	16	$150	25%	25%	CLOTHES DRYER-3	86%	0%	35.0%	35.0%	1.8
1092	Appliances	Ultrasonic Clothes Dryer	No Program	MF	NC	769	10%	77	0.01	16	$150	25%	25%	CLOTHES DRYER-4	86%	0%	35.0%	35.0%	1.8
1093	Appliances	Bolt-On Smart Dryer Sensor to Electric Dryer	No Program	SF	MO	769	5%	39	0.01	16	$150	25%	25%	DRYER SENSOR-1	86%	0%	35.0%	35.0%	0.8
1094	Appliances	Bolt-On Smart Dryer Sensor to Electric Dryer	No Program	SF	NC	769	5%	39	0.01	16	$150	25%	25%	DRYER SENSOR-2	86%	0%	35.0%	35.0%	0.8
1095	Appliances	Bolt-On Smart Dryer Sensor to Electric Dryer	No Program	MF	MO	769	5%	39	0.01	16	$150	25%	25%	DRYER SENSOR-3	86%	0%	35.0%	35.0%	0.8
1096	Appliances	Bolt-On Smart Dryer Sensor to Electric Dryer	No Program	MF	NC	769	5%	39	0.01	16	$150	25%	25%	DRYER SENSOR-4	86%	0%	35.0%	35.0%	0.8
1097	Appliances	Ozone Laundry	No Program	SF	MO	1,225	14%	175	0.03	8	$300	25%	25%	OZONE-1	86%	0%	35.0%	35.0%	1.2
1098	Appliances	Ozone Laundry	No Program	SF	NC	1,225	14%	175	0.03	8	$300	25%	25%	OZONE-2	86%	0%	35.0%	35.0%	1.2
1099	Appliances	Ozone Laundry	No Program	MF	MO	1,225	14%	175	0.03	8	$300	25%	25%	OZONE-3	86%	0%	35.0%	35.0%	1.2
1100	Appliances	Ozone Laundry	No Program	MF	NC	1,225	14%	175	0.03	8	$300	25%	25%	OZONE-4	86%	0%	35.0%	35.0%	1.2
1101	Appliances	Water Dispenser	No Program	SF	MO	320	77%	246	0.03	10	$60	100%	25%	WATER COOLER-1	5%	56%	91.0%	35.0%	8.8
1102	Appliances	Water Dispenser	No Program	SF	NC	320	77%	246	0.03	10	$60	100%	25%	WATER COOLER-2	5%	0%	91.0%	35.0%	8.8
1103	Appliances	Water Dispenser	No Program	MF	MO	320	77%	246	0.03	10	$60	100%	25%	WATER COOLER-3	5%	56%	91.0%	35.0%	8.8
1104	Appliances	Water Dispenser	No Program	MF	NC	320	77%	246	0.03	10	$60	100%	25%	WATER COOLER-4	5%	0%	91.0%	35.0%	8.8
1105	Appliances	Induction Cooktop	No Program	SF	MO	123	10%	12	0.00	16	$687	25%	25%	COOKTOP-1	66%	4%	35.0%	35.0%	1.0
1106	Appliances	Induction Cooktop	No Program	SF	NC	123	10%	12	0.00	16	$687	25%	25%	COOKTOP-2	66%	0%	35.0%	35.0%	1.0
1107	Appliances	Induction Cooktop	No Program	MF	MO	123	10%	12	0.00	16	$687	25%	25%	COOKTOP-3	66%	3%	35.0%	35.0%	1.0
1108	Appliances	Induction Cooktop	No Program	MF	NC	123	10%	12	0.00	16	$687	25%	25%	COOKTOP-4	66%	0%	35.0%	35.0%	1.0
2001	Behavior	Home Energy Reports	Residential Behavioral	SF	MO	11,455	1%	123	0.01	1	$0	100%	100%	HER-1	100%	0%	100.0%	100.0%	1.0
2002	Behavior	Home Energy Reports	Residential Behavioral	SF	NC	11,455	1%	123	0.01	1	$0	100%	100%	HER-2	100%	0%	100.0%	100.0%	1.0
2003	Behavior	Home Energy Reports	Residential Behavioral	MF	MO	5,728	2%	123	0.01	1	$0	100%	100%	HER-3	100%	0%	100.0%	100.0%	1.0
2004	Behavior	Home Energy Reports	Residential Behavioral	MF	NC	5,728	2%	123	0.01	1	$0	100%	100%	HER-4	100%	0%	100.0%	100.0%	1.0
2005	Behavior	Audit Recommendations	No Program	SF	Retrofit	11,455	1%	82	0.01	1	$0	100%	25%	AUDIT-1	100%	0%	91.0%	72.0%	1.0
2006	Behavior	Audit Recommendations	No Program	MF	Retrofit	5,728	1%	82	0.01	1	$0	100%	25%	AUDIT-2	100%	0%	91.0%	72.0%	1.0
2007	Behavior	Audit Recommendations	No Program	SF	Retrofit	11,455	1%	82	0.01	1	$0	100%	25%	AUDIT-3	100%	0%	91.0%	72.0%	1.0
2008	Behavior	Audit Recommendations	No Program	MF	Retrofit	5,728	1%	82	0.01	1	$0	100%	25%	AUDIT-4	100%	0%	91.0%	72.0%	1.0

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3001	HVAC	Air Filter	In Store Discount	SF	Retrofit	11,455	1%	79	0.00	1	$7	50%	14%	FILTER-1	97%	49%	43.0%	28.8%	3.9
3002	HVAC	Air Filter	In Store Discount	SF	Retrofit	11,455	1%	79	0.00	1	$7	100%	14%	FILTER-2	97%	49%	89.0%	28.8%	3.9
3003	HVAC	Air Filter	In Store Discount	MF	Retrofit	5,728	1%	79	0.00	1	$7	50%	14%	FILTER-3	97%	49%	43.0%	28.8%	3.9
3004	HVAC	Air Filter	In Store Discount	MF	Retrofit	5,728	1%	79	0.00	1	$7	100%	14%	FILTER-4	97%	49%	89.0%	28.8%	3.9
3005	HVAC	ASHP Tune Up	Residential Prescriptive	SF	Retrofit	6,223	5%	311	0.10	3	$225	22%	22%	HP TUNE-1	15%	49%	34.1%	34.1%	2.0
3006	HVAC	ASHP Tune Up	ne Qualified Weatheriz	SF	Retrofit	6,223	5%	311	0.10	3	$225	75%	33%	HP TUNE-2	15%	49%	60.0%	42.4%	1.3
3007	HVAC	ASHP Tune Up	Residential Prescriptive	MF	Retrofit	4,838	5%	242	0.08	3	$225	22%	22%	HP TUNE-3	15%	49%	34.1%	34.1%	1.5
3008	HVAC	ASHP Tune Up	ne Qualified Weatheriz	MF	Retrofit	4,838	5%	242	0.08	3	$225	50%	33%	HP TUNE-4	15%	49%	43.0%	42.4%	1.0
3009	HVAC	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	10%	621	0.12	16	$135	100%	100%	HP-1	15%	36%	89.0%	89.0%	2.3
3010	HVAC	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	ne Qualified Weatheriz	SF	MO	6,223	10%	621	0.12	16	$135	100%	100%	HP-2	15%	36%	89.0%	89.0%	0.1
3011	HVAC	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	idential New Construct	SF	NC	6,223	10%	621	0.12	16	$135	100%	100%	HP-3	15%	0%	89.0%	89.0%	2.1
3012	HVAC	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	10%	488	0.09	16	$135	100%	100%	HP-4	15%	36%	89.0%	89.0%	1.9
3013	HVAC	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	ne Qualified Weatheriz	MF	MO	4,838	10%	488	0.09	16	$135	100%	100%	HP-5	15%	36%	89.0%	89.0%	0.1
3014	HVAC	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	idential New Construct	MF	NC	4,838	10%	488	0.09	16	$135	100%	100%	HP-6	15%	0%	89.0%	89.0%	1.7
3015	HVAC	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	18%	1,096	0.23	16	$421	100%	71%	HP-1	15%	36%	89.0%	78.1%	3.6
3016	HVAC	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	ne Qualified Weatheriz	SF	MO	6,223	18%	1,096	0.23	16	$421	100%	100%	HP-2	15%	36%	89.0%	89.0%	0.2
3017	HVAC	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	idential New Construct	SF	NC	6,223	18%	1,096	0.23	16	$421	100%	65%	HP-3	15%	0%	89.0%	76.7%	4.0
3018	HVAC	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	18%	861	0.19	16	$421	100%	71%	HP-4	15%	36%	89.0%	78.1%	2.9
3019	HVAC	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	ne Qualified Weatheriz	MF	MO	4,838	18%	861	0.19	16	$421	100%	100%	HP-5	15%	36%	89.0%	89.0%	0.2
3020	HVAC	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	idential New Construct	MF	NC	4,838	18%	861	0.19	16	$421	100%	65%	HP-6	15%	0%	89.0%	76.7%	3.2
3021	HVAC	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	26%	1,631	0.33	16	$630	100%	63%	HP-1	15%	36%	89.0%	76.2%	3.9
3022	HVAC	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	ne Qualified Weatheriz	SF	MO	6,223	26%	1,631	0.33	16	$630	100%	100%	HP-2	15%	36%	89.0%	89.0%	0.3
3023	HVAC	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	idential New Construct	SF	NC	6,223	26%	1,631	0.33	16	$630	100%	79%	HP-3	15%	0%	89.0%	80.6%	3.2
3024	HVAC	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	26%	1,282	0.26	16	$630	100%	63%	HP-4	15%	36%	89.0%	76.2%	3.1
3025	HVAC	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	ne Qualified Weatheriz	MF	MO	4,838	26%	1,282	0.26	16	$630	100%	100%	HP-5	15%	36%	89.0%	89.0%	0.2
3026	HVAC	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	idential New Construct	MF	NC	4,838	26%	1,282	0.26	16	$630	100%	79%	HP-6	15%	0%	89.0%	80.6%	2.5
3027	HVAC	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	31%	1,950	0.42	16	$855	100%	58%	HP-1	15%	36%	89.0%	75.1%	3.9
3028	HVAC	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	ne Qualified Weatheriz	SF	MO	6,223	31%	1,950	0.42	16	$855	100%	100%	HP-2	15%	36%	89.0%	89.0%	0.4
3029	HVAC	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	idential New Construct	SF	NC	6,223	31%	1,950	0.42	16	$855	100%	58%	HP-3	15%	0%	89.0%	75.1%	3.9
3030	HVAC	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	32%	1,531	0.33	16	$855	100%	58%	HP-4	15%	36%	89.0%	75.1%	3.1
3031	HVAC	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	ne Qualified Weatheriz	MF	MO	4,838	32%	1,531	0.33	16	$855	100%	100%	HP-5	15%	36%	89.0%	89.0%	0.3
3032	HVAC	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	idential New Construct	MF	NC	4,838	32%	1,531	0.33	16	$855	100%	58%	HP-6	15%	0%	89.0%	75.1%	3.1
3033	HVAC	Ground Source Heat Pump 20 SEER - Heat pump baseline	No Program	SF	MO	6,223	27%	1,692	0.57	25	$5,186	50%	25%	HP-1	15%	36%	62.8%	46.2%	2.3
3034	HVAC	Ground Source Heat Pump 20 SEER - Heat pump baseline	No Program	SF	NC	6,223	27%	1,692	0.57	25	$5,186	50%	25%	HP-3	15%	0%	62.8%	46.2%	2.3
3035	HVAC	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	11%	657	0.12	15	$155	100%	100%	HP-1	15%	36%	89.0%	89.0%	2.3
3036	HVAC	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Residential Midstream	SF	NC	6,223	11%	657	0.12	15	$155	100%	100%	HP-3	15%	0%	89.0%	89.0%	2.3
3037	HVAC	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	11%	517	0.09	15	$124	100%	100%	HP-4	15%	36%	89.0%	89.0%	1.8
3038	HVAC	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Residential Midstream	MF	NC	4,838	11%	517	0.09	15	$124	100%	100%	HP-6	15%	0%	89.0%	89.0%	1.8
3039	HVAC	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	19%	1,159	0.23	15	$560	100%	63%	HP-1	15%	36%	89.0%	76.0%	3.1
3040	HVAC	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Residential Midstream	SF	NC	6,223	19%	1,159	0.23	15	$560	100%	63%	HP-3	15%	0%	89.0%	76.0%	3.1
3041	HVAC	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	19%	910	0.19	16	$448	100%	78%	HP-4	15%	36%	89.0%	80.2%	2.5
3042	HVAC	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Residential Midstream	MF	NC	4,838	19%	910	0.19	16	$448	100%	78%	HP-6	15%	0%	89.0%	80.2%	2.5
3043	HVAC	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	28%	1,725	0.33	16	$835	100%	60%	HP-1	15%	36%	89.0%	75.4%	3.2
3044	HVAC	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Residential Midstream	SF	NC	6,223	28%	1,725	0.33	16	$835	100%	60%	HP-3	15%	0%	89.0%	75.4%	3.2
3045	HVAC	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	28%	1,356	0.26	16	$668	100%	75%	HP-4	15%	36%	89.0%	79.1%	2.6
3046	HVAC	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Residential Midstream	MF	NC	4,838	28%	1,356	0.26	16	$668	100%	75%	HP-6	15%	0%	89.0%	79.1%	2.6
3047	HVAC	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Residential Midstream	SF	MO	6,223	33%	2,062	0.42	16	$1,650	100%	30%	HP-1	15%	36%	89.0%	72.3%	4.0
3048	HVAC	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Residential Midstream	SF	NC	6,223	33%	2,062	0.42	16	$1,650	100%	30%	HP-3	15%	0%	89.0%	72.3%	4.0
3049	HVAC	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Residential Midstream	MF	MO	4,838	33%	1,619	0.33	16	$1,320	100%	38%	HP-4	15%	36%	89.0%	72.2%	3.2
3050	HVAC	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Residential Midstream	MF	NC	4,838	33%	1,619	0.33	16	$1,320	100%	38%	HP-6	15%	0%	89.0%	72.2%	3.2
3051	HVAC	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	Residential Midstream	SF	MO	11,402	66%	7,476	0.12	16	$135	100%	100%	HP-7	21%	36%	89.0%	89.0%	15.8
3052	HVAC	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	SF	MO	11,402	66%	7,476	0.12	16	$135	100%	100%	HP-8	21%	36%	89.0%	89.0%	0.7
3053	HVAC	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	idential New Construct	SF	NC	11,402	66%	7,476	0.12	16	$135	100%	100%	HP-9	21%	0%	89.0%	89.0%	14.4
3054	HVAC	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	66%	5,972	0.09	16	$135	100%	100%	HP-10	21%	36%	89.0%	89.0%	12.6
3055	HVAC	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	MF	MO	8,982	66%	5,972	0.09	16	$135	100%	100%	HP-11	21%	36%	89.0%	89.0%	0.6
3056	HVAC	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	idential New Construct	MF	NC	8,982	66%	5,972	0.09	16	$135	100%	100%	HP-12	21%	0%	89.0%	89.0%	11.5
3057	HVAC	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	Residential Midstream	SF	MO	11,402	70%	7,951	0.23	16	$421	100%	71%	HP-7	21%	36%	89.0%	78.1%	14.9
3058	HVAC	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	SF	MO	11,402	70%	7,951	0.23	16	$421	100%	100%	HP-8	21%	36%	89.0%	89.0%	0.8

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3059	HVAC	Air Source Heat Pump 16.2 SEER2 - Electric furnace	idential New Construct	SF	NC	11,402	70%	7,951	0.23	16	$421	100%	65%	HP-9	21%	0%	89.0%	76.7%	16.2
3060	HVAC	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	71%	6,345	0.19	16	$421	100%	71%	HP-10	21%	36%	89.0%	78.1%	11.9
3061	HVAC	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	MF	MO	8,982	71%	6,345	0.19	16	$421	100%	100%	HP-11	21%	36%	89.0%	89.0%	0.7
3062	HVAC	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	idential New Construct	MF	NC	8,982	71%	6,345	0.19	16	$421	100%	65%	HP-12	21%	0%	89.0%	76.7%	13.0
3063	HVAC	Air Source Heat Pump 17.1 SEER2 - Electric furnace	Residential Midstream	SF	MO	11,402	74%	8,486	0.33	16	$630	100%	63%	HP-7	21%	36%	89.0%	76.2%	12.4
3064	HVAC	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	SF	MO	11,402	74%	8,486	0.33	16	$630	100%	100%	HP-8	21%	36%	89.0%	89.0%	0.9
3065	HVAC	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	idential New Construct	SF	NC	11,402	74%	8,486	0.33	16	$630	100%	79%	HP-9	21%	0%	89.0%	80.6%	9.9
3066	HVAC	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	75%	6,766	0.26	16	$630	100%	63%	HP-10	21%	36%	89.0%	76.2%	9.9
3067	HVAC	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	MF	MO	8,982	75%	6,766	0.26	16	$630	100%	100%	HP-11	21%	36%	89.0%	89.0%	0.7
3068	HVAC	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	idential New Construct	MF	NC	8,982	75%	6,766	0.26	16	$630	100%	79%	HP-12	21%	0%	89.0%	80.6%	7.9
3069	HVAC	Air Source Heat Pump 18.1 SEER2 - Electric furnace	Residential Midstream	SF	MO	11,402	77%	8,805	0.42	16	$855	100%	58%	HP-7	21%	36%	89.0%	75.1%	10.6
3070	HVAC	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	SF	MO	11,402	77%	8,805	0.42	16	$855	100%	100%	HP-8	21%	36%	89.0%	89.0%	1.0
3071	HVAC	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	idential New Construct	SF	NC	11,402	77%	8,805	0.42	16	$855	100%	58%	HP-9	21%	0%	89.0%	75.1%	10.6
3072	HVAC	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	78%	7,015	0.33	16	$855	100%	58%	HP-10	21%	36%	89.0%	75.1%	8.5
3073	HVAC	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	ne Qualified Weatheriz	MF	MO	8,982	78%	7,015	0.33	16	$855	100%	100%	HP-11	21%	36%	89.0%	89.0%	0.8
3074	HVAC	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	idential New Construct	MF	NC	8,982	78%	7,015	0.33	16	$855	100%	58%	HP-12	21%	0%	89.0%	75.1%	8.5
3075	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric furnace	Residential Midstream	SF	MO	11,402	54%	6,140	0.12	16	$155	100%	100%	HP-7	21%	36%	89.0%	89.0%	13.2
3076	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline	Residential Midstream	SF	NC	11,402	54%	6,140	0.12	16	$155	100%	100%	HP-9	21%	0%	89.0%	89.0%	13.2
3077	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	55%	4,904	0.09	16	$124	100%	100%	HP-10	21%	36%	89.0%	89.0%	10.5
3078	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline	Residential Midstream	MF	NC	8,982	55%	4,904	0.09	16	$124	100%	100%	HP-12	21%	0%	89.0%	89.0%	10.5
3079	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric furnace	Residential Midstream	SF	MO	11,402	58%	6,643	0.23	16	$560	100%	63%	HP-7	21%	36%	89.0%	76.0%	10.9
3080	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline	Residential Midstream	SF	NC	11,402	58%	6,643	0.23	16	$560	100%	63%	HP-9	21%	0%	89.0%	76.0%	10.9
3081	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	59%	5,297	0.19	16	$448	100%	78%	HP-10	21%	36%	89.0%	80.2%	8.7
3082	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline	Residential Midstream	MF	NC	8,982	59%	5,297	0.19	16	$448	100%	78%	HP-12	21%	0%	89.0%	80.2%	8.7
3083	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric furnace	Residential Midstream	SF	MO	11,402	63%	7,209	0.33	16	$835	100%	60%	HP-7	21%	36%	89.0%	75.4%	8.6
3084	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline	Residential Midstream	SF	NC	11,402	63%	7,209	0.33	16	$835	100%	60%	HP-9	21%	0%	89.0%	75.4%	8.6
3085	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	64%	5,743	0.26	16	$668	100%	75%	HP-10	21%	36%	89.0%	79.1%	6.9
3086	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline	Residential Midstream	MF	NC	8,982	64%	5,743	0.26	16	$668	100%	75%	HP-12	21%	0%	89.0%	79.1%	6.9
3087	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric furnace	Residential Midstream	SF	MO	11,402	66%	7,546	0.42	16	$1,650	100%	30%	HP-7	21%	36%	89.0%	72.3%	9.4
3088	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline	Residential Midstream	SF	NC	11,402	66%	7,546	0.42	16	$1,650	100%	30%	HP-9	21%	0%	89.0%	72.3%	9.4
3089	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline	Residential Midstream	MF	MO	8,982	67%	6,006	0.33	16	$1,320	100%	38%	HP-10	21%	36%	89.0%	72.2%	7.5
3090	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline	Residential Midstream	MF	NC	8,982	67%	6,006	0.33	16	$1,320	100%	38%	HP-12	21%	0%	89.0%	72.2%	7.5
3091	HVAC	AC Tune Up	Residential Prescriptive	SF	Retrofit	2,021	5%	101	0.11	3	$225	11%	11%	AC TUNE-1	64%	44%	27.4%	27.4%	2.9
3092	HVAC	AC Tune Up	ne Qualified Weatheriz	SF	Retrofit	2,021	5%	101	0.11	3	$225	50%	33%	AC TUNE-2	64%	44%	43.0%	42.4%	1.0
3093	HVAC	AC Tune Up	Residential Prescriptive	MF	Retrofit	1,468	5%	73	0.08	3	$225	11%	11%	AC TUNE-3	64%	44%	27.4%	27.4%	2.3
3094	HVAC	AC Tune Up	ne Qualified Weatheriz	MF	Retrofit	1,468	5%	73	0.08	3	$225	50%	33%	AC TUNE-4	64%	44%	43.0%	42.4%	0.8
3095	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	MO	11,402	54%	6,140	0.12	16	$155	100%	100%	HP-13	1%	36%	89.0%	89.0%	13.2
3096	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	NC	11,402	54%	6,140	0.12	16	$155	100%	100%	HP-14	1%	0%	89.0%	89.0%	13.2
3097	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	MO	8,982	55%	4,904	0.09	16	$124	100%	100%	HP-15	1%	36%	89.0%	89.0%	10.5
3098	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	NC	8,982	55%	4,904	0.09	16	$124	100%	100%	HP-16	1%	0%	89.0%	89.0%	10.5
3099	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	MO	11,402	58%	6,643	0.23	16	$560	100%	63%	HP-13	1%	36%	89.0%	76.0%	10.9
3100	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	NC	11,402	58%	6,643	0.23	16	$560	100%	63%	HP-14	1%	0%	89.0%	76.0%	10.9
3101	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	MO	8,982	59%	5,297	0.19	16	$448	100%	78%	HP-15	1%	36%	89.0%	80.2%	8.7
3102	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	NC	8,982	59%	5,297	0.19	16	$448	100%	78%	HP-16	1%	0%	89.0%	80.2%	8.7
3103	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	MO	11,402	63%	7,209	0.33	16	$835	100%	60%	HP-13	1%	36%	89.0%	75.4%	8.6
3104	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	NC	11,402	63%	7,209	0.33	16	$835	100%	60%	HP-14	1%	0%	89.0%	75.4%	8.6
3105	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	MO	8,982	64%	5,743	0.26	16	$668	100%	75%	HP-15	1%	36%	89.0%	79.1%	6.9
3106	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	NC	8,982	64%	5,743	0.26	16	$668	100%	75%	HP-16	1%	0%	89.0%	79.1%	6.9
3107	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	MO	11,402	66%	7,546	0.42	16	$1,650	100%	30%	HP-13	1%	36%	89.0%	72.3%	9.4
3108	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	Residential Midstream	SF	NC	11,402	66%	7,546	0.42	16	$1,650	100%	30%	HP-14	1%	0%	89.0%	72.3%	9.4
3109	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	MO	8,982	67%	6,006	0.33	16	$1,320	100%	38%	HP-15	1%	36%	89.0%	72.2%	7.5
3110	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	Residential Midstream	MF	NC	8,982	67%	6,006	0.33	16	$1,320	100%	38%	HP-16	1%	0%	89.0%	72.2%	7.5
3111	HVAC	Central Air Conditioner 15.2 SEER	Residential Midstream	SF	MO	2,021	6%	113	0.12	18	$1,070	23%	23%	CAC-1	64%	22%	54.3%	54.3%	1.5
3112	HVAC	Central Air Conditioner 15.2 SEER	ne Qualified Weatheriz	SF	MO	2,021	6%	113	0.12	18	$1,070	100%	100%	CAC-2	64%	22%	89.0%	89.0%	0.1
3113	HVAC	Central Air Conditioner 15.2 SEER	idential New Construct	SF	NC	2,021	6%	113	0.12	18	$1,070	9%	9%	CAC-3	64%	0%	43.8%	43.8%	3.7
3114	HVAC	Central Air Conditioner 15.2 SEER	Residential Midstream	MF	MO	1,468	6%	82	0.09	18	$1,070	23%	23%	CAC-4	64%	22%	54.3%	54.3%	1.2
3115	HVAC	Central Air Conditioner 15.2 SEER	ne Qualified Weatheriz	MF	MO	1,468	6%	82	0.09	18	$1,070	100%	100%	CAC-5	64%	22%	89.0%	89.0%	0.1
3116	HVAC	Central Air Conditioner 15.2 SEER	idential New Construct	MF	NC	1,468	6%	82	0.09	18	$1,070	9%	9%	CAC-6	64%	0%	43.8%	43.8%	2.9

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3117	HVAC	Central Air Conditioner 16.2 SEER	Residential Midstream	SF	MO	2,021	11%	223	0.23	18	$1,270	50%	24%	CAC-1	64%	22%	70.9%	49.4%	2.4
3118	HVAC	Central Air Conditioner 16.2 SEER	ne Qualified Weatheriz	SF	MO	2,021	11%	223	0.23	18	$1,270	100%	100%	CAC-2	64%	22%	89.0%	89.0%	0.2
3119	HVAC	Central Air Conditioner 16.2 SEER	idential New Construct	SF	NC	2,021	11%	223	0.23	18	$1,270	50%	8%	CAC-3	64%	0%	70.9%	39.1%	7.2
3120	HVAC	Central Air Conditioner 16.2 SEER	Residential Midstream	MF	MO	1,468	11%	162	0.19	18	$1,270	24%	24%	CAC-4	64%	22%	49.4%	49.4%	1.9
3121	HVAC	Central Air Conditioner 16.2 SEER	ne Qualified Weatheriz	MF	MO	1,468	11%	162	0.19	18	$1,270	100%	100%	CAC-5	64%	22%	89.0%	89.0%	0.2
3122	HVAC	Central Air Conditioner 16.2 SEER	idential New Construct	MF	NC	1,468	11%	162	0.19	18	$1,270	8%	8%	CAC-6	64%	0%	39.1%	39.1%	5.7
3123	HVAC	Central Air Conditioner 17.2 SEER	Residential Midstream	SF	MO	2,021	16%	321	0.34	18	$1,470	50%	27%	CAC-1	64%	22%	65.4%	48.9%	2.6
3124	HVAC	Central Air Conditioner 17.2 SEER	ne Qualified Weatheriz	SF	MO	2,021	16%	321	0.34	18	$1,470	100%	100%	CAC-2	64%	22%	89.0%	89.0%	0.3
3125	HVAC	Central Air Conditioner 17.2 SEER	idential New Construct	SF	NC	2,021	16%	321	0.34	18	$1,470	50%	7%	CAC-3	64%	0%	65.4%	36.5%	10.4
3126	HVAC	Central Air Conditioner 17.2 SEER	Residential Midstream	MF	MO	1,468	16%	233	0.27	18	$1,470	50%	27%	CAC-4	64%	22%	65.4%	48.9%	2.0
3127	HVAC	Central Air Conditioner 17.2 SEER	ne Qualified Weatheriz	MF	MO	1,468	16%	233	0.27	18	$1,470	100%	100%	CAC-5	64%	22%	89.0%	89.0%	0.2
3128	HVAC	Central Air Conditioner 17.2 SEER	idential New Construct	MF	NC	1,468	16%	233	0.27	18	$1,470	50%	7%	CAC-6	64%	0%	65.4%	36.5%	8.2
3129	HVAC	Smart Thermostat - Heat pump baseline	Residential Prescriptive	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	63%	T-STAT-1	15%	30%	89.0%	51.3%	10.2
3130	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	100%	T-STAT-1	15%	30%	89.0%	89.0%	5.1
3131	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	100%	T-STAT-1	15%	30%	89.0%	89.0%	5.1
3132	HVAC	Smart Thermostat - Heat pump baseline	Residential Prescriptive	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	63%	T-STAT-2	15%	30%	89.0%	51.3%	10.2
3133	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	100%	T-STAT-2	15%	30%	89.0%	89.0%	5.1
3134	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	100%	T-STAT-2	15%	30%	89.0%	89.0%	5.1
3135	HVAC	Smart Thermostat - Heat pump baseline	ne Qualified Weatheriz	SF	Retrofit	6,223	8%	527	0.18	11	$79	100%	100%	T-STAT-2	15%	30%	89.0%	89.0%	6.5
3136	HVAC	Smart Thermostat - Heat pump baseline	idential New Construct	SF	NC	6,223	8%	527	0.18	11	$79	100%	63%	T-STAT-3	15%	0%	89.0%	51.3%	10.2
3137	HVAC	Smart Thermostat - Heat pump baseline	Residential Prescriptive	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	63%	T-STAT-4	15%	30%	89.0%	51.3%	8.1
3138	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	100%	T-STAT-4	15%	30%	89.0%	89.0%	4.1
3139	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	100%	T-STAT-4	15%	30%	89.0%	89.0%	4.1
3140	HVAC	Smart Thermostat - Heat pump baseline	lti-Family Energy Soluti	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	100%	T-STAT-4	15%	30%	89.0%	89.0%	5.1
3141	HVAC	Smart Thermostat - Heat pump baseline	Residential Prescriptive	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	63%	T-STAT-5	15%	30%	89.0%	51.3%	8.1
3142	HVAC	Smart Thermostat - Heat pump baseline	Residential Marketplac	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	100%	T-STAT-5	15%	30%	89.0%	89.0%	4.1
3143	HVAC	Smart Thermostat - Heat pump baseline	ne Qualified Weatheriz	MF	Retrofit	4,838	8%	410	0.14	11	$79	100%	100%	T-STAT-5	15%	30%	89.0%	89.0%	4.1
3144	HVAC	Smart Thermostat - Heat pump baseline	idential New Construct	MF	NC	4,838	8%	410	0.14	11	$79	100%	63%	T-STAT-6	15%	0%	89.0%	51.3%	8.1
3145	HVAC	Smart Thermostat - Furnace baseline	Residential Prescriptive	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	63%	T-STAT-7	21%	30%	89.0%	51.3%	13.5
3146	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	100%	T-STAT-7	21%	30%	89.0%	89.0%	6.8
3147	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	100%	T-STAT-7	21%	30%	89.0%	89.0%	6.8
3148	HVAC	Smart Thermostat - Furnace baseline	Residential Prescriptive	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	63%	T-STAT-8	21%	30%	89.0%	51.3%	13.5
3149	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	100%	T-STAT-8	21%	30%	89.0%	89.0%	6.8
3150	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	100%	T-STAT-8	21%	30%	89.0%	89.0%	6.8
3151	HVAC	Smart Thermostat - Furnace baseline	ne Qualified Weatheriz	SF	Retrofit	11,402	8%	967	0.18	11	$79	100%	100%	T-STAT-8	21%	30%	89.0%	89.0%	8.6
3152	HVAC	Smart Thermostat - Furnace baseline	idential New Construct	SF	NC	11,402	8%	967	0.18	11	$79	100%	63%	T-STAT-9	21%	0%	89.0%	51.3%	13.5
3153	HVAC	Smart Thermostat - Furnace baseline	Residential Prescriptive	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	63%	T-STAT-10	21%	30%	89.0%	51.3%	10.7
3154	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	100%	T-STAT-10	21%	30%	89.0%	89.0%	5.4
3155	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	100%	T-STAT-10	21%	30%	89.0%	89.0%	5.4
3156	HVAC	Smart Thermostat - Furnace baseline	lti-Family Energy Soluti	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	100%	T-STAT-10	21%	30%	89.0%	89.0%	6.8
3157	HVAC	Smart Thermostat - Furnace baseline	Residential Prescriptive	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	63%	T-STAT-11	21%	30%	89.0%	51.3%	10.7
3158	HVAC	Smart Thermostat - Furnace baseline	Residential Marketplac	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	100%	T-STAT-11	21%	30%	89.0%	89.0%	5.4
3159	HVAC	Smart Thermostat - Furnace baseline	ne Qualified Weatheriz	MF	Retrofit	8,982	8%	762	0.14	11	$79	100%	100%	T-STAT-11	21%	30%	89.0%	89.0%	5.4
3160	HVAC	Smart Thermostat - Furnace baseline	idential New Construct	MF	NC	8,982	8%	762	0.14	11	$79	100%	63%	T-STAT-12	21%	0%	89.0%	51.3%	10.7
3161	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Prescriptive	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	51%	T-STAT-13	57%	30%	89.0%	43.4%	9.5
3162	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	63%	T-STAT-13	57%	30%	89.0%	51.3%	7.6
3163	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	63%	T-STAT-13	57%	30%	89.0%	51.3%	7.6
3164	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Prescriptive	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	51%	T-STAT-14	57%	30%	89.0%	43.4%	9.5
3165	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	63%	T-STAT-14	57%	30%	89.0%	51.3%	7.6
3166	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	63%	T-STAT-14	57%	30%	89.0%	51.3%	7.6
3167	HVAC	Smart Thermostat - Gas/CAC baseline	ne Qualified Weatheriz	SF	Retrofit	2,021	8%	170	0.18	11	$79	100%	100%	T-STAT-14	57%	30%	89.0%	89.0%	4.8
3168	HVAC	Smart Thermostat - Gas/CAC baseline	idential New Construct	SF	NC	2,021	8%	170	0.18	11	$79	100%	51%	T-STAT-15	57%	0%	89.0%	43.4%	9.5
3169	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	63%	T-STAT-16	57%	30%	89.0%	51.3%	6.2
3170	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	63%	T-STAT-16	57%	30%	89.0%	51.3%	6.2
3171	HVAC	Smart Thermostat - Gas/CAC baseline	lti-Family Energy Soluti	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	100%	T-STAT-16	57%	30%	89.0%	89.0%	3.9
3172	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Prescriptive	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	51%	T-STAT-17	57%	30%	89.0%	43.4%	7.7
3173	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	63%	T-STAT-17	57%	30%	89.0%	51.3%	6.2
3174	HVAC	Smart Thermostat - Gas/CAC baseline	ne Qualified Weatheriz	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	63%	T-STAT-17	57%	30%	89.0%	51.3%	6.2

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3175	HVAC	Smart Thermostat - Gas/CAC baseline	Residential Marketplac	MF	Retrofit	1,835	8%	154	0.14	11	$79	100%	63%	T-STAT-17	57%	30%	89.0%	51.3%	6.2
3176	HVAC	Smart Thermostat - Gas/CAC baseline	idential New Construct	MF	NC	1,835	8%	154	0.14	11	$79	100%	51%	T-STAT-18	57%	0%	89.0%	43.4%	7.7
3177	HVAC	ECM HVAC Motor	No Program	SF	Retrofit	-	0%	657	0.07	6	$350	50%	25%	ECM-1	97%	35%	48.0%	35.0%	2.6
3178	HVAC	ECM HVAC Motor	No Program	SF	NC	-	0%	657	0.07	6	$350	50%	25%	ECM-2	97%	0%	48.0%	35.0%	2.6
3179	HVAC	ECM HVAC Motor	No Program	MF	Retrofit	-	0%	438	0.07	6	$350	25%	25%	ECM-3	97%	35%	35.0%	35.0%	2.0
3180	HVAC	ECM HVAC Motor	No Program	MF	NC	-	0%	438	0.07	6	$350	25%	25%	ECM-4	97%	0%	35.0%	35.0%	2.0
3181	HVAC	Programmable Thermostat - Heat pump baseline	ne Qualified Weatheriz	SF	Retrofit	6,223	4%	268	0.00	16	$60	100%	100%	T-STAT-2	15%	30%	89.0%	89.0%	2.2
3182	HVAC	Programmable Thermostat - Heat pump baseline	ne Qualified Weatheriz	MF	Retrofit	4,838	4%	214	0.00	16	$60	100%	100%	T-STAT-5	15%	30%	89.0%	89.0%	1.8
3183	HVAC	Programmable Thermostat - Furnace baseline	ne Qualified Weatheriz	SF	Retrofit	11,402	5%	589	0.00	16	$60	100%	100%	T-STAT-8	21%	30%	89.0%	89.0%	4.8
3184	HVAC	Programmable Thermostat - Furnace baseline	ne Qualified Weatheriz	MF	Retrofit	8,982	5%	471	0.00	16	$60	100%	100%	T-STAT-11	21%	30%	89.0%	89.0%	3.9
3185	HVAC	Programmable Thermostat - Gas/CAC baseline	ne Qualified Weatheriz	SF	Retrofit	2,021	0%	0	0.00	16	$60	100%	100%	T-STAT-14	57%	30%	89.0%	89.0%	0.0
3186	HVAC	Programmable Thermostat - Gas/CAC baseline	ne Qualified Weatheriz	MF	Retrofit	1,835	0%	0	0.00	16	$60	100%	100%	T-STAT-17	57%	30%	89.0%	89.0%	0.0
3187	HVAC	ENERGY STAR Room Air Conditioner	In Store Discount	SF	MO	1,234	6%	77	0.08	12	$40	100%	63%	RAC-1	35%	53%	89.0%	50.8%	7.4
3188	HVAC	ENERGY STAR Room Air Conditioner	In Store Discount	SF	NC	1,234	6%	77	0.08	12	$40	100%	63%	RAC-2	35%	0%	89.0%	50.8%	7.4
3189	HVAC	ENERGY STAR Room Air Conditioner	In Store Discount	MF	MO	1,107	6%	70	0.08	12	$40	100%	63%	RAC-3	67%	53%	89.0%	50.8%	7.3
3190	HVAC	ENERGY STAR Room Air Conditioner	In Store Discount	MF	NC	1,107	6%	70	0.08	12	$40	100%	63%	RAC-4	67%	0%	89.0%	50.8%	7.3
3191	HVAC	Room AC Recycling	No Program	SF	Recycle	874	100%	874	0.91	4	$20	100%	25%	Room AC Recycle-1	3%	0%	91.0%	35.0%	163.9
3192	HVAC	Room AC Recycling	No Program	MF	Recycle	793	100%	793	0.91	4	$20	100%	25%	Room AC Recycle-2	3%	0%	91.0%	35.0%	161.1
3193	HVAC	Smart Vents/Sensors - Heat pump baseline	No Program	SF	Retrofit	6,223	9%	560	0.10	15	$1,625	25%	25%	Smart Vent-1	15%	16%	35.0%	35.0%	1.2
3194	HVAC	Smart Vents/Sensors - Heat pump baseline	No Program	SF	NC	6,223	9%	560	0.10	15	$1,625	25%	25%	Smart Vent-2	15%	0%	35.0%	35.0%	1.2
3195	HVAC	Smart Vents/Sensors - Heat pump baseline	No Program	MF	Retrofit	4,838	9%	435	0.04	15	$1,040	25%	25%	Smart Vent-3	15%	16%	35.0%	35.0%	1.1
3196	HVAC	Smart Vents/Sensors - Heat pump baseline	No Program	MF	NC	4,838	9%	435	0.04	15	$1,040	25%	25%	Smart Vent-4	15%	0%	35.0%	35.0%	1.1
3197	HVAC	Smart Vents/Sensors - Furnace baseline	No Program	SF	Retrofit	11,402	9%	1,026	0.18	15	$1,625	50%	25%	Smart Vent-5	21%	16%	48.0%	35.0%	2.2
3198	HVAC	Smart Vents/Sensors - Furnace baseline	No Program	SF	NC	11,402	9%	1,026	0.18	15	$1,625	50%	25%	Smart Vent-6	21%	0%	48.0%	35.0%	2.2
3199	HVAC	Smart Vents/Sensors - Furnace baseline	No Program	MF	Retrofit	8,982	9%	808	0.07	15	$1,040	50%	25%	Smart Vent-7	21%	16%	48.0%	35.0%	2.1
3200	HVAC	Smart Vents/Sensors - Furnace baseline	No Program	MF	NC	8,982	9%	808	0.07	15	$1,040	50%	25%	Smart Vent-8	21%	0%	48.0%	35.0%	2.1
3201	HVAC	Smart Vents/Sensors - Gas/CAC baseline	No Program	SF	Retrofit	2,021	9%	182	0.07	15	$1,625	25%	25%	Smart Vent-9	57%	16%	35.0%	35.0%	0.6
3202	HVAC	Smart Vents/Sensors - Gas/CAC baseline	No Program	SF	NC	2,021	9%	182	0.07	15	$1,625	25%	25%	Smart Vent-10	57%	0%	35.0%	35.0%	0.6
3203	HVAC	Smart Vents/Sensors - Gas/CAC baseline	No Program	MF	Retrofit	1,835	9%	165	0.06	15	$1,040	25%	25%	Smart Vent-11	57%	16%	35.0%	35.0%	0.8
3204	HVAC	Smart Vents/Sensors - Gas/CAC baseline	No Program	MF	NC	1,835	9%	165	0.06	15	$1,040	25%	25%	Smart Vent-12	57%	0%	35.0%	35.0%	0.8
3205	HVAC	Whole House Attic Fan	No Program	SF	Retrofit	2,021	4%	82	0.01	15	$1,128	25%	25%	WHAF-1	10%	22%	35.0%	35.0%	0.2
3206	HVAC	Whole House Attic Fan	No Program	SF	NC	2,021	4%	82	0.01	15	$1,128	25%	25%	WHAF-2	10%	0%	35.0%	35.0%	0.2
3207	HVAC	Whole House Attic Fan	No Program	MF	Retrofit	1,468	6%	82	0.01	15	$1,128	25%	25%	WHAF-3	1%	22%	35.0%	35.0%	0.2
3208	HVAC	Whole House Attic Fan	No Program	MF	NC	1,468	6%	82	0.01	15	$1,128	25%	25%	WHAF-4	1%	0%	35.0%	35.0%	0.2
3209	HVAC	Attic Fan	No Program	SF	Retrofit	2,021	4%	87	0.18	15	$125	100%	25%	AF-1	10%	22%	91.0%	35.0%	14.4
3210	HVAC	Attic Fan	No Program	SF	NC	2,021	4%	87	0.18	15	$125	100%	25%	AF-2	10%	0%	91.0%	35.0%	14.4
3211	HVAC	Attic Fan	No Program	MF	Retrofit	1,468	2%	34	0.12	15	$125	100%	25%	AF-3	1%	22%	91.0%	35.0%	9.2
3212	HVAC	Attic Fan	No Program	MF	NC	1,468	2%	34	0.12	15	$125	100%	25%	AF-4	1%	0%	91.0%	35.0%	9.2
3213	HVAC	ENERGY STAR Bath Vent Fan	In Store Discount	SF	Retrofit	47	84%	39	0.05	19	$48	100%	52%	BATH FAN-1	223%	22%	89.0%	44.2%	5.9
3214	HVAC	ENERGY STAR Bath Vent Fan	In Store Discount	SF	NC	47	84%	39	0.05	19	$48	100%	52%	BATH FAN-2	223%	0%	89.0%	44.2%	5.9
3215	HVAC	ENERGY STAR Bath Vent Fan	In Store Discount	MF	Retrofit	47	84%	39	0.05	19	$48	100%	52%	BATH FAN-3	145%	22%	89.0%	44.2%	5.9
3216	HVAC	ENERGY STAR Bath Vent Fan	In Store Discount	MF	NC	47	84%	39	0.05	19	$48	100%	52%	BATH FAN-4	145%	0%	89.0%	44.2%	5.9
3217	HVAC	Energy Recovery Ventilator - Heat Pump	No Program	SF	Retrofit	6,223	13%	794	0.06	15	$4,710	25%	25%	ERV-1	15%	0%	35.0%	35.0%	0.4
3218	HVAC	Energy Recovery Ventilator - Electric Resistance	No Program	SF	Retrofit	11,402	13%	1,458	0.11	15	$4,710	25%	25%	ERV-2	21%	0%	35.0%	35.0%	0.8
3219	HVAC	Energy Recovery Ventilator - Heat Pump	No Program	SF	NC	6,223	13%	794	0.06	15	$4,710	25%	25%	ERV-3	15%	0%	35.0%	35.0%	0.4
3220	HVAC	Energy Recovery Ventilator - Electric Resistance	No Program	SF	NC	11,402	13%	1,458	0.11	15	$4,710	25%	25%	ERV-4	21%	0%	35.0%	35.0%	0.8
3221	HVAC	Energy Recovery Ventilator - Heat Pump	No Program	MF	Retrofit	4,838	1%	38	0.00	15	$4,710	25%	25%	ERV-5	15%	0%	35.0%	35.0%	0.0
3222	HVAC	Energy Recovery Ventilator - Electric Resistance	No Program	MF	Retrofit	8,982	5%	411	0.03	15	$4,710	25%	25%	ERV-6	21%	0%	35.0%	35.0%	0.2
3223	HVAC	Energy Recovery Ventilator - Heat Pump	No Program	MF	NC	4,838	1%	38	0.00	15	$4,710	25%	25%	ERV-7	15%	0%	35.0%	35.0%	0.0
3224	HVAC	Energy Recovery Ventilator - Electric Resistance	No Program	MF	NC	8,982	5%	411	0.03	15	$4,710	25%	25%	ERV-8	21%	0%	35.0%	35.0%	0.2
3225	HVAC	Eco-Snap Air Conditioning	No Program	SF	MO	1,234	6%	75	0.05	15	$80	100%	25%	RAC-1	35%	0%	91.0%	35.0%	7.4
3226	HVAC	Eco-Snap Air Conditioning	No Program	SF	NC	1,234	6%	75	0.05	15	$80	100%	25%	RAC-2	35%	0%	91.0%	35.0%	7.4
3227	HVAC	Eco-Snap Air Conditioning	No Program	MF	MO	1,107	7%	75	0.05	15	$80	100%	25%	RAC-3	67%	0%	91.0%	35.0%	7.4
3228	HVAC	Eco-Snap Air Conditioning	No Program	MF	NC	1,107	7%	75	0.05	15	$80	100%	25%	RAC-4	67%	0%	91.0%	35.0%	7.4
3229	HVAC	Residential-Sized Sub-Wet Bulb Chiller	No Program	SF	MO	2,021	35%	707	0.50	20	$1,950	75%	25%	CAC-1	64%	0%	64.0%	35.0%	3.7
3230	HVAC	Residential-Sized Sub-Wet Bulb Chiller	No Program	SF	NC	2,021	35%	707	0.50	20	$1,950	75%	25%	CAC-2	64%	0%	64.0%	35.0%	3.7
3231	HVAC	Residential-Sized Sub-Wet Bulb Chiller	No Program	MF	MO	1,835	35%	642	0.50	20	$1,950	75%	25%	CAC-3	64%	0%	64.0%	35.0%	3.6
3232	HVAC	Residential-Sized Sub-Wet Bulb Chiller	No Program	MF	NC	1,835	35%	642	0.50	20	$1,950	75%	25%	CAC-4	64%	0%	64.0%	35.0%	3.6

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3233	HVAC	Solar-Assisted Air Conditioning	No Program	SF	MO	2,021	30%	606	0.50	15	$533	100%	25%	CAC-1	64%	0%	91.0%	35.0%	10.6
3234	HVAC	Solar-Assisted Air Conditioning	No Program	SF	NC	2,021	30%	606	0.50	15	$533	100%	25%	CAC-2	64%	0%	91.0%	35.0%	10.6
3235	HVAC	Solar-Assisted Air Conditioning	No Program	MF	MO	1,835	30%	551	0.50	15	$533	100%	25%	CAC-3	64%	0%	91.0%	35.0%	10.4
3236	HVAC	Solar-Assisted Air Conditioning	No Program	MF	NC	1,835	30%	551	0.50	15	$533	100%	25%	CAC-4	64%	0%	91.0%	35.0%	10.4
3237	HVAC	Electro Caloric Heat Pump	No Program	SF	MO	8,255	33%	2,724	1.20	15	$2,508	100%	25%	HP-1	15%	0%	91.0%	35.0%	6.4
3238	HVAC	Electro Caloric Heat Pump	No Program	SF	NC	8,255	33%	2,724	1.20	15	$2,508	100%	25%	HP-2	15%	0%	91.0%	35.0%	6.4
3239	HVAC	Electro Caloric Heat Pump	No Program	MF	MO	5,503	33%	1,816	1.20	15	$2,006	100%	25%	HP-3	15%	0%	91.0%	35.0%	7.1
3240	HVAC	Electro Caloric Heat Pump	No Program	MF	NC	5,503	33%	1,816	1.20	15	$2,006	100%	25%	HP-4	15%	0%	91.0%	35.0%	7.1
4001	Lighting	LED Nightlights	Residential Marketplac	SF	MO	15	93%	14	0.00	8	$3	100%	60%	NIGHT-1	132%	59%	95.0%	58.4%	2.0
4002	Lighting	LED Nightlights	Residential Marketplac	SF	MO	15	93%	14	0.00	8	$3	100%	60%	NIGHT-2	132%	59%	95.0%	58.4%	2.0
4003	Lighting	LED Nightlights	ne Qualified Weatheriz	SF	MO	15	47%	7	0.00	8	$3	100%	100%	NIGHT-2	132%	59%	95.0%	95.0%	0.6
4004	Lighting	LED Nightlights	Residential Marketplac	SF	NC	15	93%	14	0.00	8	$3	100%	60%	NIGHT-3	132%	0%	95.0%	58.4%	2.0
4005	Lighting	LED Nightlights	Residential Marketplac	MF	MO	15	93%	14	0.00	8	$3	100%	60%	NIGHT-4	63%	59%	95.0%	58.4%	2.0
4006	Lighting	LED Nightlights	lti-Family Energy Soluti	MF	MO	15	93%	14	0.00	8	$3	100%	100%	NIGHT-4	63%	59%	95.0%	95.0%	1.2
4007	Lighting	LED Nightlights	Residential Marketplac	MF	MO	15	93%	14	0.00	8	$3	100%	60%	NIGHT-5	63%	59%	95.0%	58.4%	2.0
4008	Lighting	LED Nightlights	ne Qualified Weatheriz	MF	MO	15	93%	14	0.00	8	$3	100%	100%	NIGHT-5	63%	59%	95.0%	95.0%	1.2
4009	Lighting	LED Nightlights	Residential Marketplac	MF	NC	15	93%	14	0.00	8	$3	100%	60%	NIGHT-6	63%	0%	95.0%	58.4%	2.0
4010	Lighting	Ceiling Fan	No Program	SF	MO	36	58%	21	0.00	10	$46	25%	25%	CFAN-1	257%	22%	35.0%	35.0%	0.6
4011	Lighting	Ceiling Fan	No Program	SF	NC	36	58%	21	0.00	10	$46	25%	25%	CFAN-2	257%	0%	35.0%	35.0%	0.6
4012	Lighting	Ceiling Fan	No Program	MF	MO	36	58%	21	0.00	10	$46	25%	25%	CFAN-3	96%	22%	35.0%	35.0%	0.6
4013	Lighting	Ceiling Fan	No Program	MF	NC	36	58%	21	0.00	10	$46	25%	25%	CFAN-4	96%	0%	35.0%	35.0%	0.6
4014	Lighting	Linear LED	No Program	SF	MO	41	45%	18	0.00	10	$10	75%	25%	LINEAR-1	509%	59%	64.0%	35.0%	1.8
4015	Lighting	Linear LED	No Program	SF	NC	41	45%	18	0.00	10	$10	75%	25%	LINEAR-2	509%	0%	64.0%	35.0%	1.8
4016	Lighting	Linear LED	No Program	MF	MO	41	45%	18	0.00	10	$10	75%	25%	LINEAR-3	325%	59%	64.0%	35.0%	1.8
4017	Lighting	Linear LED	No Program	MF	NC	41	45%	18	0.00	9	$10	75%	25%	LINEAR-4	325%	0%	64.0%	35.0%	1.6
4018	Lighting	Occupancy Sensor	No Program	SF	Retrofit	302	30%	89	0.01	10	$30	100%	25%	SENSOR-1	100%	31%	91.0%	35.0%	5.8
4019	Lighting	Occupancy Sensor	No Program	SF	NC	302	30%	89	0.01	10	$30	100%	25%	SENSOR-2	100%	0%	91.0%	35.0%	5.8
4020	Lighting	Occupancy Sensor	No Program	MF	Retrofit	302	30%	89	0.01	10	$30	100%	25%	SENSOR-3	100%	31%	91.0%	35.0%	5.8
4021	Lighting	Occupancy Sensor	No Program	MF	NC	302	30%	89	0.01	10	$30	100%	25%	SENSOR-4	100%	0%	91.0%	35.0%	5.8
4022	Lighting	Exterior Lighting Controls	No Program	SF	Retrofit	108	80%	86	0.00	10	$3	100%	25%	ELC-1	252%	31%	91.0%	35.0%	39.9
4023	Lighting	Exterior Lighting Controls	No Program	SF	NC	108	80%	86	0.00	10	$3	100%	25%	ELC-2	252%	0%	91.0%	35.0%	39.9
4024	Lighting	Exterior Lighting Controls	No Program	MF	Retrofit	108	80%	86	0.00	10	$3	100%	25%	ELC-3	145%	31%	91.0%	35.0%	39.9
4025	Lighting	Exterior Lighting Controls	No Program	MF	NC	108	80%	86	0.00	10	$3	100%	25%	ELC-4	145%	0%	91.0%	35.0%	39.9
4026	Lighting	EISA Exempt LED	No Program	SF	MO	11	50%	6	0.01	15	$2	100%	25%	EISA BULB-1	100%	59%	91.0%	35.0%	35.5
4027	Lighting	EISA Exempt LED	No Program	SF	NC	11	50%	6	0.01	15	$2	100%	25%	EISA BULB-2	100%	0%	91.0%	35.0%	35.5
4028	Lighting	EISA Exempt LED	No Program	MF	MO	11	50%	6	0.01	15	$2	100%	25%	EISA BULB-3	100%	59%	91.0%	35.0%	35.5
4029	Lighting	EISA Exempt LED	No Program	MF	NC	11	50%	6	0.01	15	$2	100%	25%	EISA BULB-4	100%	0%	91.0%	35.0%	35.5
4030	Lighting	Connected LED Lamps	No Program	SF	MO	9	33%	3	0.00	10	$20	25%	25%	CONNECTED LED-1	100%	59%	35.0%	35.0%	0.2
4031	Lighting	Connected LED Lamps	No Program	SF	NC	9	33%	3	0.00	10	$20	25%	25%	CONNECTED LED-2	100%	0%	35.0%	35.0%	0.2
4032	Lighting	Connected LED Lamps	No Program	MF	MO	9	33%	3	0.00	10	$20	25%	25%	CONNECTED LED-3	100%	59%	35.0%	35.0%	0.2
4033	Lighting	Connected LED Lamps	No Program	MF	NC	9	33%	3	0.00	10	$20	25%	25%	CONNECTED LED-4	100%	0%	35.0%	35.0%	0.2
4034	Lighting	Ultra-Efficient LED	No Program	SF	MO	11	50%	6	0.01	20	$3	100%	25%	UE LED-1	100%	59%	91.0%	35.0%	26.7
4035	Lighting	Ultra-Efficient LED	No Program	SF	NC	11	50%	6	0.01	20	$3	100%	25%	UE LED-2	100%	0%	91.0%	35.0%	26.7
4036	Lighting	Ultra-Efficient LED	No Program	MF	MO	11	50%	5	0.01	20	$3	100%	25%	UE LED-3	100%	59%	91.0%	35.0%	25.8
4037	Lighting	Ultra-Efficient LED	No Program	MF	NC	11	50%	5	0.01	20	$3	100%	25%	UE LED-4	100%	0%	91.0%	35.0%	25.8
4038	Lighting	Advanced Lighting	No Program	SF	MO	2,000	10%	200	0.02	18	$194	75%	25%	ADVANCED LIGHT-	100%	0%	64.0%	35.0%	3.3
4039	Lighting	Advanced Lighting	No Program	SF	NC	2,000	10%	200	0.02	18	$194	75%	25%	ADVANCED LIGHT-	100%	0%	64.0%	35.0%	3.3
4040	Lighting	Advanced Lighting	No Program	MF	MO	1,000	10%	100	0.01	18	$97	75%	25%	ADVANCED LIGHT-	100%	0%	64.0%	35.0%	3.3
4041	Lighting	Advanced Lighting	No Program	MF	NC	1,000	10%	100	0.01	18	$97	75%	25%	ADVANCED LIGHT-	100%	0%	64.0%	35.0%	3.3
5001	New Construction	Sub-52 HERS Kicker - Gas Heat + CAC	idential New Construct	SF	NC	11,455	13%	1,523	0.17	25	$160	100%	100%	NC-1	57%	0%	89.0%	89.0%	9.9
5002	New Construction	Whole Home - BOP 1 - Gas Heat + CAC	idential New Construct	SF	NC	11,455	3%	315	0.04	25	$95	100%	100%	NC-1	57%	0%	89.0%	89.0%	3.4
5003	New Construction	Whole Home - BOP 1 - Heat Pump	idential New Construct	SF	NC	11,455	9%	1,013	0.12	20	$375	100%	100%	NC-2	36%	0%	89.0%	89.0%	2.4
5004	New Construction	Whole Home - BOP 2 - Gas Heat + CAC	idential New Construct	SF	NC	11,455	3%	315	0.04	20	$180	100%	100%	NC-1	57%	0%	89.0%	89.0%	1.6
5005	New Construction	Whole Home - BOP 2 - Heat Pump	idential New Construct	SF	NC	11,455	12%	1,351	0.15	20	$600	100%	100%	NC-2	36%	0%	89.0%	89.0%	2.0
5006	New Construction	Sub-52 HERS Kicker - Gas Heat + CAC	idential New Construct	MF	NC	5,728	27%	1,523	0.17	20	$160	100%	100%	NC-3	57%	0%	89.0%	89.0%	3.0
5007	New Construction	Whole Home - BOP 1 - Gas Heat + CAC	idential New Construct	MF	NC	5,728	6%	315	0.04	20	$95	100%	100%	NC-3	57%	0%	89.0%	89.0%	1.1
5008	New Construction	Whole Home - BOP 1 - Heat Pump	idential New Construct	MF	NC	5,728	18%	1,013	0.12	20	$375	100%	100%	NC-4	36%	0%	89.0%	89.0%	2.4
5009	New Construction	Whole Home - BOP 2 - Gas Heat + CAC	idential New Construct	MF	NC	5,728	6%	315	0.04	20	$180	100%	100%	NC-3	57%	0%	89.0%	89.0%	0.6

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
5010	New Construction	Whole Home - BOP 2 - Heat Pump	idential New Construct	MF	NC	5,728	24%	1,351	0.15	20	$600	100%	100%	NC-4	36%	0%	89.0%	89.0%	2.0
6001	Pool/Pump	Variable Speed Pool Pump	No Program	SF	MO	1,159	26%	297	2.02	7	$314	100%	25%	POOL-1	7%	11%	91.0%	35.0%	32.3
6002	Pool/Pump	Variable Speed Pool Pump	No Program	SF	NC	1,159	26%	297	2.02	7	$314	100%	25%	POOL-2	7%	0%	91.0%	35.0%	32.3
6003	Pool/Pump	Variable Speed Pool Pump	No Program	MF	MO	1,159	26%	297	2.02	7	$314	100%	25%	POOL-3	1%	11%	91.0%	35.0%	32.3
6004	Pool/Pump	Variable Speed Pool Pump	No Program	MF	NC	1,159	26%	297	2.02	7	$314	100%	25%	POOL-4	1%	0%	91.0%	35.0%	32.3
6005	Pool/Pump	Heat Pump Swimming Pool Heater (COP >=6.0)	Residential Prescriptive	SF	MO	15,496	10%	1,594	0.00	15	$1,916	42%	42%	POOL HEATER-1	1%	2%	47.1%	47.1%	0.9
6006	Pool/Pump	Heat Pump Swimming Pool Heater (COP >=6.0)	Residential Prescriptive	SF	NC	15,496	10%	1,594	0.00	15	$1,916	42%	42%	POOL HEATER-2	1%	0%	47.1%	47.1%	0.9
6007	Pool/Pump	Heat Pump Swimming Pool Heater (COP >=6.0)	Residential Prescriptive	MF	MO	15,496	10%	1,594	0.00	15	$1,916	42%	42%	POOL HEATER-3	0%	2%	47.1%	47.1%	0.9
6008	Pool/Pump	Heat Pump Swimming Pool Heater (COP >=6.0)	Residential Prescriptive	MF	NC	15,496	10%	1,594	0.00	15	$1,916	42%	42%	POOL HEATER-4	0%	0%	47.1%	47.1%	0.9
6009	Pool/Pump	Heat Pump Swimming Pool Heater (COP 5.5-5.9)	Residential Prescriptive	SF	MO	15,496	6%	1,005	0.00	15	$1,916	18%	18%	POOL HEATER-1	1%	2%	31.8%	31.8%	1.3
6010	Pool/Pump	Heat Pump Swimming Pool Heater (COP 5.5-5.9)	Residential Prescriptive	SF	NC	15,496	6%	1,005	0.00	15	$1,916	18%	18%	POOL HEATER-2	1%	0%	31.8%	31.8%	1.3
6011	Pool/Pump	Heat Pump Swimming Pool Heater (COP 5.5-5.9)	Residential Prescriptive	MF	MO	15,496	6%	1,005	0.00	15	$1,916	18%	18%	POOL HEATER-3	0%	2%	31.8%	31.8%	1.3
6012	Pool/Pump	Heat Pump Swimming Pool Heater (COP 5.5-5.9)	Residential Prescriptive	MF	NC	15,496	6%	1,005	0.00	15	$1,916	18%	18%	POOL HEATER-4	0%	0%	31.8%	31.8%	1.3
7001	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplac	SF	Retrofit	466	12%	57	0.01	7	$10	100%	60%	TIER 1 SS-1	178%	16%	95.0%	58.6%	3.8
7002	Plug Loads	Smart Power Strips - Tier 1	In Store Discount	SF	Retrofit	466	12%	57	0.01	7	$10	100%	60%	TIER 1 SS-1	178%	16%	95.0%	58.6%	3.8
7003	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplac	SF	NC	466	12%	57	0.01	7	$10	100%	60%	TIER 1 SS-2	178%	0%	95.0%	58.6%	3.8
7004	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplac	MF	Retrofit	466	12%	57	0.01	7	$10	100%	60%	TIER 1 SS-3	178%	16%	95.0%	58.6%	3.8
7005	Plug Loads	Smart Power Strips - Tier 1	In Store Discount	MF	Retrofit	466	12%	57	0.01	7	$10	100%	60%	TIER 1 SS-3	178%	16%	95.0%	58.6%	3.8
7006	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplac	MF	NC	466	12%	57	0.01	7	$10	100%	60%	TIER 1 SS-4	178%	0%	95.0%	58.6%	3.8
7007	Plug Loads	Smart Power Strips - Tier 2	Residential Marketplac	SF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-1	100%	16%	95.0%	41.4%	11.1
7008	Plug Loads	Smart Power Strips - Tier 2	In Store Discount	SF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-1	100%	16%	95.0%	41.4%	11.1
7009	Plug Loads	Smart Power Strips - Tier 2	Residential Marketplac	SF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-2	100%	16%	95.0%	41.4%	11.1
7010	Plug Loads	Smart Power Strips - Tier 2	In Store Discount	SF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-2	100%	16%	95.0%	41.4%	11.1
7011	Plug Loads	Smart Power Strips - Tier 2	ne Qualified Weatheriz	SF	Retrofit	466	29%	136	0.02	7	$20	100%	100%	TIER 2 SS-2	100%	16%	95.0%	95.0%	3.3
7012	Plug Loads	Smart Power Strips - Tier 2	Residential Marketplac	SF	NC	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-3	100%	0%	95.0%	41.4%	11.1
7013	Plug Loads	Smart Power Strips - Tier 2	Residential Marketplac	MF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-4	100%	16%	95.0%	41.4%	11.1
7014	Plug Loads	Smart Power Strips - Tier 2	In Store Discount	MF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-4	100%	16%	95.0%	41.4%	11.1
7015	Plug Loads	Smart Power Strips - Tier 2	Residential Marketplac	MF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-5	100%	16%	95.0%	41.4%	11.1
7016	Plug Loads	Smart Power Strips - Tier 2	In Store Discount	MF	Retrofit	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-5	100%	16%	95.0%	41.4%	11.1
7017	Plug Loads	Smart Power Strips - Tier 2	ne Qualified Weatheriz	MF	Retrofit	466	29%	136	0.02	7	$20	100%	100%	TIER 2 SS-5	100%	16%	95.0%	95.0%	3.3
7018	Plug Loads	Smart Power Strips - Tier 2	Residential Marketplac	MF	NC	466	29%	136	0.02	7	$20	100%	30%	TIER 2 SS-6	100%	0%	95.0%	41.4%	11.1
7019	Plug Loads	ENERGY STAR Television	No Program	SF	MO	286	25%	72	0.01	5	$60	25%	25%	TV-1	259%	46%	35.0%	35.0%	1.5
7020	Plug Loads	ENERGY STAR Television	No Program	SF	NC	286	25%	72	0.01	5	$60	25%	25%	TV-2	259%	0%	35.0%	35.0%	1.5
7021	Plug Loads	ENERGY STAR Television	No Program	MF	MO	286	25%	72	0.01	5	$60	25%	25%	TV-3	171%	46%	35.0%	35.0%	1.5
7022	Plug Loads	ENERGY STAR Television	No Program	MF	NC	286	25%	72	0.01	5	$60	25%	25%	TV-4	171%	0%	35.0%	35.0%	1.5
7023	Plug Loads	Smart Outlets	No Program	SF	Retrofit	466	11%	50	0.01	7	$9	100%	25%	SMART SOCKET-1	100%	16%	91.0%	35.0%	9.7
7024	Plug Loads	Smart Outlets	No Program	SF	NC	466	11%	50	0.01	7	$9	100%	25%	SMART SOCKET-2	100%	0%	91.0%	35.0%	9.7
7025	Plug Loads	Smart Outlets	No Program	MF	Retrofit	466	11%	50	0.01	7	$9	100%	25%	SMART SOCKET-3	100%	16%	91.0%	35.0%	9.7
7026	Plug Loads	Smart Outlets	No Program	MF	NC	466	11%	50	0.01	7	$9	100%	25%	SMART SOCKET-4	100%	0%	91.0%	35.0%	9.7
7027	Plug Loads	Level 2 Electric Vehicle Charger	No Program	SF	Retrofit	84	72%	61	0.01	10	$47	50%	25%	EV-1	2%	31%	76.4%	72.0%	2.8
7028	Plug Loads	Level 2 Electric Vehicle Charger	No Program	SF	NC	84	72%	61	0.01	10	$47	50%	25%	EV-2	2%	0%	76.4%	72.0%	2.8
7029	Plug Loads	Level 2 Electric Vehicle Charger	No Program	MF	Retrofit	84	72%	61	0.01	10	$47	50%	25%	EV-3	2%	31%	76.4%	72.0%	2.8
7030	Plug Loads	Level 2 Electric Vehicle Charger	No Program	MF	NC	84	72%	61	0.01	10	$47	50%	25%	EV-4	2%	0%	76.4%	72.0%	2.8
8001	Shell	Advanced Walls - Heat pump	No Program	SF	Retrofit	6,223	8%	467	0.08	20	$2,470	25%	25%	WALL-1	15%	88%	45.5%	45.5%	0.8
8002	Shell	Advanced Walls - Heat pump	No Program	MF	Retrofit	4,838	8%	363	0.03	20	$1,581	25%	25%	WALL-2	15%	88%	45.5%	45.5%	0.8
8003	Shell	Advanced Walls - Electric furnace	No Program	SF	Retrofit	11,402	8%	855	0.15	20	$2,470	25%	25%	WALL-3	21%	88%	45.5%	45.5%	1.5
8004	Shell	Advanced Walls - Electric furnace	No Program	MF	Retrofit	8,982	8%	674	0.06	20	$1,581	25%	25%	WALL-4	21%	88%	45.5%	45.5%	1.4
8005	Shell	Advanced Walls - Gas Heating	No Program	SF	Retrofit	2,021	8%	152	0.06	20	$2,470	25%	25%	WALL-5	57%	88%	45.5%	45.5%	0.4
8006	Shell	Advanced Walls - Gas Heating	No Program	MF	Retrofit	1,835	8%	138	0.05	20	$1,581	25%	25%	WALL-6	57%	88%	45.5%	45.5%	0.6
8007	Shell	Air Sealing Inadequate Sealing - Heat pump	lome Energy Assessmer	SF	Retrofit	6,223	16%	979	0.18	20	$769	100%	25%	AIR SEAL-1	15%	73%	91.0%	45.5%	5.5
8008	Shell	Air Sealing Inadequate Sealing - Heat pump	ne Qualified Weatheriz	SF	Retrofit	6,223	16%	979	0.18	20	$769	100%	100%	AIR SEAL-2	15%	73%	91.0%	91.0%	1.4
8009	Shell	Air Sealing Inadequate Sealing - Heat pump	lome Energy Assessmer	MF	Retrofit	4,838	10%	467	0.04	20	$447	75%	25%	AIR SEAL-3	15%	73%	81.8%	45.5%	3.4
8010	Shell	Air Sealing Inadequate Sealing - Heat pump	ne Qualified Weatheriz	MF	Retrofit	4,838	10%	467	0.04	20	$447	100%	100%	AIR SEAL-4	15%	73%	91.0%	91.0%	0.9
8011	Shell	Air Sealing Inadequate Sealing - Electric furnace	lome Energy Assessmer	SF	Retrofit	11,402	13%	1,491	0.27	20	$769	100%	25%	AIR SEAL-5	21%	73%	91.0%	45.5%	8.4
8012	Shell	Air Sealing Inadequate Sealing - Electric furnace	ne Qualified Weatheriz	SF	Retrofit	11,402	13%	1,491	0.27	20	$769	100%	100%	AIR SEAL-6	21%	73%	91.0%	91.0%	2.1
8013	Shell	Air Sealing Inadequate Sealing - Electric furnace	lome Energy Assessmer	MF	Retrofit	8,982	8%	714	0.06	20	$447	100%	25%	AIR SEAL-7	21%	73%	91.0%	45.5%	5.3
8014	Shell	Air Sealing Inadequate Sealing - Electric furnace	ne Qualified Weatheriz	MF	Retrofit	8,982	8%	714	0.06	20	$447	100%	100%	AIR SEAL-8	21%	73%	91.0%	91.0%	1.3
8015	Shell	Air Sealing - Inadequate Sealing - Gas Heating	lome Energy Assessmer	SF	Retrofit	2,021	18%	360	0.13	20	$769	50%	25%	AIR SEAL-9	57%	73%	61.6%	45.5%	3.0

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
8016	Shell	Air Sealing - Inadequate Sealing - Gas Heating	ne Qualified Weatheriz	SF	Retrofit	2,021	18%	360	0.13	20	$769	100%	100%	AIR SEAL-10	57%	73%	91.0%	91.0%	0.7
8017	Shell	Air Sealing - Inadequate Sealing - Gas Heating	lome Energy Assessmer	MF	Retrofit	1,835	9%	170	0.06	20	$447	50%	25%	AIR SEAL-11	57%	73%	61.6%	45.5%	2.5
8018	Shell	Air Sealing - Inadequate Sealing - Gas Heating	ne Qualified Weatheriz	MF	Retrofit	1,835	9%	170	0.06	20	$447	100%	100%	AIR SEAL-12	57%	73%	91.0%	91.0%	0.6
8019	Shell	Can Foam	In Store Discount	SF	Retrofit	11,455	0%	6	0.00	20	$3	100%	33%	FOAM-1	100%	73%	91.0%	42.2%	6.5
8020	Shell	Can Foam	In Store Discount	MF	Retrofit	5,728	0%	6	0.00	20	$3	100%	33%	FOAM-2	100%	73%	91.0%	42.2%	5.0
8021	Shell	Caulk	No Program	SF	Retrofit	11,455	0%	16	0.00	10	$5	100%	25%	CAULK-1	100%	73%	91.0%	35.0%	8.2
8022	Shell	Caulk	No Program	MF	Retrofit	5,728	0%	16	0.00	10	$5	100%	25%	CAULK-2	100%	73%	91.0%	35.0%	6.3
8023	Shell	Outlet Gaskets	Residential Marketplac	SF	Retrofit	11,455	0%	3	0.00	20	$5	91%	91%	GASKET-1	100%	73%	80.6%	80.6%	1.0
8024	Shell	Outlet Gaskets	Community Connection	SF	Retrofit	11,455	0%	3	0.00	20	$5	100%	100%	GASKET-2	100%	73%	91.0%	91.0%	0.9
8025	Shell	Outlet Gaskets	Residential Marketplac	MF	Retrofit	5,728	0%	3	0.00	20	$5	91%	91%	GASKET-1	100%	73%	80.6%	80.6%	1.0
8026	Shell	Outlet Gaskets	Community Connection	MF	Retrofit	5,728	0%	3	0.00	20	$5	100%	100%	GASKET-2	100%	73%	91.0%	91.0%	0.9
8027	Shell	Door Sweep	In Store Discount	SF	Retrofit	11,455	1%	94	0.02	20	$5	100%	55%	SWEEP-1	100%	73%	91.0%	50.8%	33.8
8028	Shell	Door Sweep	Community Connection	SF	Retrofit	11,455	1%	94	0.01	20	$5	100%	100%	SWEEP-2	100%	73%	91.0%	91.0%	14.2
8029	Shell	Door Sweep	In Store Discount	MF	Retrofit	5,728	2%	94	0.02	20	$5	100%	55%	SWEEP-3	100%	73%	91.0%	50.8%	33.8
8030	Shell	Door Sweep	Community Connection	MF	Retrofit	5,728	2%	94	0.01	20	$5	100%	100%	SWEEP-4	100%	73%	91.0%	91.0%	14.2
8031	Shell	Door and Window Weather Stripping	In Store Discount	SF	Retrofit	11,455	1%	105	0.02	20	$5	100%	18%	WX STRIP-1	100%	73%	91.0%	30.1%	113.3
8032	Shell	Door and Window Weather Stripping	Residential Marketplac	SF	Retrofit	11,455	1%	105	0.02	20	$5	100%	55%	WX STRIP-1	100%	73%	91.0%	50.8%	37.8
8033	Shell	Door and Window Weather Stripping	Community Connection	SF	Retrofit	11,455	1%	105	0.02	20	$5	100%	100%	WX STRIP-2	100%	73%	91.0%	91.0%	20.7
8034	Shell	Door and Window Weather Stripping	In Store Discount	MF	Retrofit	5,728	2%	105	0.01	20	$5	100%	18%	WX STRIP-3	100%	73%	91.0%	30.1%	86.7
8035	Shell	Door and Window Weather Stripping	Residential Marketplac	MF	Retrofit	5,728	2%	105	0.01	20	$5	100%	55%	WX STRIP-3	100%	73%	91.0%	50.8%	28.9
8036	Shell	Door and Window Weather Stripping	Community Connection	MF	Retrofit	5,728	2%	105	0.01	20	$5	100%	100%	WX STRIP-4	100%	73%	91.0%	91.0%	15.8
8037	Shell	Attic Insulation - Inadequate Insulation - Heat	Residential Prescriptive	SF	Retrofit	6,223	10%	610	0.11	30	$1,243	50%	36%	ATTIC-1	15%	88%	61.6%	51.9%	1.9
8038	Shell	Attic Insulation - Inadequate Insulation - Heat	ne Qualified Weatheriz	SF	Retrofit	6,223	10%	610	0.11	30	$1,243	100%	100%	ATTIC-2	15%	88%	91.0%	91.0%	0.6
8039	Shell	Attic Insulation - Inadequate Insulation - Heat	lti-Family Energy Soluti	MF	Retrofit	4,838	12%	575	0.05	30	$1,172	100%	100%	ATTIC-3	15%	88%	91.0%	91.0%	0.5
8040	Shell	Attic Insulation - Inadequate Insulation - Heat	ne Qualified Weatheriz	MF	Retrofit	4,838	12%	575	0.05	30	$1,172	100%	100%	ATTIC-4	15%	88%	91.0%	91.0%	0.4
8041	Shell	Attic Insulation - Inadequate Insulation - Electric	Residential Prescriptive	SF	Retrofit	11,402	8%	950	0.17	30	$1,243	100%	36%	ATTIC-5	21%	88%	91.0%	51.9%	2.9
8042	Shell	Attic Insulation - Inadequate Insulation - Electric	ne Qualified Weatheriz	SF	Retrofit	11,402	8%	950	0.17	30	$1,243	100%	100%	ATTIC-6	21%	88%	91.0%	91.0%	0.9
8043	Shell	Attic Insulation - Inadequate Insulation - Electric	lti-Family Energy Soluti	MF	Retrofit	8,982	10%	895	0.08	30	$1,172	100%	100%	ATTIC-7	21%	88%	91.0%	91.0%	0.8
8044	Shell	Attic Insulation - Inadequate Insulation - Electric	ne Qualified Weatheriz	MF	Retrofit	8,982	10%	895	0.08	30	$1,172	100%	100%	ATTIC-8	21%	88%	91.0%	91.0%	0.7
8045	Shell	Attic Insulation - Inadequate Insulation - Gas	Residential Prescriptive	SF	Retrofit	2,021	15%	307	0.11	30	$1,243	50%	29%	ATTIC-9	57%	88%	61.6%	48.1%	1.7
8046	Shell	Attic Insulation - Inadequate Insulation - Gas	ne Qualified Weatheriz	SF	Retrofit	2,021	15%	307	0.11	30	$1,243	100%	57%	ATTIC-10	57%	88%	91.0%	67.5%	0.9
8047	Shell	Attic Insulation - Inadequate Insulation - Gas	lti-Family Energy Soluti	MF	Retrofit	1,835	12%	220	0.08	30	$1,172	100%	100%	ATTIC-11	57%	88%	91.0%	91.0%	0.4
8048	Shell	Attic Insulation - Inadequate Insulation - Gas	ne Qualified Weatheriz	MF	Retrofit	1,835	12%	220	0.08	30	$1,172	75%	60%	ATTIC-12	57%	88%	81.8%	70.8%	0.7
8049	Shell	Duct Sealing - Inadequate Sealing - Heat pump	Residential Prescriptive	SF	Retrofit	6,223	18%	1,105	0.20	20	$910	100%	27%	DUCT-1	15%	73%	91.0%	47.1%	4.8
8050	Shell	Duct Sealing - Inadequate Sealing - Heat pump	ne Qualified Weatheriz	SF	Retrofit	6,223	18%	1,105	0.20	20	$910	100%	27%	DUCT-2	15%	73%	91.0%	47.1%	4.8
8051	Shell	Duct Sealing - Inadequate Sealing - Heat pump	Residential Prescriptive	MF	Retrofit	4,838	15%	716	0.06	20	$455	100%	55%	DUCT-3	15%	73%	91.0%	65.9%	2.4
8052	Shell	Duct Sealing - Inadequate Sealing - Heat pump	ne Qualified Weatheriz	MF	Retrofit	4,838	15%	716	0.06	20	$455	100%	55%	DUCT-4	15%	73%	91.0%	65.9%	2.4
8053	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	Residential Prescriptive	SF	Retrofit	11,402	15%	1,670	0.30	20	$910	100%	27%	DUCT-5	21%	73%	91.0%	47.1%	7.2
8054	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	ne Qualified Weatheriz	SF	Retrofit	11,402	15%	1,670	0.30	20	$910	100%	27%	DUCT-6	21%	73%	91.0%	47.1%	7.2
8055	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	Residential Prescriptive	MF	Retrofit	8,982	12%	1,092	0.10	20	$455	100%	55%	DUCT-7	21%	73%	91.0%	65.9%	3.6
8056	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	ne Qualified Weatheriz	MF	Retrofit	8,982	12%	1,092	0.10	20	$455	100%	55%	DUCT-8	21%	73%	91.0%	65.9%	3.6
8057	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	Residential Prescriptive	SF	Retrofit	2,021	17%	341	0.12	20	$910	50%	14%	DUCT-9	57%	73%	61.6%	38.5%	4.3
8058	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	ne Qualified Weatheriz	SF	Retrofit	2,021	17%	341	0.12	20	$910	100%	14%	DUCT-10	57%	73%	91.0%	38.5%	4.3
8059	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	Residential Prescriptive	MF	Retrofit	1,835	11%	207	0.08	20	$455	50%	27%	DUCT-11	57%	73%	61.6%	47.1%	2.7
8060	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	ne Qualified Weatheriz	MF	Retrofit	1,835	11%	207	0.08	20	$455	100%	27%	DUCT-12	57%	73%	91.0%	47.1%	2.7
8061	Shell	Rim/Band Joist Insulation - Heat pump	No Program	SF	Retrofit	6,223	2%	117	0.02	30	$208	75%	25%	RIM JOIST-1	15%	88%	81.8%	45.5%	3.1
8062	Shell	Rim/Band Joist Insulation - Heat pump	No Program	MF	Retrofit	4,838	2%	117	0.01	30	$121	100%	25%	RIM JOIST-2	15%	88%	91.0%	45.5%	4.1
8063	Shell	Rim/Band Joist Insulation - Electric furnace	No Program	SF	Retrofit	11,402	2%	187	0.03	30	$208	100%	25%	RIM JOIST-3	21%	88%	91.0%	45.5%	5.0
8064	Shell	Rim/Band Joist Insulation - Electric furnace	No Program	MF	Retrofit	8,982	2%	187	0.02	30	$121	100%	25%	RIM JOIST-4	21%	88%	91.0%	45.5%	6.6
8065	Shell	Rim/Band Joist Insulation - Gas Heating	No Program	SF	Retrofit	2,021	1%	29	0.01	30	$208	25%	25%	RIM JOIST-5	57%	88%	45.5%	45.5%	1.1
8066	Shell	Rim/Band Joist Insulation - Gas Heating	No Program	MF	Retrofit	1,835	2%	29	0.01	30	$121	25%	25%	RIM JOIST-6	57%	88%	45.5%	45.5%	2.0
8067	Shell	Wall Insulation - Heat pump	Residential Prescriptive	SF	Retrofit	6,223	23%	1,442	0.26	30	$1,539	100%	25%	WALL-1	15%	88%	91.0%	45.5%	5.2
8068	Shell	Wall Insulation - Heat pump	ne Qualified Weatheriz	SF	Retrofit	6,223	23%	1,442	0.26	30	$1,539	100%	57%	WALL-2	15%	88%	91.0%	67.7%	2.3
8069	Shell	Wall Insulation - Heat pump	lti-Family Energy Soluti	MF	Retrofit	4,838	7%	340	0.03	30	$363	100%	100%	WALL-3	15%	88%	91.0%	91.0%	1.0
8070	Shell	Wall Insulation - Heat pump	ne Qualified Weatheriz	MF	Retrofit	4,838	7%	340	0.03	30	$363	100%	100%	WALL-4	15%	88%	91.0%	91.0%	0.4
8071	Shell	Wall Insulation - Electric furnace	Residential Prescriptive	SF	Retrofit	11,402	20%	2,320	0.42	30	$1,539	100%	25%	WALL-5	21%	88%	91.0%	45.5%	8.4
8072	Shell	Wall Insulation - Electric furnace	ne Qualified Weatheriz	SF	Retrofit	11,402	20%	2,320	0.42	30	$1,539	100%	57%	WALL-6	21%	88%	91.0%	67.7%	3.7
8073	Shell	Wall Insulation - Electric furnace	lti-Family Energy Soluti	MF	Retrofit	8,982	6%	547	0.05	30	$363	100%	100%	WALL-7	21%	88%	91.0%	91.0%	1.6

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
8074	Shell	Wall Insulation - Electric furnace	ne Qualified Weatheriz	MF	Retrofit	8,982	6%	547	0.05	30	$363	100%	100%	WALL-8	21%	88%	91.0%	91.0%	0.7
8075	Shell	Wall Insulation - Gas Heating	Residential Prescriptive	SF	Retrofit	2,021	17%	338	0.12	30	$1,539	25%	25%	WALL-9	57%	88%	45.5%	45.5%	1.8
8076	Shell	Wall Insulation - Gas Heating	ne Qualified Weatheriz	SF	Retrofit	2,021	17%	338	0.12	30	$1,539	75%	57%	WALL-10	57%	88%	81.8%	67.7%	0.8
8077	Shell	Wall Insulation - Gas Heating	lti-Family Energy Soluti	MF	Retrofit	1,835	6%	101	0.04	30	$363	100%	100%	WALL-11	57%	88%	91.0%	91.0%	0.6
8078	Shell	Wall Insulation - Gas Heating	ne Qualified Weatheriz	MF	Retrofit	1,835	6%	101	0.04	30	$363	100%	100%	WALL-12	57%	88%	91.0%	91.0%	0.2
8079	Shell	Basement Sidewall Insulation - Heat pump	No Program	SF	Retrofit	6,223	15%	940	0.17	30	$5,171	25%	25%	BASEMENT-1	15%	88%	42.9%	42.9%	1.0
8080	Shell	Basement Sidewall Insulation - Heat pump	No Program	MF	Retrofit	4,838	10%	470	0.04	30	$2,586	25%	25%	BASEMENT-2	15%	88%	45.5%	45.5%	0.8
8081	Shell	Basement Sidewall Insulation - Electric furnace	No Program	SF	Retrofit	11,402	14%	1,636	0.29	30	$5,171	25%	25%	BASEMENT-3	21%	88%	42.9%	42.9%	1.8
8082	Shell	Basement Sidewall Insulation - Electric furnace	No Program	MF	Retrofit	8,982	9%	818	0.07	30	$2,586	25%	25%	BASEMENT-4	21%	88%	45.5%	45.5%	1.3
8083	Shell	Basement Sidewall Insulation - Gas Heating	No Program	SF	Retrofit	2,021	3%	70	0.03	30	$5,171	25%	25%	BASEMENT-5	57%	88%	42.9%	42.9%	0.1
8084	Shell	Basement Sidewall Insulation - Gas Heating	No Program	MF	Retrofit	1,835	2%	35	0.01	30	$2,586	25%	25%	BASEMENT-6	57%	88%	45.5%	45.5%	0.1
8085	Shell	Floor Insulation Above Crawlspace - Heat pump	No Program	SF	Retrofit	6,223	17%	1,088	0.20	30	$961	100%	25%	FLOOR-1	15%	88%	91.0%	45.5%	6.3
8086	Shell	Floor Insulation Above Crawlspace - Heat pump	No Program	MF	Retrofit	4,838	11%	544	0.05	30	$905	50%	25%	FLOOR-2	15%	88%	61.6%	45.5%	2.6
8087	Shell	Floor Insulation Above Crawlspace - Electric furnace	No Program	SF	Retrofit	11,402	16%	1,819	0.33	30	$961	100%	25%	FLOOR-3	21%	88%	91.0%	45.5%	10.5
8088	Shell	Floor Insulation Above Crawlspace - Electric furnace	No Program	MF	Retrofit	8,982	10%	909	0.08	30	$905	100%	25%	FLOOR-4	21%	88%	91.0%	45.5%	4.3
8089	Shell	Floor Insulation Above Crawlspace - Gas Heating	No Program	SF	Retrofit	2,021	8%	162	0.06	30	$961	25%	25%	FLOOR-5	57%	88%	45.5%	45.5%	1.4
8090	Shell	Floor Insulation Above Crawlspace - Gas Heating	No Program	MF	Retrofit	1,835	4%	81	0.03	30	$905	25%	25%	FLOOR-6	57%	88%	45.5%	45.5%	0.7
8091	Shell	ENERGY STAR Windows - Heat pump	No Program	SF	Retrofit	6,223	30%	1,856	0.33	20	$2,159	75%	25%	WINDOW-1	15%	73%	81.8%	44.6%	3.7
8092	Shell	ENERGY STAR Windows - Heat pump	No Program	MF	Retrofit	4,838	22%	1,080	0.10	20	$1,256	50%	25%	WINDOW-2	15%	56%	61.6%	45.5%	2.8
8093	Shell	ENERGY STAR Windows - Electric furnace	No Program	SF	Retrofit	11,402	28%	3,187	0.57	20	$2,159	100%	25%	WINDOW-3	21%	73%	91.0%	44.6%	6.4
8094	Shell	ENERGY STAR Windows - Electric furnace	No Program	MF	Retrofit	8,982	21%	1,854	0.16	20	$1,256	100%	25%	WINDOW-4	21%	56%	91.0%	45.5%	4.9
8095	Shell	ENERGY STAR Windows - Gas Heating	No Program	SF	Retrofit	2,021	15%	300	0.11	20	$2,159	25%	25%	WINDOW-5	57%	73%	44.6%	44.6%	0.9
8096	Shell	ENERGY STAR Windows - Gas Heating	No Program	MF	Retrofit	1,835	9%	167	0.06	20	$1,256	25%	25%	WINDOW-6	57%	56%	45.5%	45.5%	0.9
8097	Shell	Thin Triple Windows - Heat pump	No Program	SF	Retrofit	6,223	6%	393	0.07	40	$12,964	25%	25%	WINDOW-1	15%	73%	37.5%	37.5%	0.2
8098	Shell	Thin Triple Windows - Heat pump	No Program	MF	Retrofit	4,838	5%	229	0.02	40	$8,297	25%	25%	WINDOW-2	15%	56%	39.1%	39.1%	0.1
8099	Shell	Thin Triple Windows - Electric furnace	No Program	SF	Retrofit	11,402	5%	594	0.11	40	$12,964	25%	25%	WINDOW-3	21%	73%	37.5%	37.5%	0.3
8100	Shell	Thin Triple Windows - Electric furnace	No Program	MF	Retrofit	8,982	4%	346	0.03	40	$8,297	25%	25%	WINDOW-4	21%	56%	39.1%	39.1%	0.2
8101	Shell	Thin Triple Windows - Gas heating	No Program	SF	Retrofit	2,021	10%	211	0.08	40	$12,964	25%	25%	WINDOW-5	57%	73%	37.5%	37.5%	0.2
8102	Shell	Thin Triple Windows - Gas heating	No Program	MF	Retrofit	1,835	7%	123	0.05	40	$8,297	25%	25%	WINDOW-6	57%	56%	39.1%	39.1%	0.1
8103	Shell	Window Insulation	Residential Marketplac	SF	Retrofit	11,455	0%	46	0.01	1	$0	100%	100%	WINDOW INS-1	100%	88%	91.0%	91.0%	1.3
8104	Shell	Window Insulation	Residential Marketplac	MF	Retrofit	5,728	1%	46	0.00	1	$0	100%	100%	WINDOW INS-2	100%	88%	91.0%	91.0%	1.0
8105	Shell	Insulated Cellular Shades - Heat pump	No Program	SF	Retrofit	6,223	3%	189	0.03	10	$600	25%	25%	SHADES-1	15%	73%	45.5%	45.5%	0.8
8106	Shell	Insulated Cellular Shades - Heat pump	No Program	MF	Retrofit	4,838	4%	180	0.02	10	$240	25%	25%	SHADES-2	15%	56%	45.5%	45.5%	1.5
8107	Shell	Insulated Cellular Shades - Electric furnace	No Program	SF	Retrofit	11,402	3%	324	0.06	10	$600	25%	25%	SHADES-3	21%	73%	45.5%	45.5%	1.4
8108	Shell	Insulated Cellular Shades - Electric furnace	No Program	MF	Retrofit	8,982	4%	315	0.03	10	$240	50%	25%	SHADES-4	21%	56%	61.6%	45.5%	2.6
8109	Shell	Insulated Cellular Shades - Gas Heating / CAC	No Program	SF	Retrofit	2,021	6%	116	0.04	10	$600	25%	25%	SHADES-5	57%	73%	45.5%	45.5%	0.7
8110	Shell	Insulated Cellular Shades - Gas Heating / CAC	No Program	MF	Retrofit	1,835	5%	85	0.03	10	$240	25%	25%	SHADES-6	57%	56%	45.5%	45.5%	1.4
8111	Shell	Multifamily Whole Building Aerosol Sealing - Heat	lti-Family Energy Soluti	MF	Retrofit	4,838	15%	733	0.06	20	$533	100%	100%	AEROSOL-1	15%	73%	91.0%	91.0%	1.1
8112	Shell	Multifamily Whole Building Aerosol Sealing - Electric furnace	lti-Family Energy Soluti	MF	Retrofit	8,982	14%	1,276	0.11	20	$533	100%	100%	AEROSOL-2	21%	73%	91.0%	91.0%	2.0
8113	Shell	Multifamily Whole Building Aerosol Sealing - Gas Heating / CAC	lti-Family Energy Soluti	MF	Retrofit	1,835	0%	0	0.00	20	$533	100%	100%	AEROSOL-3	57%	73%	91.0%	91.0%	0.0
8114	Shell	Basement Wall Insulation - Nanoinsulation	No Program	SF	Retrofit	11,455	6%	630	0.11	25	$1,327	50%	25%	NANO-1	100%	0%	61.6%	45.5%	2.4
8115	Shell	Basement Wall Insulation - Nanoinsulation	No Program	MF	Retrofit	5,728	6%	315	0.03	25	$1,327	25%	25%	NANO-2	100%	0%	45.5%	45.5%	0.9
8116	Shell	Ceiling / Attic Insulation - Nanoinsulation	No Program	SF	Retrofit	11,455	20%	2,291	0.41	25	$6,310	25%	25%	NANO-3	100%	0%	41.3%	41.3%	1.8
8117	Shell	Ceiling / Attic Insulation - Nanoinsulation	No Program	MF	Retrofit	5,728	20%	1,146	0.10	25	$6,310	25%	25%	NANO-4	100%	0%	41.3%	41.3%	0.7
8118	Shell	Crawlspace Insulation - Nanoinsulation	No Program	SF	Retrofit	11,455	30%	3,437	0.62	25	$1,313	100%	25%	NANO-5	100%	0%	91.0%	45.5%	13.1
8119	Shell	Crawlspace Insulation - Nanoinsulation	No Program	MF	Retrofit	5,728	30%	1,718	0.15	25	$1,313	100%	25%	NANO-6	100%	0%	91.0%	45.5%	5.0
8120	Shell	Floor Insulation - Nanoinsulation	No Program	SF	Retrofit	11,455	2%	229	0.04	25	$1,269	25%	25%	NANO-7	100%	0%	45.5%	45.5%	0.9
8121	Shell	Floor Insulation - Nanoinsulation	No Program	MF	Retrofit	5,728	2%	115	0.01	25	$1,269	25%	25%	NANO-8	100%	0%	45.5%	45.5%	0.3
8122	Shell	Rim and Band Joist Insulation - Nanoinsulation	No Program	SF	Retrofit	11,455	2%	229	0.04	25	$169	100%	25%	NANO-9	100%	0%	91.0%	45.5%	6.8
8123	Shell	Rim and Band Joist Insulation - Nanoinsulation	No Program	MF	Retrofit	5,728	2%	115	0.01	25	$169	50%	25%	NANO-10	100%	0%	61.6%	45.5%	2.6
8124	Shell	Wall Insulation - Nanoinsulation	No Program	SF	Retrofit	11,455	14%	1,604	0.29	25	$3,426	50%	25%	NANO-11	100%	0%	61.6%	45.5%	2.3
8125	Shell	Wall Insulation - Nanoinsulation	No Program	MF	Retrofit	5,728	14%	802	0.07	25	$3,426	25%	25%	NANO-12	100%	0%	45.5%	45.5%	0.9
9001	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Prescriptive	SF	MO	3,242	57%	1,855	0.09	15	$1,030	100%	78%	HPWH-1	21%	17%	93.0%	84.3%	1.3
9002	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Midstream	SF	MO	3,242	57%	1,855	0.09	15	$1,030	100%	49%	HPWH-1	21%	17%	93.0%	77.8%	2.1
9003	Water Heating	Heat Pump Water Heater-electric resistance heat	idential New Construct	SF	NC	3,242	57%	1,855	0.09	15	$1,030	100%	49%	HPWH-2	21%	0%	93.0%	77.8%	2.1
9004	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Prescriptive	MF	MO	3,045	56%	1,707	0.08	15	$1,030	78%	78%	HPWH-3	21%	17%	84.3%	84.3%	1.2
9005	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Midstream	MF	MO	3,045	56%	1,707	0.08	15	$1,030	75%	49%	HPWH-3	21%	17%	83.5%	77.8%	2.0
9006	Water Heating	Heat Pump Water Heater-electric resistance heat	idential New Construct	MF	NC	3,045	56%	1,707	0.08	15	$1,030	75%	49%	HPWH-4	21%	0%	83.5%	77.8%	2.0

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
9007	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Prescriptive	SF	MO	3,242	57%	1,863	0.09	15	$1,030	100%	78%	HPWH-5	15%	17%	93.0%	84.3%	1.3
9008	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Midstream	SF	MO	3,242	57%	1,863	0.09	15	$1,030	100%	49%	HPWH-5	15%	17%	93.0%	77.8%	2.1
9009	Water Heating	Heat Pump Water Heater-heat pump heat	idential New Construct	SF	NC	3,242	57%	1,863	0.09	15	$1,030	100%	49%	HPWH-6	15%	0%	93.0%	77.8%	2.1
9010	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Prescriptive	MF	MO	3,045	56%	1,714	0.08	15	$1,030	78%	78%	HPWH-7	15%	17%	84.3%	84.3%	1.2
9011	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Midstream	MF	MO	3,045	56%	1,714	0.08	15	$1,030	75%	49%	HPWH-7	15%	17%	83.5%	77.8%	2.0
9012	Water Heating	Heat Pump Water Heater-heat pump heat	idential New Construct	MF	NC	3,045	56%	1,714	0.08	15	$1,030	75%	49%	HPWH-8	15%	0%	83.5%	77.8%	2.0
9013	Water Heating	Heat Pump Water Heater-gas heat	Residential Prescriptive	SF	MO	3,242	58%	1,872	0.09	15	$1,030	100%	78%	HPWH-9	4%	17%	93.0%	84.3%	1.3
9014	Water Heating	Heat Pump Water Heater-gas heat	Residential Midstream	SF	MO	3,242	58%	1,872	0.09	15	$1,030	100%	49%	HPWH-9	4%	17%	93.0%	77.8%	2.2
9015	Water Heating	Heat Pump Water Heater-gas heat	idential New Construct	SF	NC	3,242	58%	1,872	0.09	15	$1,030	100%	49%	HPWH-10	4%	0%	93.0%	77.8%	2.2
9016	Water Heating	Heat Pump Water Heater-gas heat	Residential Prescriptive	MF	MO	3,045	57%	1,722	0.08	15	$1,030	78%	78%	HPWH-11	4%	17%	84.3%	84.3%	1.2
9017	Water Heating	Heat Pump Water Heater-gas heat	Residential Midstream	MF	MO	3,045	57%	1,722	0.08	15	$1,030	75%	49%	HPWH-11	4%	17%	83.5%	77.8%	2.0
9018	Water Heating	Heat Pump Water Heater-gas heat	idential New Construct	MF	NC	3,045	57%	1,722	0.08	15	$1,030	75%	49%	HPWH-12	4%	0%	83.5%	77.8%	2.0
9019	Water Heating	Thermostatic Restrictor Shower Valve	Residential Marketplac	SF	Retrofit	3,242	2%	80	0.00	10	$35	86%	86%	TRSV-1	90%	14%	75.8%	75.8%	1.1
9020	Water Heating	Thermostatic Restrictor Shower Valve	Residential Marketplac	SF	NC	3,242	2%	80	0.00	10	$35	86%	86%	TRSV-2	90%	0%	75.8%	75.8%	1.1
9021	Water Heating	Thermostatic Restrictor Shower Valve	Residential Marketplac	MF	Retrofit	3,045	2%	65	0.00	10	$35	86%	86%	TRSV-3	58%	14%	75.8%	75.8%	0.9
9022	Water Heating	Thermostatic Restrictor Shower Valve	Residential Marketplac	MF	NC	3,045	2%	65	0.00	10	$35	86%	86%	TRSV-4	58%	0%	75.8%	75.8%	0.9
9023	Water Heating	Drain water Heat Recovery	No Program	SF	Retrofit	3,242	17%	538	0.05	30	$744	75%	25%	DWHR-1	40%	1%	64.0%	35.0%	3.2
9024	Water Heating	Drain water Heat Recovery	No Program	SF	NC	3,242	17%	538	0.05	30	$744	75%	25%	DWHR-2	40%	0%	64.0%	35.0%	3.2
9025	Water Heating	Drain water Heat Recovery	No Program	MF	Retrofit	3,045	14%	439	0.05	30	$744	50%	25%	DWHR-3	40%	1%	48.0%	35.0%	2.8
9026	Water Heating	Drain water Heat Recovery	No Program	MF	NC	3,045	14%	439	0.05	30	$744	50%	25%	DWHR-4	40%	0%	48.0%	35.0%	2.8
9027	Water Heating	Shower Timer	No Program	SF	Retrofit	3,242	3%	92	0.03	2	$5	100%	25%	ST-1	90%	5%	91.0%	35.0%	15.5
9028	Water Heating	Shower Timer	No Program	SF	NC	3,242	3%	92	0.03	2	$5	100%	25%	ST-2	90%	0%	91.0%	35.0%	15.5
9029	Water Heating	Shower Timer	No Program	MF	Retrofit	3,045	2%	76	0.03	2	$5	100%	25%	ST-3	58%	5%	91.0%	35.0%	12.7
9030	Water Heating	Shower Timer	No Program	MF	NC	3,045	2%	76	0.03	2	$5	100%	25%	ST-4	58%	0%	91.0%	35.0%	12.7
9031	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Marketplac	SF	Retrofit	3,242	8%	271	0.03	10	$7	100%	36%	LFSH-1	90%	61%	93.0%	46.0%	54.9
9032	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Marketplac	SF	Retrofit	3,242	8%	271	0.03	10	$7	100%	36%	LFSH-2	90%	61%	93.0%	48.2%	54.9
9033	Water Heating	Low Flow Showerhead 1.5 gpm	ne Qualified Weatheriz	SF	Retrofit	3,242	8%	271	0.03	10	$12	100%	100%	LFSH-2	90%	61%	93.0%	93.0%	11.4
9034	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Marketplac	SF	NC	3,242	8%	271	0.03	10	$7	100%	36%	LFSH-3	90%	0%	93.0%	48.2%	54.9
9035	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Marketplac	MF	Retrofit	3,045	6%	193	0.02	10	$7	100%	36%	LFSH-4	58%	51%	93.0%	48.2%	41.6
9036	Water Heating	Low Flow Showerhead 1.5 gpm	lti-Family Energy Soluti	MF	Retrofit	3,045	6%	193	0.02	10	$12	100%	100%	LFSH-4	58%	51%	93.0%	93.0%	5.0
9037	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Marketplac	MF	Retrofit	3,045	6%	193	0.02	10	$7	100%	36%	LFSH-5	58%	51%	93.0%	48.2%	41.6
9038	Water Heating	Low Flow Showerhead 1.5 gpm	ne Qualified Weatheriz	MF	Retrofit	3,045	6%	193	0.02	10	$7	100%	100%	LFSH-5	58%	51%	93.0%	93.0%	14.9
9039	Water Heating	Low Flow Showerhead 1.5 gpm	lti-Family Energy Soluti	MF	Retrofit	3,045	6%	193	0.02	10	$12	100%	100%	LFSH-5	58%	51%	93.0%	93.0%	8.7
9040	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Marketplac	MF	NC	3,045	6%	193	0.02	10	$7	100%	36%	LFSH-6	58%	0%	93.0%	48.2%	41.6
9041	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplac	SF	Retrofit	3,242	7%	239	0.05	10	$3	100%	83%	KITCH-1	40%	49%	93.0%	73.2%	64.1
9042	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplac	SF	Retrofit	3,242	7%	239	0.05	10	$3	100%	100%	KITCH-2	40%	49%	93.0%	93.0%	53.4
9043	Water Heating	Kitchen Faucet Aerator 1.5 gpm	ne Qualified Weatheriz	SF	Retrofit	3,242	7%	239	0.05	10	$8	100%	100%	KITCH-2	40%	49%	93.0%	93.0%	20.0
9044	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplac	SF	NC	3,242	7%	239	0.05	10	$3	100%	83%	KITCH-3	40%	0%	93.0%	73.2%	64.1
9045	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplac	MF	Retrofit	3,045	6%	195	0.05	10	$3	100%	83%	KITCH-4	40%	38%	93.0%	73.2%	57.8
9046	Water Heating	Kitchen Faucet Aerator 1.5 gpm	lti-Family Energy Soluti	MF	Retrofit	3,045	6%	195	0.05	10	$3	100%	100%	KITCH-4	40%	38%	93.0%	93.0%	48.2
9047	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplac	MF	Retrofit	3,045	6%	195	0.05	10	$3	100%	83%	KITCH-5	40%	38%	93.0%	73.2%	57.8
9048	Water Heating	Kitchen Faucet Aerator 1.5 gpm	ne Qualified Weatheriz	MF	Retrofit	3,045	6%	195	0.05	10	$3	100%	100%	KITCH-5	40%	38%	93.0%	93.0%	48.2
9049	Water Heating	Kitchen Faucet Aerator 1.5 gpm	lti-Family Energy Soluti	MF	Retrofit	3,045	6%	195	0.05	10	$8	100%	100%	KITCH-5	40%	38%	93.0%	93.0%	18.1
9050	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplac	MF	NC	3,045	6%	177	0.04	10	$3	100%	83%	KITCH-6	40%	0%	93.0%	73.2%	52.4
9051	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplac	SF	Retrofit	3,242	1%	49	0.07	10	$3	100%	33%	BATH-1	70%	49%	93.0%	44.7%	129.2
9052	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplac	SF	Retrofit	3,242	1%	49	0.07	10	$3	100%	100%	BATH-2	70%	49%	93.0%	93.0%	42.2
9053	Water Heating	Bathroom Aerator 1.0 gpm	ne Qualified Weatheriz	SF	Retrofit	3,242	1%	49	0.07	10	$8	100%	100%	BATH-2	70%	49%	93.0%	93.0%	15.8
9054	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplac	SF	NC	3,242	1%	49	0.07	10	$3	100%	33%	BATH-3	70%	0%	93.0%	44.7%	129.2
9055	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplac	MF	Retrofit	3,045	1%	40	0.04	10	$3	100%	33%	BATH-4	52%	38%	93.0%	44.7%	75.3
9056	Water Heating	Bathroom Aerator 1.0 gpm	lti-Family Energy Soluti	MF	Retrofit	3,045	1%	40	0.04	10	$3	100%	100%	BATH-4	52%	38%	93.0%	93.0%	24.6
9057	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplac	MF	Retrofit	3,045	1%	40	0.04	10	$3	100%	33%	BATH-5	52%	38%	93.0%	44.7%	75.3
9058	Water Heating	Bathroom Aerator 1.0 gpm	ne Qualified Weatheriz	MF	Retrofit	3,045	1%	40	0.04	10	$3	100%	100%	BATH-5	52%	38%	93.0%	93.0%	24.6
9059	Water Heating	Bathroom Aerator 1.0 gpm	lti-Family Energy Soluti	MF	Retrofit	3,045	1%	40	0.04	10	$8	100%	100%	BATH-5	52%	38%	93.0%	93.0%	9.2
9060	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplac	MF	NC	3,045	1%	40	0.04	10	$3	100%	33%	BATH-6	52%	0%	93.0%	44.7%	75.3
9061	Water Heating	Pipe Wrap	In Store Discount	SF	Retrofit	3,242	8%	247	0.03	12	$18	100%	25%	PIPE-1	40%	17%	93.0%	37.0%	33.7
9062	Water Heating	Pipe Wrap	Residential Marketplac	SF	Retrofit	3,242	8%	247	0.03	12	$18	100%	11%	PIPE-1	40%	17%	93.0%	26.3%	75.8
9063	Water Heating	Pipe Wrap	In Store Discount	SF	Retrofit	3,242	8%	247	0.03	12	$18	100%	100%	PIPE-2	40%	17%	93.0%	93.0%	8.4
9064	Water Heating	Pipe Wrap	Residential Marketplac	SF	Retrofit	3,242	8%	247	0.03	12	$18	100%	11%	PIPE-2	40%	17%	93.0%	26.3%	75.8

Appendix B: Residential Measure Assumptions

Measure #	End-Use	Measure Name	Program	Home Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
9065	Water Heating	Pipe Wrap	ne Qualified Weatheriz	SF	Retrofit	3,242	8%	247	0.03	12	$18	100%	100%	PIPE-2	40%	17%	93.0%	93.0%	8.4
9066	Water Heating	Pipe Wrap	In Store Discount	MF	Retrofit	3,045	8%	247	0.03	12	$18	100%	25%	PIPE-3	40%	17%	93.0%	37.0%	33.7
9067	Water Heating	Pipe Wrap	Residential Marketplac	MF	Retrofit	3,045	8%	247	0.03	12	$18	100%	11%	PIPE-3	40%	17%	93.0%	26.3%	75.8
9068	Water Heating	Pipe Wrap	In Store Discount	MF	Retrofit	3,045	8%	247	0.03	12	$18	100%	100%	PIPE-4	40%	17%	93.0%	93.0%	8.4
9069	Water Heating	Pipe Wrap	Residential Marketplac	MF	Retrofit	3,045	8%	247	0.03	12	$18	100%	11%	PIPE-4	40%	17%	93.0%	26.3%	75.8
9070	Water Heating	Pipe Wrap	ne Qualified Weatheriz	MF	Retrofit	3,045	8%	247	0.03	12	$18	100%	100%	PIPE-4	40%	17%	93.0%	93.0%	8.4
9071	Water Heating	Water Heater Temperature Setback	No Program	SF	Retrofit	3,242	4%	121	0.01	2	$5	100%	25%	WH TEMP-1	40%	54%	91.0%	35.0%	13.5
9072	Water Heating	Water Heater Temperature Setback	No Program	SF	Retrofit	3,242	4%	121	0.01	2	$5	100%	25%	WH TEMP-2	40%	54%	91.0%	35.0%	3.4
9073	Water Heating	Water Heater Temperature Setback	No Program	SF	Retrofit	3,242	4%	121	0.01	2	$5	100%	25%	WH TEMP-2	40%	54%	91.0%	35.0%	3.4
9074	Water Heating	Water Heater Temperature Setback	No Program	MF	Retrofit	3,045	4%	121	0.01	2	$5	100%	25%	WH TEMP-3	40%	54%	91.0%	35.0%	13.5
9075	Water Heating	Water Heater Temperature Setback	No Program	MF	Retrofit	3,045	4%	121	0.01	2	$5	100%	25%	WH TEMP-4	40%	54%	91.0%	35.0%	3.4
9076	Water Heating	Water Heater Temperature Setback	No Program	MF	Retrofit	3,045	4%	121	0.01	2	$5	100%	25%	WH TEMP-4	40%	54%	91.0%	35.0%	3.4
9077	Water Heating	Recirculating Pump Controls	No Program	SF	MO	3,242	15%	484	0.04	15	$222	100%	25%	RECIRC-1	40%	36%	91.0%	35.0%	5.6
9078	Water Heating	Recirculating Pump Controls	No Program	SF	NC	3,242	15%	484	0.04	15	$222	100%	25%	RECIRC-2	40%	0%	91.0%	35.0%	5.6
9079	Water Heating	Recirculating Pump Controls	No Program	MF	MO	3,045	15%	460	0.03	15	$222	100%	25%	RECIRC-3	40%	36%	91.0%	35.0%	5.2
9080	Water Heating	Recirculating Pump Controls	No Program	MF	NC	3,045	15%	460	0.03	15	$222	100%	25%	RECIRC-4	40%	0%	91.0%	35.0%	5.2
3241	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline	Income Qualified HEAR	SF	MO	11,402	54%	6,140	0.12	16	$3,608	100%	83%	HP-8	21%	36%	89.0%	81.9%	1.1
3242	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric furnace baseline	Income Qualified HEAR	MF	MO	8,982	55%	4,904	0.09	16	$2,886	100%	100%	HP-11	21%	36%	89.0%	89.0%	0.9
3243	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline	Income Qualified HEAR	SF	MO	11,402	58%	6,643	0.23	16	$4,013	100%	75%	HP-8	21%	36%	89.0%	79.1%	1.3
3244	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric furnace baseline	Income Qualified HEAR	MF	MO	8,982	59%	5,297	0.19	16	$3,210	100%	93%	HP-11	21%	36%	89.0%	86.0%	1.0
3245	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline	Income Qualified HEAR	SF	MO	11,402	63%	7,209	0.33	16	$4,288	100%	70%	HP-8	21%	36%	89.0%	77.8%	1.4
3246	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric furnace baseline	Income Qualified HEAR	MF	MO	8,982	64%	5,743	0.26	16	$3,430	100%	87%	HP-11	21%	36%	89.0%	83.6%	1.1
3247	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline	Income Qualified HEAR	SF	MO	11,402	66%	7,546	0.42	16	$5,103	100%	59%	HP-8	21%	36%	89.0%	73.3%	1.6
3248	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric furnace baseline	Income Qualified HEAR	MF	MO	8,982	67%	6,006	0.33	16	$4,082	100%	73%	HP-11	21%	36%	89.0%	78.7%	1.2
3249	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	SF	MO	11,402	54%	6,140	0.12	16	$3,608	100%	83%	HP-8	1%	36%	89.0%	81.9%	1.1
3250	HVAC	Ductless Heat Pump 8.5 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	MF	MO	8,982	55%	4,904	0.09	16	$2,886	100%	100%	HP-11	1%	36%	89.0%	89.0%	0.9
3251	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	SF	MO	11,402	58%	6,643	0.23	16	$4,013	100%	75%	HP-8	1%	36%	89.0%	79.1%	1.3
3252	HVAC	Ductless Heat Pump 9.4 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	MF	MO	8,982	59%	5,297	0.19	16	$3,210	100%	93%	HP-11	1%	36%	89.0%	86.0%	1.0
3253	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	SF	MO	11,402	63%	7,209	0.33	16	$4,288	100%	70%	HP-8	1%	36%	89.0%	77.8%	1.4
3254	HVAC	Ductless Heat Pump 10.8 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	MF	MO	8,982	64%	5,743	0.26	16	$3,430	100%	87%	HP-11	1%	36%	89.0%	83.6%	1.1
3255	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	SF	MO	11,402	66%	7,546	0.42	16	$5,103	100%	59%	HP-8	1%	36%	89.0%	73.3%	1.6
3256	HVAC	Ductless Heat Pump 11.7 HSPF2 - Electric baseboard baseline	Income Qualified HEAR	MF	MO	8,982	67%	6,006	0.33	16	$4,082	100%	73%	HP-11	1%	36%	89.0%	78.7%	1.2
9081	Water Heating	Heat Pump Water Heater-electric resistance heat	Income Qualified HEAR	SF	MO	3,242	57%	1,855	0.09	15	$2,062	100%	100%	HPWH-13	21%	17%	93.0%	93.0%	0.5
9082	Water Heating	Heat Pump Water Heater-electric resistance heat	Income Qualified HEAR	MF	MO	3,045	56%	1,707	0.08	15	$2,062	100%	100%	HPWH-14	21%	17%	93.0%	93.0%	0.5
9083	Water Heating	Heat Pump Water Heater-heat pump heat	Income Qualified HEAR	SF	MO	3,242	57%	1,863	0.09	15	$2,062	100%	100%	HPWH-15	15%	17%	93.0%	93.0%	0.5
9084	Water Heating	Heat Pump Water Heater-heat pump heat	Income Qualified HEAR	MF	MO	3,045	56%	1,714	0.08	15	$2,062	100%	100%	HPWH-16	15%	17%	93.0%	93.0%	0.5
9085	Water Heating	Heat Pump Water Heater-gas heat	Income Qualified HEAR	SF	MO	3,242	58%	1,872	0.09	15	$2,062	100%	100%	HPWH-17	4%	17%	93.0%	93.0%	0.5
9086	Water Heating	Heat Pump Water Heater-gas heat	Income Qualified HEAR	MF	MO	3,045	57%	1,722	0.08	15	$2,062	100%	100%	HPWH-18	4%	17%	93.0%	93.0%	0.5

APPENDIX C. C&I MEASURE DETAIL

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Assembly	TOS	per unit	19,496	39%	7,532	0.88	0.80	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
2	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Education	TOS	per unit	19,496	39%	7,532	0.88	0.29	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
3	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Food Sales	TOS	per unit	19,496	39%	7,532	0.88	0.95	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	5.0
4	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Food Service	TOS	per unit	19,496	39%	7,532	0.88	1.24	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	5.0
5	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Health	TOS	per unit	19,496	39%	7,532	0.88	0.76	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
6	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Lodging	TOS	per unit	19,496	39%	7,532	0.88	0.74	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
7	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Retail	TOS	per unit	19,496	39%	7,532	0.88	0.95	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	5.0
8	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Office	TOS	per unit	19,496	39%	7,532	0.88	0.80	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
9	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Warehouse	TOS	per unit	19,496	39%	7,532	0.88	0.80	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
10	Cooking	Commercial Combination Oven (Electric)	Biz - Prescriptive	Other	TOS	per unit	19,496	39%	7,532	0.88	0.86	12	$2,270	100%	44%	67%	1	17%	55%	88.0%	81.6%	84.0%	4.9
11	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Assembly	TOS	per unit	10,864	19%	2,064	0.19	0.22	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
12	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Education	TOS	per unit	10,864	19%	2,064	0.19	0.08	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
13	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Food Sales	TOS	per unit	10,864	19%	2,064	0.19	0.26	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
14	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Food Service	TOS	per unit	10,864	19%	2,064	0.19	0.34	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
15	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Health	TOS	per unit	10,864	19%	2,064	0.19	0.21	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
16	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Lodging	TOS	per unit	10,864	19%	2,064	0.19	0.20	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
17	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Retail	TOS	per unit	10,864	19%	2,064	0.19	0.26	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
18	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Office	TOS	per unit	10,864	19%	2,064	0.19	0.22	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
19	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Warehouse	TOS	per unit	10,864	19%	2,064	0.19	0.22	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
20	Cooking	Commercial Electric Convection Oven	Biz - Prescriptive	Other	TOS	per unit	10,864	19%	2,064	0.19	0.24	12	$960	100%	36%	63%	1	17%	19%	88.0%	77.2%	81.5%	3.6
21	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Assembly	TOS	per unit	17,056	15%	2,596	0.23	0.28	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
22	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Education	TOS	per unit	17,056	15%	2,596	0.23	0.10	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
23	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Food Sales	TOS	per unit	17,056	15%	2,596	0.23	0.33	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
24	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Food Service	TOS	per unit	17,056	15%	2,596	0.23	0.43	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.9
25	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Health	TOS	per unit	17,056	15%	2,596	0.23	0.26	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
26	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Lodging	TOS	per unit	17,056	15%	2,596	0.23	0.25	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
27	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Retail	TOS	per unit	17,056	15%	2,596	0.23	0.33	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
28	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Office	TOS	per unit	17,056	15%	2,596	0.23	0.28	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
29	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Warehouse	TOS	per unit	17,056	15%	2,596	0.23	0.28	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
30	Cooking	Commercial Electric Griddle	Biz - Prescriptive	Other	TOS	per unit	17,056	15%	2,596	0.23	0.30	12	$0	100%	100%	100%	2	14%	19%	88.0%	88.0%	88.0%	2.8
31	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Assembly	TOS	per unit	17,057	80%	13,645	2.43	1.45	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
32	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Education	TOS	per unit	17,057	80%	13,645	2.43	0.52	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.6
33	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Food Sales	TOS	per unit	17,057	80%	13,645	2.43	1.72	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
34	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Food Service	TOS	per unit	17,057	80%	13,645	2.43	2.24	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.8
35	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Health	TOS	per unit	17,057	80%	13,645	2.43	1.38	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
36	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Lodging	TOS	per unit	17,057	80%	13,645	2.43	1.34	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
37	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Retail	TOS	per unit	17,057	80%	13,645	2.43	1.71	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
38	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Office	TOS	per unit	17,057	80%	13,645	2.43	1.45	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
39	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Warehouse	TOS	per unit	17,057	80%	13,645	2.43	1.45	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
40	Cooking	Commercial Electric Steam Cooker	Biz - Prescriptive	Other	TOS	per unit	17,057	80%	13,645	2.43	1.56	12	$2,757	100%	22%	51%	3	6%	25%	88.0%	82.0%	84.0%	17.7
41	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Assembly	TOS	per unit	35,655	44%	15,766	0.98	1.68	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.6
42	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Education	TOS	per unit	35,655	44%	15,766	0.98	0.60	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.3
43	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Food Sales	TOS	per unit	35,655	44%	15,766	0.98	1.99	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.7
44	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Food Service	TOS	per unit	35,655	44%	15,766	0.98	2.59	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.8
45	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Health	TOS	per unit	35,655	44%	15,766	0.98	1.59	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.6
46	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Lodging	TOS	per unit	35,655	44%	15,766	0.98	1.55	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.6
47	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Retail	TOS	per unit	35,655	44%	15,766	0.98	1.98	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.7
48	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Office	TOS	per unit	35,655	44%	15,766	0.98	1.68	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.6
49	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Warehouse	TOS	per unit	35,655	44%	15,766	0.98	1.68	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.6
50	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz - Prescriptive	Other	TOS	per unit	35,655	44%	15,766	0.98	1.80	16	$467	100%	75%	10%	4	26%	6%	88.0%	87.7%	86.9%	30.6
51	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Assembly	TOS	per unit	38,282	16%	6,279	0.39	0.67	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
52	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Education	TOS	per unit	38,282	16%	6,279	0.39	0.24	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.2
53	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Food Sales	TOS	per unit	38,282	16%	6,279	0.39	0.79	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
54	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Food Service	TOS	per unit	38,282	16%	6,279	0.39	1.03	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
55	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Health	TOS	per unit	38,282	16%	6,279	0.39	0.63	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
56	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Lodging	TOS	per unit	38,282	16%	6,279	0.39	0.62	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
57	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Retail	TOS	per unit	38,282	16%	6,279	0.39	0.79	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
58	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Office	TOS	per unit	38,282	16%	6,279	0.39	0.67	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
59	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Warehouse	TOS	per unit	38,282	16%	6,279	0.39	0.67	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
60	Cooking	Dishwasher High Temp Door (Energy Star)	Biz - Prescriptive	Other	TOS	per unit	38,282	16%	6,279	0.39	0.72	15	$1,550	100%	61%	59%	4	26%	6%	88.0%	84.2%	84.0%	4.3
61	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Assembly	TOS	per unit	18,955	17%	3,274	0.22	0.35	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
62	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Education	TOS	per unit	18,955	17%	3,274	0.22	0.13	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.5
63	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Food Sales	TOS	per unit	18,955	17%	3,274	0.22	0.41	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
64	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Food Service	TOS	per unit	18,955	17%	3,274	0.22	0.54	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
65	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Health	TOS	per unit	18,955	17%	3,274	0.22	0.33	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
66	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Lodging	TOS	per unit	18,955	17%	3,274	0.22	0.32	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
67	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Retail	TOS	per unit	18,955	17%	3,274	0.22	0.41	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
68	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Office	TOS	per unit	18,955	17%	3,274	0.22	0.35	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
69	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Warehouse	TOS	per unit	18,955	17%	3,274	0.22	0.35	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
70	Cooking	Energy efficient electric fryer	Biz - Prescriptive	Other	TOS	per unit	18,955	17%	3,274	0.22	0.37	12	$1,500	100%	16%	64%	5	27%	25%	88.0%	69.4%	81.7%	7.6
71	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Assembly	TOS	per unit	1,478	37%	545	0.06	0.06	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
72	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Education	TOS	per unit	1,478	37%	545	0.06	0.02	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
73	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Food Sales	TOS	per unit	1,478	37%	545	0.06	0.07	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
74	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Food Service	TOS	per unit	1,478	37%	545	0.06	0.09	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
75	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Health	TOS	per unit	1,478	37%	545	0.06	0.06	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
76	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Lodging	TOS	per unit	1,478	37%	545	0.06	0.05	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
77	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Retail	TOS	per unit	1,478	37%	545	0.06	0.07	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
78	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Office	TOS	per unit	1,478	37%	545	0.06	0.06	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
79	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Warehouse	TOS	per unit	1,478	37%	545	0.06	0.06	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
80	Cooking	Insulated Holding Cabinets	Biz - Prescriptive	Other	TOS	per unit	1,478	37%	545	0.06	0.06	12	$1,000	30%	30%	16%	6	3%	15%	39.8%	32.0%	32.0%	1.2
81	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Assembly	TOS	per 10 hp	23,742	21%	4,935	1.28	0.59	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
82	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Education	TOS	per 10 hp	23,742	21%	4,935	1.28	0.56	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
83	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Food Sales	TOS	per 10 hp	23,742	21%	4,935	1.28	0.57	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
84	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Food Service	TOS	per 10 hp	23,742	21%	4,935	1.28	0.59	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
85	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Health	TOS	per 10 hp	23,742	21%	4,935	1.28	0.56	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
86	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Lodging	TOS	per 10 hp	23,742	21%	4,935	1.28	0.64	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
87	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Retail	TOS	per 10 hp	23,742	21%	4,935	1.28	0.57	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
88	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Office	TOS	per 10 hp	23,742	21%	4,935	1.28	0.56	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
89	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Warehouse	TOS	per 10 hp	23,742	21%	4,935	1.28	0.54	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
90	Compressed Air	Efficient Air Compressors (VSD)	Biz - Prescriptive	Other	TOS	per 10 hp	23,742	21%	4,935	1.28	0.58	13	$3,368	100%	22%	45%	2	100%	20%	88.0%	57.6%	70.4%	6.6
91	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Assembly	TOS	per unit (1/4")	1,130	50%	565	0.15	0.07	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
92	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Education	TOS	per unit (1/4")	1,130	50%	565	0.15	0.06	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
93	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Food Sales	TOS	per unit (1/4")	1,130	50%	565	0.15	0.06	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
94	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Food Service	TOS	per unit (1/4")	1,130	50%	565	0.15	0.07	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
95	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Health	TOS	per unit (1/4")	1,130	50%	565	0.15	0.06	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
96	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Lodging	TOS	per unit (1/4")	1,130	50%	565	0.15	0.07	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
97	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Retail	TOS	per unit (1/4")	1,130	50%	565	0.15	0.07	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
98	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Office	TOS	per unit (1/4")	1,130	50%	565	0.15	0.06	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
99	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Warehouse	TOS	per unit (1/4")	1,130	50%	565	0.15	0.06	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.7
100	Compressed Air	Efficient Air Nozzles	Biz - Prescriptive	Other	TOS	per unit (1/4")	1,130	50%	565	0.15	0.07	15	$57	100%	70%	10%	4	5%	20%	88.0%	86.8%	84.4%	15.8
101	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Assembly	RET	per unit	476,154	0%	1,970	0.30	0.23	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
102	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Education	RET	per unit	476,154	0%	1,970	0.30	0.22	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
103	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Food Sales	RET	per unit	476,154	0%	1,970	0.30	0.23	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
104	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Food Service	RET	per unit	476,154	0%	1,970	0.30	0.23	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
105	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Health	RET	per unit	476,154	0%	1,970	0.30	0.22	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
106	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Lodging	RET	per unit	476,154	0%	1,970	0.30	0.25	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
107	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Retail	RET	per unit	476,154	0%	1,970	0.30	0.23	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
108	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Office	RET	per unit	476,154	0%	1,970	0.30	0.23	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
109	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Warehouse	RET	per unit	476,154	0%	1,970	0.30	0.21	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
110	Compressed Air	No Loss Condensate Drain	Biz - Prescriptive	Other	RET	per unit	476,154	0%	1,970	0.30	0.23	10	$244	100%	82%	19%	3	100%	5%	88.0%	87.1%	84.0%	6.3
111	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Assembly	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.8
112	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Education	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.5
113	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Food Sales	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.9
114	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Food Service	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	3.3
115	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Health	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.7
116	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Lodging	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.6
117	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Retail	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	3.0
118	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Office	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.6
119	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Warehouse	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.8
120	Compressed Air	Compressed Air Leak Repair	Biz - Prescriptive	Other	RET	per kWh	6	17%	1	0.00	0.00	3	$0	100%	100%	10%	1	100%	39%	88.0%	88.0%	85.1%	2.8
121	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Assembly	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.5
122	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Education	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.2
123	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Food Sales	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.6
124	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Food Service	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.9
125	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Health	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.4
126	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Lodging	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.3
127	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Retail	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.6
128	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Office	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.3
129	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Warehouse	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.5
130	Compressed Air	Retro-commissioning_Compressed Air Optimization	Biz - Custom	Other	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	1	100%	20%	66.0%	63.6%	63.0%	2.5
131	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Assembly	TOS	per ton	891	9%	79	0.03	0.00	15	$63	100%	48%	43%	5	23%	5%	88.0%	66.5%	62.9%	4.0
132	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Education	TOS	per ton	643	9%	57	0.03	0.00	15	$63	100%	48%	31%	5	0%	5%	88.0%	55.4%	46.8%	3.6
133	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	1,094	9%	97	0.03	0.00	15	$63	100%	48%	52%	5	23%	5%	88.0%	73.4%	76.2%	4.2
134	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Food Service	TOS	per ton	1,210	9%	107	0.03	0.00	15	$63	100%	48%	58%	5	25%	5%	88.0%	76.4%	78.9%	4.4
135	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Health	TOS	per ton	1,431	9%	127	0.03	0.00	15	$63	100%	48%	68%	5	0%	5%	88.0%	78.4%	82.0%	4.7
136	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Lodging	TOS	per ton	1,381	9%	123	0.03	0.00	15	$63	100%	48%	66%	5	0%	5%	88.0%	78.1%	81.4%	4.7
137	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Retail	TOS	per ton	737	9%	65	0.03	0.00	15	$63	100%	48%	35%	5	22%	5%	88.0%	58.8%	53.3%	3.7
138	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Office	TOS	per ton	2,218	9%	197	0.03	0.00	15	$63	100%	48%	69%	5	6%	5%	88.0%	81.6%	84.0%	5.9
139	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	345	9%	31	0.03	0.00	15	$63	100%	48%	17%	5	38%	5%	88.0%	34.2%	24.0%	3.2
140	Cooling	Air Conditioner - Tier 1 (15.2 SEER2) (<5 Tons)	Biz - Prescriptive	Other	TOS	per ton	1,169	9%	104	0.03	0.00	15	$63	100%	48%	56%	5	0%	5%	88.0%	75.4%	78.1%	4.4
141	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Assembly	TOS	per ton	891	13%	120	0.05	0.00	15	$127	100%	24%	32%	5	23%	8%	88.0%	44.7%	48.8%	6.0
142	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Education	TOS	per ton	643	13%	86	0.05	0.00	15	$127	100%	24%	23%	5	0%	8%	88.0%	33.0%	32.8%	5.4
143	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	1,094	13%	147	0.05	0.00	15	$127	100%	24%	39%	5	23%	8%	88.0%	51.7%	57.9%	6.4

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
144	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Food Service	TOS	per ton	1,210	13%	163	0.05	0.00	15	$127	100%	24%	43%	5	25%	8%	88.0%	54.6%	64.2%	6.7
145	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Health	TOS	per ton	1,431	13%	192	0.05	0.00	15	$127	100%	24%	51%	5	0%	8%	88.0%	58.8%	75.1%	7.2
146	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Lodging	TOS	per ton	1,381	13%	186	0.05	0.01	15	$127	100%	24%	50%	5	0%	8%	88.0%	58.0%	73.0%	7.1
147	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Retail	TOS	per ton	737	13%	99	0.05	0.00	15	$127	100%	24%	26%	5	22%	8%	88.0%	36.9%	38.6%	5.6
148	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Office	TOS	per ton	2,218	13%	298	0.05	0.01	15	$127	100%	24%	77%	5	6%	8%	88.0%	74.7%	84.0%	8.9
149	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	345	13%	46	0.05	0.00	15	$127	100%	24%	12%	5	38%	8%	88.0%	26.0%	26.0%	4.8
150	Cooling	Air Conditioner - Tier 2 (16 SEER2) (<5 Tons)	Biz - Prescriptive	Other	TOS	per ton	1,169	13%	157	0.05	0.00	15	$127	100%	24%	42%	5	0%	8%	88.0%	53.6%	61.8%	6.6
151	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Assembly	TOS	per ton	863	9%	79	0.03	0.00	15	$63	100%	48%	43%	1	21%	8%	88.0%	66.6%	63.1%	4.0
152	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Education	TOS	per ton	622	9%	57	0.03	0.00	15	$63	100%	48%	31%	1	27%	8%	88.0%	55.5%	47.0%	3.6
153	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	1,060	9%	98	0.03	0.00	15	$63	100%	48%	53%	1	19%	8%	88.0%	73.6%	76.4%	4.3
154	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Food Service	TOS	per ton	1,172	9%	108	0.03	0.00	15	$63	100%	48%	58%	1	21%	8%	88.0%	76.5%	78.9%	4.4
155	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Health	TOS	per ton	1,386	9%	128	0.03	0.00	15	$63	100%	48%	69%	1	28%	8%	88.0%	78.4%	82.1%	4.8
156	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Lodging	TOS	per ton	1,338	9%	123	0.03	0.00	15	$63	100%	48%	66%	1	13%	8%	88.0%	78.1%	81.5%	4.7
157	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Retail	TOS	per ton	714	9%	66	0.03	0.00	15	$63	100%	48%	35%	1	17%	8%	88.0%	58.9%	53.5%	3.7
158	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Office	TOS	per ton	2,148	9%	198	0.03	0.00	15	$63	100%	48%	69%	1	28%	8%	88.0%	81.7%	84.0%	5.9
159	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	334	9%	31	0.03	0.00	15	$63	100%	48%	17%	1	31%	8%	88.0%	34.3%	26.0%	3.2
160	Cooling	Air Conditioner - 15.7 IEER (5-20 Tons)	Biz - Prescriptive	Other	TOS	per ton	1,133	9%	104	0.03	0.00	15	$63	100%	48%	56%	1	28%	8%	88.0%	75.5%	78.2%	4.4
161	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Assembly	TOS	per ton	863	17%	150	0.06	0.00	15	$127	100%	24%	40%	1	21%	8%	88.0%	52.2%	58.6%	7.5
162	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Education	TOS	per ton	622	17%	108	0.06	0.00	15	$127	100%	24%	29%	1	27%	8%	88.0%	40.7%	43.5%	6.8
163	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	1,060	17%	184	0.06	0.00	15	$127	100%	24%	49%	1	19%	8%	88.0%	57.7%	72.3%	8.0
164	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Food Service	TOS	per ton	1,172	17%	203	0.06	0.00	15	$127	100%	24%	54%	1	21%	8%	88.0%	61.0%	77.5%	8.4
165	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Health	TOS	per ton	1,386	17%	240	0.06	0.00	15	$127	100%	24%	64%	1	28%	8%	88.0%	67.7%	80.9%	9.0
166	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Lodging	TOS	per ton	1,338	17%	232	0.06	0.01	15	$127	100%	24%	62%	1	13%	8%	88.0%	66.4%	80.2%	8.8
167	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Retail	TOS	per ton	714	17%	124	0.06	0.00	15	$127	100%	24%	33%	1	17%	8%	88.0%	45.9%	50.4%	7.0
168	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Office	TOS	per ton	2,148	17%	373	0.06	0.01	15	$127	100%	24%	71%	1	28%	8%	88.0%	78.4%	84.0%	11.1
169	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	334	17%	58	0.06	0.00	15	$127	100%	24%	15%	1	31%	8%	88.0%	26.0%	26.0%	6.0
170	Cooling	Air Conditioner - 17.3 IEER (5-20 Tons)	Biz - Prescriptive	Other	TOS	per ton	1,133	17%	196	0.06	0.00	15	$127	100%	24%	52%	1	28%	8%	88.0%	59.5%	76.3%	8.2
171	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Assembly	TOS	per ton	949	9%	86	0.04	0.00	15	$19	100%	100%	55%	2	21%	8%	88.0%	88.0%	84.0%	4.3
172	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Education	TOS	per ton	685	9%	62	0.04	0.00	15	$19	100%	100%	67%	2	27%	8%	88.0%	88.0%	84.0%	3.9
173	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	1,166	9%	106	0.04	0.00	15	$19	100%	100%	44%	2	19%	8%	88.0%	88.0%	84.0%	4.6
174	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Food Service	TOS	per ton	1,289	9%	117	0.04	0.00	15	$19	100%	100%	38%	2	21%	8%	88.0%	88.0%	84.0%	4.8
175	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Health	TOS	per ton	1,524	9%	139	0.04	0.00	15	$19	100%	100%	27%	2	28%	8%	88.0%	88.0%	84.0%	5.2
176	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Lodging	TOS	per ton	1,472	9%	134	0.04	0.01	15	$19	100%	100%	30%	2	13%	8%	88.0%	88.0%	84.0%	5.1
177	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Retail	TOS	per ton	785	9%	71	0.04	0.00	15	$19	100%	100%	62%	2	17%	8%	88.0%	88.0%	84.0%	4.1
178	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Office	TOS	per ton	2,363	9%	215	0.04	0.00	15	$19	100%	100%	10%	2	28%	8%	88.0%	88.0%	84.8%	6.4
179	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	368	9%	33	0.04	0.00	15	$19	100%	100%	60%	2	31%	8%	88.0%	88.0%	79.5%	3.4
180	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz - Prescriptive	Other	TOS	per ton	1,246	9%	113	0.04	0.00	15	$19	100%	100%	40%	2	28%	8%	88.0%	88.0%	84.0%	4.8
181	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Assembly	TOS	per ton	949	17%	158	0.07	0.00	15	$38	100%	79%	58%	2	21%	8%	88.0%	86.0%	84.0%	7.9
182	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Education	TOS	per ton	685	17%	114	0.07	0.00	15	$38	100%	79%	70%	2	27%	8%	88.0%	85.2%	84.0%	7.2
183	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	1,166	17%	194	0.07	0.00	15	$38	100%	79%	49%	2	19%	8%	88.0%	86.4%	84.0%	8.5
184	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Food Service	TOS	per ton	1,289	17%	215	0.07	0.00	15	$38	100%	79%	43%	2	21%	8%	88.0%	86.5%	84.0%	8.8
185	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Health	TOS	per ton	1,524	17%	254	0.07	0.00	15	$38	100%	79%	33%	2	28%	8%	88.0%	86.7%	84.0%	9.5
186	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Lodging	TOS	per ton	1,472	17%	245	0.07	0.01	15	$38	100%	79%	35%	2	13%	8%	88.0%	86.7%	84.0%	9.3
187	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Retail	TOS	per ton	785	17%	131	0.07	0.00	15	$38	100%	79%	66%	2	17%	8%	88.0%	85.6%	84.0%	7.5
188	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Office	TOS	per ton	2,363	17%	394	0.07	0.01	15	$38	100%	79%	10%	2	28%	8%	88.0%	87.2%	84.5%	11.8
189	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	368	17%	61	0.07	0.00	15	$38	100%	79%	55%	2	31%	8%	88.0%	82.9%	77.7%	6.3
190	Cooling	Air Conditioner - 15.6 IEER (20+ Tons)	Biz - Prescriptive	Other	TOS	per ton	1,246	17%	208	0.07	0.00	15	$38	100%	79%	45%	2	28%	8%	88.0%	86.5%	84.0%	8.7
191	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Assembly	TOS	per ton	1,299	10%	134	0.06	0.00	8	$84	100%	36%	35%	7	0%	20%	88.0%	67.8%	67.3%	4.1
192	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Education	TOS	per ton	937	10%	97	0.06	0.00	8	$84	100%	36%	25%	7	0%	20%	88.0%	56.4%	52.1%	3.7
193	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Food Sales	TOS	per ton	1,595	10%	165	0.06	0.00	8	$84	100%	36%	43%	7	38%	20%	88.0%	74.6%	77.3%	4.4
194	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Food Service	TOS	per ton	1,765	10%	183	0.06	0.00	8	$84	100%	36%	47%	7	33%	20%	88.0%	77.1%	79.0%	4.6
195	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Health	TOS	per ton	2,086	10%	216	0.06	0.00	8	$84	100%	36%	56%	7	0%	20%	88.0%	78.7%	81.5%	4.9
196	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Lodging	TOS	per ton	2,014	10%	208	0.06	0.01	8	$84	100%	36%	54%	7	15%	20%	88.0%	78.4%	81.0%	4.9
197	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Retail	TOS	per ton	1,074	10%	111	0.06	0.00	8	$84	100%	36%	29%	7	19%	20%	88.0%	60.3%	57.2%	3.9
198	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Office	TOS	per ton	3,234	10%	335	0.06	0.01	8	$84	100%	36%	60%	7	6%	20%	88.0%	81.9%	84.0%	6.2
199	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Warehouse	TOS	per ton	503	10%	52	0.06	0.00	8	$84	100%	36%	13%	7	0%	20%	88.0%	36.0%	36.0%	3.3
200	Cooling	PTAC - 7,000 to 15,000 Btuh	Biz - Prescriptive	Other	TOS	per ton	1,705	10%	176	0.06	0.00	8	$84	100%	36%	46%	7	0%	20%	88.0%	76.5%	78.4%	4.5
201	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Assembly	RET	per ton	1,164	5%	58	0.02	0.00	3	$35	50%	23%	16%	3	42%	50%	65.0%	60.0%	60.0%	2.8
202	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Education	RET	per ton	840	5%	42	0.02	0.00	3	$35	50%	17%	11%	3	55%	50%	65.0%	60.0%	60.0%	3.5
203	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Food Sales	RET	per ton	1,430	5%	71	0.02	0.00	3	$35	50%	29%	19%	3	38%	50%	65.0%	60.0%	60.0%	2.5
204	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Food Service	RET	per ton	1,581	5%	79	0.02	0.00	3	$35	50%	32%	21%	3	42%	50%	65.0%	60.0%	60.0%	2.3
205	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Health	RET	per ton	1,869	5%	93	0.02	0.00	3	$35	75%	37%	25%	3	57%	50%	65.0%	60.0%	60.0%	2.1
206	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Lodging	RET	per ton	1,805	5%	90	0.02	0.00	3	$35	75%	36%	24%	3	27%	50%	65.0%	60.0%	60.0%	2.2
207	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Retail	RET	per ton	963	5%	48	0.02	0.00	3	$35	50%	19%	13%	3	33%	50%	65.0%	60.0%	60.0%	3.2
208	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Office	RET	per ton	2,898	5%	145	0.02	0.00	3	$35	100%	58%	39%	3	55%	50%	66.0%	63.0%	61.7%	1.7
209	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Warehouse	RET	per ton	451	5%	23	0.02	0.00	3	$35	50%	9%	10%	3	62%	50%	65.0%	59.8%	59.9%	5.6
210	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz - Custom	Other	RET	per ton	1,528	5%	76	0.02	0.00	3	$35	50%	31%	20%	3	57%	50%	65.0%	60.0%	60.0%	2.4
211	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Assembly	RET	per ton	549	19%	103	0.04	0.00	10	$4,883	0%	0%	10%	10	3%	10%	26.2%	26.2%	26.2%	7.8
212	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Education	RET	per ton	396	19%	74	0.03	0.00	10	$4,883	0%	0%	10%	10	5%	10%	26.2%	26.2%	26.2%	8.0
213	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Food Sales	RET	per ton	674	19%	126	0.08	0.00	10	$4,883	0%	0%	10%	10	0%	10%	26.2%	26.2%	26.2%	10.7
214	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Food Service	RET	per ton	746	19%	139	0.06	0.00	10	$4,883	0%	0%	10%	10	0%	10%	26.2%	26.2%	26.2%	8.3

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
215	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Health	RET	per ton	882	19%	165	0.05	0.00	10	$4,883	0%	0%	10%	10	4%	10%	26.2%	26.2%	26.2%	6.4
216	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Lodging	RET	per ton	851	19%	159	0.05	0.01	10	$4,883	0%	0%	10%	10	5%	10%	26.2%	26.2%	26.2%	6.3
217	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Retail	RET	per ton	454	19%	85	0.04	0.00	10	$4,883	0%	0%	10%	10	3%	10%	26.2%	26.2%	26.2%	8.6
218	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Office	RET	per ton	1,367	19%	256	0.09	0.01	10	$4,883	1%	1%	10%	10	3%	10%	26.2%	26.2%	26.2%	7.1
219	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Warehouse	RET	per ton	213	19%	40	0.02	0.00	10	$4,883	0%	0%	10%	10	0%	10%	26.2%	26.2%	26.2%	8.2
220	Cooling	Cooling Tower Water Side Economizer	Biz - Custom	Other	RET	per ton	721	19%	135	0.06	0.00	10	$4,883	0%	0%	10%	10	4%	10%	26.2%	26.2%	26.2%	7.7
221	Cooling	Air Cooled Chiller	Biz - Prescriptive	Assembly	TOS	per ton	891	10%	89	0.04	0.00	23	$265	50%	11%	14%	8	31%	8%	30.1%	26.0%	26.0%	6.0
222	Cooling	Air Cooled Chiller	Biz - Prescriptive	Education	TOS	per ton	643	10%	65	0.04	0.00	23	$265	50%	11%	10%	8	41%	8%	29.7%	26.0%	26.0%	5.5
223	Cooling	Air Cooled Chiller	Biz - Prescriptive	Food Sales	TOS	per ton	1,095	10%	110	0.04	0.00	23	$265	50%	11%	18%	8	0%	8%	35.3%	26.0%	26.0%	6.5
224	Cooling	Air Cooled Chiller	Biz - Prescriptive	Food Service	TOS	per ton	1,211	10%	122	0.04	0.00	23	$265	75%	11%	20%	8	0%	8%	56.9%	26.0%	26.0%	6.7
225	Cooling	Air Cooled Chiller	Biz - Prescriptive	Health	TOS	per ton	1,432	10%	144	0.04	0.00	23	$265	75%	11%	23%	8	39%	8%	62.5%	26.0%	26.0%	7.2
226	Cooling	Air Cooled Chiller	Biz - Prescriptive	Lodging	TOS	per ton	1,382	10%	139	0.04	0.01	23	$265	75%	11%	22%	8	42%	8%	61.0%	26.0%	26.0%	7.1
227	Cooling	Air Cooled Chiller	Biz - Prescriptive	Retail	TOS	per ton	737	10%	74	0.04	0.00	23	$265	50%	11%	12%	8	23%	8%	29.7%	26.0%	26.0%	5.7
228	Cooling	Air Cooled Chiller	Biz - Prescriptive	Office	TOS	per ton	2,219	10%	223	0.04	0.01	23	$265	100%	11%	36%	8	29%	8%	88.0%	34.7%	47.0%	9.0
229	Cooling	Air Cooled Chiller	Biz - Prescriptive	Warehouse	TOS	per ton	345	10%	35	0.04	0.00	23	$265	50%	11%	10%	8	0%	8%	29.7%	26.0%	26.0%	4.8
230	Cooling	Air Cooled Chiller	Biz - Prescriptive	Other	TOS	per ton	1,170	10%	117	0.04	0.00	23	$265	75%	11%	19%	8	39%	8%	56.0%	26.0%	26.0%	6.7
231	Cooling	Water Cooled Chiller	Biz - Prescriptive	Assembly	TOS	per ton	549	10%	54	0.02	0.00	23	$62	100%	48%	38%	9	4%	8%	88.0%	55.0%	49.4%	3.7
232	Cooling	Water Cooled Chiller	Biz - Prescriptive	Education	TOS	per ton	396	10%	39	0.02	0.00	23	$62	100%	48%	27%	9	5%	8%	88.0%	44.6%	32.5%	3.3
233	Cooling	Water Cooled Chiller	Biz - Prescriptive	Food Sales	TOS	per ton	674	10%	67	0.02	0.00	23	$62	100%	48%	46%	9	0%	8%	88.0%	61.0%	59.3%	3.9
234	Cooling	Water Cooled Chiller	Biz - Prescriptive	Food Service	TOS	per ton	746	10%	74	0.02	0.00	23	$62	100%	48%	51%	9	0%	8%	88.0%	65.1%	67.3%	4.1
235	Cooling	Water Cooled Chiller	Biz - Prescriptive	Health	TOS	per ton	882	10%	88	0.02	0.00	23	$62	100%	48%	61%	9	4%	8%	88.0%	71.1%	77.7%	4.4
236	Cooling	Water Cooled Chiller	Biz - Prescriptive	Lodging	TOS	per ton	851	10%	84	0.02	0.00	23	$62	100%	48%	59%	9	5%	8%	88.0%	69.9%	76.6%	4.3
237	Cooling	Water Cooled Chiller	Biz - Prescriptive	Retail	TOS	per ton	454	10%	45	0.02	0.00	23	$62	100%	48%	31%	9	3%	8%	88.0%	49.3%	38.5%	3.5
238	Cooling	Water Cooled Chiller	Biz - Prescriptive	Office	TOS	per ton	1,367	10%	136	0.02	0.00	23	$62	100%	48%	78%	9	3%	8%	88.0%	79.2%	84.0%	5.5
239	Cooling	Water Cooled Chiller	Biz - Prescriptive	Warehouse	TOS	per ton	213	10%	21	0.02	0.00	23	$62	100%	48%	15%	9	0%	8%	88.0%	26.0%	26.0%	2.9
240	Cooling	Water Cooled Chiller	Biz - Prescriptive	Other	TOS	per ton	721	10%	72	0.02	0.00	23	$62	100%	48%	50%	9	4%	8%	88.0%	63.7%	64.6%	4.1
241	Cooling	Smart Thermostat	Biz - Prescriptive	Assembly	RET	per thermostat	5,058	14%	716	0.17	0.01	11	$175	100%	57%	59%	6	23%	15%	88.0%	83.8%	84.0%	5.9
242	Cooling	Smart Thermostat	Biz - Prescriptive	Education	RET	per thermostat	3,649	14%	517	0.17	0.01	11	$175	100%	57%	70%	6	0%	15%	88.0%	82.4%	84.0%	5.1
243	Cooling	Smart Thermostat	Biz - Prescriptive	Food Sales	RET	per thermostat	6,213	14%	880	0.17	0.00	11	$175	100%	57%	50%	6	23%	15%	88.0%	84.6%	84.0%	6.5
244	Cooling	Smart Thermostat	Biz - Prescriptive	Food Service	RET	per thermostat	6,871	14%	973	0.17	0.02	11	$175	100%	57%	44%	6	25%	15%	88.0%	84.9%	84.0%	6.9
245	Cooling	Smart Thermostat	Biz - Prescriptive	Health	RET	per thermostat	8,124	14%	1,150	0.17	0.02	11	$175	100%	57%	34%	6	0%	15%	88.0%	85.4%	84.0%	7.6
246	Cooling	Smart Thermostat	Biz - Prescriptive	Lodging	RET	per thermostat	7,843	14%	1,111	0.17	0.04	11	$175	100%	57%	37%	6	0%	15%	88.0%	85.3%	84.0%	7.4
247	Cooling	Smart Thermostat	Biz - Prescriptive	Retail	RET	per thermostat	4,183	14%	592	0.17	0.01	11	$175	100%	57%	66%	6	22%	15%	88.0%	83.1%	84.0%	5.4
248	Cooling	Smart Thermostat	Biz - Prescriptive	Office	RET	per thermostat	12,593	14%	1,783	0.17	0.04	11	$175	100%	57%	10%	6	6%	15%	88.0%	86.3%	84.5%	10.1
249	Cooling	Smart Thermostat	Biz - Prescriptive	Warehouse	RET	per thermostat	1,959	14%	277	0.17	0.00	11	$175	100%	57%	44%	6	38%	15%	88.0%	78.0%	72.0%	4.2
250	Cooling	Smart Thermostat	Biz - Prescriptive	Other	RET	per thermostat	6,639	14%	940	0.17	0.02	11	$175	100%	57%	46%	6	0%	15%	88.0%	84.8%	84.0%	6.8
251	Cooling	Window Film	Biz - Prescriptive	Assembly	RET	per 100 sq ft	6,364	4%	280	0.12	0.01	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	3.1
252	Cooling	Window Film	Biz - Prescriptive	Education	RET	per 100 sq ft	6,364	4%	280	0.12	0.00	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	3.1
253	Cooling	Window Film	Biz - Prescriptive	Food Sales	RET	per 100 sq ft	6,364	4%	280	0.18	0.00	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	4.2
254	Cooling	Window Film	Biz - Prescriptive	Food Service	RET	per 100 sq ft	6,364	4%	280	0.13	0.01	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	3.3
255	Cooling	Window Film	Biz - Prescriptive	Health	RET	per 100 sq ft	6,364	4%	280	0.09	0.00	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	2.5
256	Cooling	Window Film	Biz - Prescriptive	Lodging	RET	per 100 sq ft	6,364	4%	280	0.09	0.01	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	2.5
257	Cooling	Window Film	Biz - Prescriptive	Retail	RET	per 100 sq ft	6,364	4%	280	0.14	0.00	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	3.4
258	Cooling	Window Film	Biz - Prescriptive	Office	RET	per 100 sq ft	6,364	4%	280	0.10	0.01	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	2.8
259	Cooling	Window Film	Biz - Prescriptive	Warehouse	RET	per 100 sq ft	6,364	4%	280	0.13	0.00	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	3.2
260	Cooling	Window Film	Biz - Prescriptive	Other	RET	per 100 sq ft	6,364	4%	280	0.12	0.01	10	$154	100%	65%	47%	11	100%	25%	88.0%	80.8%	77.3%	3.0
261	Cooling	Secondary Windows	Biz - Custom	Assembly	RET	per 100 sq ft	6,364	0%	0	0.00	0.00	30	$3,200	100%	0%	100%	11	100%	25%	66.0%	66.0%	66.0%	2.0
262	Cooling	Secondary Windows	Biz - Custom	Education	RET	per 100 sq ft	6,364	7%	449	0.20	0.00	30	$3,200	2%	2%	10%	11	100%	25%	38.5%	38.5%	38.5%	17.3
263	Cooling	Secondary Windows	Biz - Custom	Food Sales	RET	per 100 sq ft	6,364	0%	0	0.00	0.00	30	$3,200	100%	0%	100%	11	100%	25%	66.0%	66.0%	66.0%	2.0
264	Cooling	Secondary Windows	Biz - Custom	Food Service	RET	per 100 sq ft	6,364	6%	397	0.18	0.01	30	$3,200	2%	2%	10%	11	100%	25%	38.5%	38.5%	38.5%	18.0
265	Cooling	Secondary Windows	Biz - Custom	Health	RET	per 100 sq ft	6,364	8%	526	0.16	0.01	30	$3,200	2%	2%	10%	11	100%	25%	38.5%	38.5%	38.5%	13.9
266	Cooling	Secondary Windows	Biz - Custom	Lodging	RET	per 100 sq ft	6,364	7%	457	0.14	0.02	30	$3,200	2%	2%	10%	11	100%	25%	38.5%	38.5%	38.5%	13.7
267	Cooling	Secondary Windows	Biz - Custom	Retail	RET	per 100 sq ft	6,364	7%	464	0.23	0.00	30	$3,200	2%	2%	10%	11	100%	25%	38.5%	38.5%	38.5%	18.7
268	Cooling	Secondary Windows	Biz - Custom	Office	RET	per 100 sq ft	6,364	7%	439	0.16	0.01	30	$3,200	2%	2%	10%	11	100%	25%	38.5%	38.5%	38.5%	15.4
269	Cooling	Secondary Windows	Biz - Custom	Warehouse	RET	per 100 sq ft	6,364	0%	0	0.00	0.00	30	$3,200	100%	0%	100%	11	100%	25%	66.0%	66.0%	66.0%	2.0
270	Cooling	Secondary Windows	Biz - Custom	Other	RET	per 100 sq ft	6,364	0%	0	0.00	0.00	30	$3,200	100%	0%	100%	11	100%	25%	66.0%	66.0%	66.0%	2.0
271	Cooling	Triple Pane Windows	Biz - Custom	Assembly	TOS	per 100 sq ft	6,364	6%	382	0.16	0.01	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	16.9
272	Cooling	Triple Pane Windows	Biz - Custom	Education	TOS	per 100 sq ft	6,364	6%	382	0.17	0.00	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	17.3
273	Cooling	Triple Pane Windows	Biz - Custom	Food Sales	TOS	per 100 sq ft	6,364	6%	382	0.25	0.00	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	23.0
274	Cooling	Triple Pane Windows	Biz - Custom	Food Service	TOS	per 100 sq ft	6,364	6%	382	0.18	0.01	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	18.0
275	Cooling	Triple Pane Windows	Biz - Custom	Health	TOS	per 100 sq ft	6,364	6%	382	0.12	0.01	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	13.9
276	Cooling	Triple Pane Windows	Biz - Custom	Lodging	TOS	per 100 sq ft	6,364	6%	382	0.12	0.02	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	13.7
277	Cooling	Triple Pane Windows	Biz - Custom	Retail	TOS	per 100 sq ft	6,364	6%	382	0.19	0.00	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	18.7
278	Cooling	Triple Pane Windows	Biz - Custom	Office	TOS	per 100 sq ft	6,364	6%	382	0.14	0.01	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	15.4
279	Cooling	Triple Pane Windows	Biz - Custom	Warehouse	TOS	per 100 sq ft	6,364	6%	382	0.17	0.00	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	17.7
280	Cooling	Triple Pane Windows	Biz - Custom	Other	TOS	per 100 sq ft	6,364	6%	382	0.16	0.01	30	$700	100%	8%	26%	11	100%	2%	66.0%	19.6%	21.6%	16.6
281	Cooling	Energy Recovery Ventilator	Biz - Custom	Assembly	RET	per ton	949	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	42%	2%	66.0%	66.0%	66.0%	2.0
282	Cooling	Energy Recovery Ventilator	Biz - Custom	Education	RET	per ton	685	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	55%	2%	66.0%	66.0%	66.0%	2.0
283	Cooling	Energy Recovery Ventilator	Biz - Custom	Food Sales	RET	per ton	1,166	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	38%	2%	66.0%	66.0%	66.0%	2.0
284	Cooling	Energy Recovery Ventilator	Biz - Custom	Food Service	RET	per ton	1,289	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	42%	2%	66.0%	66.0%	66.0%	2.0
285	Cooling	Energy Recovery Ventilator	Biz - Custom	Health	RET	per ton	1,524	29%	446	0.14	0.01	15	$1,500	4%	4%	10%	4	57%	2%	19.6%	19.6%	19.6%	8.8

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
286	Cooling	Energy Recovery Ventilator	Biz - Custom	Lodging	RET	per ton	1,472	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	27%	2%	66.0%	66.0%	66.0%	2.0
287	Cooling	Energy Recovery Ventilator	Biz - Custom	Retail	RET	per ton	785	4%	35	0.02	0.00	15	$1,500	0%	0%	10%	4	33%	2%	19.6%	19.6%	19.6%	11.8
288	Cooling	Energy Recovery Ventilator	Biz - Custom	Office	RET	per ton	2,363	14%	327	0.12	0.01	15	$1,500	3%	3%	10%	4	55%	2%	19.6%	19.6%	19.6%	9.8
289	Cooling	Energy Recovery Ventilator	Biz - Custom	Warehouse	RET	per ton	368	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	62%	2%	66.0%	66.0%	66.0%	2.0
290	Cooling	Energy Recovery Ventilator	Biz - Custom	Other	RET	per ton	1,246	0%	0	0.00	0.00	15	$1,500	100%	0%	100%	4	57%	2%	66.0%	66.0%	66.0%	2.0
291	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Assembly	TOS	per ton	3,708	25%	917	0.10	0.21	15	$100	100%	10%	10%	1	20%	15%	88.0%	84.1%	84.1%	69.4
292	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Education	TOS	per ton	2,603	25%	643	0.09	0.17	15	$100	100%	10%	36%	1	0%	15%	88.0%	82.6%	84.0%	53.7
293	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Food Sales	TOS	per ton	3,444	25%	846	0.09	0.22	15	$100	100%	10%	15%	1	23%	15%	88.0%	83.8%	84.0%	64.1
294	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Food Service	TOS	per ton	3,241	24%	792	0.09	0.16	15	$100	100%	10%	21%	1	24%	15%	88.0%	83.5%	84.0%	61.0
295	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Health	TOS	per ton	3,932	24%	962	0.09	0.20	15	$100	100%	10%	10%	1	0%	15%	88.0%	84.3%	84.3%	69.6
296	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Lodging	TOS	per ton	3,910	24%	957	0.09	0.22	15	$100	100%	10%	10%	1	0%	15%	88.0%	84.2%	84.2%	69.6
297	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Retail	TOS	per ton	2,792	25%	689	0.09	0.15	15	$100	100%	10%	31%	1	20%	15%	88.0%	82.9%	84.0%	55.8
298	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Office	TOS	per ton	6,292	24%	1,541	0.09	0.34	15	$100	100%	10%	10%	1	4%	15%	88.0%	85.7%	85.7%	99.2
299	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Warehouse	TOS	per ton	2,378	25%	593	0.09	0.14	15	$100	100%	10%	41%	1	13%	15%	88.0%	82.2%	84.0%	51.0
300	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz - Prescriptive	Other	TOS	per ton	3,767	25%	926	0.09	0.21	15	$100	100%	10%	10%	1	0%	15%	88.0%	84.1%	84.1%	67.9
301	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Assembly	TOS	per ton	2,631	8%	222	0.09	0.05	15	$100	100%	10%	75%	2	13%	15%	88.0%	67.5%	83.6%	33.6
302	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Education	TOS	per ton	1,854	9%	160	0.09	0.04	15	$100	100%	10%	54%	2	22%	15%	88.0%	56.1%	77.5%	30.5
303	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Food Sales	TOS	per ton	2,552	11%	272	0.09	0.07	15	$100	100%	10%	73%	2	13%	15%	88.0%	74.3%	84.0%	36.3
304	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Food Service	TOS	per ton	2,475	12%	301	0.09	0.06	15	$100	100%	10%	70%	2	14%	15%	88.0%	77.0%	84.0%	37.6
305	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Health	TOS	per ton	2,988	12%	356	0.09	0.07	15	$100	100%	10%	64%	2	15%	15%	88.0%	78.7%	84.0%	40.4
306	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Lodging	TOS	per ton	2,954	12%	344	0.09	0.08	15	$100	100%	10%	66%	2	8%	15%	88.0%	78.3%	84.0%	39.9
307	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Retail	TOS	per ton	2,008	9%	183	0.09	0.04	15	$100	100%	10%	62%	2	10%	15%	88.0%	59.8%	80.3%	31.7
308	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Office	TOS	per ton	4,752	12%	552	0.09	0.12	15	$100	100%	10%	45%	2	13%	15%	88.0%	81.8%	84.0%	50.5
309	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Warehouse	TOS	per ton	1,595	5%	86	0.09	0.02	15	$100	100%	10%	29%	2	7%	15%	88.0%	34.9%	44.1%	26.7
310	Heating	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz - Prescriptive	Other	TOS	per ton	2,780	10%	291	0.09	0.07	15	$100	100%	10%	71%	2	11%	15%	88.0%	76.2%	84.0%	37.2
311	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Assembly	TOS	per ton	2,703	9%	242	0.10	0.06	15	$100	100%	10%	76%	3	12%	15%	88.0%	70.6%	84.0%	36.7
312	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Education	TOS	per ton	1,905	9%	175	0.10	0.05	15	$100	100%	10%	59%	3	22%	15%	88.0%	58.3%	79.3%	33.4
313	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Food Sales	TOS	per ton	2,621	11%	298	0.10	0.08	15	$100	100%	10%	70%	3	13%	15%	88.0%	76.8%	84.0%	39.7
314	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Food Service	TOS	per ton	2,541	13%	329	0.10	0.07	15	$100	100%	10%	67%	3	13%	15%	88.0%	77.9%	84.0%	41.1
315	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Health	TOS	per ton	3,067	13%	389	0.10	0.08	15	$100	100%	10%	61%	3	14%	15%	88.0%	79.4%	84.0%	44.2
316	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Lodging	TOS	per ton	3,033	12%	376	0.10	0.09	15	$100	100%	10%	62%	3	8%	15%	88.0%	79.1%	84.0%	43.6
317	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Retail	TOS	per ton	2,063	10%	200	0.10	0.04	15	$100	100%	10%	68%	3	10%	15%	88.0%	63.6%	81.9%	34.6
318	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Office	TOS	per ton	4,878	12%	603	0.10	0.13	15	$100	100%	10%	40%	3	13%	15%	88.0%	82.3%	84.0%	55.1
319	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Warehouse	TOS	per ton	1,641	6%	94	0.10	0.02	15	$100	100%	10%	32%	3	7%	15%	88.0%	37.9%	48.6%	29.2
320	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz - Prescriptive	Other	TOS	per ton	2,855	11%	318	0.10	0.07	15	$100	100%	10%	68%	3	11%	15%	88.0%	77.6%	84.0%	40.6
321	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Assembly	TOS	per ton	2,834	11%	318	0.14	0.07	15	$100	100%	10%	68%	4	12%	15%	88.0%	77.6%	84.0%	48.2
322	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Education	TOS	per ton	1,998	11%	229	0.14	0.06	15	$100	100%	10%	77%	4	22%	15%	88.0%	68.7%	84.0%	43.7
323	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Food Sales	TOS	per ton	2,760	14%	390	0.14	0.10	15	$100	100%	10%	61%	4	13%	15%	88.0%	79.4%	84.0%	52.0
324	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Food Service	TOS	per ton	2,683	16%	432	0.14	0.09	15	$100	100%	10%	57%	4	13%	15%	88.0%	80.2%	84.0%	53.9
325	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Health	TOS	per ton	3,237	16%	510	0.14	0.11	15	$100	100%	10%	49%	4	14%	15%	88.0%	81.3%	84.0%	57.9
326	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Lodging	TOS	per ton	3,200	15%	493	0.14	0.12	15	$100	100%	10%	51%	4	8%	15%	88.0%	81.1%	84.0%	57.1
327	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Retail	TOS	per ton	2,166	12%	263	0.14	0.06	15	$100	100%	10%	74%	4	10%	15%	88.0%	73.2%	84.0%	45.4
328	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Office	TOS	per ton	5,146	15%	791	0.14	0.17	15	$100	100%	10%	21%	4	13%	15%	88.0%	83.5%	84.0%	72.3
329	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Warehouse	TOS	per ton	1,710	7%	123	0.14	0.03	15	$100	100%	10%	42%	4	7%	15%	88.0%	48.4%	61.4%	38.3
330	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz - Prescriptive	Other	TOS	per ton	3,006	14%	417	0.14	0.10	15	$100	100%	10%	58%	4	11%	15%	88.0%	79.9%	84.0%	53.3
331	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Assembly	TOS	per ton	3,703	47%	1,753	0.18	0.40	25	$8,338	3%	3%	10%	5	3%	15%	30.3%	30.3%	30.3%	7.7
332	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Education	TOS	per ton	2,604	47%	1,231	0.18	0.32	25	$8,338	2%	2%	10%	5	4%	15%	30.3%	30.3%	30.3%	8.7
333	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Food Sales	TOS	per ton	3,498	47%	1,628	0.18	0.43	25	$8,338	3%	3%	10%	5	6%	15%	30.3%	30.3%	30.3%	7.9
334	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Food Service	TOS	per ton	3,331	46%	1,532	0.18	0.32	25	$8,338	3%	3%	10%	5	9%	15%	30.3%	30.3%	30.3%	8.0
335	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Health	TOS	per ton	4,033	46%	1,858	0.18	0.39	25	$8,338	3%	3%	10%	5	0%	15%	30.3%	30.3%	30.3%	7.5
336	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Lodging	TOS	per ton	4,002	46%	1,848	0.18	0.43	25	$8,338	3%	3%	10%	5	6%	15%	30.3%	30.3%	30.3%	7.5
337	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Retail	TOS	per ton	2,803	47%	1,320	0.18	0.29	25	$8,338	2%	2%	10%	5	5%	15%	30.3%	30.3%	30.3%	8.5
338	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Office	TOS	per ton	6,439	46%	2,974	0.18	0.65	25	$8,338	5%	5%	16%	5	3%	15%	30.3%	30.3%	30.3%	6.7
339	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Warehouse	TOS	per ton	2,326	48%	1,125	0.18	0.27	25	$8,338	2%	2%	10%	5	0%	15%	30.3%	30.3%	30.3%	9.0
340	Heating	Geothermal HP - 20 EER < 135kbtu	Biz - Custom	Other	TOS	per ton	3,820	47%	1,781	0.18	0.41	25	$8,338	3%	3%	10%	5	0%	15%	30.3%	30.3%	30.3%	7.6
341	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Assembly	TOS	per ton	2,035	41%	835	0.03	0.19	15	$84	100%	100%	10%	6	0%	15%	88.0%	88.0%	84.4%	5.0
342	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Education	TOS	per ton	4,918	55%	2,724	0.03	0.71	15	$84	100%	100%	10%	6	0%	15%	88.0%	88.0%	86.9%	14.7
343	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Food Sales	TOS	per ton	6,318	52%	3,291	0.03	0.87	15	$84	100%	100%	10%	6	10%	15%	88.0%	88.0%	87.1%	17.6
344	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Food Service	TOS	per ton	5,807	49%	2,866	0.03	0.59	15	$84	100%	100%	10%	6	0%	15%	88.0%	88.0%	86.9%	15.3
345	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Health	TOS	per ton	7,073	50%	3,525	0.03	0.73	15	$84	100%	100%	10%	6	0%	15%	88.0%	88.0%	87.1%	18.7
346	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Lodging	TOS	per ton	7,066	50%	3,559	0.03	0.84	15	$84	100%	100%	10%	6	15%	15%	88.0%	88.0%	87.2%	18.9
347	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Retail	TOS	per ton	5,238	55%	2,861	0.03	0.63	15	$84	100%	100%	10%	6	10%	15%	88.0%	88.0%	86.9%	15.3
348	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Office	TOS	per ton	11,374	50%	5,733	0.03	1.26	15	$84	100%	100%	10%	6	10%	15%	88.0%	88.0%	87.5%	29.9
349	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Warehouse	TOS	per ton	4,680	60%	2,799	0.03	0.68	15	$84	100%	100%	10%	6	0%	15%	88.0%	88.0%	86.9%	15.0
350	Heating	PTHP - 7,000 to 15,000 Btuh	Biz - Prescriptive	Other	TOS	per ton	6,932	52%	3,636	0.03	0.83	15	$84	100%	100%	10%	6	0%	15%	88.0%	88.0%	87.2%	19.3
351	Heating	High Speed Overhead Doors	0	Assembly	TOS	per garage door	50,000	1%	500	0.07	0.12	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
352	Heating	High Speed Overhead Doors	0	Education	TOS	per garage door	50,000	1%	500	0.08	0.13	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
353	Heating	High Speed Overhead Doors	0	Food Sales	TOS	per garage door	50,000	1%	500	0.11	0.13	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
354	Heating	High Speed Overhead Doors	0	Food Service	TOS	per garage door	50,000	1%	500	0.08	0.10	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
355	Heating	High Speed Overhead Doors	0	Health	TOS	per garage door	50,000	1%	500	0.05	0.10	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
356	Heating	High Speed Overhead Doors	0	Lodging	TOS	per garage door	50,000	1%	500	0.05	0.12	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
357	Heating	High Speed Overhead Doors	0	Retail	TOS	per garage door	50,000	1%	500	0.08	0.11	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
358	Heating	High Speed Overhead Doors	0	Office	TOS	per garage door	50,000	1%	500	0.06	0.11	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
359	Heating	High Speed Overhead Doors	0	Warehouse	TOS	per garage door	50,000	1%	500	0.08	0.12	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
360	Heating	High Speed Overhead Doors	0	Other	TOS	per garage door	50,000	1%	500	0.07	0.11	20	$201	100%	0%	75%	7	100%	2%	66.0%	50.9%	63.0%	2.0
361	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Assembly	TOS	per HP	1,503	28%	417	0.19	0.06	15	$198	100%	30%	71%	1	35%	64%	88.0%	74.1%	82.7%	11.1
362	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Education	TOS	per HP	2,296	28%	637	0.19	0.05	15	$198	100%	30%	68%	1	45%	77%	88.0%	81.6%	84.0%	12.9
363	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Food Sales	TOS	per HP	3,823	28%	1,060	0.19	0.24	15	$198	100%	30%	47%	1	0%	20%	88.0%	82.9%	84.0%	16.7
364	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Food Service	TOS	per HP	1,611	28%	447	0.19	0.05	15	$198	100%	30%	76%	1	0%	11%	88.0%	76.1%	83.8%	11.4
365	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Health	TOS	per HP	4,349	28%	1,206	0.19	0.06	15	$198	100%	30%	39%	1	43%	72%	88.0%	83.5%	84.0%	17.6
366	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Lodging	TOS	per HP	3,628	28%	1,006	0.19	0.12	15	$198	100%	30%	49%	1	47%	10%	88.0%	82.7%	84.0%	16.0
367	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Retail	TOS	per HP	1,675	28%	465	0.19	0.13	15	$198	100%	30%	77%	1	26%	8%	88.0%	77.1%	84.0%	11.6
368	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Office	TOS	per HP	3,090	28%	857	0.19	0.06	15	$198	100%	30%	57%	1	32%	13%	88.0%	81.9%	84.0%	14.8
369	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Warehouse	TOS	per HP	538	28%	149	0.19	0.01	15	$198	100%	30%	26%	1	0%	26%	88.0%	40.7%	40.7%	8.9
370	Ventilation	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz - Prescriptive	Other	TOS	per HP	2,088	28%	579	0.19	0.08	15	$198	100%	30%	71%	1	43%	33%	88.0%	79.1%	84.0%	12.5
371	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Assembly	RET	per 5 HP motor	7,655	29%	4,516	0.80	0.55	15	$2,250	100%	13%	68%	2	65%	64%	88.0%	71.2%	81.9%	13.9
372	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Education	RET	per 5 HP motor	7,655	29%	4,516	0.81	0.62	15	$2,250	100%	13%	68%	2	55%	77%	88.0%	81.6%	81.9%	13.9
373	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Food Sales	RET	per 5 HP motor	16,266	29%	9,596	1.40	1.35	15	$2,250	100%	13%	57%	2	100%	20%	88.0%	80.4%	84.0%	27.1
374	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Food Service	RET	per 5 HP motor	13,903	29%	8,202	1.24	1.07	15	$2,250	100%	13%	64%	2	100%	11%	88.0%	79.2%	84.0%	23.5
375	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Health	RET	per 5 HP motor	11,036	29%	6,510	0.84	0.73	15	$2,250	100%	13%	71%	2	57%	72%	88.0%	77.6%	84.0%	17.5
376	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Lodging	RET	per 5 HP motor	10,560	29%	6,229	1.21	0.64	15	$2,250	100%	13%	72%	2	53%	10%	88.0%	75.8%	84.0%	19.9
377	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Retail	RET	per 5 HP motor	13,400	29%	7,905	1.45	0.94	15	$2,250	100%	13%	65%	2	74%	8%	88.0%	78.9%	84.0%	24.7
378	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Office	RET	per 5 HP motor	6,786	29%	4,003	0.61	0.45	15	$2,250	100%	13%	60%	2	68%	13%	88.0%	60.2%	79.7%	11.5
379	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Warehouse	RET	per 5 HP motor	13,008	29%	7,674	1.20	0.92	15	$2,250	100%	13%	66%	2	100%	26%	88.0%	78.6%	84.0%	22.3
380	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz - Prescriptive	Other	RET	per 5 HP motor	11,883	29%	7,010	1.21	0.84	15	$2,250	100%	13%	69%	2	57%	33%	88.0%	77.8%	84.0%	21.2
381	Ventilation	Switch Reluctance Motors	Biz - Custom	Assembly	TOS	per 10HP	48,244	31%	14,763	2.15	2.16	15	$528	100%	100%	10%	2	35%	1%	66.0%	66.0%	65.0%	6.1
382	Ventilation	Switch Reluctance Motors	Biz - Custom	Education	TOS	per 10HP	26,808	31%	8,203	1.83	0.70	15	$528	100%	100%	10%	2	45%	1%	66.0%	66.0%	64.3%	7.3
383	Ventilation	Switch Reluctance Motors	Biz - Custom	Food Sales	TOS	per 10HP	56,966	31%	17,432	0.00	3.97	15	$528	100%	100%	10%	2	0%	1%	66.0%	66.0%	65.2%	3.7
384	Ventilation	Switch Reluctance Motors	Biz - Custom	Food Service	TOS	per 10HP	48,691	31%	14,899	3.17	1.61	15	$528	100%	100%	10%	2	0%	1%	66.0%	66.0%	65.0%	7.2
385	Ventilation	Switch Reluctance Motors	Biz - Custom	Health	TOS	per 10HP	38,649	31%	11,826	2.36	0.59	15	$528	100%	100%	10%	2	43%	1%	66.0%	66.0%	64.8%	6.9
386	Ventilation	Switch Reluctance Motors	Biz - Custom	Lodging	TOS	per 10HP	36,982	31%	11,316	1.34	1.30	15	$528	100%	100%	10%	2	47%	1%	66.0%	66.0%	64.7%	5.6
387	Ventilation	Switch Reluctance Motors	Biz - Custom	Retail	TOS	per 10HP	46,930	31%	14,361	0.39	3.98	15	$528	100%	100%	10%	2	26%	1%	66.0%	66.0%	65.0%	4.1
388	Ventilation	Switch Reluctance Motors	Biz - Custom	Office	TOS	per 10HP	23,765	31%	7,272	1.24	0.55	15	$528	100%	100%	10%	2	32%	1%	66.0%	66.0%	64.0%	6.4
389	Ventilation	Switch Reluctance Motors	Biz - Custom	Warehouse	TOS	per 10HP	45,557	31%	13,940	2.45	1.32	15	$528	100%	100%	10%	2	0%	1%	66.0%	66.0%	65.0%	6.5
390	Ventilation	Switch Reluctance Motors	Biz - Custom	Other	TOS	per 10HP	41,616	31%	12,734	1.91	1.68	15	$528	100%	100%	10%	2	43%	1%	66.0%	66.0%	64.9%	6.1
391	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Assembly	TOS	per 5 HP motor	24,122	3%	748	0.09	0.09	15	$137	100%	76%	45%	3	65%	10%	66.0%	64.7%	63.0%	5.7
392	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Education	TOS	per 5 HP motor	13,404	3%	416	0.09	0.06	15	$137	100%	43%	70%	3	55%	10%	66.0%	60.7%	63.0%	7.4
393	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Food Sales	TOS	per 5 HP motor	28,483	3%	883	0.09	0.12	15	$137	100%	90%	35%	3	100%	10%	66.0%	65.6%	63.0%	5.4
394	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Food Service	TOS	per 5 HP motor	24,345	3%	755	0.09	0.10	15	$137	100%	77%	45%	3	100%	10%	66.0%	64.8%	63.0%	5.7
395	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Health	TOS	per 5 HP motor	19,324	3%	599	0.09	0.07	15	$137	100%	61%	56%	3	57%	10%	66.0%	63.3%	63.0%	6.2
396	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Lodging	TOS	per 5 HP motor	18,491	3%	573	0.09	0.06	15	$137	100%	59%	58%	3	53%	10%	66.0%	63.0%	63.0%	6.4
397	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Retail	TOS	per 5 HP motor	23,465	3%	727	0.09	0.09	15	$137	100%	74%	47%	3	74%	10%	66.0%	64.6%	63.0%	5.8
398	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Office	TOS	per 5 HP motor	11,883	3%	368	0.09	0.04	15	$137	100%	38%	73%	3	68%	10%	66.0%	59.5%	63.0%	7.9
399	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Warehouse	TOS	per 5 HP motor	22,778	3%	706	0.09	0.08	15	$137	100%	72%	48%	3	100%	10%	66.0%	64.4%	63.0%	5.8
400	Ventilation	Cogged V-Belt (Synchronous)	Biz - Custom	Other	TOS	per 5 HP motor	20,808	3%	645	0.09	0.08	15	$137	100%	66%	53%	3	57%	10%	66.0%	63.8%	63.0%	6.1
401	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Assembly	RET	per 1000 sq ft	1,920	3%	398	0.06	0.05	10	$236	100%	24%	43%	3	100%	10%	66.0%	47.5%	55.4%	4.6
402	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Education	RET	per 1000 sq ft	1,920	3%	377	0.08	0.04	10	$236	100%	22%	41%	3	100%	10%	66.0%	45.2%	53.1%	5.3
403	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Food Sales	RET	per 1000 sq ft	0	2%	450	0.07	0.05	10	$236	100%	27%	49%	3	100%	10%	66.0%	52.1%	58.6%	4.5
404	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Food Service	RET	per 1000 sq ft	2,550	1%	626	0.13	0.07	10	$236	100%	37%	68%	3	100%	10%	66.0%	59.4%	62.5%	5.2
405	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Health	RET	per 1000 sq ft	305	3%	554	0.09	0.05	10	$236	100%	33%	60%	3	100%	10%	66.0%	58.1%	61.2%	4.5
406	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Lodging	RET	per 1000 sq ft	2,045	3%	937	0.13	0.12	10	$236	100%	56%	60%	3	100%	10%	66.0%	62.7%	63.0%	4.4
407	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Retail	RET	per 1000 sq ft	1,663	3%	339	0.07	0.04	10	$236	100%	20%	37%	3	100%	10%	66.0%	42.4%	48.5%	5.3
408	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Office	RET	per 1000 sq ft	1,313	2%	280	0.04	0.03	10	$236	50%	17%	31%	3	100%	10%	49.6%	37.3%	41.3%	4.5
409	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Warehouse	RET	per 1000 sq ft	0	3%	518	0.08	0.06	10	$236	100%	31%	57%	3	100%	10%	66.0%	56.7%	60.4%	4.5
410	WholeBldg_HVAC	Demand Control Ventilation	Biz - Custom	Other	RET	per 1000 sq ft	1,925	2%	398	0.06	0.05	10	$236	100%	24%	43%	3	100%	10%	66.0%	47.5%	55.4%	4.6
411	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Assembly	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.3
412	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Education	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	7.2
413	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Food Sales	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.2
414	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Food Service	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	7.1
415	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Health	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.2
416	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Lodging	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.0
417	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Retail	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	7.3
418	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Office	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.1
419	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Warehouse	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.1
420	WholeBldg_HVAC	High Efficiency DOAS	Biz - Custom	Other	RET	per sq ft	7	25%	2	0.00	0.00	15	$15	2%	2%	10%	4	100%	1%	18.8%	18.8%	18.8%	6.3
421	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Assembly	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	42%	10%	66.0%	58.8%	63.0%	6.3
422	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Education	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	55%	10%	66.0%	58.8%	63.0%	7.2
423	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Food Sales	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	38%	10%	66.0%	58.8%	63.0%	6.2
424	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Food Service	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	42%	10%	66.0%	58.8%	63.0%	7.1
425	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Health	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	57%	10%	66.0%	58.8%	63.0%	6.2
426	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Lodging	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	27%	10%	66.0%	58.8%	63.0%	6.0
427	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Retail	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	33%	10%	66.0%	58.8%	63.0%	7.3

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
428	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Office	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	55%	10%	66.0%	58.8%	63.0%	6.1
429	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Warehouse	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	62%	10%	66.0%	58.8%	63.0%	6.1
430	WholeBldg_HVAC	HVAC - Energy Management System	Biz - Custom	Other	RET	per kWh	13	8%	1	0.00	0.00	15	$0	100%	35%	75%	1	57%	10%	66.0%	58.8%	63.0%	6.2
431	WholeBldg_HVAC	GREM Controls	Biz - Custom	Assembly	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
432	WholeBldg_HVAC	GREM Controls	Biz - Custom	Education	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
433	WholeBldg_HVAC	GREM Controls	Biz - Custom	Food Sales	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
434	WholeBldg_HVAC	GREM Controls	Biz - Custom	Food Service	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
435	WholeBldg_HVAC	GREM Controls	Biz - Custom	Health	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
436	WholeBldg_HVAC	GREM Controls	Biz - Custom	Lodging	RET	er HVAC controll	4,853	19%	936	0.13	0.12	15	$260	100%	50%	64%	2	75%	20%	66.0%	62.0%	63.0%	6.0
437	WholeBldg_HVAC	GREM Controls	Biz - Custom	Retail	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
438	WholeBldg_HVAC	GREM Controls	Biz - Custom	Office	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
439	WholeBldg_HVAC	GREM Controls	Biz - Custom	Warehouse	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
440	WholeBldg_HVAC	GREM Controls	Biz - Custom	Other	RET	er HVAC controll	0	0%	0	0.00	0.00	15	$0	100%	0%	100%	2	0%	20%	66.0%	66.0%	66.0%	2.0
441	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Assembly	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.1
442	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Education	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.5
443	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Food Sales	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.0
444	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Food Service	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.4
445	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Health	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.0
446	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Lodging	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	2.9
447	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Retail	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.5
448	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Office	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.0
449	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Warehouse	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.0
450	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz - Custom	Other	RET	per kWh	13	8%	1	0.00	0.00	5	$0	100%	100%	17%	6	100%	15%	66.0%	66.0%	63.0%	3.1
451	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Assembly	RET	per linear ft	556	2%	11	0.00	0.00	10	$8	75%	20%	36%	5	100%	25%	60.9%	41.5%	46.8%	4.6
452	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Education	RET	per linear ft	699	2%	14	0.00	0.00	10	$8	100%	25%	45%	5	100%	25%	66.0%	48.9%	56.8%	5.3
453	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Food Sales	RET	per linear ft	970	2%	19	0.00	0.00	10	$8	100%	34%	62%	5	100%	25%	66.0%	58.5%	61.6%	4.5
454	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Food Service	RET	per linear ft	308	2%	6	0.00	0.00	10	$8	50%	11%	20%	5	100%	25%	47.5%	40.0%	40.0%	5.2
455	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Health	RET	per linear ft	916	2%	18	0.00	0.00	10	$8	100%	32%	59%	5	100%	25%	66.0%	57.8%	60.9%	4.5
456	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Lodging	RET	per linear ft	1,021	2%	20	0.00	0.00	10	$8	100%	36%	66%	5	100%	25%	66.0%	59.0%	62.1%	4.4
457	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Retail	RET	per linear ft	889	2%	18	0.00	0.00	10	$8	100%	31%	57%	5	100%	25%	66.0%	57.1%	60.6%	5.3
458	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Office	RET	per linear ft	696	2%	14	0.00	0.00	10	$8	100%	24%	45%	5	100%	25%	66.0%	48.6%	56.6%	4.5
459	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Warehouse	RET	per linear ft	765	2%	15	0.00	0.00	10	$8	100%	27%	49%	5	100%	25%	66.0%	52.2%	58.7%	4.5
460	WholeBldg_HVAC	Commercial Weatherstripping	Biz - Custom	Other	RET	per linear ft	674	2%	13	0.00	0.00	10	$8	100%	24%	43%	5	100%	25%	66.0%	47.4%	55.3%	4.6
461	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Assembly	TOS	per 100 gal cap	10,591	73%	7,766	1.11	1.55	15	$1,797	100%	28%	57%	1	100%	0%	88.0%	81.7%	84.0%	13.2
462	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Education	TOS	per 100 gal cap	17,641	73%	12,936	1.85	2.58	15	$1,797	100%	28%	28%	1	100%	9%	88.0%	84.0%	84.0%	21.9
463	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Food Sales	TOS	per 100 gal cap	16,398	73%	12,025	1.72	1.87	15	$1,797	100%	28%	33%	1	100%	0%	88.0%	83.7%	84.0%	20.3
464	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Food Service	TOS	per 100 gal cap	19,318	73%	14,166	2.03	2.20	15	$1,797	100%	28%	21%	1	100%	17%	88.0%	84.3%	84.0%	23.9
465	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Health	TOS	per 100 gal cap	24,473	73%	17,947	2.57	1.96	15	$1,797	100%	28%	10%	1	100%	25%	88.0%	85.1%	84.4%	30.1
466	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Lodging	TOS	per 100 gal cap	22,206	73%	16,284	2.33	3.15	15	$1,797	100%	28%	10%	1	100%	23%	88.0%	84.8%	84.0%	27.6
467	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Retail	TOS	per 100 gal cap	16,398	73%	12,025	1.72	1.05	15	$1,797	100%	28%	33%	1	100%	9%	88.0%	83.7%	84.0%	20.1
468	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Office	TOS	per 100 gal cap	15,870	73%	11,638	1.67	1.81	15	$1,797	100%	28%	35%	1	100%	9%	88.0%	83.6%	84.0%	19.6
469	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Warehouse	TOS	per 100 gal cap	10,591	73%	7,766	1.11	1.20	15	$1,797	100%	28%	57%	1	100%	0%	88.0%	81.7%	84.0%	13.1
470	Hot Water	Heat Pump Water Heater	Biz - Prescriptive	Other	TOS	per 100 gal cap	17,237	73%	12,640	1.81	1.96	15	$1,797	100%	28%	30%	1	100%	14%	88.0%	83.9%	84.0%	21.3
471	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Assembly	RET	per unit	502	25%	128	0.04	0.03	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	14.6
472	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Education	RET	per unit	602	25%	153	0.06	0.03	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	19.9
473	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Food Sales	RET	per unit	366	25%	93	0.01	0.01	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	7.2
474	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Food Service	RET	per unit	1,273	16%	209	0.03	0.03	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	15.5
475	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Health	RET	per unit	1,649	25%	420	0.05	0.05	10	$14	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	16.3
476	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Lodging	RET	per unit	156	25%	40	0.00	0.01	10	$8	100%	69%	50%	2	15%	85%	89.5%	88.0%	88.0%	3.2
477	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Retail	RET	per unit	367	25%	94	0.01	0.01	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	7.2
478	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Office	RET	per unit	544	25%	139	0.04	0.02	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	15.4
479	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Warehouse	RET	per unit	251	25%	64	0.02	0.01	10	$8	100%	100%	20%	2	15%	85%	89.5%	88.0%	88.0%	7.4
480	Hot Water	Low Flow Faucet Aerator	Biz - Custom	Other	RET	per unit	502	25%	128	0.04	0.02	10	$8	100%	100%	10%	2	15%	85%	89.5%	88.0%	88.0%	14.5
481	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Assembly	RET	per unit	18,059	54%	9,789	0.00	1.95	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	431.9
482	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Education	RET	per unit	18,059	54%	9,789	0.00	1.95	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	431.9
483	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Food Sales	RET	per unit	18,059	54%	9,789	0.00	1.52	5	$54	100%	9%	10%	3	20%	72%	88.0%	87.8%	87.8%	428.8
484	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Food Service	RET	per unit	18,059	54%	9,789	0.00	1.52	5	$54	100%	9%	10%	3	20%	72%	88.0%	87.8%	87.8%	428.8
485	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Health	RET	per unit	18,059	54%	9,789	0.00	1.07	5	$54	100%	9%	10%	3	20%	72%	88.0%	87.8%	87.8%	425.7
486	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Lodging	RET	per unit	18,059	54%	9,789	0.00	1.89	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	431.5
487	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Retail	RET	per unit	18,059	54%	9,789	0.00	0.85	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	424.2
488	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Office	RET	per unit	18,059	54%	9,789	0.00	1.52	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	428.8
489	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Warehouse	RET	per unit	18,059	54%	9,789	0.00	1.52	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	428.8
490	Hot Water	Pre-Rinse Spray Valves - DI	Biz - Prescriptive	Other	RET	per unit	18,059	54%	9,789	0.00	1.52	5	$54	100%	9%	10%	3	15%	72%	88.0%	87.8%	87.8%	428.8
491	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Assembly	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
492	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Education	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
493	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Food Sales	RET	per unit	996	76%	755	0.09	0.10	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
494	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Food Service	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
495	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Health	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
496	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Lodging	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
497	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Retail	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
498	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Office	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
499	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Warehouse	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
500	Lighting_Ext	Ext LED Replacing 100W MH (24/7)	Biz - Prescriptive	Other	RET	per unit	996	76%	755	0.09	0.09	10	$97	100%	41%	22%	1	13%	60%	95.0%	89.7%	88.0%	10.7
501	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Assembly	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
502	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Education	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
503	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Food Sales	RET	per unit	1,744	71%	1,239	0.14	0.16	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.6
504	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Food Service	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
505	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Health	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
506	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Lodging	RET	per unit	1,744	71%	1,239	0.14	0.14	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
507	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Retail	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
508	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Office	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
509	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Warehouse	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
510	Lighting_Ext	Ext LED Replacing 175W MH (24/7)	Biz - Prescriptive	Other	RET	per unit	1,744	71%	1,239	0.14	0.15	10	$124	100%	32%	10%	2	13%	60%	95.0%	90.3%	88.7%	17.5
511	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Assembly	RET	per unit	2,490	67%	1,659	0.19	0.19	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
512	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Education	RET	per unit	2,490	67%	1,659	0.19	0.19	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
513	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Food Sales	RET	per unit	2,490	67%	1,659	0.19	0.21	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
514	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Food Service	RET	per unit	2,490	67%	1,659	0.19	0.20	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
515	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Health	RET	per unit	2,490	67%	1,659	0.19	0.20	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
516	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Lodging	RET	per unit	2,490	67%	1,659	0.19	0.19	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
517	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Retail	RET	per unit	2,490	67%	1,659	0.19	0.20	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
518	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Office	RET	per unit	2,490	67%	1,659	0.19	0.19	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
519	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Warehouse	RET	per unit	2,490	67%	1,659	0.19	0.20	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
520	Lighting_Ext	Ext LED Replacing 250W MH (24/7)	Biz - Prescriptive	Other	RET	per unit	2,490	67%	1,659	0.19	0.19	10	$134	100%	37%	10%	3	13%	60%	95.0%	91.4%	89.9%	18.8
521	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Assembly	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
522	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Education	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
523	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Food Sales	RET	per unit	3,984	65%	2,570	0.29	0.33	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
524	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Food Service	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
525	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Health	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
526	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Lodging	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
527	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Retail	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
528	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Office	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
529	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Warehouse	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
530	Lighting_Ext	Ext LED Replacing 400W MH (24/7)	Biz - Prescriptive	Other	RET	per unit	3,984	65%	2,570	0.29	0.30	10	$196	100%	51%	10%	4	13%	60%	95.0%	92.4%	90.2%	14.6
531	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Assembly	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
532	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Education	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
533	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Food Sales	RET	per unit	9,467	70%	6,666	0.76	0.84	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
534	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Food Service	RET	per unit	9,467	70%	6,666	0.76	0.79	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
535	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Health	RET	per unit	9,467	70%	6,666	0.76	0.79	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
536	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Lodging	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
537	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Retail	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
538	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Office	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
539	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Warehouse	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
540	Lighting_Ext	Ext LED Replacing 1000W MH (24/7)	Biz - Prescriptive	Other	RET	per unit	9,467	70%	6,666	0.76	0.78	10	$319	100%	50%	10%	5	13%	60%	95.0%	93.3%	92.0%	23.6
541	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Assembly	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
542	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Education	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
543	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Food Sales	RET	per unit	489	76%	370	0.00	0.05	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
544	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Food Service	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
545	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Health	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
546	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Lodging	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
547	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Retail	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
548	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Office	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
549	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Warehouse	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
550	Lighting_Ext	Ext LED Replacing 100W MH (D2D)	Biz - Prescriptive	Other	RET	per unit	489	76%	370	0.00	0.04	16	$97	100%	41%	62%	6	7%	60%	95.0%	83.4%	88.0%	4.9
551	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Assembly	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
552	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Education	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
553	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Food Sales	RET	per unit	856	71%	608	0.00	0.08	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
554	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Food Service	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
555	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Health	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
556	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Lodging	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
557	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Retail	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
558	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Office	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
559	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Warehouse	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
560	Lighting_Ext	Ext LED Replacing 175W MH (D2D)	Biz - Prescriptive	Other	RET	per unit	856	71%	608	0.00	0.07	16	$124	100%	32%	51%	7	7%	60%	95.0%	84.8%	88.0%	8.0
561	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Assembly	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
562	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Education	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
563	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Food Sales	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
564	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Food Service	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
565	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Health	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
566	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Lodging	RET	per unit	1,222	67%	814	0.00	0.09	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
567	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Retail	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
568	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Office	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
569	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Warehouse	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
570	Lighting_Ext	Ext LED Replacing 250W MH (D2D)	Biz - Prescriptive	Other	RET	per unit	1,222	67%	814	0.00	0.10	16	$134	100%	37%	39%	8	7%	60%	95.0%	87.7%	88.0%	8.6
571	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Assembly	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
572	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Education	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
573	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Food Sales	RET	per unit	1,956	65%	1,262	0.00	0.16	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
574	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Food Service	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
575	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Health	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
576	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Lodging	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
577	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Retail	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
578	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Office	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
579	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Warehouse	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
580	Lighting_Ext	Ext LED Replacing 400W MH (D2D)	Biz - Prescriptive	Other	RET	per unit	1,956	65%	1,262	0.00	0.15	16	$196	100%	51%	36%	9	7%	60%	95.0%	89.7%	88.0%	6.6
581	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Assembly	RET	per unit	4,647	70%	3,272	0.00	0.38	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
582	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Education	RET	per unit	4,647	70%	3,272	0.00	0.38	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
583	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Food Sales	RET	per unit	4,647	70%	3,272	0.00	0.41	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.8
584	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Food Service	RET	per unit	4,647	70%	3,272	0.00	0.39	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
585	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Health	RET	per unit	4,647	70%	3,272	0.00	0.39	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
586	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Lodging	RET	per unit	4,647	70%	3,272	0.00	0.38	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
587	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Retail	RET	per unit	4,647	70%	3,272	0.00	0.38	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
588	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Office	RET	per unit	4,647	70%	3,272	0.00	0.38	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
589	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Warehouse	RET	per unit	4,647	70%	3,272	0.00	0.39	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
590	Lighting_Ext	Ext LED Replacing 1000W MH (D2D)	Biz - Prescriptive	Other	RET	per unit	4,647	70%	3,272	0.00	0.38	16	$319	100%	50%	10%	10	7%	60%	95.0%	91.6%	88.9%	10.7
591	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Assembly	RET	per unit	126	74%	93	0.02	0.01	15	$59	100%	8%	54%	1	19%	60%	95.0%	68.0%	71.5%	19.7
592	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Education	RET	per unit	127	74%	94	0.03	0.01	15	$59	100%	8%	54%	1	11%	60%	95.0%	68.0%	71.9%	22.3
593	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Food Sales	RET	per unit	220	74%	162	0.03	0.02	12	$59	100%	8%	73%	1	8%	60%	95.0%	68.0%	88.0%	25.2
594	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Food Service	RET	per unit	230	74%	170	0.03	0.02	12	$59	100%	8%	71%	1	5%	60%	95.0%	68.8%	88.0%	27.1
595	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Health	RET	per unit	251	74%	185	0.02	0.02	12	$59	100%	8%	69%	1	16%	60%	95.0%	71.7%	88.0%	24.7
596	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Lodging	RET	per unit	178	74%	131	0.02	0.02	15	$59	100%	8%	75%	1	15%	60%	95.0%	68.0%	87.1%	24.2
597	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Retail	RET	per unit	171	74%	126	0.03	0.02	15	$59	100%	8%	72%	1	4%	60%	95.0%	68.0%	85.5%	25.9
598	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Office	RET	per unit	126	74%	93	0.02	0.01	15	$59	100%	8%	53%	1	4%	60%	95.0%	68.0%	71.2%	19.6
599	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Warehouse	RET	per unit	122	74%	90	0.03	0.01	15	$59	100%	8%	52%	1	2%	60%	95.0%	68.0%	69.3%	22.6
600	Lighting_Int	LED Interior Direction (Track lighting / Wall-Wash Fixture)	Biz - Prescriptive	Other	RET	per unit	140	74%	103	0.03	0.01	15	$59	100%	8%	59%	1	7%	60%	95.0%	68.0%	76.6%	22.2
601	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Assembly	RET	per unit	91	51%	47	0.01	0.01	10	$15	100%	33%	69%	2	46%	60%	95.0%	78.4%	88.0%	7.2
602	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Education	RET	per unit	92	51%	47	0.01	0.01	10	$15	100%	33%	68%	2	69%	60%	95.0%	78.5%	88.0%	8.2
603	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Food Sales	RET	per unit	159	51%	82	0.01	0.01	10	$15	100%	33%	46%	2	53%	60%	95.0%	86.1%	88.0%	11.0
604	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Food Service	RET	per unit	166	51%	85	0.02	0.01	10	$15	100%	33%	43%	2	64%	60%	95.0%	86.6%	88.0%	11.8
605	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Health	RET	per unit	181	51%	93	0.01	0.01	10	$15	100%	33%	38%	2	43%	60%	95.0%	87.4%	88.0%	10.8
606	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Lodging	RET	per unit	128	51%	66	0.01	0.01	10	$15	100%	33%	56%	2	44%	60%	95.0%	83.6%	88.0%	8.9
607	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Retail	RET	per unit	123	51%	63	0.01	0.01	10	$15	100%	33%	58%	2	63%	60%	95.0%	83.1%	88.0%	9.6
608	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Office	RET	per unit	91	51%	47	0.01	0.00	10	$15	100%	33%	69%	2	55%	60%	95.0%	78.3%	88.0%	7.2
609	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Warehouse	RET	per unit	88	51%	45	0.01	0.00	10	$15	100%	33%	70%	2	37%	60%	95.0%	77.8%	88.0%	8.3
610	Lighting_Int	LED Linear Replacement Lamps (Replacing T8)	Biz - Prescriptive	Other	RET	per unit	101	51%	52	0.01	0.01	10	$15	100%	33%	65%	2	62%	60%	95.0%	80.1%	88.0%	8.2
611	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Assembly	RET	per unit	94	34%	32	0.01	0.00	15	$22	100%	23%	49%	2	46%	60%	95.0%	68.0%	68.0%	6.8
612	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Education	RET	per unit	95	34%	32	0.01	0.00	15	$22	100%	23%	50%	2	69%	60%	95.0%	68.0%	68.0%	7.7
613	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Food Sales	RET	per unit	164	34%	56	0.01	0.01	12	$22	100%	23%	74%	2	53%	60%	95.0%	70.4%	87.8%	8.7
614	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Food Service	RET	per unit	172	34%	58	0.01	0.01	12	$22	100%	23%	73%	2	64%	60%	95.0%	71.7%	88.0%	9.3
615	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Health	RET	per unit	187	34%	64	0.01	0.01	12	$22	100%	23%	71%	2	43%	60%	95.0%	73.8%	88.0%	8.5
616	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Lodging	RET	per unit	133	34%	45	0.01	0.01	15	$22	100%	23%	70%	2	44%	60%	95.0%	68.0%	83.9%	8.3
617	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Retail	RET	per unit	127	34%	43	0.01	0.01	15	$22	100%	23%	67%	2	63%	60%	95.0%	68.0%	82.2%	8.9
618	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Office	RET	per unit	94	34%	32	0.01	0.00	15	$22	100%	23%	49%	2	55%	60%	95.0%	68.0%	68.0%	6.7
619	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Warehouse	RET	per unit	91	34%	31	0.01	0.00	15	$22	100%	23%	48%	2	37%	60%	95.0%	68.0%	68.0%	7.8
620	Lighting_Int	LED Troffers (Replacing 1-Lamp T8)	Biz - Prescriptive	Other	RET	per unit	104	34%	35	0.01	0.00	15	$22	100%	23%	55%	2	62%	60%	95.0%	68.0%	72.5%	7.6
621	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Assembly	RET	per unit	184	51%	95	0.02	0.01	15	$61	100%	16%	53%	2	46%	60%	95.0%	68.0%	70.4%	10.0
622	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Education	RET	per unit	186	51%	96	0.03	0.01	15	$61	100%	16%	53%	2	69%	60%	95.0%	68.0%	71.1%	11.3
623	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Food Sales	RET	per unit	321	51%	165	0.03	0.02	12	$61	100%	16%	73%	2	53%	60%	95.0%	69.9%	88.0%	12.8
624	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Food Service	RET	per unit	336	51%	173	0.03	0.02	12	$61	100%	16%	72%	2	64%	60%	95.0%	71.4%	88.0%	13.8
625	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Health	RET	per unit	366	51%	188	0.02	0.02	12	$61	100%	16%	69%	2	43%	60%	95.0%	73.5%	88.0%	12.6
626	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Lodging	RET	per unit	260	51%	133	0.02	0.02	15	$61	100%	16%	74%	2	44%	60%	95.0%	68.0%	86.5%	12.3
627	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Retail	RET	per unit	249	51%	128	0.03	0.02	15	$61	100%	16%	71%	2	63%	60%	95.0%	68.0%	84.9%	13.2
628	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Office	RET	per unit	183	51%	94	0.02	0.01	15	$61	100%	16%	52%	2	55%	60%	95.0%	68.0%	70.0%	10.0
629	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Warehouse	RET	per unit	179	51%	92	0.03	0.01	15	$61	100%	16%	51%	2	37%	60%	95.0%	68.0%	68.0%	11.5
630	Lighting_Int	LED Troffers (Replacing 2-Lamp T8)	Biz - Prescriptive	Other	RET	per unit	204	51%	105	0.03	0.01	15	$61	100%	16%	58%	2	62%	60%	95.0%	68.0%	75.9%	11.3
631	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Assembly	RET	per unit	273	54%	148	0.03	0.02	15	$76	100%	20%	66%	2	46%	60%	95.0%	68.0%	81.6%	10.4
632	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Education	RET	per unit	275	54%	149	0.04	0.02	15	$76	100%	20%	66%	2	69%	60%	95.0%	68.0%	81.9%	11.8
633	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Food Sales	RET	per unit	475	54%	257	0.05	0.03	12	$76	100%	20%	66%	2	53%	60%	95.0%	76.3%	88.0%	13.3
634	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Food Service	RET	per unit	498	54%	269	0.05	0.04	12	$76	100%	20%	65%	2	64%	60%	95.0%	77.2%	88.0%	14.3
635	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Health	RET	per unit	543	54%	294	0.04	0.03	12	$76	100%	20%	61%	2	43%	60%	95.0%	78.8%	88.0%	13.1
636	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Lodging	RET	per unit	385	54%	208	0.04	0.02	15	$76	100%	20%	73%	2	44%	60%	95.0%	71.6%	88.0%	12.8
637	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Retail	RET	per unit	370	54%	200	0.04	0.03	15	$76	100%	20%	74%	2	63%	60%	95.0%	70.4%	88.0%	13.7
638	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Office	RET	per unit	272	54%	147	0.03	0.02	15	$76	100%	20%	66%	2	55%	60%	95.0%	68.0%	81.4%	10.4
639	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Warehouse	RET	per unit	265	54%	143	0.05	0.02	15	$76	100%	20%	64%	2	37%	60%	95.0%	68.0%	80.2%	11.9
640	Lighting_Int	LED Troffers (Replacing 3-Lamp T8)	Biz - Prescriptive	Other	RET	per unit	302	54%	163	0.04	0.02	15	$76	100%	20%	73%	2	62%	60%	95.0%	68.0%	85.8%	11.7

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
641	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Assembly	RET	per unit	364	54%	198	0.05	0.03	15	$104	100%	19%	64%	2	46%	60%	95.0%	68.0%	80.6%	10.4
642	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Education	RET	per unit	367	54%	199	0.06	0.02	15	$104	100%	19%	65%	2	69%	60%	95.0%	68.0%	81.0%	11.8
643	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Food Sales	RET	per unit	634	54%	344	0.06	0.04	12	$104	100%	19%	67%	2	53%	60%	95.0%	75.7%	88.0%	13.4
644	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Food Service	RET	per unit	664	54%	360	0.07	0.05	12	$104	100%	19%	65%	2	64%	60%	95.0%	76.7%	88.0%	14.4
645	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Health	RET	per unit	724	54%	393	0.05	0.04	12	$104	100%	19%	62%	2	43%	60%	95.0%	78.3%	88.0%	13.1
646	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Lodging	RET	per unit	513	54%	278	0.05	0.03	15	$104	100%	19%	73%	2	44%	60%	95.0%	70.8%	88.0%	12.8
647	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Retail	RET	per unit	493	54%	267	0.06	0.04	15	$104	100%	19%	74%	2	63%	60%	95.0%	69.3%	88.0%	13.7
648	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Office	RET	per unit	362	54%	197	0.05	0.02	15	$104	100%	19%	64%	2	55%	60%	95.0%	68.0%	80.4%	10.4
649	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Warehouse	RET	per unit	353	54%	191	0.06	0.02	15	$104	100%	19%	62%	2	37%	60%	95.0%	68.0%	79.2%	12.0
650	Lighting_Int	LED Troffers (Replacing 4-Lamp T8)	Biz - Prescriptive	Other	RET	per unit	403	54%	219	0.05	0.03	15	$104	100%	19%	71%	2	62%	60%	95.0%	68.0%	84.9%	11.8
651	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Assembly	RET	per unit	184	50%	92	0.02	0.01	15	$47	100%	11%	67%	2	46%	60%	95.0%	68.0%	82.4%	19.5
652	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Education	RET	per unit	185	50%	93	0.03	0.01	15	$47	100%	11%	68%	2	69%	60%	95.0%	68.0%	82.8%	22.2
653	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Food Sales	RET	per unit	320	50%	161	0.03	0.02	12	$47	100%	11%	66%	2	53%	60%	95.0%	74.5%	88.0%	25.1
654	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Food Service	RET	per unit	335	50%	169	0.03	0.02	12	$47	100%	11%	64%	2	64%	60%	95.0%	75.5%	88.0%	26.9
655	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Health	RET	per unit	365	50%	184	0.02	0.02	12	$47	100%	11%	61%	2	43%	60%	95.0%	77.2%	88.0%	24.5
656	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Lodging	RET	per unit	259	50%	130	0.02	0.02	15	$47	100%	11%	72%	2	44%	60%	95.0%	68.6%	88.0%	24.0
657	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Retail	RET	per unit	249	50%	125	0.03	0.02	15	$47	100%	11%	73%	2	63%	60%	95.0%	68.0%	88.0%	25.7
658	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Office	RET	per unit	183	50%	92	0.02	0.01	15	$47	100%	11%	67%	2	55%	60%	95.0%	68.0%	82.2%	19.4
659	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Warehouse	RET	per unit	178	50%	90	0.03	0.01	15	$47	100%	11%	65%	2	37%	60%	95.0%	68.0%	81.1%	22.4
660	Lighting_Int	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	Biz - Prescriptive	Other	RET	per unit	203	50%	102	0.02	0.01	15	$47	100%	11%	74%	2	62%	60%	95.0%	68.0%	86.6%	22.1
661	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Assembly	RET	per unit	485	53%	258	0.06	0.03	15	$152	100%	3%	58%	2	46%	60%	95.0%	68.0%	75.2%	54.4
662	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Education	RET	per unit	489	53%	260	0.08	0.03	15	$152	100%	3%	58%	2	69%	60%	95.0%	68.0%	75.6%	61.8
663	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Food Sales	RET	per unit	844	53%	449	0.08	0.05	12	$152	100%	3%	70%	2	53%	60%	95.0%	68.0%	88.0%	69.9
664	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Food Service	RET	per unit	884	53%	470	0.09	0.06	12	$152	100%	3%	69%	2	64%	60%	95.0%	69.5%	88.0%	74.9
665	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Health	RET	per unit	964	53%	513	0.06	0.05	12	$152	100%	3%	66%	2	43%	60%	95.0%	72.1%	88.0%	68.4
666	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Lodging	RET	per unit	683	53%	363	0.06	0.04	15	$152	100%	3%	76%	2	44%	60%	95.0%	68.0%	88.0%	66.9
667	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Retail	RET	per unit	656	53%	349	0.08	0.05	15	$152	100%	3%	77%	2	63%	60%	95.0%	68.0%	88.0%	71.7
668	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Office	RET	per unit	482	53%	256	0.06	0.03	15	$152	100%	3%	57%	2	55%	60%	95.0%	68.0%	75.0%	54.2
669	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Warehouse	RET	per unit	470	53%	250	0.08	0.03	15	$152	100%	3%	56%	2	37%	60%	95.0%	68.0%	73.6%	62.6
670	Lighting_Int	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	Biz - Prescriptive	Other	RET	per unit	536	53%	285	0.07	0.04	15	$152	100%	3%	64%	2	62%	60%	95.0%	68.0%	80.0%	61.5
671	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Assembly	RET	per unit	508	67%	340	0.08	0.04	15	$43	100%	12%	21%	3	5%	60%	95.0%	87.0%	88.0%	71.8
672	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Education	RET	per unit	512	67%	343	0.10	0.04	15	$43	100%	12%	20%	3	8%	60%	95.0%	87.1%	88.0%	81.5
673	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Food Sales	RET	per unit	883	67%	592	0.11	0.07	12	$43	100%	12%	10%	3	6%	60%	95.0%	90.5%	90.4%	92.2
674	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Food Service	RET	per unit	926	67%	620	0.12	0.08	12	$43	100%	12%	10%	3	7%	60%	95.0%	90.7%	90.6%	98.9
675	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Health	RET	per unit	1,009	67%	676	0.08	0.07	12	$43	100%	12%	10%	3	5%	60%	95.0%	91.1%	91.0%	90.2
676	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Lodging	RET	per unit	715	67%	479	0.09	0.06	15	$43	100%	12%	10%	3	5%	60%	95.0%	89.5%	89.4%	88.3
677	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Retail	RET	per unit	687	67%	460	0.10	0.07	15	$43	100%	12%	10%	3	7%	60%	95.0%	89.2%	89.1%	94.6
678	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Office	RET	per unit	505	67%	338	0.08	0.04	15	$43	100%	12%	21%	3	6%	60%	95.0%	87.0%	88.0%	71.5
679	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Warehouse	RET	per unit	492	67%	330	0.10	0.04	15	$43	100%	12%	23%	3	4%	60%	95.0%	86.7%	88.0%	82.5
680	Lighting_Int	LED Low-Bay Fixture	Biz - Prescriptive	Other	RET	per unit	561	67%	376	0.09	0.05	15	$43	100%	12%	12%	3	7%	60%	95.0%	87.9%	88.0%	81.1
681	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Assembly	RET	per unit	950	57%	542	0.13	0.07	15	$48	100%	62%	10%	4	6%	60%	95.0%	92.7%	89.4%	19.1
682	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Education	RET	per unit	958	57%	546	0.16	0.07	15	$48	100%	62%	10%	4	6%	60%	95.0%	92.7%	89.5%	21.6
683	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Food Sales	RET	per unit	1,654	57%	943	0.17	0.11	12	$48	100%	62%	10%	4	23%	60%	95.0%	93.7%	91.8%	24.5
684	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Food Service	RET	per unit	1,734	57%	988	0.18	0.13	12	$48	100%	62%	10%	4	3%	60%	95.0%	93.7%	91.9%	26.3
685	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Health	RET	per unit	1,890	57%	1,077	0.13	0.11	12	$48	100%	62%	10%	4	7%	60%	95.0%	93.8%	92.2%	24.0
686	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Lodging	RET	per unit	1,339	57%	764	0.14	0.09	15	$48	100%	62%	10%	4	0%	60%	95.0%	93.3%	91.0%	23.4
687	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Retail	RET	per unit	1,286	57%	733	0.16	0.11	15	$48	100%	62%	10%	4	14%	60%	95.0%	93.3%	90.9%	25.1
688	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Office	RET	per unit	946	57%	539	0.13	0.06	15	$48	100%	62%	10%	4	19%	60%	95.0%	92.7%	89.4%	19.0
689	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Warehouse	RET	per unit	921	57%	525	0.17	0.06	15	$48	100%	62%	10%	4	38%	60%	95.0%	92.6%	89.2%	21.9
690	Lighting_Int	LED High-Bay Fixture (Replacing T8 High Bay)	Biz - Prescriptive	Other	RET	per unit	1,051	57%	600	0.15	0.07	15	$48	100%	62%	10%	4	5%	60%	95.0%	92.9%	89.9%	21.5
691	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Assembly	RET	per unit	3,815	72%	2,758	0.65	0.35	15	$188	100%	85%	10%	5	17%	50%	95.0%	94.3%	90.7%	18.2
692	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Education	RET	per unit	3,847	72%	2,781	0.81	0.34	15	$188	100%	85%	10%	5	2%	50%	95.0%	94.3%	90.7%	20.7
693	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Food Sales	RET	per unit	6,639	72%	4,801	0.85	0.57	12	$188	100%	85%	10%	5	9%	50%	95.0%	94.6%	92.5%	23.4
694	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Food Service	RET	per unit	6,958	72%	5,031	0.94	0.66	12	$188	100%	85%	10%	5	1%	50%	95.0%	94.6%	92.6%	25.1
695	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Health	RET	per unit	7,584	72%	5,484	0.67	0.56	12	$188	100%	85%	10%	5	1%	50%	95.0%	94.6%	92.8%	22.9
696	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Lodging	RET	per unit	5,375	72%	3,886	0.69	0.45	15	$188	100%	85%	10%	5	1%	50%	95.0%	94.5%	92.0%	22.4
697	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Retail	RET	per unit	5,163	72%	3,733	0.83	0.54	15	$188	100%	85%	10%	5	8%	50%	95.0%	94.5%	91.8%	24.0
698	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Office	RET	per unit	3,795	72%	2,744	0.65	0.29	15	$188	100%	85%	10%	5	11%	50%	95.0%	94.3%	90.7%	18.1
699	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Warehouse	RET	per unit	3,698	72%	2,674	0.85	0.29	15	$188	100%	85%	10%	5	19%	50%	95.0%	94.3%	90.6%	20.9
700	Lighting_Int	LED High-Bay Fixture (Replacing Metal Halide)	Biz - Prescriptive	Other	RET	per unit	4,220	72%	3,051	0.74	0.38	15	$188	100%	85%	10%	5	4%	50%	95.0%	94.4%	91.1%	20.6
701	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Assembly	RET	per unit	66	71%	47	0.01	0.01	5	$33	92%	92%	21%	8	1%	85%	91.3%	91.3%	88.0%	0.6
702	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Education	RET	per unit	66	71%	47	0.01	0.01	5	$33	92%	92%	21%	8	1%	85%	91.3%	91.3%	88.0%	0.6
703	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Food Sales	RET	per unit	63	71%	45	0.01	0.01	5	$33	92%	92%	20%	8	1%	85%	91.1%	91.1%	88.0%	0.5
704	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Food Service	RET	per unit	65	71%	46	0.01	0.01	5	$33	92%	92%	21%	8	1%	85%	91.2%	91.2%	88.0%	0.5
705	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Health	RET	per unit	69	71%	49	0.01	0.01	5	$33	92%	92%	22%	8	1%	85%	91.4%	91.4%	88.0%	0.6
706	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Lodging	RET	per unit	66	71%	47	0.01	0.01	5	$33	92%	92%	21%	8	1%	85%	91.3%	91.3%	88.0%	0.5
707	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Retail	RET	per unit	66	71%	47	0.01	0.01	5	$33	92%	92%	21%	8	1%	85%	91.3%	91.3%	88.0%	0.5
708	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Office	RET	per unit	67	71%	48	0.01	0.01	5	$33	92%	92%	22%	8	1%	85%	91.3%	91.3%	88.0%	0.6
709	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Warehouse	RET	per unit	61	71%	44	0.01	0.00	5	$33	92%	92%	20%	8	1%	85%	91.0%	91.0%	88.0%	0.5
710	Lighting_Int	LED Exit Sign	Biz - Prescriptive	Other	RET	per unit	65	71%	46	0.01	0.01	5	$33	92%	92%	21%	8	1%	85%	91.2%	91.2%	88.0%	0.5
711	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Assembly	RET	per unit	81	100%	81	0.02	0.01	11	$19	100%	27%	56%	6	46%	0%	88.0%	81.7%	84.0%	13.5

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
712	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Education	RET	per unit	82	100%	82	0.02	0.01	11	$19	100%	27%	56%	6	69%	0%	88.0%	81.7%	84.0%	15.3
713	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Food Sales	RET	per unit	141	100%	141	0.03	0.02	11	$19	100%	27%	24%	6	53%	0%	88.0%	84.2%	84.0%	20.6
714	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Food Service	RET	per unit	148	100%	148	0.03	0.02	11	$19	100%	27%	20%	6	64%	0%	88.0%	84.4%	84.0%	22.1
715	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Health	RET	per unit	161	100%	161	0.02	0.02	11	$19	100%	27%	13%	6	43%	0%	88.0%	84.7%	84.0%	20.1
716	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Lodging	RET	per unit	114	100%	114	0.02	0.01	11	$19	100%	27%	38%	6	44%	0%	88.0%	83.4%	84.0%	16.6
717	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Retail	RET	per unit	110	100%	110	0.02	0.02	11	$19	100%	27%	41%	6	63%	0%	88.0%	83.2%	84.0%	17.8
718	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Office	RET	per unit	81	100%	81	0.02	0.01	11	$19	100%	27%	56%	6	55%	0%	88.0%	81.6%	84.0%	13.5
719	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Warehouse	RET	per unit	79	100%	79	0.02	0.01	11	$19	100%	27%	57%	6	37%	0%	88.0%	81.5%	84.0%	15.5
720	Lighting_Int	Fluorescent Delamping	Biz - Prescriptive	Other	RET	per unit	90	100%	90	0.02	0.01	11	$19	100%	27%	51%	6	62%	0%	88.0%	82.2%	84.0%	15.3
721	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Assembly	RET	per control/fixtur	422	30%	126	0.02	0.02	15	$65	100%	46%	66%	7	90%	15%	88.0%	77.7%	81.3%	3.8
722	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Education	RET	per control/fixtur	425	30%	128	0.03	0.02	15	$65	100%	46%	66%	7	90%	15%	88.0%	77.8%	81.4%	4.4
723	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Food Sales	RET	per control/fixtur	734	30%	220	0.03	0.03	15	$65	100%	46%	66%	7	90%	15%	88.0%	81.9%	84.0%	6.2
724	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Food Service	RET	per control/fixtur	769	30%	231	0.04	0.03	15	$65	100%	46%	65%	7	90%	15%	88.0%	82.1%	84.0%	6.7
725	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Health	RET	per control/fixtur	838	30%	251	0.02	0.03	15	$65	100%	46%	62%	7	90%	15%	88.0%	82.6%	84.0%	6.0
726	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Lodging	RET	per control/fixtur	594	30%	178	0.02	0.02	15	$65	100%	46%	73%	7	90%	15%	88.0%	80.5%	84.0%	4.9
727	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Retail	RET	per control/fixtur	571	30%	171	0.03	0.02	15	$65	100%	46%	74%	7	90%	15%	88.0%	80.3%	84.0%	5.3
728	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Office	RET	per control/fixtur	419	30%	126	0.02	0.01	15	$65	100%	46%	65%	7	90%	15%	88.0%	77.7%	81.2%	3.8
729	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Warehouse	RET	per control/fixtur	409	30%	123	0.03	0.01	15	$65	100%	46%	64%	7	90%	15%	88.0%	77.4%	80.7%	4.6
730	Lighting_Int	Lighting Occupancy Sensor	Biz - Prescriptive	Other	RET	per control/fixtur	466	30%	140	0.03	0.02	15	$65	100%	46%	73%	7	90%	15%	88.0%	78.6%	83.0%	4.4
731	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Assembly	RET	per control/fixtur	540	28%	151	0.03	0.02	15	$58	100%	52%	74%	7	90%	15%	88.0%	81.1%	84.0%	4.6
732	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Education	RET	per control/fixtur	544	28%	152	0.03	0.02	15	$58	100%	52%	73%	7	90%	15%	88.0%	81.2%	84.0%	5.2
733	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Food Sales	RET	per control/fixtur	940	28%	263	0.04	0.03	15	$58	100%	52%	54%	7	90%	15%	88.0%	83.8%	84.0%	7.4
734	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Food Service	RET	per control/fixtur	985	28%	276	0.04	0.04	15	$58	100%	52%	52%	7	90%	15%	88.0%	84.0%	84.0%	8.1
735	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Health	RET	per control/fixtur	1,073	28%	301	0.03	0.03	15	$58	100%	52%	48%	7	90%	15%	88.0%	84.3%	84.0%	7.2
736	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Lodging	RET	per control/fixtur	761	28%	213	0.03	0.02	15	$58	100%	52%	63%	7	90%	15%	88.0%	83.0%	84.0%	5.9
737	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Retail	RET	per control/fixtur	731	28%	205	0.04	0.03	15	$58	100%	52%	64%	7	90%	15%	88.0%	82.8%	84.0%	6.4
738	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Office	RET	per control/fixtur	537	28%	150	0.03	0.02	15	$58	100%	52%	74%	7	90%	15%	88.0%	81.1%	84.0%	4.6
739	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Warehouse	RET	per control/fixtur	523	28%	147	0.04	0.02	15	$58	100%	52%	75%	7	90%	15%	88.0%	80.9%	84.0%	5.5
740	Lighting_Int	Lighting Daylight Sensor	Biz - Prescriptive	Other	RET	per control/fixtur	597	28%	167	0.03	0.02	15	$58	100%	52%	71%	7	90%	15%	88.0%	81.7%	84.0%	5.3
741	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Assembly	RET	per control	241	38%	92	0.02	0.01	15	$75	100%	40%	41%	7	90%	15%	88.0%	59.8%	60.8%	2.8
742	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Education	RET	per control	243	38%	92	0.02	0.01	15	$75	100%	40%	42%	7	90%	15%	88.0%	60.1%	61.4%	3.2
743	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Food Sales	RET	per control	419	38%	159	0.02	0.02	15	$75	100%	40%	72%	7	90%	15%	88.0%	77.6%	82.9%	4.5
744	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Food Service	RET	per control	439	38%	167	0.03	0.02	15	$75	100%	40%	76%	7	90%	15%	88.0%	78.1%	83.6%	4.9
745	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Health	RET	per control	479	38%	182	0.02	0.02	15	$75	100%	40%	76%	7	90%	15%	88.0%	78.8%	84.0%	4.4
746	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Lodging	RET	per control	339	38%	129	0.02	0.01	15	$75	100%	40%	58%	7	90%	15%	88.0%	72.6%	79.0%	3.5
747	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Retail	RET	per control	326	38%	124	0.02	0.02	15	$75	100%	40%	56%	7	90%	15%	88.0%	71.3%	78.2%	3.8
748	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Office	RET	per control	240	38%	91	0.02	0.01	15	$75	100%	40%	41%	7	90%	15%	88.0%	59.5%	60.4%	2.8
749	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Warehouse	RET	per control	233	38%	89	0.02	0.01	15	$75	100%	40%	40%	7	90%	15%	88.0%	58.7%	58.7%	3.3
750	Lighting_Int	Dual Occupancy / Daylight Sensor	Biz - Prescriptive	Other	RET	per control	266	38%	101	0.02	0.01	15	$75	100%	40%	46%	7	90%	15%	88.0%	64.0%	67.9%	3.2
751	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Assembly	RET	per control	241	61%	147	0.03	0.02	15	$56	100%	40%	74%	7	90%	15%	88.0%	79.5%	84.0%	5.9
752	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Education	RET	per control	338	61%	206	0.03	0.02	15	$56	100%	40%	63%	7	90%	15%	88.0%	81.8%	84.0%	8.1
753	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Food Sales	RET	per control	419	61%	256	0.04	0.03	15	$56	100%	40%	54%	7	90%	15%	88.0%	82.9%	84.0%	9.6
754	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Food Service	RET	per control	439	61%	268	0.04	0.03	15	$56	100%	40%	52%	7	90%	15%	88.0%	83.1%	84.0%	10.4
755	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Health	RET	per control	479	61%	292	0.03	0.03	15	$56	100%	40%	48%	7	90%	15%	88.0%	83.5%	84.0%	9.3
756	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Lodging	RET	per control	339	61%	207	0.03	0.02	15	$56	100%	40%	63%	7	90%	15%	88.0%	81.8%	84.0%	7.6
757	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Retail	RET	per control	552	61%	337	0.04	0.05	15	$56	100%	40%	40%	7	90%	15%	88.0%	84.0%	84.0%	11.3
758	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Office	RET	per control	363	61%	221	0.03	0.02	15	$56	100%	40%	61%	7	90%	15%	88.0%	82.2%	84.0%	7.6
759	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Warehouse	RET	per control	381	61%	232	0.04	0.03	15	$56	100%	40%	58%	7	90%	15%	88.0%	82.5%	84.0%	9.1
760	Lighting_Int	Luminaire-Level Lighting Controls	Biz - Prescriptive	Other	RET	per control	266	61%	163	0.03	0.02	15	$56	100%	40%	71%	7	90%	15%	88.0%	80.3%	84.0%	6.9
761	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Assembly	RET	Wh saved per sq	2	35%	1	0.00	0.00	15	$0	100%	73%	57%	7	90%	15%	88.0%	81.9%	78.6%	2.1
762	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Education	RET	Wh saved per sq	3	35%	1	0.00	0.00	15	$1	100%	53%	58%	7	90%	15%	88.0%	77.8%	78.8%	2.8
763	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Food Sales	RET	Wh saved per sq	3	35%	1	0.00	0.00	15	$1	100%	42%	57%	7	90%	15%	88.0%	73.3%	78.7%	3.4
764	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Food Service	RET	Wh saved per sq	4	35%	1	0.00	0.00	15	$1	100%	41%	58%	7	90%	15%	88.0%	72.5%	78.8%	3.7
765	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Health	RET	Wh saved per sq	4	35%	1	0.00	0.00	15	$1	100%	37%	57%	7	90%	15%	88.0%	70.6%	78.7%	3.3
766	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Lodging	RET	Wh saved per sq	3	35%	1	0.00	0.00	15	$1	100%	53%	58%	7	90%	15%	88.0%	77.8%	78.9%	2.7
767	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Retail	RET	Wh saved per sq	5	35%	2	0.00	0.00	15	$1	100%	32%	58%	7	90%	15%	88.0%	68.2%	78.8%	4.0
768	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Office	RET	Wh saved per sq	3	35%	1	0.00	0.00	15	$1	100%	49%	58%	7	90%	15%	88.0%	77.1%	78.8%	2.7
769	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Warehouse	RET	Wh saved per sq	3	35%	1	0.00	0.00	15	$1	100%	47%	58%	7	90%	15%	88.0%	76.0%	78.9%	3.2
770	Lighting_Int	Networked Lighting Control	Biz - Prescriptive	Other	RET	Wh saved per sq	2	35%	1	0.00	0.00	15	$0	100%	67%	58%	7	90%	15%	88.0%	80.6%	78.7%	2.4
771	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Assembly	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
772	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Education	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
773	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Food Sales	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
774	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Food Service	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
775	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Health	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	1%	2%	40.6%	40.6%	43.5%	2.6
776	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Lodging	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
777	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Retail	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	1%	2%	40.6%	40.6%	43.5%	2.6
778	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Office	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
779	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Warehouse	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	1%	2%	40.6%	40.6%	43.5%	2.6
780	Misc	Non-Refrigerated Vending Machine Controls	Biz - Prescriptive	Other	RET	per unit	385	61%	237	0.00	0.03	5	$233	9%	9%	15%	1	0%	2%	40.6%	40.6%	43.5%	2.6
781	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Assembly	TOS	per hood CFM	8,846	50%	4,423	0.55	0.53	20	$1,192	100%	3%	63%	2	10%	20%	88.0%	78.3%	84.0%	144.7
782	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Education	TOS	per hood CFM	8,846	50%	4,423	0.55	0.50	20	$1,192	100%	3%	63%	2	7%	20%	88.0%	78.3%	84.0%	144.6

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
783	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Food Sales	TOS	per hood CFM	8,846	50%	4,423	0.55	0.56	20	$1,192	100%	3%	63%	2	1%	20%	88.0%	78.3%	84.0%	144.8
784	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Food Service	TOS	per hood CFM	8,846	50%	4,423	0.55	0.53	20	$1,192	100%	3%	63%	2	2%	20%	88.0%	78.3%	84.0%	144.7
785	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Health	TOS	per hood CFM	8,846	50%	4,423	0.55	0.50	20	$1,192	100%	3%	63%	2	2%	20%	88.0%	78.3%	84.0%	144.6
786	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Lodging	TOS	per hood CFM	8,846	50%	4,423	0.55	0.57	20	$1,192	100%	3%	63%	2	5%	20%	88.0%	78.3%	84.0%	144.8
787	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Retail	TOS	per hood CFM	8,846	50%	4,423	0.55	0.51	20	$1,192	100%	3%	63%	2	0%	20%	88.0%	78.3%	84.0%	144.6
788	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Office	TOS	per hood CFM	8,846	50%	4,423	0.55	0.51	20	$1,192	100%	3%	63%	2	5%	20%	88.0%	78.3%	84.0%	144.6
789	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Warehouse	TOS	per hood CFM	8,846	50%	4,423	0.55	0.48	20	$1,192	100%	3%	63%	2	0%	20%	88.0%	78.3%	84.0%	144.5
790	Misc	Kitchen Exhaust Hood Demand Ventilation Control System	Biz - Prescriptive	Other	TOS	per hood CFM	8,846	50%	4,423	0.55	0.52	20	$1,192	100%	3%	63%	2	0%	20%	88.0%	78.3%	84.0%	144.6
791	Misc	High Efficiency Hand Dryers	Biz - Custom	Assembly	TOS	per unit	2,093	83%	1,737	0.10	0.21	10	$483	100%	50%	64%	3	1%	50%	66.0%	62.0%	63.0%	3.3
792	Misc	High Efficiency Hand Dryers	Biz - Custom	Education	TOS	per unit	2,093	83%	1,737	0.16	0.20	10	$483	100%	50%	64%	3	1%	50%	66.0%	62.0%	63.0%	3.7
793	Misc	High Efficiency Hand Dryers	Biz - Custom	Food Sales	TOS	per unit	3,819	83%	3,170	0.28	0.40	10	$483	100%	92%	34%	3	1%	50%	66.0%	65.6%	63.0%	3.7
794	Misc	High Efficiency Hand Dryers	Biz - Custom	Food Service	TOS	per unit	1,909	83%	1,585	0.09	0.19	10	$483	100%	46%	67%	3	1%	50%	66.0%	61.3%	63.0%	3.3
795	Misc	High Efficiency Hand Dryers	Biz - Custom	Health	TOS	per unit	1,909	83%	1,585	0.10	0.18	10	$483	100%	46%	67%	3	1%	50%	66.0%	61.3%	63.0%	3.4
796	Misc	High Efficiency Hand Dryers	Biz - Custom	Lodging	TOS	per unit	262	83%	217	0.04	0.03	10	$483	6%	6%	12%	3	1%	50%	59.0%	59.0%	59.0%	4.8
797	Misc	High Efficiency Hand Dryers	Biz - Custom	Retail	TOS	per unit	1,909	83%	1,585	0.09	0.18	10	$483	100%	46%	67%	3	1%	50%	66.0%	61.3%	63.0%	3.3
798	Misc	High Efficiency Hand Dryers	Biz - Custom	Office	TOS	per unit	262	83%	217	0.04	0.02	10	$483	6%	6%	12%	3	1%	50%	59.0%	59.0%	59.0%	4.8
799	Misc	High Efficiency Hand Dryers	Biz - Custom	Warehouse	TOS	per unit	262	83%	217	0.04	0.02	10	$483	6%	6%	12%	3	1%	50%	59.0%	59.0%	59.0%	4.8
800	Misc	High Efficiency Hand Dryers	Biz - Custom	Other	TOS	per unit	262	83%	217	0.10	0.03	10	$483	50%	6%	12%	3	1%	50%	62.5%	59.0%	59.0%	8.1
801	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Assembly	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
802	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Education	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
803	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Food Sales	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
804	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Food Service	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
805	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Health	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
806	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Lodging	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
807	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Retail	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
808	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Office	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
809	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Warehouse	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
810	Misc	ENERGY STAR Uninterrupted Power Supply	Biz - Custom	Other	RET	per unit	3,125	4%	114	0.02	0.01	15	$59	100%	27%	66%	4	0%	0%	66.0%	52.6%	61.0%	6.4
811	Misc	Miscellaneous Custom	Biz - Custom	Assembly	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	89%	10%	66.0%	58.8%	61.9%	4.4
812	Misc	Miscellaneous Custom	Biz - Custom	Education	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	92%	10%	66.0%	58.8%	61.9%	3.8
813	Misc	Miscellaneous Custom	Biz - Custom	Food Sales	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	98%	10%	66.0%	58.8%	61.9%	5.1
814	Misc	Miscellaneous Custom	Biz - Custom	Food Service	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	97%	10%	66.0%	58.8%	61.9%	5.1
815	Misc	Miscellaneous Custom	Biz - Custom	Health	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	96%	10%	66.0%	58.8%	61.9%	4.1
816	Misc	Miscellaneous Custom	Biz - Custom	Lodging	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	94%	10%	66.0%	58.8%	61.9%	4.0
817	Misc	Miscellaneous Custom	Biz - Custom	Retail	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	98%	10%	66.0%	58.8%	61.9%	4.6
818	Misc	Miscellaneous Custom	Biz - Custom	Office	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	94%	10%	66.0%	58.8%	61.9%	4.0
819	Misc	Miscellaneous Custom	Biz - Custom	Warehouse	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	98%	10%	66.0%	58.8%	61.9%	4.3
820	Misc	Miscellaneous Custom	Biz - Custom	Other	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	5	99%	10%	66.0%	58.8%	61.9%	4.3
821	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Assembly	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	18%	15%	88.0%	87.3%	84.9%	4.1
822	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Education	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	23%	15%	88.0%	87.3%	84.9%	4.1
823	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Food Sales	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	21%	15%	88.0%	87.3%	84.9%	4.1
824	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Food Service	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	12%	15%	88.0%	87.3%	84.9%	4.1
825	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Health	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	16%	15%	88.0%	87.3%	84.9%	4.1
826	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Lodging	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	5%	15%	88.0%	87.3%	84.9%	4.1
827	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Retail	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	21%	15%	88.0%	87.3%	84.9%	4.1
828	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Office	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	26%	15%	88.0%	87.3%	84.9%	4.1
829	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Warehouse	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	25%	15%	88.0%	87.3%	84.9%	4.1
830	Plug_Office	Advanced Power Strip – Tier 1 Commercial Use	Biz - Prescriptive	Other	RET	per unit	188	61%	115	0.00	0.01	7	$10	100%	80%	10%	2	17%	15%	88.0%	87.3%	84.9%	4.1
831	Plug_Office	Smart Socket	Biz - Custom	Assembly	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	18%	15%	66.0%	64.6%	63.0%	2.0
832	Plug_Office	Smart Socket	Biz - Custom	Education	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	23%	15%	66.0%	64.6%	63.0%	2.0
833	Plug_Office	Smart Socket	Biz - Custom	Food Sales	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	21%	15%	66.0%	64.6%	63.0%	2.0
834	Plug_Office	Smart Socket	Biz - Custom	Food Service	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	12%	15%	66.0%	64.6%	63.0%	2.0
835	Plug_Office	Smart Socket	Biz - Custom	Health	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	16%	15%	66.0%	64.6%	63.0%	2.0
836	Plug_Office	Smart Socket	Biz - Custom	Lodging	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	5%	15%	66.0%	64.6%	63.0%	2.0
837	Plug_Office	Smart Socket	Biz - Custom	Retail	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	21%	15%	66.0%	64.6%	63.0%	2.0
838	Plug_Office	Smart Socket	Biz - Custom	Office	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	26%	15%	66.0%	64.6%	63.0%	2.0
839	Plug_Office	Smart Socket	Biz - Custom	Warehouse	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	25%	15%	66.0%	64.6%	63.0%	2.0
840	Plug_Office	Smart Socket	Biz - Custom	Other	RET	per unit	80	61%	48	0.00	0.01	7	$9	100%	75%	46%	2	17%	15%	66.0%	64.6%	63.0%	2.0
841	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Assembly	TOS	per unit	418	26%	110	0.02	0.01	6	$0	100%	100%	100%	1	16%	95%	96.5%	96.0%	96.0%	2.9
842	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Education	TOS	per unit	418	26%	110	0.01	0.01	6	$0	100%	100%	100%	1	9%	95%	96.5%	96.0%	96.0%	2.5
843	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Food Sales	TOS	per unit	418	26%	110	0.02	0.01	6	$0	100%	100%	100%	1	12%	95%	96.5%	96.0%	96.0%	3.4
844	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Food Service	TOS	per unit	418	26%	110	0.02	0.01	6	$0	100%	100%	100%	1	24%	95%	96.5%	96.0%	96.0%	3.4
845	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Health	TOS	per unit	418	26%	110	0.01	0.01	6	$0	100%	100%	100%	1	19%	95%	96.5%	96.0%	96.0%	2.8
846	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Lodging	TOS	per unit	418	26%	110	0.01	0.01	6	$0	100%	100%	100%	1	33%	95%	96.5%	96.0%	96.0%	2.7
847	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Retail	TOS	per unit	418	26%	110	0.02	0.01	6	$0	100%	100%	100%	1	12%	95%	96.5%	96.0%	96.0%	3.1
848	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Office	TOS	per unit	418	26%	110	0.01	0.01	6	$0	100%	100%	100%	1	6%	95%	96.5%	96.0%	96.0%	2.7
849	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Warehouse	TOS	per unit	418	26%	110	0.01	0.01	6	$0	100%	100%	100%	1	6%	95%	96.5%	96.0%	96.0%	2.9
850	Plug_Office	Energy Star Printer/Copier/Fax	Biz - Custom	Other	TOS	per unit	418	26%	110	0.01	0.01	6	$0	100%	100%	100%	1	18%	95%	96.5%	96.0%	96.0%	2.9
851	Plug_Office	Energy Star Server	Biz - Custom	Assembly	TOS	per server	2,167	30%	650	0.09	0.08	9	$301	100%	30%	51%	3	21%	25%	66.0%	56.2%	59.7%	4.0
852	Plug_Office	Energy Star Server	Biz - Custom	Education	TOS	per server	2,167	30%	650	0.06	0.07	9	$301	100%	30%	51%	3	27%	25%	66.0%	56.2%	59.7%	3.5
853	Plug_Office	Energy Star Server	Biz - Custom	Food Sales	TOS	per server	2,167	30%	650	0.13	0.08	9	$301	100%	30%	51%	3	24%	25%	66.0%	56.2%	59.7%	4.7

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
854	Plug_Office	Energy Star Server	Biz - Custom	Food Service	TOS	per server	2,167	30%	650	0.13	0.08	9	$301	100%	30%	51%	3	14%	25%	66.0%	56.2%	59.7%	4.7
855	Plug_Office	Energy Star Server	Biz - Custom	Health	TOS	per server	2,167	30%	650	0.08	0.07	9	$301	100%	30%	51%	3	18%	25%	66.0%	56.2%	59.7%	3.8
856	Plug_Office	Energy Star Server	Biz - Custom	Lodging	TOS	per server	2,167	30%	650	0.07	0.08	9	$301	100%	30%	51%	3	6%	25%	66.0%	56.2%	59.7%	3.7
857	Plug_Office	Energy Star Server	Biz - Custom	Retail	TOS	per server	2,167	30%	650	0.10	0.07	9	$301	100%	30%	51%	3	24%	25%	66.0%	56.2%	59.7%	4.3
858	Plug_Office	Energy Star Server	Biz - Custom	Office	TOS	per server	2,167	30%	650	0.07	0.07	9	$301	100%	30%	51%	3	30%	25%	66.0%	56.2%	59.7%	3.7
859	Plug_Office	Energy Star Server	Biz - Custom	Warehouse	TOS	per server	2,167	30%	650	0.09	0.07	9	$301	100%	30%	51%	3	30%	25%	66.0%	56.2%	59.7%	4.0
860	Plug_Office	Energy Star Server	Biz - Custom	Other	TOS	per server	2,167	30%	650	0.09	0.08	9	$301	100%	30%	51%	3	20%	25%	66.0%	56.2%	59.7%	3.9
861	Plug_Office	Server Virtualization	Biz - Custom	Assembly	RET	per server	2,167	14%	301	0.04	0.04	9	$27	100%	100%	10%	3	21%	25%	66.0%	66.0%	63.6%	6.3
862	Plug_Office	Server Virtualization	Biz - Custom	Education	RET	per server	2,167	14%	301	0.03	0.03	9	$27	100%	100%	10%	3	27%	25%	66.0%	66.0%	63.6%	5.4
863	Plug_Office	Server Virtualization	Biz - Custom	Food Sales	RET	per server	2,167	14%	301	0.06	0.04	9	$27	100%	100%	10%	3	24%	25%	66.0%	66.0%	63.6%	7.4
864	Plug_Office	Server Virtualization	Biz - Custom	Food Service	RET	per server	2,167	14%	301	0.06	0.04	9	$27	100%	100%	10%	3	14%	25%	66.0%	66.0%	63.6%	7.3
865	Plug_Office	Server Virtualization	Biz - Custom	Health	RET	per server	2,167	14%	301	0.04	0.03	9	$27	100%	100%	10%	3	18%	25%	66.0%	66.0%	63.6%	6.0
866	Plug_Office	Server Virtualization	Biz - Custom	Lodging	RET	per server	2,167	14%	301	0.03	0.04	9	$27	100%	100%	10%	3	6%	25%	66.0%	66.0%	63.6%	5.7
867	Plug_Office	Server Virtualization	Biz - Custom	Retail	RET	per server	2,167	14%	301	0.05	0.03	9	$27	100%	100%	10%	3	24%	25%	66.0%	66.0%	63.6%	6.6
868	Plug_Office	Server Virtualization	Biz - Custom	Office	RET	per server	2,167	14%	301	0.03	0.03	9	$27	100%	100%	10%	3	30%	25%	66.0%	66.0%	63.6%	5.7
869	Plug_Office	Server Virtualization	Biz - Custom	Warehouse	RET	per server	2,167	14%	301	0.04	0.03	9	$27	100%	100%	10%	3	30%	25%	66.0%	66.0%	63.6%	6.2
870	Plug_Office	Server Virtualization	Biz - Custom	Other	RET	per server	2,167	14%	301	0.04	0.04	9	$27	100%	100%	10%	3	20%	25%	66.0%	66.0%	63.6%	6.2
871	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Assembly	RET	per unit	86,783	18%	15,778	2.20	1.88	15	$480	100%	100%	10%	4	21%	25%	66.0%	66.0%	65.2%	27.3
872	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Education	RET	per unit	86,783	18%	15,778	1.42	1.78	15	$480	100%	100%	10%	4	27%	25%	66.0%	66.0%	65.2%	23.5
873	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Food Sales	RET	per unit	86,783	18%	15,778	3.20	1.99	15	$480	100%	100%	10%	4	24%	25%	66.0%	66.0%	65.2%	32.3
874	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Food Service	RET	per unit	86,783	18%	15,778	3.15	1.88	15	$480	100%	100%	10%	4	14%	25%	66.0%	66.0%	65.2%	32.0
875	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Health	RET	per unit	86,783	18%	15,778	1.92	1.78	15	$480	100%	100%	10%	4	18%	25%	66.0%	66.0%	65.2%	25.9
876	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Lodging	RET	per unit	86,783	18%	15,778	1.70	2.04	15	$480	100%	100%	10%	4	6%	25%	66.0%	66.0%	65.2%	24.9
877	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Retail	RET	per unit	86,783	18%	15,778	2.53	1.82	15	$480	100%	100%	10%	4	24%	25%	66.0%	66.0%	65.2%	29.0
878	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Office	RET	per unit	86,783	18%	15,778	1.72	1.80	15	$480	100%	100%	10%	4	30%	25%	66.0%	66.0%	65.2%	24.9
879	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Warehouse	RET	per unit	86,783	18%	15,778	2.15	1.71	15	$480	100%	100%	10%	4	30%	25%	66.0%	66.0%	65.2%	27.0
880	Plug_Office	Electrically Commutated Plug Fans in data centers	Biz - Custom	Other	RET	per unit	86,783	18%	15,778	2.11	1.86	15	$480	100%	100%	10%	4	20%	25%	66.0%	66.0%	65.2%	26.9
881	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Assembly	TOS	per ton	9,272	28%	2,596	0.30	0.31	15	$750	100%	48%	65%	5	21%	25%	66.0%	61.7%	63.0%	5.5
882	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Education	TOS	per ton	9,272	28%	2,596	0.30	0.29	15	$750	100%	48%	65%	5	27%	25%	66.0%	61.7%	63.0%	5.5
883	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Food Sales	TOS	per ton	9,272	28%	2,596	0.30	0.33	15	$750	100%	48%	65%	5	24%	25%	66.0%	61.7%	63.0%	5.5
884	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Food Service	TOS	per ton	9,272	28%	2,596	0.30	0.31	15	$750	100%	48%	65%	5	14%	25%	66.0%	61.7%	63.0%	5.5
885	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Health	TOS	per ton	9,272	28%	2,596	0.30	0.29	15	$750	100%	48%	65%	5	18%	25%	66.0%	61.7%	63.0%	5.5
886	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Lodging	TOS	per ton	9,272	28%	2,596	0.30	0.34	15	$750	100%	48%	65%	5	6%	25%	66.0%	61.7%	63.0%	5.5
887	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Retail	TOS	per ton	9,272	28%	2,596	0.30	0.30	15	$750	100%	48%	65%	5	24%	25%	66.0%	61.7%	63.0%	5.5
888	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Office	TOS	per ton	9,272	28%	2,596	0.30	0.30	15	$750	100%	48%	65%	5	30%	25%	66.0%	61.7%	63.0%	5.5
889	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Warehouse	TOS	per ton	9,272	28%	2,596	0.30	0.28	15	$750	100%	48%	65%	5	30%	25%	66.0%	61.7%	63.0%	5.5
890	Plug_Office	High Efficiency CRAC unit	Biz - Custom	Other	TOS	per ton	9,272	28%	2,596	0.30	0.31	15	$750	100%	48%	65%	5	20%	25%	66.0%	61.7%	63.0%	5.5
891	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Assembly	RET	mbtu/hr	764	47%	358	0.05	0.04	15	$82	100%	61%	56%	5	21%	25%	66.0%	63.3%	63.0%	5.9
892	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Education	RET	mbtu/hr	764	47%	358	0.03	0.04	15	$82	100%	61%	56%	5	27%	25%	66.0%	63.3%	63.0%	5.1
893	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Food Sales	RET	mbtu/hr	764	47%	358	0.07	0.05	15	$82	100%	61%	56%	5	24%	25%	66.0%	63.3%	63.0%	7.0
894	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Food Service	RET	mbtu/hr	764	47%	358	0.07	0.04	15	$82	100%	61%	56%	5	14%	25%	66.0%	63.3%	63.0%	7.0
895	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Health	RET	mbtu/hr	764	47%	358	0.04	0.04	15	$82	100%	61%	56%	5	18%	25%	66.0%	63.3%	63.0%	5.6
896	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Lodging	RET	mbtu/hr	764	47%	358	0.04	0.05	15	$82	100%	61%	56%	5	6%	25%	66.0%	63.3%	63.0%	5.4
897	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Retail	RET	mbtu/hr	764	47%	358	0.06	0.04	15	$82	100%	61%	56%	5	24%	25%	66.0%	63.3%	63.0%	6.3
898	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Office	RET	mbtu/hr	764	47%	358	0.04	0.04	15	$82	100%	61%	56%	5	30%	25%	66.0%	63.3%	63.0%	5.4
899	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Warehouse	RET	mbtu/hr	764	47%	358	0.05	0.04	15	$82	100%	61%	56%	5	30%	25%	66.0%	63.3%	63.0%	5.9
900	Plug_Office	Computer Room Air Conditioner Economizer	Biz - Custom	Other	RET	mbtu/hr	764	47%	358	0.05	0.04	15	$82	100%	61%	56%	5	20%	25%	66.0%	63.3%	63.0%	5.8
901	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Assembly	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	21%	25%	66.0%	63.3%	63.0%	4.4
902	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Education	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	27%	25%	66.0%	63.3%	63.0%	3.8
903	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Food Sales	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	24%	25%	66.0%	63.3%	63.0%	5.1
904	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Food Service	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	14%	25%	66.0%	63.3%	63.0%	5.1
905	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Health	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	18%	25%	66.0%	63.3%	63.0%	4.1
906	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Lodging	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	6%	25%	66.0%	63.3%	63.0%	4.0
907	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Retail	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	24%	25%	66.0%	63.3%	63.0%	4.6
908	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Office	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	30%	25%	66.0%	63.3%	63.0%	4.0
909	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Warehouse	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	30%	25%	66.0%	63.3%	63.0%	4.3
910	Plug_Office	Data Center Hot/Cold Aisle Configuration	Biz - Custom	Other	RET	er DC w/ H/C aisl	13	8%	1	0.00	0.00	10	$0	100%	61%	57%	7	20%	25%	66.0%	63.3%	63.0%	4.3
911	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Assembly	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	1	0%	25%	88.0%	88.0%	88.0%	0.0
912	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Education	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	1	13%	25%	88.0%	88.0%	88.0%	0.0
913	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Food Sales	RET	per ln sq/ft	536	15%	80	0.01	0.01	4	$10	100%	98%	21%	1	19%	25%	88.0%	87.9%	84.0%	2.2
914	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Food Service	RET	per ln sq/ft	96	15%	14	0.00	0.00	4	$10	98%	98%	17%	1	7%	25%	87.4%	87.4%	54.8%	0.4
915	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Health	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	1	9%	25%	88.0%	88.0%	88.0%	0.0
916	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Lodging	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	1	12%	25%	88.0%	88.0%	88.0%	0.0
917	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Retail	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	1	13%	25%	88.0%	88.0%	88.0%	0.0
918	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Office	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	1	36%	25%	88.0%	88.0%	88.0%	0.0
919	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Warehouse	RET	per ln sq/ft	689	15%	103	0.01	0.01	4	$10	100%	98%	10%	1	40%	25%	88.0%	87.9%	84.4%	2.8
920	Refrigeration	Strip Curtains, Cooler	Biz - Prescriptive	Other	RET	per ln sq/ft	100	15%	15	0.00	0.00	4	$10	98%	98%	18%	1	10%	25%	87.4%	87.4%	56.1%	0.4
921	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Assembly	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	0%	27%	66.0%	63.9%	63.0%	4.9
922	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Education	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	13%	58%	70.6%	66.4%	66.4%	4.9
923	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Food Sales	RET	per building	1,259,893	0%	2,399	0.62	0.28	8	$502	100%	67%	52%	1	19%	32%	66.0%	63.9%	63.0%	4.9
924	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Food Service	RET	per building	1,259,893	0%	2,399	0.62	0.26	8	$502	100%	67%	52%	1	7%	54%	67.8%	63.9%	63.2%	4.9

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
925	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Health	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	9%	27%	66.0%	63.9%	63.0%	4.9
926	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Lodging	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	12%	27%	66.0%	63.9%	63.0%	4.9
927	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Retail	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	13%	27%	66.0%	63.9%	63.0%	4.9
928	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Office	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	36%	27%	66.0%	63.9%	63.0%	4.9
929	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Warehouse	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	40%	27%	66.0%	63.9%	63.0%	4.9
930	Refrigeration	Automated Door Closer for Refrigerator	Biz - Custom	Other	RET	per building	1,259,893	0%	2,399	0.62	0.27	8	$502	100%	67%	52%	1	10%	27%	66.0%	63.9%	63.0%	4.9
931	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Assembly	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	0%	25%	88.0%	88.0%	88.0%	0.0
932	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Education	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	7%	25%	88.0%	88.0%	88.0%	0.0
933	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Food Sales	RET	per ln sq/ft	1,473	15%	221	0.03	0.03	4	$10	100%	98%	10%	2	10%	25%	88.0%	88.0%	86.3%	6.0
934	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Food Service	RET	per ln sq/ft	489	15%	73	0.01	0.01	4	$10	100%	98%	28%	2	4%	25%	88.0%	87.9%	84.0%	2.0
935	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Health	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	5%	25%	88.0%	88.0%	88.0%	0.0
936	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Lodging	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	6%	25%	88.0%	88.0%	88.0%	0.0
937	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Retail	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	7%	25%	88.0%	88.0%	88.0%	0.0
938	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Office	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	19%	25%	88.0%	88.0%	88.0%	0.0
939	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Warehouse	RET	per ln sq/ft	0	0%	0	0.00	0.00	4	$10	98%	98%	100%	2	21%	25%	88.0%	88.0%	88.0%	0.0
940	Refrigeration	Strip Curtains, Freezer	Biz - Prescriptive	Other	RET	per ln sq/ft	144	15%	22	0.00	0.00	4	$10	98%	98%	26%	2	5%	25%	87.6%	87.6%	72.3%	0.6
941	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Assembly	RET	per building	1,259,893	1%	6,949	1.30	0.77	8	$502	100%	100%	10%	2	0%	27%	66.0%	66.0%	64.0%	8.0
942	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Education	RET	per building	1,259,893	1%	6,949	1.30	0.78	8	$502	100%	100%	10%	2	7%	58%	70.6%	66.4%	66.4%	8.0
943	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Food Sales	RET	per building	1,259,893	1%	6,949	1.30	0.82	8	$502	100%	100%	10%	2	10%	32%	66.0%	66.0%	64.0%	8.0
944	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Food Service	RET	per building	1,259,893	1%	6,949	1.30	0.75	8	$502	100%	100%	10%	2	4%	54%	67.8%	66.0%	64.0%	8.0
945	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Health	RET	per building	1,259,893	1%	6,949	1.30	0.79	8	$502	100%	100%	10%	2	5%	27%	66.0%	66.0%	64.0%	8.0
946	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Lodging	RET	per building	1,259,893	1%	6,949	1.30	0.77	8	$502	100%	100%	10%	2	6%	27%	66.0%	66.0%	64.0%	8.0
947	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Retail	RET	per building	1,259,893	1%	6,949	1.30	0.77	8	$502	100%	100%	10%	2	7%	27%	66.0%	66.0%	64.0%	8.0
948	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Office	RET	per building	1,259,893	1%	6,949	1.30	0.77	8	$502	100%	100%	10%	2	19%	27%	66.0%	66.0%	64.0%	8.0
949	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Warehouse	RET	per building	1,259,893	1%	6,949	1.30	0.77	8	$502	100%	100%	10%	2	21%	27%	66.0%	66.0%	64.0%	8.0
950	Refrigeration	Automated Door Closer for Freezer	Biz - Custom	Other	RET	per building	1,259,893	1%	6,949	1.30	0.77	8	$502	100%	100%	10%	2	5%	27%	66.0%	66.0%	64.0%	8.0
951	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Assembly	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	0%	34%	88.0%	80.7%	84.0%	30.5
952	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Education	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	10%	34%	88.0%	80.7%	84.0%	30.5
953	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Food Sales	RET	per motor	2,884	55%	1,586	0.18	0.19	15	$347	100%	12%	54%	3	14%	34%	88.0%	80.7%	84.0%	30.6
954	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Food Service	RET	per motor	2,884	55%	1,586	0.18	0.17	15	$347	100%	12%	54%	3	6%	34%	88.0%	80.7%	84.0%	30.5
955	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Health	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	7%	34%	88.0%	80.7%	84.0%	30.6
956	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Lodging	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	9%	34%	88.0%	80.7%	84.0%	30.5
957	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Retail	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	10%	34%	88.0%	80.7%	84.0%	30.5
958	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Office	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	27%	34%	88.0%	80.7%	84.0%	30.5
959	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Warehouse	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	30%	34%	88.0%	80.7%	84.0%	30.5
960	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz - Prescriptive	Other	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	3	8%	34%	88.0%	80.7%	84.0%	30.5
961	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Assembly	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	0%	2%	66.0%	64.5%	63.0%	12.5
962	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Education	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	10%	2%	66.0%	64.5%	63.0%	12.5
963	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Food Sales	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	14%	2%	66.0%	64.5%	63.0%	12.5
964	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Food Service	RET	per motor	2,091	24%	505	0.40	0.05	10	$96	100%	74%	47%	3	6%	2%	66.0%	64.5%	63.0%	12.5
965	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Health	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	7%	2%	66.0%	64.5%	63.0%	12.5
966	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Lodging	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	9%	2%	66.0%	64.5%	63.0%	12.5
967	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Retail	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	10%	2%	66.0%	64.5%	63.0%	12.5
968	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Office	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	27%	2%	66.0%	64.5%	63.0%	12.5
969	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Warehouse	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	30%	2%	66.0%	64.5%	63.0%	12.5
970	Refrigeration	Q-Sync Motor for Walk-In Evaporator Fan Motor	Biz - Custom	Other	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	3	8%	2%	66.0%	64.5%	63.0%	12.5
971	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Assembly	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	0%	34%	66.0%	50.2%	59.3%	4.9
972	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Education	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	10%	34%	66.0%	50.2%	59.3%	4.9
973	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Food Sales	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	14%	34%	66.0%	50.2%	59.3%	4.9
974	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Food Service	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	6%	34%	66.0%	50.2%	59.3%	4.9
975	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Health	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	7%	34%	66.0%	50.2%	59.3%	4.9
976	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Lodging	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	9%	34%	66.0%	50.2%	59.3%	4.9
977	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Retail	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	10%	34%	66.0%	50.2%	59.3%	4.9
978	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Office	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	27%	34%	66.0%	50.2%	59.3%	4.9
979	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Warehouse	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	30%	34%	66.0%	50.2%	59.3%	4.9
980	Refrigeration	Evaporator Fan Motor Controls	Biz - Custom	Other	RET	per motor	1,298	23%	293	0.03	0.03	13	$162	100%	25%	56%	4	8%	34%	66.0%	50.2%	59.3%	4.9
981	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Assembly	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	0%	20%	37.8%	36.0%	36.0%	3.6
982	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Education	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	10%	20%	37.8%	36.0%	36.0%	3.6
983	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Food Sales	RET	per HP	1,228	25%	307	0.00	0.04	15	$431	10%	10%	24%	6	14%	20%	37.8%	36.0%	36.0%	3.6
984	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Food Service	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	6%	20%	37.8%	36.0%	36.0%	3.6
985	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Health	RET	per HP	1,228	25%	307	0.00	0.04	15	$431	10%	10%	24%	6	7%	20%	37.8%	36.0%	36.0%	3.6
986	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Lodging	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	9%	20%	37.8%	36.0%	36.0%	3.6
987	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Retail	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	10%	20%	37.8%	36.0%	36.0%	3.6
988	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Office	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	27%	20%	37.8%	36.0%	36.0%	3.6
989	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Warehouse	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	30%	20%	37.8%	36.0%	36.0%	3.6
990	Refrigeration	Floating Head Pressure Controls	Biz - Custom	Other	RET	per HP	1,228	25%	307	0.00	0.03	15	$431	10%	10%	24%	6	8%	20%	37.8%	36.0%	36.0%	3.6
991	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Assembly	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	2%	25%	88.0%	87.5%	84.0%	2.1
992	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Education	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	2%	25%	88.0%	87.5%	84.0%	2.1
993	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Food Sales	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	14%	25%	88.0%	87.5%	84.0%	2.1
994	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Food Service	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	7%	25%	88.0%	87.5%	84.0%	2.1
995	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Health	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	4%	25%	88.0%	87.5%	84.0%	2.1

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
996	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Lodging	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	2	2%	25%	88.0%	87.5%	84.0%	2.1
997	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Retail	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	23%	25%	88.0%	87.5%	84.0%	2.1
998	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Office	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	5%	25%	88.0%	87.5%	84.0%	2.1
999	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Warehouse	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	3%	25%	88.0%	87.5%	84.0%	2.1
1000	Refrigeration	Door Heater Controls for Cooler	Biz - Prescriptive	Other	RET	per door	752	45%	338	0.02	0.04	10	$80	100%	94%	57%	7	9%	25%	88.0%	87.5%	84.0%	2.1
1001	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Assembly	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	2%	25%	47.5%	40.0%	40.0%	4.1
1002	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Education	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	2%	25%	47.5%	40.0%	40.0%	4.1
1003	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Food Sales	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	14%	25%	47.5%	40.0%	40.0%	4.1
1004	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Food Service	RET	per door	682	100%	682	0.05	0.07	12	$735	50%	13%	27%	7	7%	25%	47.5%	40.0%	40.0%	4.1
1005	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Health	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	4%	25%	47.5%	40.0%	40.0%	4.1
1006	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Lodging	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	2%	25%	47.5%	40.0%	40.0%	4.1
1007	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Retail	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	23%	25%	47.5%	40.0%	40.0%	4.1
1008	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Office	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	5%	25%	47.5%	40.0%	40.0%	4.1
1009	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Warehouse	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	3%	25%	47.5%	40.0%	40.0%	4.1
1010	Refrigeration	Zero Energy Doors for Refrigerated Cases	Biz - Custom	Other	RET	per door	682	100%	682	0.05	0.08	12	$735	50%	13%	27%	7	9%	25%	47.5%	40.0%	40.0%	4.1
1011	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Assembly	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	6.0
1012	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Education	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	6.0
1013	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Food Sales	RET	per linear ft	1,558	50%	779	0.09	0.09	15	$390	100%	28%	68%	8	3%	25%	66.0%	53.7%	61.4%	5.6
1014	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Food Service	RET	per linear ft	1,558	50%	779	0.11	0.08	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	6.0
1015	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Health	RET	per linear ft	1,558	50%	779	0.12	0.09	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	6.2
1016	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Lodging	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	5.9
1017	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Retail	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	6.0
1018	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Office	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	1%	25%	66.0%	53.7%	61.4%	6.0
1019	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Warehouse	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	0%	25%	66.0%	53.7%	61.4%	6.0
1020	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz - Custom	Other	RET	per linear ft	1,558	50%	779	0.11	0.09	15	$390	100%	28%	68%	8	1%	25%	66.0%	53.7%	61.4%	6.0
1021	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Assembly	RET	per unit	45,880	10%	4,588	0.65	0.51	10	$312	100%	100%	10%	8	0%	27%	66.0%	66.0%	64.2%	9.0
1022	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Education	RET	per unit	45,880	10%	4,588	0.67	0.52	10	$312	100%	100%	10%	8	0%	58%	70.6%	66.4%	66.4%	9.1
1023	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Food Sales	RET	per unit	45,880	10%	4,588	0.56	0.54	10	$312	100%	100%	10%	8	3%	32%	66.0%	66.0%	64.2%	8.5
1024	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Food Service	RET	per unit	45,880	10%	4,588	0.65	0.50	10	$312	100%	100%	10%	8	0%	54%	67.8%	66.0%	64.2%	9.0
1025	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Health	RET	per unit	45,880	10%	4,588	0.71	0.52	10	$312	100%	100%	10%	8	0%	27%	66.0%	66.0%	64.2%	9.3
1026	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Lodging	RET	per unit	45,880	10%	4,588	0.63	0.51	10	$312	100%	100%	10%	8	0%	27%	66.0%	66.0%	64.2%	8.9
1027	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Retail	RET	per unit	45,880	10%	4,588	0.65	0.51	10	$312	100%	100%	10%	8	0%	27%	66.0%	66.0%	64.2%	9.0
1028	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Office	RET	per unit	45,880	10%	4,588	0.65	0.51	10	$312	100%	100%	10%	8	1%	27%	66.0%	66.0%	64.2%	9.0
1029	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Warehouse	RET	per unit	45,880	10%	4,588	0.65	0.51	10	$312	100%	100%	10%	8	0%	27%	66.0%	66.0%	64.2%	9.0
1030	Refrigeration	Aerofoils for Open Display Cases	Biz - Custom	Other	RET	per unit	45,880	10%	4,588	0.65	0.51	10	$312	100%	100%	10%	8	1%	27%	66.0%	66.0%	64.2%	9.0
1031	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Assembly	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1032	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Education	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1033	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Food Sales	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	3%	55%	82.1%	79.3%	81.8%	3.0
1034	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Food Service	RET	per sq ft	1,511	9%	136	0.00	0.01	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1035	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Health	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1036	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Lodging	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1037	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Retail	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1038	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Office	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	1%	55%	82.1%	79.3%	81.8%	3.0
1039	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Warehouse	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	0%	55%	82.1%	79.3%	81.8%	3.0
1040	Refrigeration	Night Covers for Coolers	Biz - Prescriptive	Other	RET	per sq ft	1,511	9%	136	0.00	0.02	5	$42	50%	24%	48%	8	1%	55%	82.1%	79.3%	81.8%	3.0
1041	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Assembly	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	3%	25%	88.0%	87.9%	85.9%	8.3
1042	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Education	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	0%	25%	88.0%	87.9%	85.9%	8.3
1043	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Food Sales	RET	per door	3,024	45%	1,361	0.07	0.16	10	$80	100%	94%	10%	9	31%	25%	88.0%	87.9%	85.9%	8.3
1044	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Food Service	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	9%	25%	88.0%	87.9%	85.9%	8.3
1045	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Health	RET	per door	3,024	45%	1,361	0.07	0.16	10	$80	100%	94%	10%	9	1%	25%	88.0%	87.9%	85.9%	8.3
1046	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Lodging	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	1%	25%	88.0%	87.9%	85.9%	8.3
1047	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Retail	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	23%	25%	88.0%	87.9%	85.9%	8.3
1048	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Office	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	7%	25%	88.0%	87.9%	85.9%	8.3
1049	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Warehouse	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	0%	25%	88.0%	87.9%	85.9%	8.3
1050	Refrigeration	Door Heater Controls for Freezer	Biz - Prescriptive	Other	RET	per door	3,024	45%	1,361	0.07	0.15	10	$80	100%	94%	10%	9	16%	25%	88.0%	87.9%	85.9%	8.3
1051	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Assembly	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1052	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Education	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1053	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Food Sales	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	4%	55%	88.0%	82.2%	84.0%	4.6
1054	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Food Service	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1055	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Health	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1056	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Lodging	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1057	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Retail	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1058	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Office	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1059	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Warehouse	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	0%	55%	88.0%	82.2%	84.0%	4.6
1060	Refrigeration	Night Covers for Freezers	Biz - Prescriptive	Other	RET	per sq ft	2,349	9%	211	0.00	0.02	5	$42	100%	24%	50%	10	1%	55%	88.0%	82.2%	84.0%	4.6
1061	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Assembly	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	2%	34%	88.0%	80.7%	84.0%	30.5
1062	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Education	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	1%	34%	88.0%	80.7%	84.0%	30.5
1063	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Food Sales	RET	per motor	2,884	55%	1,586	0.18	0.19	15	$347	100%	12%	54%	11	26%	34%	88.0%	80.7%	84.0%	30.6
1064	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Food Service	RET	per motor	2,884	55%	1,586	0.18	0.17	15	$347	100%	12%	54%	11	8%	34%	88.0%	80.7%	84.0%	30.5
1065	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Health	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	3%	34%	88.0%	80.7%	84.0%	30.6
1066	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Lodging	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	1%	34%	88.0%	80.7%	84.0%	30.5

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1067	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Retail	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	23%	34%	88.0%	80.7%	84.0%	30.5
1068	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Office	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	6%	34%	88.0%	80.7%	84.0%	30.5
1069	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Warehouse	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	1%	34%	88.0%	80.7%	84.0%	30.5
1070	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz - Prescriptive	Other	RET	per motor	2,884	55%	1,586	0.18	0.18	15	$347	100%	12%	54%	11	14%	34%	88.0%	80.7%	84.0%	30.5
1071	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Assembly	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	2%	2%	66.0%	64.5%	63.0%	12.5
1072	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Education	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	1%	2%	66.0%	64.5%	63.0%	12.5
1073	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Food Sales	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	26%	2%	66.0%	64.5%	63.0%	12.5
1074	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Food Service	RET	per motor	2,091	24%	505	0.40	0.05	10	$96	100%	74%	47%	11	8%	2%	66.0%	64.5%	63.0%	12.5
1075	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Health	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	3%	2%	66.0%	64.5%	63.0%	12.5
1076	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Lodging	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	1%	2%	66.0%	64.5%	63.0%	12.5
1077	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Retail	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	23%	2%	66.0%	64.5%	63.0%	12.5
1078	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Office	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	6%	2%	66.0%	64.5%	63.0%	12.5
1079	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Warehouse	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	1%	2%	66.0%	64.5%	63.0%	12.5
1080	Refrigeration	Q-Sync Motor for Reach-In Evaporator Fan Motor	Biz - Custom	Other	RET	per motor	2,091	24%	505	0.40	0.06	10	$96	100%	74%	47%	11	14%	2%	66.0%	64.5%	63.0%	12.5
1081	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Assembly	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	1%	35%	88.0%	85.4%	84.0%	9.4
1082	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Education	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	1%	35%	88.0%	85.4%	84.0%	9.4
1083	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Food Sales	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	13%	35%	88.0%	85.4%	84.0%	9.4
1084	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Food Service	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	4%	35%	88.0%	85.4%	84.0%	9.4
1085	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Health	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	1%	35%	88.0%	85.4%	84.0%	9.4
1086	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Lodging	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	1%	35%	88.0%	85.4%	84.0%	9.4
1087	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Retail	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	11%	35%	88.0%	85.4%	84.0%	9.4
1088	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Office	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	3%	35%	88.0%	85.4%	84.0%	9.4
1089	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Warehouse	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	1%	35%	88.0%	85.4%	84.0%	9.4
1090	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz - Prescriptive	Other	TOS	per linear ft	115	74%	84	0.01	0.01	9	$11	100%	50%	23%	12	7%	35%	88.0%	85.4%	84.0%	9.4
1091	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Assembly	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	71%	55%	88.0%	80.2%	83.5%	3.2
1092	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Education	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	47%	55%	88.0%	80.2%	83.5%	3.2
1093	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Food Sales	TOS	per unit	953	32%	301	0.03	0.04	12	$123	100%	49%	72%	13	9%	55%	88.0%	80.2%	83.5%	3.2
1094	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Food Service	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	54%	55%	88.0%	80.2%	83.5%	3.2
1095	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Health	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	58%	55%	88.0%	80.2%	83.5%	3.2
1096	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Lodging	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	48%	55%	88.0%	80.2%	83.5%	3.2
1097	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Retail	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	21%	55%	88.0%	80.2%	83.5%	3.2
1098	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Office	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	14%	55%	88.0%	80.2%	83.5%	3.2
1099	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Warehouse	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	17%	55%	88.0%	80.2%	83.5%	3.2
1100	Refrigeration	Solid/Glass ENERGY STAR Refrigerator	Biz - Prescriptive	Other	TOS	per unit	953	32%	301	0.03	0.03	12	$123	100%	49%	72%	13	38%	55%	88.0%	80.2%	83.5%	3.2
1101	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Assembly	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	19%	2%	88.0%	88.0%	84.1%	3.4
1102	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Education	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	25%	2%	88.0%	88.0%	84.1%	3.4
1103	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Food Sales	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	4%	2%	88.0%	88.0%	84.1%	3.4
1104	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Food Service	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	13%	2%	88.0%	88.0%	84.1%	3.3
1105	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Health	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	17%	2%	88.0%	88.0%	84.1%	3.4
1106	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Lodging	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	24%	2%	88.0%	88.0%	84.1%	3.4
1107	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Retail	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	8%	2%	88.0%	88.0%	84.1%	3.4
1108	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Office	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	13%	2%	88.0%	88.0%	84.1%	3.4
1109	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Warehouse	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	14%	2%	88.0%	88.0%	84.1%	3.4
1110	Refrigeration	Solid/Glass ENERGY STAR Freezer	Biz - Prescriptive	Other	TOS	per unit	2,654	20%	526	0.06	0.06	12	$57	100%	100%	10%	14	13%	2%	88.0%	88.0%	84.1%	3.4
1111	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Assembly	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	4%	5%	88.0%	81.8%	78.2%	1.9
1112	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Education	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	3%	5%	88.0%	81.8%	78.2%	1.9
1113	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Food Sales	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	0%	5%	88.0%	81.8%	78.2%	1.9
1114	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Food Service	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	3%	5%	88.0%	81.8%	78.2%	1.9
1115	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Health	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	3%	5%	88.0%	81.8%	78.2%	1.9
1116	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Lodging	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	5%	5%	88.0%	81.8%	78.2%	1.9
1117	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Retail	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	1%	5%	88.0%	81.8%	78.2%	1.9
1118	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Office	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	5%	5%	88.0%	81.8%	78.2%	1.9
1119	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Warehouse	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	28%	5%	88.0%	81.8%	78.2%	1.9
1120	Refrigeration	Commercial Ice Marker	Biz - Prescriptive	Other	TOS	per unit	5,551	8%	440	0.08	0.05	9	$222	100%	68%	47%	15	4%	5%	88.0%	81.8%	78.2%	1.9
1121	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Assembly	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	2%	21%	34.9%	34.9%	34.9%	3.4
1122	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Education	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	3%	21%	34.9%	34.9%	34.9%	3.4
1123	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Food Sales	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	0%	21%	34.9%	34.9%	34.9%	3.4
1124	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Food Service	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	0%	21%	34.9%	34.9%	34.9%	3.4
1125	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Health	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	3%	21%	34.9%	34.9%	34.9%	3.4
1126	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Lodging	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	5%	21%	34.9%	34.9%	34.9%	3.4
1127	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Retail	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	4%	21%	34.9%	34.9%	34.9%	3.4
1128	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Office	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	10%	21%	34.9%	34.9%	34.9%	3.4
1129	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Warehouse	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	9%	21%	34.9%	34.9%	34.9%	3.4
1130	Refrigeration	ESTAR Refrigerated Vending Machine	Biz - Custom	Other	TOS	per unit	1,278	12%	153	0.00	0.02	14	$500	4%	4%	10%	16	5%	21%	34.9%	34.9%	34.9%	3.4
1131	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Assembly	RET	per unit	1,478	25%	370	0.00	0.04	5	$245	14%	14%	22%	16	2%	31%	55.9%	55.9%	58.3%	2.3
1132	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Education	RET	per unit	1,478	26%	381	0.00	0.04	5	$245	14%	14%	23%	16	3%	31%	56.6%	56.6%	59.4%	2.4
1133	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Food Sales	RET	per unit	1,478	20%	301	0.00	0.04	5	$245	14%	14%	18%	16	0%	31%	51.7%	49.9%	51.3%	1.9
1134	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Food Service	RET	per unit	1,478	21%	304	0.00	0.03	5	$245	14%	14%	18%	16	0%	31%	51.7%	50.2%	51.7%	1.9
1135	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Health	RET	per unit	1,478	16%	236	0.00	0.03	5	$245	14%	14%	14%	16	3%	31%	51.7%	44.8%	44.8%	1.5
1136	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Lodging	RET	per unit	1,478	19%	283	0.00	0.03	5	$245	14%	14%	17%	16	5%	31%	51.7%	47.9%	49.0%	1.8
1137	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Retail	RET	per unit	1,478	24%	347	0.00	0.04	5	$245	14%	14%	21%	16	4%	31%	54.2%	54.2%	56.3%	2.2

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1138	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Office	RET	per unit	1,478	25%	374	0.00	0.04	5	$245	14%	14%	22%	16	10%	31%	56.2%	56.2%	58.6%	2.3
1139	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Warehouse	RET	per unit	1,478	26%	378	0.00	0.04	5	$245	14%	14%	23%	16	9%	31%	56.4%	56.4%	59.0%	2.3
1140	Refrigeration	Refrigerated Vending Machine Controls	Biz - Prescriptive	Other	RET	per unit	1,478	25%	370	0.00	0.04	5	$245	14%	14%	22%	16	5%	31%	55.9%	55.9%	58.3%	2.3
1141	Refrigeration	Refrigeration - Custom	Biz - Custom	Assembly	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	4%	25%	66.0%	58.8%	61.9%	4.4
1142	Refrigeration	Refrigeration - Custom	Biz - Custom	Education	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	22%	25%	66.0%	58.8%	61.9%	4.4
1143	Refrigeration	Refrigeration - Custom	Biz - Custom	Food Sales	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	81%	25%	66.0%	58.8%	61.9%	4.1
1144	Refrigeration	Refrigeration - Custom	Biz - Custom	Food Service	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	27%	25%	66.0%	58.8%	61.9%	4.4
1145	Refrigeration	Refrigeration - Custom	Biz - Custom	Health	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	19%	25%	66.0%	58.8%	61.9%	4.5
1146	Refrigeration	Refrigeration - Custom	Biz - Custom	Lodging	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	21%	25%	66.0%	58.8%	61.9%	4.3
1147	Refrigeration	Refrigeration - Custom	Biz - Custom	Retail	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	65%	25%	66.0%	58.8%	61.9%	4.4
1148	Refrigeration	Refrigeration - Custom	Biz - Custom	Office	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	67%	25%	66.0%	58.8%	61.9%	4.4
1149	Refrigeration	Refrigeration - Custom	Biz - Custom	Warehouse	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	63%	25%	66.0%	58.8%	61.9%	4.4
1150	Refrigeration	Refrigeration - Custom	Biz - Custom	Other	RET	per kWh	7	15%	1	0.00	0.00	10	$0	100%	35%	64%	17	43%	25%	66.0%	58.8%	61.9%	4.4
1151	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Assembly	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	4%	15%	66.0%	63.6%	63.0%	2.5
1152	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Education	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	22%	15%	66.0%	63.6%	63.0%	2.5
1153	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Food Sales	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	81%	15%	66.0%	63.6%	63.0%	2.4
1154	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Food Service	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	27%	15%	66.0%	63.6%	63.0%	2.5
1155	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Health	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	19%	15%	66.0%	63.6%	63.0%	2.6
1156	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Lodging	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	21%	15%	66.0%	63.6%	63.0%	2.5
1157	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Retail	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	65%	15%	66.0%	63.6%	63.0%	2.5
1158	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Office	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	67%	15%	66.0%	63.6%	63.0%	2.5
1159	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Warehouse	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	63%	15%	66.0%	63.6%	63.0%	2.5
1160	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz - Custom	Other	RET	per kWh	5	21%	1	0.00	0.00	5	$0	100%	64%	55%	17	43%	15%	66.0%	63.6%	63.0%	2.5
1161	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Assembly	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.9
1162	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Education	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	11.4
1163	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Food Sales	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.8
1164	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Food Service	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	11.2
1165	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Health	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.8
1166	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Lodging	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.4
1167	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Retail	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	11.5
1168	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Office	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.6
1169	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Warehouse	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.7
1170	WholeBldg	Power Distribution Equipment Upgrades (Transformers)	Biz - Custom	Other	RET	per kVA	990	1%	6	0.00	0.00	30	$6	100%	12%	43%	2	100%	20%	66.0%	36.0%	39.1%	9.9
1171	WholeBldg	WholeBlg - Com RET	Biz - Custom	Assembly	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.3
1172	WholeBldg	WholeBlg - Com RET	Biz - Custom	Education	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	7.2
1173	WholeBldg	WholeBlg - Com RET	Biz - Custom	Food Sales	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.2
1174	WholeBldg	WholeBlg - Com RET	Biz - Custom	Food Service	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	7.1
1175	WholeBldg	WholeBlg - Com RET	Biz - Custom	Health	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.2
1176	WholeBldg	WholeBlg - Com RET	Biz - Custom	Lodging	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.0
1177	WholeBldg	WholeBlg - Com RET	Biz - Custom	Retail	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	7.3
1178	WholeBldg	WholeBlg - Com RET	Biz - Custom	Office	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.1
1179	WholeBldg	WholeBlg - Com RET	Biz - Custom	Warehouse	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.1
1180	WholeBldg	WholeBlg - Com RET	Biz - Custom	Other	RET	per kWh	7	15%	1	0.00	0.00	15	$0	100%	35%	75%	1	80%	0%	66.0%	58.8%	63.0%	6.2
1181	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Assembly	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.3
1182	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Education	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	7.2
1183	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Food Sales	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.2
1184	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Food Service	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	7.1
1185	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Health	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.2
1186	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Lodging	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.0
1187	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Retail	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	7.3
1188	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Office	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.1
1189	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Warehouse	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.1
1190	WholeBldg_NC	WholeBlg - Com NC	Biz - Custom	Other	NEW	per kWh	4	25%	1	0.00	0.00	15	$0	100%	35%	75%	1	100%	60%	72.0%	68.0%	68.0%	6.2
1191	WholeBldg	COM Competitions	Biz - Custom	Assembly	RET	per kWh	0	0%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.1
1192	WholeBldg	COM Competitions	Biz - Custom	Education	RET	per kWh	0	0%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.7
1193	WholeBldg	COM Competitions	Biz - Custom	Food Sales	RET	per kWh	0	0%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.1
1194	WholeBldg	COM Competitions	Biz - Custom	Food Service	RET	per kWh	53	2%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.6
1195	WholeBldg	COM Competitions	Biz - Custom	Health	RET	per kWh	0	0%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.1
1196	WholeBldg	COM Competitions	Biz - Custom	Lodging	RET	per kWh	53	2%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.0
1197	WholeBldg	COM Competitions	Biz - Custom	Retail	RET	per kWh	53	2%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.7
1198	WholeBldg	COM Competitions	Biz - Custom	Office	RET	per kWh	53	2%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.0
1199	WholeBldg	COM Competitions	Biz - Custom	Warehouse	RET	per kWh	0	0%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.0
1200	WholeBldg	COM Competitions	Biz - Custom	Other	RET	per kWh	0	0%	1	0.00	0.00	2	$0	100%	100%	10%	3	100%	0%	66.0%	66.0%	64.9%	4.1
1201	WholeBldg	Business Energy Reports	Biz - Custom	Assembly	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.2
1202	WholeBldg	Business Energy Reports	Biz - Custom	Education	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.3
1203	WholeBldg	Business Energy Reports	Biz - Custom	Food Sales	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.2
1204	WholeBldg	Business Energy Reports	Biz - Custom	Food Service	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.3
1205	WholeBldg	Business Energy Reports	Biz - Custom	Health	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.2
1206	WholeBldg	Business Energy Reports	Biz - Custom	Lodging	RET	per kWh	313	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.1
1207	WholeBldg	Business Energy Reports	Biz - Custom	Retail	RET	per kWh	313	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.4
1208	WholeBldg	Business Energy Reports	Biz - Custom	Office	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.2

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1209	WholeBldg	Business Energy Reports	Biz - Custom	Warehouse	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.2
1210	WholeBldg	Business Energy Reports	Biz - Custom	Other	RET	per kWh	313	0%	1	0.00	0.00	2	$0	75%	70%	32%	3	100%	0%	64.5%	64.2%	62.1%	1.2
1211	WholeBldg	Building Benchmarking	Biz - Custom	Assembly	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	64%	29%	3	100%	0%	64.4%	63.6%	61.5%	1.2
1212	WholeBldg	Building Benchmarking	Biz - Custom	Education	RET	per kWh	83	1%	1	0.00	0.00	2	$0	75%	64%	29%	3	100%	0%	64.4%	63.6%	61.5%	1.3
1213	WholeBldg	Building Benchmarking	Biz - Custom	Food Sales	RET	per kWh	0	0%	1	0.00	0.00	2	$0	64%	64%	29%	3	100%	0%	63.6%	63.6%	61.5%	1.2
1214	WholeBldg	Building Benchmarking	Biz - Custom	Food Service	RET	per kWh	0	0%	1	0.00	0.00	2	$0	75%	64%	29%	3	100%	0%	64.4%	63.6%	61.5%	1.3
1215	WholeBldg	Building Benchmarking	Biz - Custom	Health	RET	per kWh	114	1%	1	0.00	0.00	2	$0	64%	64%	29%	3	100%	0%	63.6%	63.6%	61.5%	1.2
1216	WholeBldg	Building Benchmarking	Biz - Custom	Lodging	RET	per kWh	263	0%	1	0.00	0.00	2	$0	64%	64%	29%	3	100%	0%	63.6%	63.6%	61.5%	1.1
1217	WholeBldg	Building Benchmarking	Biz - Custom	Retail	RET	per kWh	97	1%	1	0.00	0.00	2	$0	75%	64%	29%	3	100%	0%	64.4%	63.6%	61.5%	1.4
1218	WholeBldg	Building Benchmarking	Biz - Custom	Office	RET	per kWh	114	1%	1	0.00	0.00	2	$0	64%	64%	29%	3	100%	0%	63.6%	63.6%	61.5%	1.2
1219	WholeBldg	Building Benchmarking	Biz - Custom	Warehouse	RET	per kWh	0	0%	1	0.00	0.00	2	$0	64%	64%	29%	3	100%	0%	63.6%	63.6%	61.5%	1.2
1220	WholeBldg	Building Benchmarking	Biz - Custom	Other	RET	per kWh	0	0%	1	0.00	0.00	2	$0	64%	64%	29%	3	100%	0%	63.6%	63.6%	61.5%	1.2
1221	WholeBldg	Strategic Energy Management	Biz - Custom	Assembly	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.6
1222	WholeBldg	Strategic Energy Management	Biz - Custom	Education	RET	per kWh	33	3%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	3.0
1223	WholeBldg	Strategic Energy Management	Biz - Custom	Food Sales	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.6
1224	WholeBldg	Strategic Energy Management	Biz - Custom	Food Service	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	3.0
1225	WholeBldg	Strategic Energy Management	Biz - Custom	Health	RET	per kWh	33	3%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.6
1226	WholeBldg	Strategic Energy Management	Biz - Custom	Lodging	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.5
1227	WholeBldg	Strategic Energy Management	Biz - Custom	Retail	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	3.0
1228	WholeBldg	Strategic Energy Management	Biz - Custom	Office	RET	per kWh	33	3%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.6
1229	WholeBldg	Strategic Energy Management	Biz - Custom	Warehouse	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.6
1230	WholeBldg	Strategic Energy Management	Biz - Custom	Other	RET	per kWh	0	0%	1	0.00	0.00	5	$0	100%	52%	55%	3	100%	0%	66.0%	62.2%	62.4%	2.6
1231	WholeBldg	BEIMS	Biz - Custom	Assembly	RET	per kWh	0	0%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.2
1232	WholeBldg	BEIMS	Biz - Custom	Education	RET	per kWh	43	2%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.3
1233	WholeBldg	BEIMS	Biz - Custom	Food Sales	RET	per kWh	20	5%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.2
1234	WholeBldg	BEIMS	Biz - Custom	Food Service	RET	per kWh	20	5%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.3
1235	WholeBldg	BEIMS	Biz - Custom	Health	RET	per kWh	50	2%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.2
1236	WholeBldg	BEIMS	Biz - Custom	Lodging	RET	per kWh	20	5%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.1
1237	WholeBldg	BEIMS	Biz - Custom	Retail	RET	per kWh	20	5%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.4
1238	WholeBldg	BEIMS	Biz - Custom	Office	RET	per kWh	29	4%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.2
1239	WholeBldg	BEIMS	Biz - Custom	Warehouse	RET	per kWh	0	0%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.2
1240	WholeBldg	BEIMS	Biz - Custom	Other	RET	per kWh	50	2%	1	0.00	0.00	2	$0	32%	32%	15%	3	100%	2%	44.3%	44.3%	52.6%	1.2
1241	WholeBldg	Building Operator Certification	Biz - Custom	Assembly	RET	per 1000 sq ft	0	0%	1	0.00	0.00	3	$0	75%	48%	32%	3	100%	2%	63.8%	61.7%	60.5%	1.7
1242	WholeBldg	Building Operator Certification	Biz - Custom	Education	RET	per 1000 sq ft	17,825	0%	45	0.01	0.00	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.8%	41.5
1243	WholeBldg	Building Operator Certification	Biz - Custom	Food Sales	RET	per 1000 sq ft	60,523	0%	151	0.02	0.02	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.9%	122.2
1244	WholeBldg	Building Operator Certification	Biz - Custom	Food Service	RET	per 1000 sq ft	49,444	0%	124	0.03	0.01	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.9%	113.3
1245	WholeBldg	Building Operator Certification	Biz - Custom	Health	RET	per 1000 sq ft	27,632	0%	69	0.01	0.01	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.9%	55.6
1246	WholeBldg	Building Operator Certification	Biz - Custom	Lodging	RET	per 1000 sq ft	14,600	0%	37	0.01	0.00	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.8%	28.5
1247	WholeBldg	Building Operator Certification	Biz - Custom	Retail	RET	per 1000 sq ft	18,200	0%	46	0.01	0.01	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.8%	42.7
1248	WholeBldg	Building Operator Certification	Biz - Custom	Office	RET	per 1000 sq ft	20,140	0%	50	0.01	0.01	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.8%	40.1
1249	WholeBldg	Building Operator Certification	Biz - Custom	Warehouse	RET	per 1000 sq ft	7,272	0%	18	0.00	0.00	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.6%	14.5
1250	WholeBldg	Building Operator Certification	Biz - Custom	Other	RET	per 1000 sq ft	13,644	0%	34	0.01	0.00	3	$0	100%	100%	10%	3	100%	2%	66.0%	66.0%	65.8%	27.8
1251	Cooking	Advanced Cooking	Biz - Custom	Assembly	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	6.5
1252	Cooking	Advanced Cooking	Biz - Custom	Education	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	3.1
1253	Cooking	Advanced Cooking	Biz - Custom	Food Sales	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	5.9
1254	Cooking	Advanced Cooking	Biz - Custom	Food Service	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	5.1
1255	Cooking	Advanced Cooking	Biz - Custom	Health	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	7.3
1256	Cooking	Advanced Cooking	Biz - Custom	Lodging	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	7.5
1257	Cooking	Advanced Cooking	Biz - Custom	Retail	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	6.5
1258	Cooking	Advanced Cooking	Biz - Custom	Office	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	6.5
1259	Cooking	Advanced Cooking	Biz - Custom	Warehouse	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	6.5
1260	Cooking	Advanced Cooking	Biz - Custom	Other	RET	per kWh	250	0%	1	0.00	0.00	12	$14	1%	1%	10%	7	100%	2%	19.6%	19.6%	19.6%	5.7
1261	Lighting_Int	Advanced Lighting	Biz - Custom	Assembly	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.7
1262	Lighting_Int	Advanced Lighting	Biz - Custom	Education	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.1
1263	Lighting_Int	Advanced Lighting	Biz - Custom	Food Sales	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.6
1264	Lighting_Int	Advanced Lighting	Biz - Custom	Food Service	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	6.2
1265	Lighting_Int	Advanced Lighting	Biz - Custom	Health	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.6
1266	Lighting_Int	Advanced Lighting	Biz - Custom	Lodging	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.0
1267	Lighting_Int	Advanced Lighting	Biz - Custom	Retail	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	6.5
1268	Lighting_Int	Advanced Lighting	Biz - Custom	Office	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.3
1269	Lighting_Int	Advanced Lighting	Biz - Custom	Warehouse	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	6.0
1270	Lighting_Int	Advanced Lighting	Biz - Custom	Other	RET	per kWh	2	42%	1	0.00	0.00	15	$2	6%	6%	15%	8	100%	2%	19.6%	19.6%	19.6%	5.6
1271	Plug_Office	Advanced IT	Biz - Custom	Assembly	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	31%	2%	66.0%	66.0%	63.8%	3.6
1272	Plug_Office	Advanced IT	Biz - Custom	Education	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	39%	2%	66.0%	66.0%	63.8%	3.1
1273	Plug_Office	Advanced IT	Biz - Custom	Food Sales	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	35%	2%	66.0%	66.0%	63.8%	4.2
1274	Plug_Office	Advanced IT	Biz - Custom	Food Service	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	20%	2%	66.0%	66.0%	63.8%	4.2
1275	Plug_Office	Advanced IT	Biz - Custom	Health	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	26%	2%	66.0%	66.0%	63.8%	3.4
1276	Plug_Office	Advanced IT	Biz - Custom	Lodging	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	9%	2%	66.0%	66.0%	63.8%	3.3
1277	Plug_Office	Advanced IT	Biz - Custom	Retail	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	34%	2%	66.0%	66.0%	63.8%	3.8
1278	Plug_Office	Advanced IT	Biz - Custom	Office	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	43%	2%	66.0%	66.0%	63.8%	3.3
1279	Plug_Office	Advanced IT	Biz - Custom	Warehouse	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	42%	2%	66.0%	66.0%	63.8%	3.6

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type (TOS=Time of Sale)	Unit	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	Per Unit Winter kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1280	Plug_Office	Advanced IT	Biz - Custom	Other	RET	per kWh	5	20%	1	0.00	0.00	4	$0	100%	100%	10%	8	28%	2%	66.0%	66.0%	63.8%	3.6
1281	Ventilation	Advanced Motors	Biz - Custom	Assembly	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	6.1
1282	Ventilation	Advanced Motors	Biz - Custom	Education	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	7.3
1283	Ventilation	Advanced Motors	Biz - Custom	Food Sales	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	3.6
1284	Ventilation	Advanced Motors	Biz - Custom	Food Service	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	7.2
1285	Ventilation	Advanced Motors	Biz - Custom	Health	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	6.9
1286	Ventilation	Advanced Motors	Biz - Custom	Lodging	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	5.6
1287	Ventilation	Advanced Motors	Biz - Custom	Retail	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	4.1
1288	Ventilation	Advanced Motors	Biz - Custom	Office	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	6.4
1289	Ventilation	Advanced Motors	Biz - Custom	Warehouse	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	6.5
1290	Ventilation	Advanced Motors	Biz - Custom	Other	RET	per kWh	8	12%	1	0.00	0.00	15	$0	100%	56%	60%	4	100%	2%	66.0%	62.7%	63.0%	6.1
1291	Refrigeration	Advanced Refrigeration	Biz - Custom	Assembly	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	4%	2%	19.6%	19.6%	19.6%	7.4
1292	Refrigeration	Advanced Refrigeration	Biz - Custom	Education	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	22%	2%	19.6%	19.6%	19.6%	7.4
1293	Refrigeration	Advanced Refrigeration	Biz - Custom	Food Sales	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	81%	2%	19.6%	19.6%	19.6%	6.9
1294	Refrigeration	Advanced Refrigeration	Biz - Custom	Food Service	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	27%	2%	19.6%	19.6%	19.6%	7.4
1295	Refrigeration	Advanced Refrigeration	Biz - Custom	Health	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	19%	2%	19.6%	19.6%	19.6%	7.6
1296	Refrigeration	Advanced Refrigeration	Biz - Custom	Lodging	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	21%	2%	19.6%	19.6%	19.6%	7.3
1297	Refrigeration	Advanced Refrigeration	Biz - Custom	Retail	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	65%	2%	19.6%	19.6%	19.6%	7.4
1298	Refrigeration	Advanced Refrigeration	Biz - Custom	Office	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	67%	2%	19.6%	19.6%	19.6%	7.4
1299	Refrigeration	Advanced Refrigeration	Biz - Custom	Warehouse	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	63%	2%	19.6%	19.6%	19.6%	7.4
1300	Refrigeration	Advanced Refrigeration	Biz - Custom	Other	RET	per kWh	8	13%	1	0.00	0.00	20	$34	0%	0%	10%	18	43%	2%	19.6%	19.6%	19.6%	7.4
1301	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Assembly	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.3
1302	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Education	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	7.2
1303	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Food Sales	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.2
1304	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Food Service	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	7.1
1305	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Health	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.2
1306	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Lodging	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.0
1307	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Retail	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	7.3
1308	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Office	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.1
1309	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Warehouse	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.1
1310	WholeBldg_HVAC	Advanced HVAC	Biz - Custom	Other	RET	per kWh	8	12%	1	0.00	0.00	15	$1	100%	28%	68%	7	100%	2%	66.0%	53.7%	61.4%	6.2
1311	Compressed Air	Efficient Air Compressor Equipment	Biz - Custom	Industrial	TOS	per kWh	9	11%	1	0.00	0.00	13	$0	100%	34%	76%	1	100%	25%	66.0%	58.6%	63.0%	5.6
1312	Compressed Air	Efficient Air Compressor Controls	Biz - Custom	Industrial	RET	per kWh	15	7%	1	0.00	0.00	3	$0	100%	100%	43%	2	100%	25%	66.0%	66.0%	63.9%	1.9
1313	HVAC	Efficient HVAC Equipment	Biz - Custom	Industrial	TOS	per kWh	8	13%	1	0.00	0.00	15	$0	100%	72%	64%	1	100%	25%	66.0%	64.4%	63.9%	5.6
1314	HVAC	Efficient HVAC O&M	Biz - Custom	Industrial	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	26%	2	100%	25%	66.0%	66.0%	63.9%	2.2
1315	Lighting_Int	Efficient Lighting Equipment	Biz - Prescriptive	Industrial	RET	per kWh	2	42%	1	0.00	0.00	15	$0	100%	81%	60%	1	100%	65%	88.0%	86.7%	85.2%	6.2
1316	Lighting_Int	Efficient Lighting O&M	Biz - Prescriptive	Industrial	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	10%	2	100%	30%	88.0%	88.0%	85.5%	3.4
1317	Motors	Efficient MachDr Equipment	Biz - Custom	Industrial	TOS	per kWh	8	12%	1	0.00	0.00	15	$0	100%	82%	59%	1	100%	25%	66.0%	65.1%	63.9%	3.6
1318	Motors	Efficient MachDr O&M	Biz - Custom	Industrial	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	27%	2	100%	25%	66.0%	66.0%	63.9%	1.5
1319	Process Heat	Efficient ProcHeat Equipment	Biz - Custom	Industrial	TOS	per kWh	33	3%	1	0.00	0.00	15	$0	100%	81%	60%	1	100%	25%	66.0%	65.0%	63.9%	6.3
1320	Process Heat	Efficient ProcHeat O&M	Biz - Custom	Industrial	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	10%	2	100%	25%	66.0%	66.0%	63.9%	3.1
1321	Process Refrig	Efficient ProcRefrig Equipment	Biz - Custom	Industrial	TOS	per kWh	6	16%	1	0.00	0.00	15	$0	100%	79%	61%	1	100%	25%	66.0%	64.9%	63.9%	5.7
1322	Process Refrig	Efficient ProcRefrig O&M	Biz - Custom	Industrial	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	34%	2	100%	25%	66.0%	66.0%	63.9%	2.1
1323	Process Other	Other Process Equip	Biz - Custom	Industrial	TOS	per kWh	4	26%	1	0.00	0.00	11	$0	100%	40%	79%	1	100%	25%	66.0%	60.2%	63.8%	5.3
1324	Process Other	Other Process O&M	Biz - Custom	Industrial	RET	per kWh	14	7%	1	0.00	0.00	11	$0	100%	46%	77%	2	100%	25%	66.0%	61.3%	63.9%	5.3
1325	WholeBldg	Power Distribution (Transformers)	Biz - Custom	Industrial	RET	per kWh	179	1%	1	0.00	0.00	30	$1	100%	12%	41%	1	100%	25%	66.0%	40.0%	40.0%	10.7
1326	WholeBldg	Strategic Energy Management	Biz - RCx	Industrial	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	20%	2	100%	25%	66.0%	66.0%	63.9%	2.9
1327	Water_WW	Water Supply & Wastewater treatment pumps and process efficiency	Biz - Custom	Industrial	RET	per kWh	5	19%	1	0.00	0.00	11	$0	75%	31%	61%	1	100%	25%	62.7%	57.1%	61.0%	2.9
1328	Lighting_Int	Advanced Lighting Controls	Biz - Custom	Industrial	RET	per kWh	2	42%	1	0.00	0.00	15	$2	50%	6%	15%	3	100%	25%	43.6%	38.5%	38.5%	9.8
1329	Compressed Air	Process Improvement - Air Compressor	Biz - Custom	Industrial	RET	per kWh	20	5%	1	0.00	0.00	15	$1	100%	28%	67%	3	100%	25%	66.0%	53.3%	61.2%	55.5
1330	Process Heat	Process Improvement - Heat	Biz - Custom	Industrial	RET	per kWh	20	5%	1	0.00	0.00	15	$0	100%	100%	24%	3	100%	25%	66.0%	66.0%	63.9%	84.9
1331	Process Other	Process Improvement - Other	Biz - Custom	Industrial	RET	per kWh	10	10%	1	0.00	0.00	10	$0	100%	64%	68%	3	100%	25%	66.0%	63.7%	63.9%	21.5
1332	Process Refrig	Process Improvement - Refrigeration and Cooling	Biz - Custom	Industrial	RET	per kWh	8	13%	1	0.00	0.00	10	$0	100%	52%	74%	3	100%	25%	66.0%	62.2%	63.9%	17.1
1333	Motors	Efficient Motor Pmp Equipment - Q1 Cost	Biz - Custom	Agriculture	TOS	per kWh	8	13%	1	0.00	0.00	15	$0	100%	100%	10%	1	100%	25%	66.0%	66.0%	65.8%	3.6
1334	Motors	Efficient Motor Pmp Equipment - Q2 Cost	Biz - Custom	Agriculture	TOS	per kWh	8	13%	1	0.00	0.00	15	$0	100%	100%	10%	1	100%	25%	66.0%	66.0%	65.5%	3.6
1335	Motors	Efficient Motor Pmp Equipment - Q3 Cost	Biz - Custom	Agriculture	TOS	per kWh	8	13%	1	0.00	0.00	15	$0	100%	100%	10%	1	100%	25%	66.0%	66.0%	64.7%	3.6
1336	Motors	Efficient Motor Pmp O&M	Biz - Custom	Agriculture	RET	per kWh	33	3%	1	0.00	0.00	15	$0	100%	100%	10%	2	100%	25%	66.0%	66.0%	63.4%	5.4
1337	Refrigeration	Efficient Refrigeration Equipment	Biz - Custom	Agriculture	TOS	per kWh	7	15%	1	0.00	0.00	15	$0	100%	79%	44%	1	100%	25%	66.0%	64.9%	63.0%	5.7
1338	Refrigeration	Refrigeration Equipment O&M	Biz - Custom	Agriculture	RET	per kWh	33	3%	1	0.00	0.00	3	$0	100%	100%	10%	2	100%	25%	66.0%	66.0%	63.1%	2.0
1339	Lighting_Int	Efficient Lighting	Biz - Prescriptive	Agriculture	TOS	per kWh	2	42%	1	0.00	0.00	15	$0	100%	80%	43%	1	100%	65%	88.0%	86.6%	84.0%	6.2
1340	Lighting_Int	Grow Lighting	Biz - Prescriptive	Agriculture	RET	per kWh	3	39%	1	0.00	0.00	15	$0	100%	52%	63%	2	100%	50%	88.0%	83.0%	84.0%	6.2
1341	Ventilation	Efficient Ventilation	Biz - Custom	Agriculture	TOS	per kWh	2	54%	1	0.00	0.00	10	$0	100%	44%	69%	1	100%	25%	66.0%	60.9%	63.0%	4.1
1342	WholeBldg	Efficient Dehumidification	Biz - Custom	Agriculture	TOS	per kWh	4	27%	1	0.00	0.00	10	$0	100%	74%	47%	1	100%	25%	66.0%	64.5%	63.0%	4.1
1343	WholeBldg	Efficient HVAC	Biz - Custom	Agriculture	TOS	per kWh	8	13%	1	0.00	0.00	15	$0	100%	74%	47%	1	100%	25%	66.0%	64.5%	63.0%	5.6

APPENDIX D. DEMAND RESPONSE DETAIL

DR Program Option	Assumption	Value	Source/Notes
DLC HVAC Switch	# of Control Units per Res Participant	1.123	CenterPoint 2024 evaluation
	Existing Participants - Res	18,258 currently; assumed to decrease to 9,258 by 2027	CenterPoint data response; decreasing by 3000 switches per year
	Participant Annual Incentive - Res	$15/participant (summer only)	CenterPoint data response
	Annual Number of Control Hours	60 hours	Assumes 15 events, 4 hours each (summer only)
	Per Participant Load Reduction - Summer - Res	0.214 kW	CenterPoint 2024 evaluation
	Per Participant Load Reduction - Winter - Res	N/A	N/A
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost - Res	N/A - not installing new switches	CenterPoint data response
	Participant Share of Equipment/Labor Cost	$0	N/A
	One Time Incentive Towards Cost of Equipment	$0	N/A
	O&M Res	$16,000 in 2028, decreases to 0 by 2031	Based on what CenterPoint is spending on O&M costs
	Vendor Service Fees Res	$65,000 in 2028, decreases to 0 by 2031	Based on what CenterPoint is spending on vendor costs
	Evaluation costs	$64,000 per switch program per year	Based on what CenterPoint is currently spending on evaluations
	Participation Rate MAP Res	Transitioning to thermostats via Smart Cycle program, about 3000/year.	CenterPoint

DR Program Option	Assumption	Value	Source/Notes
		Keeping remaining 20% of switches once rest of switches have transitioned, assuming those participants don't have sufficient internet for thermostats. Assumes remaining 10% of switches fail per year.	
	Participation Rate RAP Res	Transitioning to thermostats via Smart Cycle program, about 3000/year. Keeping remaining 20% of switches once rest of switches have transitioned, assuming those participants don't have sufficient internet for thermostats. Assumes remaining 10% of switches fail per year.	CenterPoint
	End Use Saturation Res	87% AC	CenterPoint Market Research - March 2025
DLC Thermostat	# of Control Units per Res Participant	1.123	CenterPoint 2024 evaluation
	Existing Participants Res - Smart Cycle	1,352 currently; assumed to increase to 10,352 by 2027	CenterPoint data response; increasing by 3000 per year
	Existing Participants Res - BYOT	7,308 currently; assumed to increase to 11,208 by 2027	CenterPoint data response; increasing by 1300 per year
	Participant Annual Incentive - Res	$67.5/year (currently summer only- $7.50/month)	CenterPoint data response
	Participant Annual Incentive - C&I	$67.5/year (currently summer only- $7.50/month)	CenterPoint data response
	Annual Number of Control Hours	100 hours	Assumes 25 events, 4 hours each (year round); summer only: 15 events; 4 hours each
	Per Participant Load Reduction - Summer - Res	0.95 kW	CenterPoint 2024 evaluation
	Per Participant Load Reduction - Winter - Res	1.371 kW	Average of studies: Puget Sound Energy 2022, BPA 2021, PGE 2021, NRECA 2021

DR Program Option	Assumption	Value	Source/Notes
	Per Participant Load Reduction - Summer - C&I	1.948 kW	Average of studies: Xcel Energy 2022, Puget Sound Energy 2022, CenterPoint 2021, Pacificorp 2019
	Per Participant Load Reduction - Winter - C&I	2.542 kW	Average of studies: Puget Sound Energy 2022, Pacificorp 2019
	Control Equipment Useful Life	11 years	Illinois TRM v13
	Utility Per Unit Equipment/ Labor Cost - Smart Cycle only	$445/new participant	CenterPoint data response (includes labor, shipping, and thermostat)
	Participant Share of Equipment/Labor Cost - BYOT only	$370	Assumes participant will pay the cost of the new thermostat minus the one-time rebate
	One Time Incentive Towards Cost of Equipment - BYOT only	$75	CenterPoint data response
	O&M/Vendor Service Fees per Customer Res	$36/participant-year	CenterPoint data response
	O&M/Vendor Service Fees per Customer C&I	$36/participant-year	CenterPoint data response
	Evaluation costs	$30,000 per thermostat program per year	Based on what CenterPoint is currently spending on evaluations
	Participation Rate MAP Res	45%	Xcel Energy 2022
	Participation Rate RAP Res	32%	Average of studies: Pacificorp 2023, BPA 2021 (using combined participation rates for AC switches & thermostats, since CNP's switches are transitioning to thermostats)
	Participation Rate MAP C&I	25%	Puget Sound Energy 2022
	Participation Rate RAP C&I	14%	Xcel Energy 2022, Pacificorp 2021
	End Use Saturation Res	87% AC; 39% Electric Space Heating	CenterPoint Market Research - March 2025
	End Use Saturation C&I	81.5% AC; 31.1% Electric Space Heating	CenterPoint 2021 data response for AC; CBECS midwest region for electric heating
DLC Water Heater Switch	# of Control Units per Participant	1.021	CenterPoint 2024 evaluation

DR Program Option	Assumption	Value	Source/Notes
	Existing Participants Res	5,520 currently; assumed to decrease to 4,485 by 2027	CenterPoint data response; decreasing to 0 by 2040
	Participant Annual Incentive - Res	$6/participant-year	CenterPoint data response
	Participant Annual Incentive - C&I	$6/participant-year	CenterPoint data response
	Annual Number of Control Hours	60 hours	Assumes 15 events, 4 hours each (summer only)
	Per Participant Load Reduction - Summer - Res	0.104 kW	CenterPoint 2024 evaluation
	Per Participant Load Reduction - Winter - Res	N/A	N/A
	Per Participant Load Reduction - Summer - C&I	1.5 kW	Pacificorp 2019
	Per Participant Load Reduction - Winter - C&I	N/A	N/A
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost	N/A - not installing new switches	CenterPoint data response
	Participant Share of Equipment/Labor Cost	$0	N/A
	One Time Incentive Towards Cost of Equipment	$0	N/A
	O&M Res	$11,000 in 2028, increases to $30,000 per year starting in 2031 (escalates by 3%)	Based on what CenterPoint is spending on O&M costs
	Vendor Service Fees Res	$43,000 in 2028, increases to $117,000 per year starting in 2031 (escalates by 3%)	Based on what CenterPoint is spending on vendor costs

DR Program Option	Assumption	Value	Source/Notes
	Participation Rate MAP Res	N/A - decreasing to 0	CenterPoint
	Participation Rate RAP Res	N/A - decreasing to 0	CenterPoint
	Participation Rate MAP C&I	N/A - decreasing to 0	CenterPoint
	Participation Rate RAP C&I	N/A - decreasing to 0	CenterPoint
	End Use Saturation Res	30%	CenterPoint Market Research - March 2025. Electric resistance WH.
	End Use Saturation C&I	40.1%	CenterPoint 2021 data response
DLC Grid Enabled Water Heater	# of Control Units per Participant	1.021	CenterPoint 2024 evaluation
	Existing Participants	0	
	Participant Annual Incentive - Res	$26/participant-year for year-round	Average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021, Xcel Energy 2022, Florida Power and Light program
	Participant Annual Incentive - C&I	$30/participant-year for year-round participation	Pacificorp 2023
	Annual Number of Control Hours	100 hours	Assumes 25 events, 4 hours each (year round)
	Per Participant Load Reduction - Summer - Res	0.43 kW	CenterPoint 2024 evaluation
	Per Participant Load Reduction - Winter - Res	0.63 kW	Ratio of winter:summer load reduction from studies applied to CenterPoint's summer load reduction: NREL 2022, PGE 2016, BPA 2021, Minnesota 2013, Puget Sound 2022, CenterPoint 2023, Xcel Energy 2022, Pacificorp 2023
	Per Participant Load Reduction - Summer - C&I	1.5 kW	Pacificorp 2019
	Per Participant Load Reduction - Winter - C&I	1.5 kW	Pacificorp 2019
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost	$50	Cost of communication module. Average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021

DR Program Option	Assumption	Value	Source/Notes
	Participant Share of Equipment/Labor Cost	$250	Assuming utility pays rebate for program participation. Costs for 50-gallon electric grid enabled water heaters range from $500-$800. Assumed $650 for mid-range WH.
	One Time Incentive Towards Cost of Equipment	$400	Xcel Energy 2022
	O&M/Vendor Service Fees per Customer Res	$16/participant-year	Average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021
	O&M/Vendor Service Fees per Customer C&I	$16/participant-year	Average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021
	Participation Rate MAP Res	50%	BPA 2021
	Participation Rate RAP Res	25%	Puget Sound Energy 2022, NREL 2022, BPA 2021, PGE 2016
	Participation Rate MAP C&I	50%	Assumes same as residential
	Participation Rate RAP C&I	25%	Pacificorp 2023
	End Use Saturation Res	30%	CenterPoint Market Research - March 2025
	End Use Saturation C&I	40.1%	CenterPoint 2021 data response
DLC EVs	# of Control Units per Participant	1	
	Existing Participants	0	
	Participant Annual Incentive - Res	$37/participant-year for year-round participation	Eversource 2021, Puget Sound Energy 2022, BPA 2021, Pacificorp 2023, Delaware Electric Coop program
	Annual Number of Control Hours	100 hours	Assumes 25 events, 4 hours each (year round)
	Per Participant Load Reduction - Summer - Res	0.304 kW	Average of studies: Eversource 2021, Puget Sound 2022, Pacificorp 2023, National Grid 2022, BPA 2021, NRECA 2020
	Per Participant Load Reduction - Winter - Res	0.295 kW	Average of studies: Eversource 2021, Pacificorp 2023
	Per Participant Load Reduction - Summer - C&I	0.02 kW	Xcel Energy 2022
	Per Participant Load Reduction - Winter - C&I	0.03 kW	Xcel Energy 2022

DR Program Option	Assumption	Value	Source/Notes
	Control Equipment Useful Life	10 years	US DOE, Costs Associated with Non-Residential EV Supply Equipment, 2015
	Utility Per Unit Equipment/ Labor Cost	0	N/A
	Participant Share of Equipment/Labor Cost	$845	Assumes installed cost of level 2 charger is $1000. Must have networked Level 2 charger to participate. NYSERDA 2022 white paper found that only 10% of residential EV chargers are already networked level 2 chargers. Remainder would need to be upgraded to participate.
	One Time Incentive Towards Cost of Equipment	$155/new participant	Eversource 2021, National Grid 2022, NRECA 2020, Delaware Electric Coop program
	O&M/Vendor Service Fees per Customer Res	$10/participant-year	Pacificorp 2023, Puget Sound Energy 2022, BPA 2021
	O&M/Vendor Service Fees per Customer C&I	$10/participant-year	Pacificorp 2023, Puget Sound Energy 2022, BPA 2021
	Participation Rate MAP Res	25%	Pacificorp 2019
	Participation Rate RAP Res	20%	BPA 2021
	Participation Rate MAP C&I	20%	Xcel Energy 2022
	Participation Rate RAP C&I	10%	GDS assumption of about 50% of MAP
TOU + CPP Rate	# of Control Units per Participant	1	
	Existing Participants	Targeting 500 customers to start pilot in 2025	CenterPoint data response
	Participant Annual Incentive	$0	N/A
	Annual Number of Control Hours	60 for CPP; 1564 for TOU	Assumes up to 15 events per year, 4 hours per event for CPP; TOU: 6 hrs/week day, year round (CenterPoint's existing rate - 1 to 7pm, weekdays)

DR Program Option	Assumption	Value	Source/Notes
	Per Participant Load Reduction - Summer - Res	12.8% for CPP; 8.6% for TOU	CPP: average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021; TOU: average of studies: BPA 2021, Pacificorp 2023, PG&E 2023, Maryland Evaluation 2020, Dominion Energy 2022 Evaluation
	Per Participant Load Reduction - Winter - Res	7.7% for CPP; 3.6% for TOU	CPP: average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021; TOU: average of studies: BPA 2021, Pacificorp 2023, PG&E 2023, Maryland Evaluation 2020, Dominion Energy 2022 Evaluation
	Per Participant Load Reduction - Summer - C&I	7.1% for CPP; 2.0% for TOU	CPP: average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021; TOU: average of studies: Pacificorp 2023
	Per Participant Load Reduction - Winter - C&I	6.3% for CPP; 1.0% for TOU	CPP: average of studies: Pacificorp 2023, Puget Sound Energy 2022, BPA 2021; TOU: average of studies: Pacificorp 2023
	Control Equipment Useful Life	20 years	Useful life of smart meter. https://docs.cpuc.ca.gov/published/FINAL_DECISION/58362-07.htm#:~:text=The%20AMI%20system's%20useful%20life%20does%20not,is%20a%20reasonable%20forecast%20for%20the%20purposes
	Utility Per Unit Equipment/ Labor Cost	$0	No cost to join rate
	Participant Share of Equipment/Labor Cost	$0	No cost to join rate
	One Time Incentive Towards Cost of Equipment	$0	No cost to join rate
	O&M/Vendor Service Fees per Customer Res	$0	N/A, utility runs rate programs
	Participation Rate MAP Res	15%	Duke Energy 2020, OGE- Brattle Group 2023 Paper
	Participation Rate RAP Res	10%	Duke Energy 2020
	Participation Rate MAP C&I	15%	Assumed same as residential
	Participation Rate RAP C&I	10%	Assumed same as residential

DR Program Option	Assumption	Value	Source/Notes
Battery Storage	# of Control Units per Participant	1	
	Existing Participants	0	
	Participant Annual Incentive Res	$400/participant	Average of studies: Massachusetts Energy Storage Demand Reduction Evaluation 2024, Xcel Energy 2022, Pacificorp 2023
	Participant Annual Incentive Com	$1500/participant	Based on incentive per kW for residential programs, for 11.25 kW C&I battery
	Annual Number of Control Hours	180 hours	Eversource 2021, Massachusetts Energy Storage Demand Reduction Evaluation 2024
	Per Participant Load Reduction - Summer - Res	3 kW	Assumes utility could use 60% of 5kW residential battery
	Per Participant Load Reduction - Winter - Res	3 kW	Assumes utility could use 60% of 5kW residential battery
	Per Participant Load Reduction - Summer - C&I	11.25 kW	2017 SGIP Advanced Energy Storage Impact Evaluation. Peak demand reduction of 45% of rebated capacity for a 25 kW battery - Figure 4-36 of study.
	Per Participant Load Reduction - Winter - C&I	11.25 kW	2017 SGIP Advanced Energy Storage Impact Evaluation. Peak demand reduction of 45% of rebated capacity for a 25 kW battery - Figure 4-36 of study.
	Control Equipment Useful Life	10 years	Tesla Powerwall warranty
	Utility Per Unit Equipment/ Labor Cost	$0	Assume BYOB program
	Participant Share of Equipment/Labor Cost - Res	$0	Assume BYOB program
	Participant Share of Equipment/Labor Cost - C&I	$0	Assume BYOB program
	One Time Incentive Towards Cost of Equipment	$0	Assume BYOB program
	O&M/Vendor Service Fees per Customer Res	$77/kW starting in 2027; decreases to $58/kW in 2045	NREL 2024 cost forecast: https://atb.nrel.gov/electricity/2024/residential_battery_storage

DR Program Option	Assumption	Value	Source/Notes
	O&M/Vendor Service Fees per Customer C&I	$230.50/kW starting in 2027; decreases to $173/kW in 2045	NREL 2024 cost forecast: https://atb.nrel.gov/electricity/2024/residential_battery_storage
	Participation Rate MAP Res	60%	Pacificorp 2023
	Participation Rate RAP Res	50%	Xcel Energy 2022
	Participation Rate MAP C&I	60%	Assumes same as residential
	Participation Rate RAP C&I	50%	Assumes same as residential
	Saturation Res	8.63% of customers with solar	CenterPoint / Itron
	Saturation C&I	8% of customers with solar	LBL Tracking The Sun Report 2024
General Program Costs (unless otherwise noted)	Implementation	$150,000 per new program	BPA 2021, Puget Sound Energy 2022
	Admin	$72,750 per program	Assumes 50% of 1 full time staff's time
	Marketing	$50 per new participant for residential & small C&I customers; $200 per new participant for large C&I programs (ie for Curtailment & Capacity Bidding Programs)	BPA 2021, Puget Sound Energy 2022, Pacificorp 2019
	Evaluation costs for new programs	$30,000 per year	Based on what CenterPoint is currently spending on evaluations for thermostat programs

Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey

CenterPoint Energy

2025 CNP Residential Energy Efficiency Baseline Survey

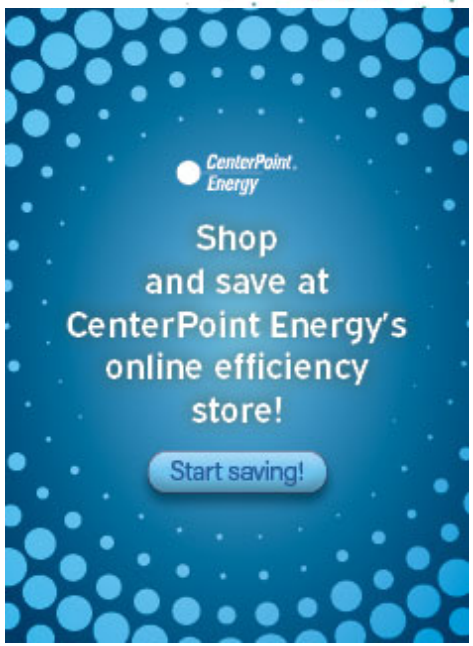


Michael Lloyd

April 28, 2025

Background and Methodology

An online survey was conducted to understand Indiana residential customer experiences and thoughts regarding energy efficiency programs and equipment in their home. A mostly similar study was last conducted in June 2021.



Methodology:

- The survey ran from February 17th and was closed at end-of-day on February 28th with a grand total of 1,048 responses (people who started the survey).
- Seven hundred-thirty respondents completed the entire survey (through Q.47 of the additional questions), meaning 5.4% completed the entire questionnaire.
- Respondents who competed the survey were entered into a random drawing for a chance to win one of fifteen $100 gift cards.
- A topline summary of the results and all data was previously issued on March 3rd.

Executive Summary

Results from this research show:

- Continue promotions around Smart Thermostats.
  - Most popular smart home technology
  - Most likely to be purchased in next year
- Surveyed customers look for energy efficient appliances and heating & cooling systems when selecting these items for their home. The ENERGY STAR label is also important.
- Continue to promote and quantify the savings a customer would receive on their energy bill with energy efficient equipment and the energy savings produced.
- Rebates are drivers to energy efficiency program participation and appliance selection. The higher the rebate, the better.
- CenterPoint energy efficient program participation is still rather low, although slightly better than results found in 2021 for the Summer Cycler or Smart Cycle program.

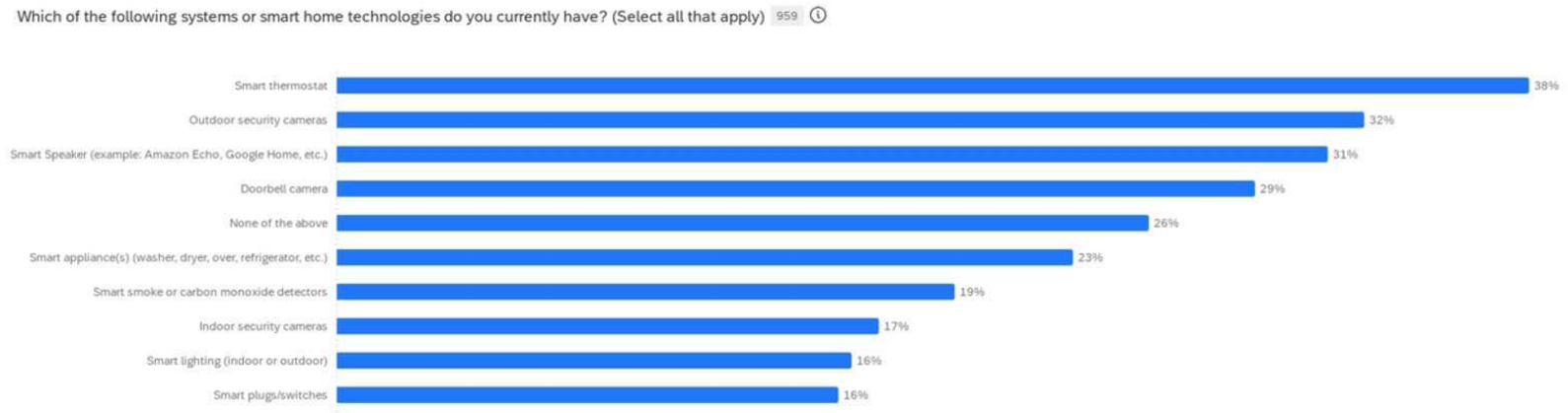
Information about their Homes

- 100% of surveyed customer said CenterPoint Energy (CNP) provides their electric service and 63% said CNP provides their gas service.
- 78% describe their home/residence as a House and 13% replied Apartment building or Condominium. Over three in four (78%) own their residence. Average household size is 1.7 occupants.
- Most describe their home as Well insulated (31%) or Adequately insulated (48%). Others said Poorly (12%) or Not insulated at all (1%). 41% percent said their home is Rarely drafty and 36% responded, Some of the time.



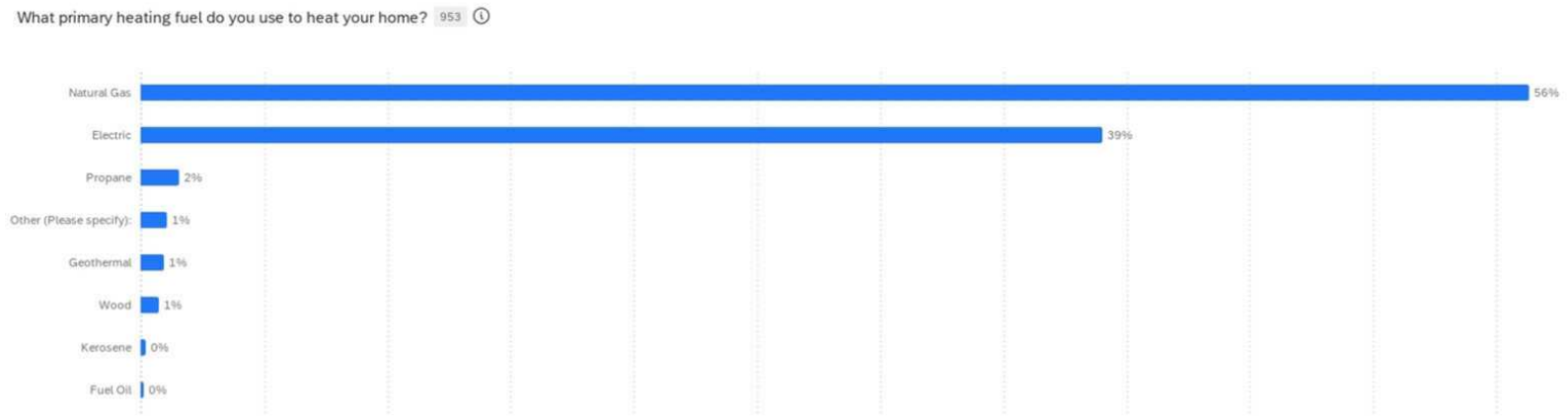
Current Smart Home Systems and Technology

- Leading smart home technologies are Smart thermostat (38%), Outdoor security cameras (32%), Smart speaker (31%), Doorbell camera (29%) and Smart appliances (23%). One-quarter replied None of the above. These findings are mostly comparable to 2021 results, although Outdoor security cameras gained some 14% points and None of the above dropped 8% points. Types of thermostats installed include Programmable thermostat (37%), Digital thermostat (26%) and Wi-Fi thermostat (19%).



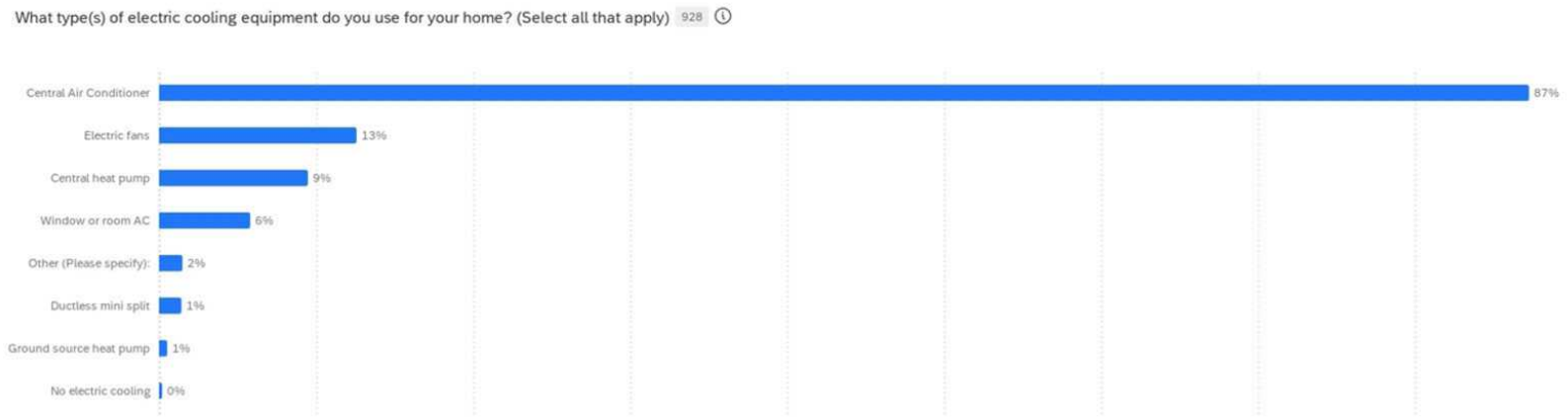
Current Home Heating System

- Homes tend to be heated by Natural gas (56%) or Electric (39%), utilizing most often either a Gas furnace (59%) or Electric furnace (21%) as their primary heating system.
- About an equal percentage said their heating system in their home is either Less than 1 year to 4 years old (29%), 5 – 10 years old (31%) or Older than 10 years (29%). One in ten are Unsure.



Current Home Cooling System

- Electric cooling equipment is dominated by replies for Central Air Conditioner (87%). Thirteen percent use Electric fans.
- Like heating systems, about an equal percentage said their cooling system in their home is either Less than 1 year to 4 years old (30%), 5 – 10 years old (32%) or Older than 10 years (26%). Some 12% are Unsure. Eighty-two percent of those surveyed have One cooling unit and 14% have More than one.



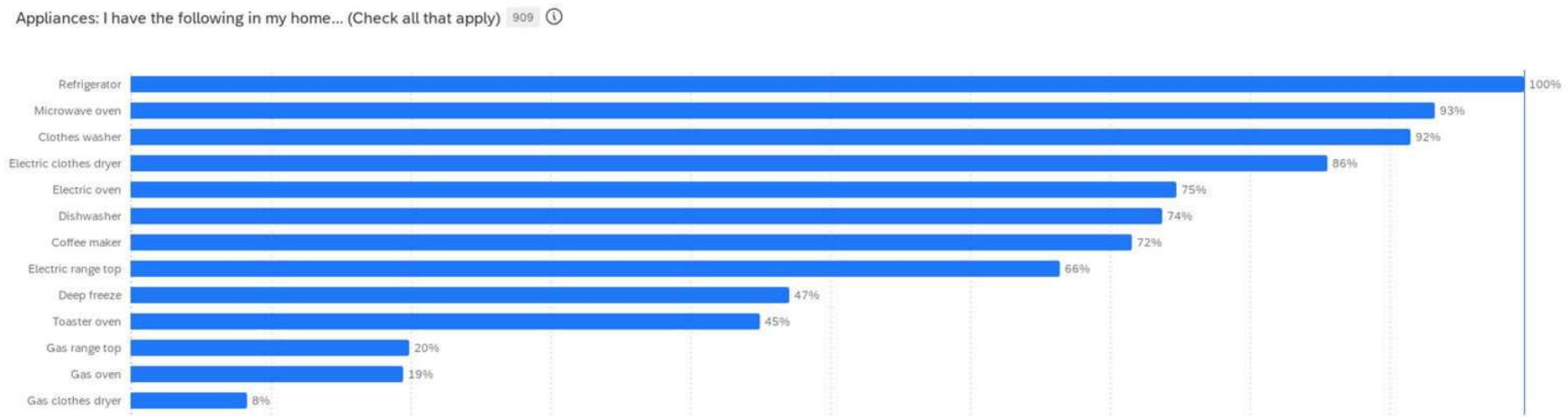
Water Heating Fuels



- Main water heating fuels used for home are Natural gas (53%) and Electric resistance (30%).
- Respondents mostly have a Medium tank (31 to 49 gallons) (40%), a Large tank (50 gallons or more) (21%), a Small tank (30 gallons or less) (10%) or have a Tankless (9%) water heater. One in five are Unsure.

Appliances Found in Home

- Appliances found in most homes include Refrigerator (100%), Microwave oven (93%), Clothes washer (92%), Electric clothes dryer (86%), Electric oven (75%), Dishwasher (74%), Coffee maker (72%) and Electric range top (66%).

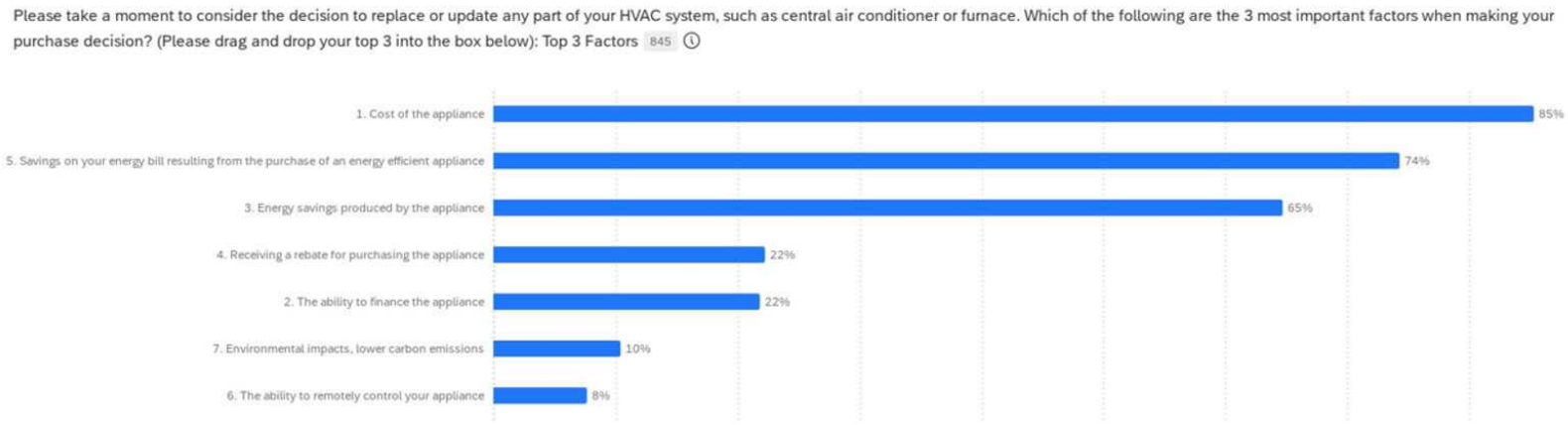


Participation in Utility Sponsored Rebate Programs

- 6% of surveyed residents indicted they have participated in any utility sponsored rebate program in the past 12 months. This percentage was at 9% in 2021.
- When purchasing appliances or heating & cooling equipment for their home, 82% purchase energy efficient equipment that may have an ENERGY STAR label and 18% buy standard equipment.

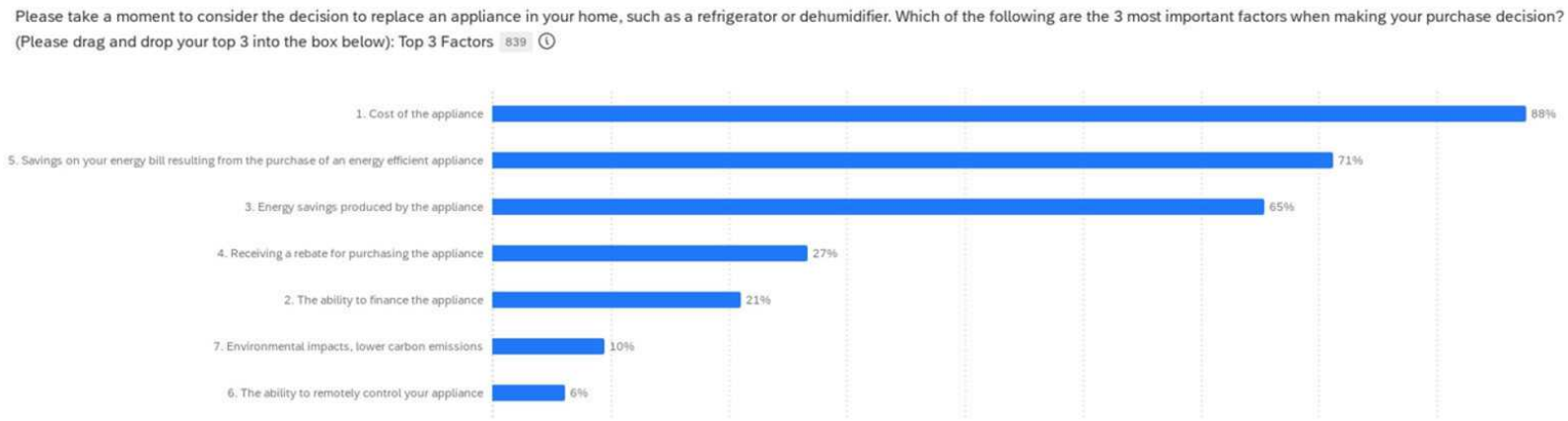
Factors Impacting Decisions when Replacing HVAC System

- Leading factors considered when **replacing or updating any part of their HVAC system** are Cost of the appliance (85%), Savings on your energy bill resulting from the purchase of an energy efficient appliance (74%) and Energy savings produced by the appliance (65%).



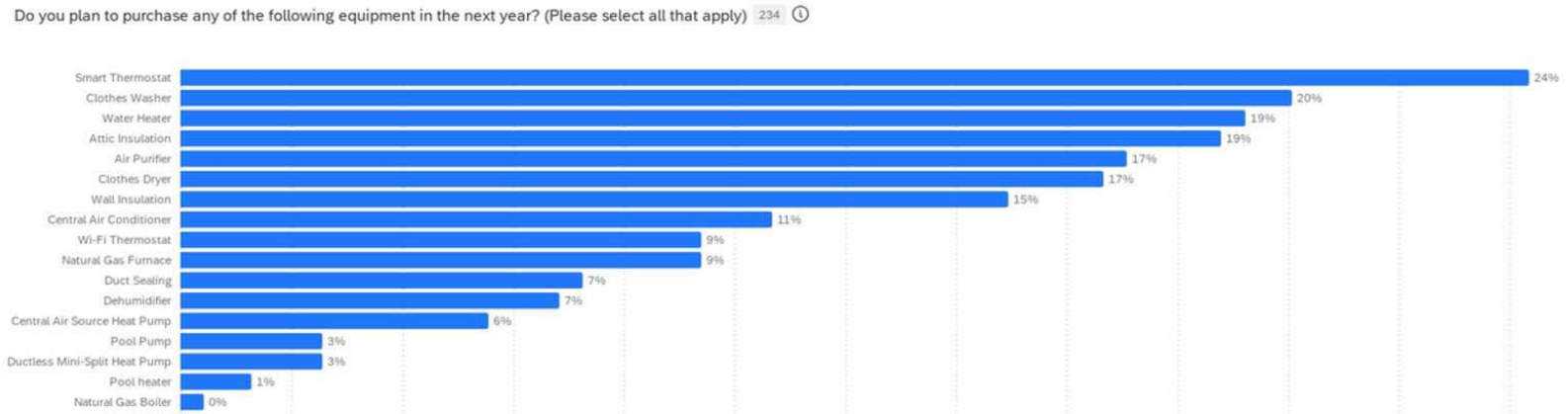
Factors Impacting Decisions for Replacing an Appliance

- The top three factors considered for **replacing an appliance in one's home** are also Cost of the appliance (88%), Savings on your energy bill resulting from the purchase of an energy efficient appliance (71%) and Energy savings produced by the appliance (65%).



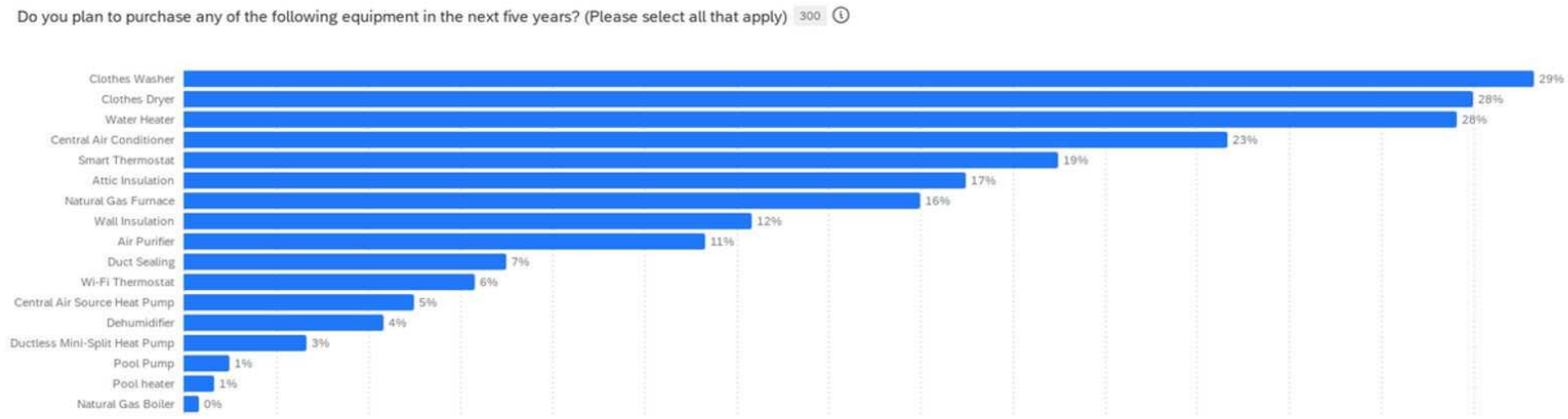
Future Equipment Purchases In the New Year

- Equipment planned to be purchased **in the next year** are Smart Thermostat (24%), Clothes Washer (20%), Water Heater, Attic Insulation (19% each), Clothes Dryer, Air Purifier (17% each), Wall Insulation (15%) and Central Air Conditioner (11%).
- With these expected purchases, the vast majority would be Extremely likely or Somewhat likely to select energy efficient equipment.



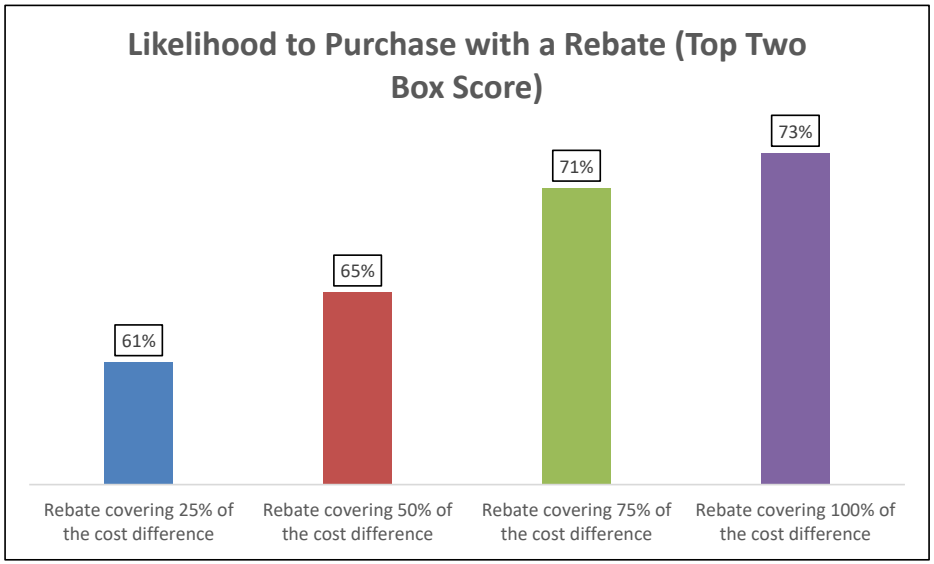
Future Equipment Purchases In the Next Five Years

- Expected purchases **in the next five years** include Clothes Washer (29%), Clothes Dryer (28%), Water Heater (28%), Central Air Conditioner (23%) and Smart Thermostat (19%).
- Again, with these expected purchases, the overwhelming majority would be Extremely likely or Somewhat likely to select energy efficient equipment.



Decision to Purchase Energy Efficient Appliance Based on Rebate Amount

- Almost all respondents would consider purchasing an energy efficient appliance priced at $1,200 if they received a rebate of at least 25% of the cost difference from a standard electric appliance. The higher the rebate percentage, the higher the likelihood.



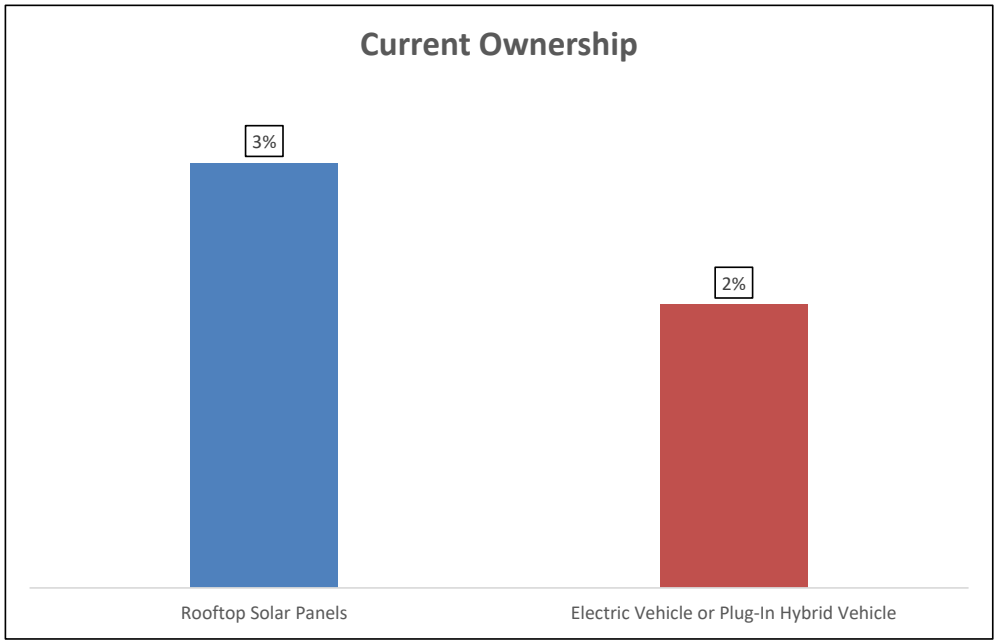
Participation in CenterPoint Energy Programs

- 14% said they are in the CenterPoint Energy Summer Cycler or Smart Cycle program and 10% participate in Smart Thermostat. Summer Cycler was at 6% in 2021 and Smart Thermostat wasn't asked. This year, 83% replied None of the above.
- Leading barriers to participation include Concerns about allowing your utility to control your thermostat(s) during events (58% Top Two Box Score), Concerns about the indoor temperature being uncomfortable (54%) and Concerns about data security due to the thermostat's Wi-Fi connection (44%). Motivators to enroll in a thermostat control program are Incentives and/or bill credits (66%) and Reducing power supply costs for all utility customers (54%).

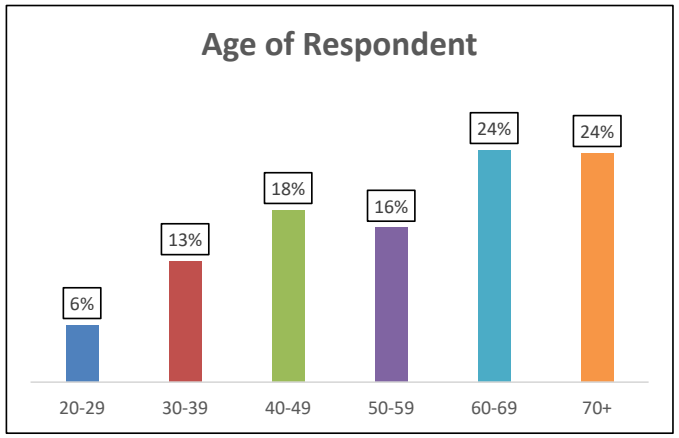


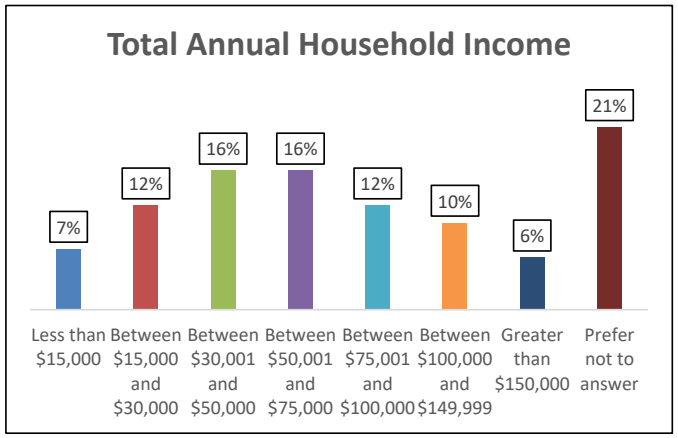
Ownership of Solar Panels and Electric Vehicles

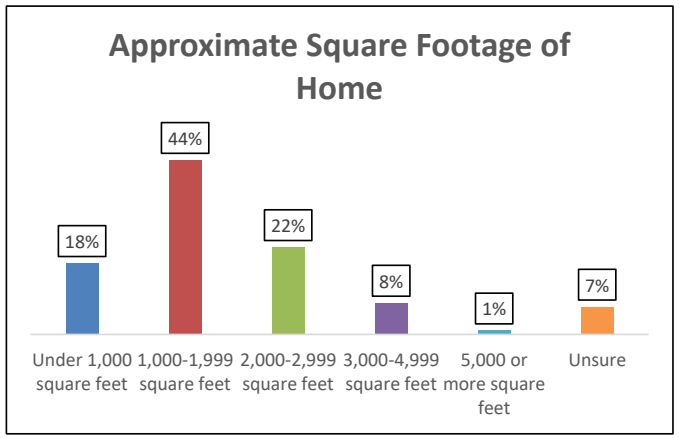
- 3% have rooftop solar panels installed at their home and 2% own an electric vehicle or a plug-in hybrid vehicle.

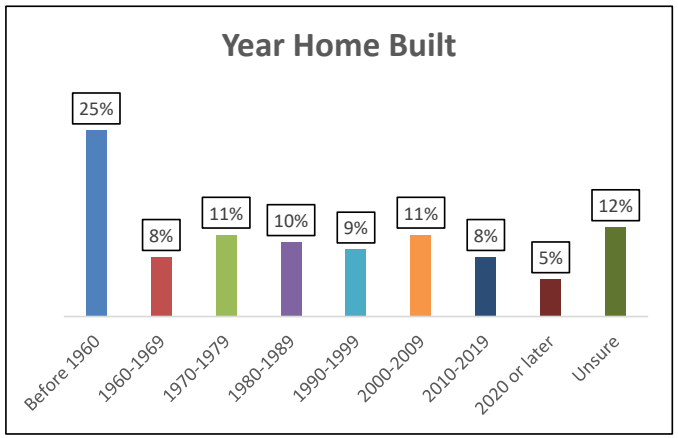


Respondent Demographics









Questions & Answers



Attachment 3.8 CEIS Distribution System Long Range Planning Report

DISTRIBUTION SYSTEM LONG RANGE PLAN

CENTERPOINT ENERGY, INDIANA

Final Report

July 2025

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Transmittal/Professional Engineer Certification

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Section 1: Executive Summary

Section 1: Executive Summary

Purpose of Report

This Distribution System Long-Range Plan (LRP) provides guidance for CenterPoint Energy, Indiana (CenterPoint) system facility expansion and upgrades over a 20-year planning horizon. The system improvements recommended in the Preferred Expansion Plan were developed to prepare the CenterPoint electric system with the timely installation of facilities that support reliable and economic service to its customers now and in the future.

Sound system planning is essential to provide management with guidance such that new investment in electric system facilities is in step with load growth and revenue. The Preferred Expansion Plan should include the following to ensure interim changes and system additions will be compatible with the capacity level needs as system load growth occurs.

- Improvements in the quality of service to customers as opportunities materialize
- Expansion of the existing system far beyond the present design requirements
- Evaluation of new construction to meet the required capacity

Power Centric Solutions, an ENERCON Company (PCS) prepared this document with significant collaboration with CenterPoint stakeholders. Periodic reviews of the LRP are advised to adjust the recommendations contained herein considering actual system developments. Detailed system upgrades should be evaluated in each short-term Capital Improvement Pan (CIP) to align with the LRP goals.

Summary and Recommendations

The CenterPoint electric distribution system was analyzed to serve multiple forecast scenarios through 2043 based on the 2022-2023 Integrated Resource Plan (IRP) and system knowledge of CenterPoint stakeholders. Input from CenterPoint management and staff on known developments in the service area were also integrated into the LRP forecast. Projected system loads for the 20-year LRP period included system-wide impacts from:

- Distributed Energy Resources (DER) Penetration
- Electric Vehicle (EV) Charging Saturation
- Energy Efficiency (EE) Adoption

System analysis at existing and future loads for the LRP planning period included an evaluation of the impacts of the load projections on substation transformer capacity, feeder capacity, conductor capacity, voltage, and other criteria presented in **Section 2**. Based on the LRP analysis, a Preferred Expansion Plan was identified to include the following:

- Six (6) new substations identified in the LRP include Mt. Vernon, Old State Road, Orchid Street, Pelzer, Stacer, and Vogel Road, which may be renamed by CenterPoint
- Substation improvements, including transformer upgrades and additional transformers and feeder breakers at fourteen (14) existing sites
- New feeder ties and strengthening existing ties to enhance contingency operations and improve reliability
- Distribution upgrades and load transfers to relieve equipment loading and improve system voltage and performance
- Replacement of aging facilities to maintain reliable service to customers

A summary of the Preferred Expansion Plan is presented in **Section 4**, and details of each project are included in **Appendix B** with the proposed Load Level of construction for each forecast scenario. **Table 1.1** presents the estimated capital requirements for each forecast scenario in each of the first five Load Levels of the Preferred Expansion Plan. **Table 1.2** and **Figure 1.1** summarize the estimated capital requirements for each forecast scenario for Load Levels 1 - 20. Costs for new transmission facilities are not included.

Overall, the forecast scenarios do not make a dramatic impact on the total capital requirements for the 20-year planning period. The Energy Efficiency Adoption scenario provides the most cost savings over the Base Load Growth scenario by delaying projects outside of the 20-year LRP. In contrast, the EV Charging Saturation scenario has a minor impact on the Preferred Expansion Plan requiring some of the recommended improvements to be implemented sooner than the Base Load Growth scenario. With all of the forecast scenarios combined, the total capital requirements are distributed more evenly throughout the 20-year planning period.

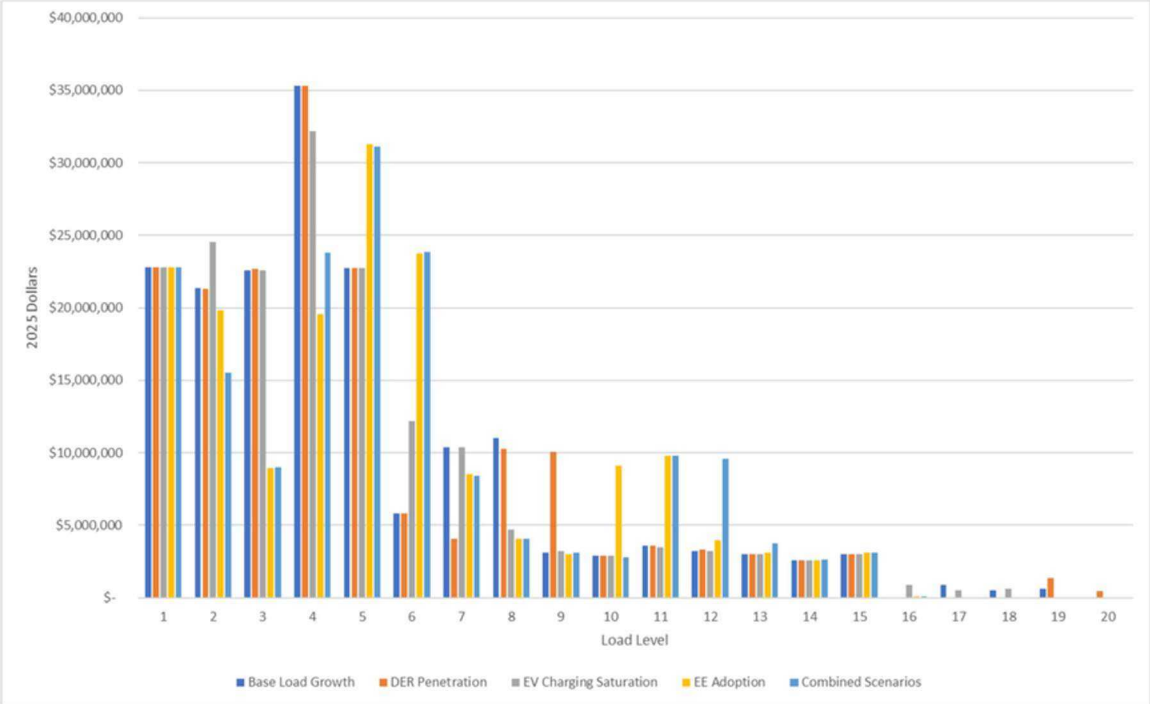
Table 1.1: 5-Year Capital Requirements Summary

Forecast Scenario	Load Levels ($2025)					Total Cost
	1	2	3	4	5	
Base Load Growth	$22,795,800	$21,371,600	$22,595,200	$35,329,700	$22,761,200	**$124,853,500**
DER Penetration	$22,795,800	$21,301,600	$22,665,200	$35,329,700	$22,761,200	**$124,853,500**
EV Charging Saturation	$22,795,800	$24,537,000	$22,575,200	$32,184,300	$22,761,200	**$124,853,500**
EE Adoption	$22,795,800	$19,819,300	$8,956,700	$19,574,200	$31,260,700	**$102,406,700**
Combined Scenarios	$22,795,800	$15,528,300	$9,016,700	$23,805,200	$31,112,400	**$102,258,400**

Table 1.2: 20-Year Capital Requirements Summary

Forecast Scenario	Load Levels ($2025)			Total Cost
	1-5	6-10	11-20	
Base Load Growth	$124,853,500	$33,241,600	$17,342,700	**$175,437,800**
DER Penetration	$124,853,500	$33,133,100	$17,263,600	**$175,250,200**
EV Charging Saturation	$124,853,500	$33,330,100	$17,254,200	**$175,437,800**
EE Adoption	$102,406,700	$48,406,100	$22,633,300	**$173,446,100**
Combined Scenarios	$102,258,400	$42,225,800	$28,961,900	**$173,446,100**

Figure 1.1: 20-Year Capital Requirements ($2025)



General Basis of Study

PCS has prepared this plan based on available information related to the performance and condition of the existing electric system, and assumptions of future loads and their impacts. PCS believes the recommendations contained herein are reasonable, considering the information provided by others and the analysis performed. However, future performance and the actual field condition of electric facilities may differ from those assumed, resulting in a variance in the projected outcomes and design/construction costs.

Section 2: Basis of Analysis & Planning Criteria

Section 2: Basis of Analysis & Planning Criteria

Introduction

This section contains the basis for evaluating CenterPoint's electric system performance at existing and projected peak loading conditions to determine where upgrades are required to maintain reasonable and reliable service to its customers. The supporting system information, engineering models, and condition of assets were provided by CenterPoint.

System Overview

CenterPoint provides service to approximately 150,000 electric customers located near Evansville, Indiana in all or parts of Posey, Vanderburgh, Warrick, Spencer, Gibson, Pike and Dubois counties. CenterPoint distributes power to its customers through (196) 12.47/7.2 kV and (7) 4.16/2.4 kV distribution circuits at (110) transformers at (74) substations with a total capacity of 2,559 MVA. CenterPoint constructs, owns, and operates the transmission lines and substations.

Forecasts

CenterPoint prepared their 2022-2023 IRP to determine the optimal resource mix to ensure the availability of low-cost power for its electric customers considering future risks as required by the Indiana Utility Regulatory Commission (IURC). The IRP projects demand and energy needs for the electric system through 2042, including area economics, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand, and customer adoption of solar and electric vehicles drivers.

Based on the IRP projections, recent growth rates experienced system-wide, and CenterPoint's knowledge of the service territory, an average annual growth rate of 1.5% was selected to represent demand growth for the Base forecast scenario for the 20-year LRP period. The following assumptions were used to develop the additional LRP forecast scenarios based on the findings presented in the IRP.

- **Base Forecast:** Average annual growth rate of 1.5%, initiating from the non-coincident substation summer peak in 2023 of 965.6 MW
- **DER Penetration:** Base Forecast - 1.5 MW/year
- **EV Charging Saturation:** Base Forecast + 1.0 MW/year
- **EE Adoption: -** 0.5% of the Base system forecast
- **Combined Scenarios:** Net of annual contribution for all scenarios

A total of (331) spot loads were identified by CenterPoint across the distribution system, adding an estimated 84.1 MW to the overall LRP forecast. **Table 2.1** provides a summary of the spot loads by category.

Table 2.1: Spot Load Summary

Load Category	Quantity	Total Diversified Load (MW)
Single-Family	2	10.62
Multi-Family	1	0.30
Commercial	15	16.23
Large Demand	1	2.00
Entertainment EV	3	1.62
Fleet EV	5	4.50
Gas Station EV	121	7.68
Grocery EV	24	10.80
Hotel EV	41	7.14
Restaurant EV	95	14.49
Retail Store EV	23	8.73
TOTALS	**331**	**84.11**

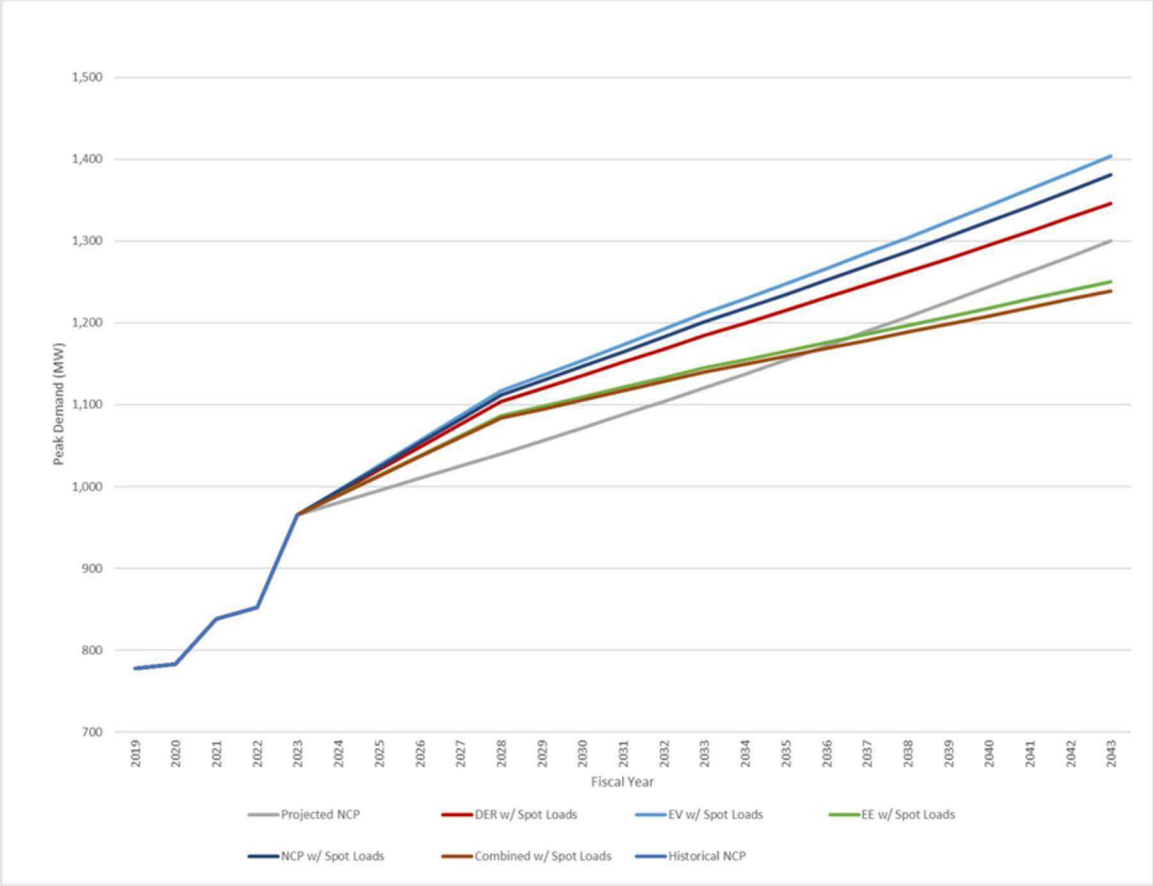
A uniform growth, or an Area Growth Rate of 1.0, is anticipated for each substation and feeder during the planning period, apart from the substations and feeders identified by CenterPoint and presented in **Table 2.2** below. The resulting non-coincident design load for the Base Forecast scenario of the LRP is 1,380.7 MW. Each of the LRP forecast scenarios are presented in **Appendix A**.

Table 2.2: Area Growth Exceptions

Load Category	Area Growth Factor
Anderson Rd Substation	5.0
Azteca - Azteca Milling Feeder	0.0
Deaconess Substation	0.0
Gateway Substation - T1	0.0
Mead Jo Park Substation - T1	0.0
Saint Mary's Substation	0.0
USI Substation - T1	0.0
VIP Substation - T1	0.0
Whirlpool Substation	0.0

The historical and projected system peak loads for each forecast scenario are presented in **Figure 2.1**. The load milestones represented in each year of the substation and feeder forecast are referred to as a Load Level (LL) to identify in-service targets of each recommended facility upgrade or improvement instead of specific years.

Figure 2.1: Historical & Projected System NCP



System Model

CYME version 8.2 r8 models for each substation and their respective distribution feeders were provided by CenterPoint, and version 9.0 r6 was used by PCS for the analysis presented herein. The CYME models included the substation transformers, voltage regulation devices and settings, overhead and underground lines, capacitors, protective devices and settings, service transformers, and customer elements. Prior to the LRP analysis, each substation CYME model was reviewed and compared to the substation one-line to identify missing or conflicting data. CenterPoint provided the missing data and provided guidance on data discrepancies. CYME version 9.0 r6 Load Allocation and Load Flow modules were used for the LRP analysis.

In preparation for the LRP analysis, PCS performed the following modifications to the CYME models provided by CenterPoint.

- Group spot load elements in the CYME model were based on transformer size and assigned power for each classification presented in **Table 2.3**.
- Loading data provided by CenterPoint for the summer 2023 peak were identified for each substation/transformer, feeder, and Primary Meter customers for load allocation based on the following:
    - **Feeders:** individual feeder peaks were allocated for each substation/transformer.
    - **Primary Meter Customers:** individually assigned based on the recorded coincident peak information provided by CenterPoint and the substation's configuration.
    - **Capacitors:** turned off during load allocation
- After the existing and project loads were allocated to the CYME model, LTCs and regulators were set to regulate at 126 V at the substation transformer, substation bus, or feeders depending on the substation configuration. Settings for voltage regulators on feeders outside of the substation were not adjusted.
- DER locations on the distribution system and rated output capacities were identified by CenterPoint. The existing DER was assumed to be at capacity during the system peak, and the accumulated DER capacity was added to the recorded peak for each feeder to determine the native load for load allocation. All DER in the CYME model was turned OFF for load allocation and turned ON for the load analysis summarized herein.

Table 2.3: CYME Spot Load Data

Spot Load Element Group	Group Transformer Size (kVA)	Group Power Factor (%)
Residential	≤ 75	95
Commercial	> 75 & ≤ 500	95
Industrial	> 500	90
Primary Meter	- [1]	90 [2]

1. Primary Meter spot load data was provided by CenterPoint and was specific to each customer.
2. A 90% power factor was assumed if not provided.

Planning & Operating Criteria

Table 2.4 presents the criteria used to assess the electric system's performance for the planning period.

Table 2.4: System Criteria

System Planning & Operating Criteria
Substations
Transformer Loading < 100% of top nameplate
Breaker Loading (2) Feeders/20 MVA transformer < 400 A
Breaker Loading (3) Feeders/20 MVA transformer < 300 A
Breaker Loading (4) Feeders/20 MVA transformer < 280 A
Voltage Regulation = 126 V (2 V bandwidth)[1]
Power Factor: 95% - 100% lagging
Feeders
Backbone Conductor Loading < 65% of rating
Large Lateral Conductor Loading < 90% of rating
Small Lateral Conductor Loading < 100% of rating
Voltage > 118 V and < 126 V (primary system)
Line Devices
Regulator Loading < 100% of rating
Regulator Voltage Regulation = 123 V (2 V bandwidth)[1]
Protective Device Loading < 100% of nameplate

Notes:
1. Line Drop Compensation is feeder dependent.

Environmentally Sensitive Areas

When distribution lines were assumed to be constructed or reconductored to a larger conductor size, existing distribution line routing was planned to be used where possible. Environmentally sensitive areas were considered in cases where new substation, transmission, or distribution lines were required. Such areas were avoided or locations/routes were selected to minimize the impact of the new construction.

Distribution Line Ratings

The conductor ratings from the CenterPoint CYME model of the distribution system are given in **Table 2.5**. Overhead and underground conductors loaded at or above the planning ratings were reviewed. If load cannot be transferred off the overloaded

conductor to an existing or proposed feeder, the line section was reconductored to a larger size per CenterPoint standard conductor sizes.

Table 2.5: Overhead and Underground Line Ratings

Conductor/Cable	Rating (Amps)	Planning Rating (Amps)
Overhead		
8 CU	96	96
6 CU	128	128
4 ACSR	140	140
4 CU	165	165
2 ACSR	180	180
3 CU	195	195
2 CU	225	225
1/0 ACSR	230	230
1/0 AAAC	256	256
1/0 CU	310	310
2/0 CU	360	360
3/0 ACSR	300	270
3/0 AAAC	342	308
336 AAC	513	333
355 ACAR	519	337
336 ACSR	530	345
636 AAC	765	497
Underground		
2 AL	118	118
1/0 AL	155	155
4/0 AL	225	203
350 CU	382	344
500 AL	373	242
500 CU	467	304
750 AL	462	300
750 CU	560	364
1000 CU	599	389

1) Based on ratings defined in the CYME model provided by CenterPoint.
2) Planning ratings are shown in **Table 2.4**.

Financial Criteria

Inflation

A general inflation rate is required to provide a common basis for developing projected costs of required system improvements throughout the LRP planning period. Based on discussions between the CenterPoint management and staff and PCS, a general inflation rate of 3% was used for the study period.

Distribution Line & Equipment Costs

The planning-level costs estimates presented in **Table 2.6** were provided by CenterPoint and were used to determine the cost of construction for each project in 2025 dollars. Project costs were escalated based on the proposed date of construction and the assume rate of inflation.

Table 2.6: Unit Construction Costs

Category	Unit Cost (2025 Dollars)
Substation	
138 kV - New (2) 20 MVA / (4) Feeder Substation	$11,400,000/ea.
69 kV - New (2) 20 MVA / (4) Feeder Substation	$9,700,000/ea.
138 kV - New (1) 20 MVA / (2) Feeder Substation	$7,800,000/ea.
69 kV - New (1) 20 MVA / (2) Feeder Substation	$6,800,000/ea.
138 kV - Add (1) 20 MVA / (2) Feeder Substation	$5,320,000/ea.
69 kV - Add (1) 20 MVA / (2) Feeder Substation	$5,950,000/ea.
Replace with (1) 20 MVA Transformer	$3,100,000/ea.
Replace with (1) 25 MVA Transformer	$2,200,000/ea.
Add (1) Feeder to Existing Substation	$1,400,000/ea.
Distribution Line	
1-ph 1/0 AAAC	$195,000/mi.
3-ph 1/0 AAAC	$280,000/mi.
3-ph 3/0 AAAC	$310,000/mi.
3-ph 336 AAC	$410,000/mi.
3-ph 336 AAC Double Circuit	$800,000/mi.
3-ph 636 AAC	$500,000/mi.
3-ph 636 AAC Double Circuit	$950,000/mi.

Category	Unit Cost (2025 Dollars)
1-ph 1/0 AL UG	$425,000/mi.
3-ph 1/0 AL UG	$520,000/mi.
3-ph 4/0 AL UG	$635,000/mi.
3-ph 500 MCM CU UG	$1,100,000/mi.
3-ph 750 MCM CU UG	$1,750,000/mi.
3-ph 1000 MCM CU UG	$3,000,000/mi.
Distribution Regulators	
(1) 1-ph 167 kVA (219 A)	$70,000/ea.
(3) 1-ph 167 kVA (219 A)	$130,000/ea.
(3) 1-ph 250 kVA (328 A)	$150,000/ea.
Relocate (1) Regulator Bank	$25,500/ea.
Remove (1) Regulator Bank	$16,000/ea.
Capacitors	
(1) 600 kVAR Bank	$55,000/ea.
(1) 900 kVAR Bank	$65,000/ea.
(1) 1200 kVAR Bank	$75,000/ea.
Distribution Devices	
(1) Overhead Gang Switch	$20,000/ea.

Adequacy of Data Provided

An up-to-date CYME model of the distribution system was provided by CenterPoint for the analysis detailed herein. Additional data including financial, operating, reliability, and measured and customer load data was also provided by CenterPoint and is accepted as accurate and sufficient to perform the study. Assumptions for this LRP were made in collaboration with PCS and CenterPoint and industry best practices.

Section 3: Analysis of Existing System

Summary of System Analysis

The projected LRP design loads shown in **Appendix A** were allocated in CYME model based on the existing system configuration of the CenterPoint distribution system. Load-flow results for each of the substations and distribution feeders were compared to the planning criteria presented in **Section 2**. A summary of the existing system analysis is detailed in this section.

Existing Substation Analysis

CenterPoint serves the existing distribution system from (110) transformers at (74) substations with a total capacity of 2,559 MVA; however, transformer capacity was limited to the top nameplate rating at 55 °C for the LRP. Substation transformers exceeding the planning capacity ratings at the LRP design loads are shown in **Table 3.1**. Based on the existing configuration and ratings of the substation facilities, the projected LRP design loads exceeded the planning capacity ratings of only (13) substation transformers. Additional details for the projected loading on each substation transformer are presented in the LRP load forecast in **Appendix A**.

Table 3.1: Substation Loading

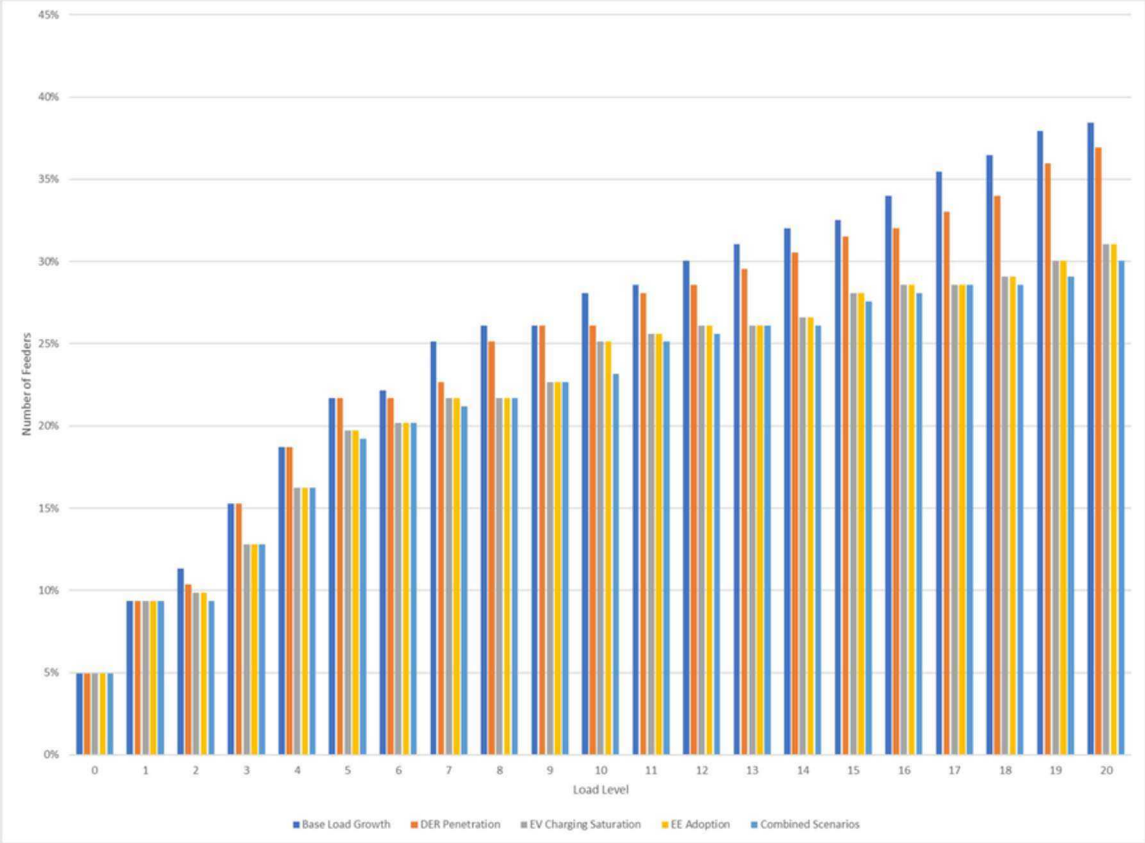
Substation Xfmr	LRP Cap. (MVA)	Exist. Load. (%)	Forecast Scenario LL20 Loading (%)				
			Base	DER	EV	EE	Comb.
Anderson Road	20.0	32.2%	160.5%	144.1%	172.3%	105.7%	101.7%
Azteca	20.0	83.5%	120.9%	118.0%	122.8%	109.9%	108.9%
Broadview T2	20.0	71.2%	102.1%	99.6%	103.7%	92.7%	91.9%
Devon T2	20.0	89.4%	127.5%	124.4%	129.5%	115.7%	114.6%
East Industrial T2	20.0	84.8%	121.5%	118.5%	123.4%	110.3%	109.3%
Libbert	20.0	64.5%	154.1%	151.8%	155.6%	145.6%	144.8%
Mohr Road	20.0	81.6%	111.2%	108.4%	113.1%	100.5%	99.5%
Oak Grove T1	20.0	61.1%	111.4%	109.3%	112.9%	103.4%	102.7%
Saint James	20.0	74.2%	112.7%	110.1%	114.4%	103.0%	102.1%
Southwind T1	20.0	77.6%	105.6%	102.9%	107.3%	95.3%	94.4%
Sunbeam T1	20.0	74.2%	101.2%	98.7%	102.9%	91.5%	90.6%
Tekoppel T2	20.0	74.5%	114.8%	112.2%	116.5%	105.0%	104.1%
Tepe Park	20.0	87.9%	121.2%	118.2%	123.2%	109.6%	108.6%

1) System changes can impact transformer loading for each forecast scenario and can be adjusted by CenterPoint.

Existing Circuit Analysis

The CenterPoint distribution system is served through (196) 12.47/7.2 kV and (7) 4.16/2.4 kV distribution circuits, and each was evaluated against the planning criteria described in **Section 2** at the projected loads for each load growth scenario. Based on the existing configuration and installed distribution facilities, the projected load for (78) feeders exceed the planning criteria in the Base Load Growth scenario, with only (61) feeders in the Combined scenario. **Figure 3.1** shows the percentage of CenterPoint's feeders that exceed planning capacity for each load growth scenario. Additional details for the projected loading on each distribution feeder are presented in the LRP load forecast in **Appendix A**.

Figure 3.1: Percentage of CenterPoint's Feeders Exceeding Planning Capacity



Section 4: Preferred Expansion Plan

Exploratory Plans

The purpose of this section is to describe the Preferred Expansion Plan jointly developed by CenterPoint and PCS to better serve the system's present load, the load as the system expands, and the LRP design loads selected. The recommended solutions were developed to address substation and distribution system deficiencies and reliability issues.

Plan Development

Alternatives were evaluated to serve the LRP design loads with the following considerations. Each exploratory plan identifies the major facilities and operating conditions required to provide a transition from the existing to the projected system LRP design loads to resolve the system deficiencies identified in **Section 3**.

- The existing substation locations with load transfers to reduce the overall loading on power transformers and distribution lines
- The existing substation locations, with distribution line and power transformer capacity upgrades
- New substation locations to serve projected load where the rated capacity of the existing substation was exceeded
- New distribution circuits to improve conductor loading and voltage on the system

Preferred Expansion Plan

Various alternative solutions were evaluated with CenterPoint to meet the future requirements. The recommendations are included in the Preferred Expansion Plan to resolve the system deficiencies identified in **Section 3**. Costs for new transmission facilities are not included.

Details of each project in the Preferred Expansion Plan are included in **Appendix B** with the proposed Load Level for construction based on the various load growth scenarios. **Table 4.1** presents the estimated capital requirements for each forecast scenario in each of the first five Load Levels of the Preferred Expansion Plan. **Table 4.2** and **Figure 4.1** summarize the estimated capital requirements for each forecast scenario for Load Levels 1 - 20. Costs for new transmission facilities are not included.

Overall, the forecast scenarios do not make a dramatic impact on the total capital requirements for the 20-year planning period. The Energy Efficiency Adoption scenario provides the most cost savings over the Base Load Growth scenario by delaying projects outside of the 20-year LRP. In contrast, the EV Charging Saturation scenario has a minor impact on the Preferred Expansion Plan requiring some of the recommended improvements to be implemented sooner than the Base Load Growth scenario. With all of the forecast scenarios combined, the total capital requirements are distributed more evenly throughout the 20-year planning period.

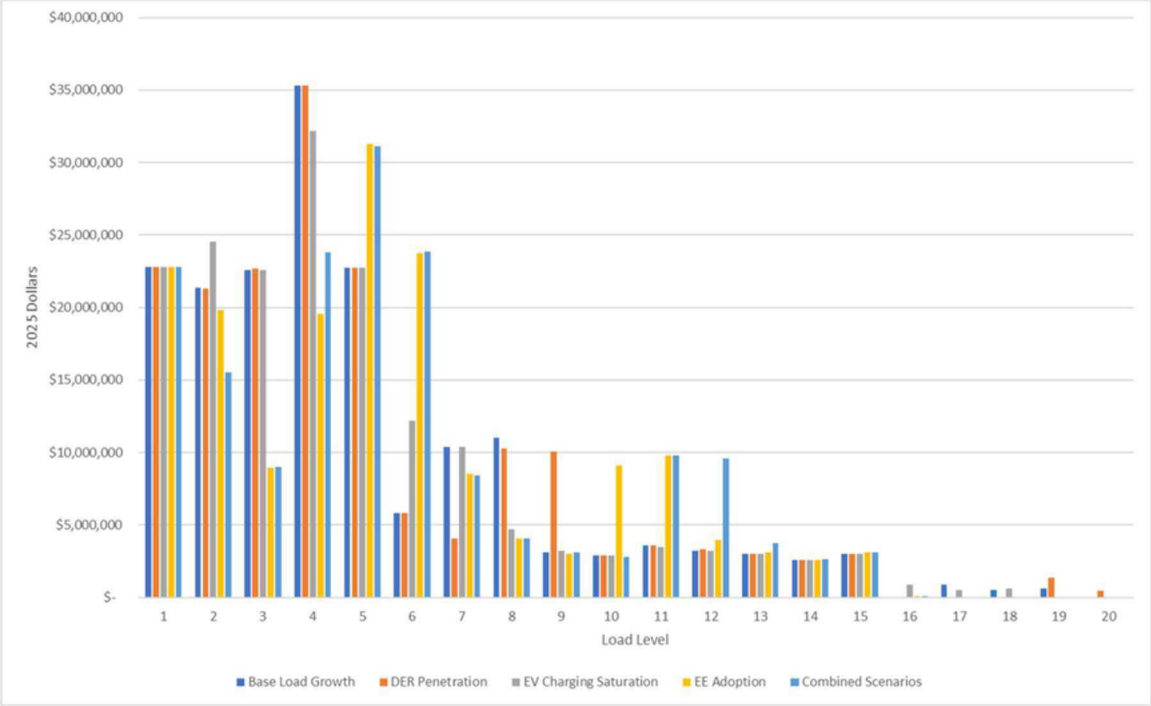
Table 4.1: 5-Year Capital Requirements Summary

Forecast Scenario	Load Levels ($2025)					Total Cost
	1	2	3	4	5	
Base Load Growth	$22,795,800	$21,371,600	$22,595,200	$35,329,700	$22,761,200	**$124,853,500**
DER Penetration	$22,795,800	$21,301,600	$22,665,200	$35,329,700	$22,761,200	**$124,853,500**
EV Charging Saturation	$22,795,800	$24,537,000	$22,575,200	$32,184,300	$22,761,200	**$124,853,500**
EE Adoption	$22,795,800	$19,819,300	$8,956,700	$19,574,200	$31,260,700	**$102,406,700**
Combined Scenarios	$22,795,800	$15,528,300	$9,016,700	$23,805,200	$31,112,400	**$102,258,400**

Table 4.2: 20-Year Capital Requirements Summary

Forecast Scenario	Load Levels ($2025)			Total Cost
	1-5	6-10	11-20	
Base Load Growth	$124,853,500	$33,241,600	$17,342,700	**$175,437,800**
DER Penetration	$124,853,500	$33,133,100	$17,263,600	**$175,250,200**
EV Charging Saturation	$124,853,500	$33,330,100	$17,254,200	**$175,437,800**
EE Adoption	$102,406,700	$48,406,100	$22,633,300	**$173,446,100**
Combined Scenarios	$102,258,400	$42,225,800	$28,961,900	**$173,446,100**

Figure 4.1: 20-Year Capital Requirements ($2025)



Details of the new substations are provided below and a summary of the recommended LRP improvements by project type is shown in **Table 4.3** for the Base Load Growth scenario only. Additional services for customers, security lights, service capacity increases, pole replacements, and retirements are not included.

Table 4.3: LRP Project Summary

Category	Quantity / Miles (Base Load Growth Scenario)		
	Load Level 5	Load Level 10	Load Level 20
New Substations[1]	6	6	6
New Substation Transformers	6	7	7
Substation Transformer Upgrades	2	2	2
New Feeders	15	17	17
Line Reconductor	42.9 mi.	80.11 mi.	101.58 mi.
New Line Construction	20.64 mi.	22.14 mi.	22.14 mi.
Double Circuit	0.05 mi.	0.05 mi.	0.05 mi.
Multi-Phase	15.1 mi.	21.31 mi.	59.29 mi.
Load Transfers	56	64	69

1) New greenfield substations.

Additional Considerations

The LRP Preferred Expansion Plan includes new distribution facilities and upgrades required to serve the projected loads based on the assumptions summarized in this report. Available N-1 contingencies were not evaluated; however, reserve capacities integrated within the planning criteria were assumed to provide sufficient system reliability under these conditions. Larger DER sites may also mask actual loading on the system during N-1 conditions.

In addition, the proposed locations for new substations were recommended based on the projected load centers on the distribution system, proximity to CenterPoint transmission, and land availability identified from aerial maps. Alternative sites for the proposed substations may be required or selected by CenterPoint, which may also impact the recommended switching for the proposed system configuration. Recommendations to reconfigure CenterPoint's existing Distribution Automation (DA) for the proposed system configuration were not included in the Plan.

Attachment 3.9 VEC-008 Electric Transmission Planning Criteria

CenterPoint Energy	TRANSMISSION PLANNING	Revision Number 26
VEC-008 Electric Transmission Planning Criteria		
This document is compliant with NERC Transmission Planning Standards		

Transmission Planning (TPL)

VEC-008 Control Document
Electric Transmission Planning Criteria

Reviewed and Approved By:

Ryan Snyder
Digitally signed by Ryan Snyder
Date: 2025.08.18 09:00:12 -05'00'

Ryan Snyder | Manager, Indiana Planning and Protection | Date

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Date: 2025.08.18 09:14:27 -05'00'

Raja Srivastava | Engineer, System Planning Engineer | Date

CenterPoint Energy	TRANSMISSION PLANNING	Revision Number 26
VEC-008 Electric Transmission Planning Criteria		
This document is compliant with NERC Transmission Planning Standards		

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CenterPoint Energy	TRANSMISSION PLANNING	Revision Number 26
VEC-008 Electric Transmission Planning Criteria		
This document is compliant with NERC Transmission Planning Standards		

1 Introduction

1.1 Purpose

Southern Indiana Gas & Electric Company (SIGE) continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of SIGE's planning process can be summarized as follows[1]:

a. Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels that meet our customers' needs during normal conditions and during a system contingency or set of contingencies
b. Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions
c. Analyzing the dynamic stability of the transmission system under various contingency conditions
d. Ensuring the fault current imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer
e. Optimizing a system configuration that minimizes capital and operating costs while maintaining reliability and providing a plan for system upgrades to meet performance requirements
f. Coordinating transmission planning activities in broader regional evaluations with the Midcontinent Independent System Operator (MISO), ReliabilityFirst (RF), and neighboring transmission owners
g. Performing an annual assessment of the electric transmission system over a ten-year planning horizon
h. Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria
i. Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth, and to address age and condition of existing facilities
j. Ensuring compliance with NERC Reliability Standards for Transmission Planning (applicable MOD and TPL standards)

Indiana Planning and Protection's transmission performance planning models include existing facilities at or above 69 kV, critical system conditions, and study years. Modeled Facilities may be uncommitted but should represent, at a minimum, required upgrades and could include optimistic planned facilities. The models may include distribution circuits and substations. The models will

[1] *For criteria or processes not specifically addressed VEC-008, SIGE follows the methodology outlined in MISO's BPM-020, Transmission Planning Business Practices Manual*

analyze More Probable, Less Probable and Extreme Contingency events. The studied time periods may be for near-term (1 to 5 years) or long-term (6 to 10 years) and for peak and off-peak demand periods; however, Indiana Planning and Protection could increase the planning horizon to include transmission or generation plans. Using these models, Indiana Planning and Protection may study system growth, generator interconnections, transmission interconnections, Load Serving Entity (LSE) interconnections, and other studies as needed.

1.2 Roles and Responsibilities

Indiana Planning and Protection's responsibilities include, but are not limited to, building steady state, short circuit, and dynamic models and simulations according to NERC Reliability Standard **MOD-032 Data for Power System Modeling and Analysis**, **VEC-014 Electric Generation and Transmission System Facility Ratings,** and **VEC-008**.

2 Electric Transmission Planning Procedure

2.1 Model Types

2.1.1 Steady-State Models

2.1.1.1 Operational Models (Current and Next Season)

Indiana Planning and Protection develops models to analyze switching procedures, planned transmission and generation outages, and contingencies for the current system configuration. These models are also used for optimizing the system operation and reducing losses. The models will be available and current for the upcoming season. These models will be analyzed with More Probable, Less Probable and Extreme Contingency events.

2.1.1.2 Model Development

The four critical elements that must be balanced in the model are: A) the load, B) the generation, C) the system voltage, and D) the net interchange. Indiana Planning and Protection tests each of these elements against the equipment ratings and connectivity.

a. Indiana Planning and Protection obtains the peak forecasted real and reactive load from SIGE's Integrated Resource Plan (IRP) as well as from other municipal and Local Balancing Areas' load forecasts for each modeled year. This load includes all transmission and distribution losses. The model load is reduced uniformly by the

calculated value of the transmission losses. Losses for the distribution system remain in the model load. Exceptions to this rule apply to identified non-conforming loads (e.g. Alcoa, SABIC, Toyota, Waupaca). The modeled load represents the expected steady-state behavior of loads that could impact the study area. Off-peak or seasonal loads are calculated based on the peak forecast load for that period.

The operational or AFC models define interruptible load but are not used for long-range planning. Interruptible load is not used because its long-term availability is uncertain.

b. Indiana Planning and Protection obtains the maximum available generation from the IRP. Generation resources (supply or demand side) are dispatched as required to meet the system load demand plus the system losses based on a merit order dispatch set by Power Supply.

   SIGE conducts sensitivity studies to represent market-based dispatch. The study determines if import capability is available in lieu of running peaking turbines and select generation outages. Off-peak model studies determine the amount of export capability.

   Upon request from a Load Serving Entity (LSE) or Distribution Provider (DP), SIGE studies Capacity Benefit Margin (CBM). Automatic Reserve Sharing (ARS) provides the capacity for the short term and MISO controls the generation dispatch. Studies for ARS are not normally conducted unless specifically requested.

c. Indiana Planning and Protection typically set the bus voltages at generation plants to operate at or near 1.05 per unit of nominal voltage. The generator terminal voltages on the high end and the auxiliary bus voltages on the low end usually limit the plant bus voltages.

d. Indiana Planning and Protection also includes long-term committed power transfers, as needed, and coordinates with the interchanging party. Contingency analysis may require model imports of an additional 300MW for an outage of the largest generating unit or 570MW for the two largest generating units. Imports may also be used for additional capacity and reserves during peak load. No generating unit is modeled above its rated capacity. To determine the maximum import and export capability of the transmission

system, Indiana Planning and Protection could conduct additional studies by adjusting the generation.

e. Indiana Planning and Protection includes Alcoa Warrick Operations' (Warrick) significant generation and load in the SIGE Control Area of the MISO and RF models.

f. Models include all reactive resources as applicable (generators, capacitors, etc.).

g. Indiana Planning and Protection's models include, at a minimum, planned outages of six months or more of SIGE's bulk electric equipment for the demand levels and time periods studied.

h. Models include applicable Facility Ratings of all facilities. Indiana Planning and Protection defines ratings in **VEC-014 Transmission and Generation System Facility Ratings**.

i. Developed sensitivity case(s) demonstrate the impact of changes to the basic assumptions used in the model. The Planning Assessment's sensitivity analysis must sufficiently stress the system within a range of credible conditions that demonstrate a measurable change in the system's response by varying one or more of the following conditions:

   i. Real and reactive forecasted Load
   ii. Expected transfers
   iii. Expected in service dates of new or modified Transmission Facilities
   iv. Reactive resource capability
   v. Generation additions, retirements, or other dispatch scenarios
   vi. Controllable Loads and Demand Side Management
   vii. Duration or timing of known Transmission outages

j. The automatic operation of load tap changing (LTC) transformers and switched capacitors reflect an optimized base case model.

2.1.1.3 Contingencies

Indiana Planning and Protection models the entire SIGE system and the facilities three buses, at a minimum, into neighboring control areas for the selected steady-state contingencies. Single contingencies include all facilities at or above 69kV. Double contingencies include facilities at 100kV or above internal to SIGE. Select 69kV facilities may be included for sensitivity studies.

Models include special contingencies in the appropriate severity category to model the effects of existing and planned protection systems and control devices (including any backup or redundant systems). Indiana Planning and Protection also models any concerns or conditions identified by Transmission System Operations (TSO). The effects of existing and planned protection systems to be studied include:

- Removing all elements protected by the protection system
- Tripping generators when the generator bus voltage (or high side of the GSU bus voltage) is less than the known or assumed generator steady state voltage limit (or voltage ride-through capability)
- Tripping appropriate elements when relay loadability limits are exceeded
- Successful and unsuccessful high speed reclosing (in instances where high speed reclosing is used)
- Tripping of transmission elements when transient swings causes protection system operation based on generic relay models
- Any other effects as deemed appropriate by SIGE's Indiana Planning and Protection

During the contingency analysis simulations, the models are solved allowing the automatic operation of load tap changing (LTC) transformers. The operation of the switched capacitors on SIGE's system is a manual process; therefore, the automatic operation of the switched capacitors is disabled during the simulation solution.

SIGE tests the following types of contingencies on SIGE's transmission system per the NERC TPL requirements:

No Contingencies:

a. Normal system conditions per NERC Category P0 as identified in **Table 1**.

More Probable Contingencies:

a. Sudden outage of any transmission facility (circuit, transformer, generator, etc.) for normal system configuration per NERC Category P1 and P2 in **Table 1**.

Less Probable Contingencies:

a. Sudden outage of multiple transmission facilities (circuit, transformer, generator, etc.) while the transmission system is reconfigured for any other generator rated 200 MVA or more out of service.

b. Additional NERC Category P3 through P7 contingencies as described on the table found in **Table 1**.

Extreme Contingencies:
SIGE's extreme contingencies are expected to be caused by a tornado, earthquake, ice storm, or other catastrophic event. Mitigation measures to reduce the possibility of an extreme contingency at a substation may include the following: redesign, modifications to substations, the use of ring busses, breaker-and-a-half busses, or primary and secondary alternate busses.

Extreme Contingencies include:
a. Outage of a bus and any associated transformers at any substation with three or more lines at 100 kV or above.
b. Additional NERC Extreme Events contingencies as described in **Table 1**.

2.1.1.4 Performance

Acceptable operating performance for the above contingencies is as follows:

For No Contingencies:
The system is stable and all facility loadings are within normal ratings and all bus voltages are within normal limits.

For More Probable Contingencies:
Before any operator directed system adjustments are made but after a sudden outage, the system is stable and all facility loadings are within normal ratings and all bus voltages are within normal limits (161kV within emergency limits). Any loss of radial load is restored through routine operator directed switching procedures, if possible.

Normal bus voltage limits are 0.95 and 1.05 per unit. The post contingency maximum voltage deviation allowed is 0.20 per unit.

Emergency bus voltage limits are 0.90 and 1.05 per unit. The post contingency maximum voltage deviation allowed is 0.20 per unit.

Non-consequential load loss and interruption of firm transmission services are not acceptable.

For Less Probable Contingencies:
Before any operator directed system adjustments are made after a sudden outage, the system is stable and facility loadings are within Emergency ratings and bus voltages are within Emergency limits. Any loss of load is restored through routine operator directed switching procedures, if possible.

Emergency bus voltage limits are 0.90 and 1.05 per unit. The post contingency maximum voltage deviation allowed is 0.20 per unit.

Non-consequential load loss and interruption of firm transmission services are not acceptable.

For Extreme Contingencies:
After a sudden multiple event outage, the remaining system is stable without voltage collapse or loss of system integrity. SIGE's system may contain an Island, or be an Island itself to protect the Bulk Electric System.

Extreme contingencies are used to ensure regional system stability, to identify SIGE's system weaknesses, and to develop system restoration procedures. SIGE does not design the system to completely eliminate the effects of an extreme contingency but analyzes extreme contingencies to minimize both the probability of occurrence and the resulting impact.

2.1.2 Dynamics Models

2.1.2.1 Model Development

Dynamics models use the Steady-State models as described in Section 2.1.2.2 for the base topology. Indiana Planning and Protection annually develops dynamics models to include a range of system conditions, load levels, and years as deemed appropriate. The models may include Peak and Off-Peak load scenarios for both Near-Term and Long-Term, as well as sensitivity cases as needed. Dynamics models use the following data and methods.

a. The base Dynamics model includes model types for the generator, governor, exciter, stabilizer (where applicable), and compensator (where applicable). Indiana Planning and Protection populates these devices with the data provided by the Generator Owner from the MOD-032 data submission.

b. In the Steady-State data portion of the PSS/E model (the "Network Data"), enter the Source Impedance of each machine. Indiana Planning and Protection reviews the Source Impedance data for the Dynamics/Transient analysis; it is not used for Steady-State analysis. The Source Impedance ("Xsource") is equivalent to the X"d value in the generator device model for all model types currently used in SIGE's control area.

c. Before the Steady-State model can be used with the Dynamics model, the following adjustments must be made (in the order listed):
   i. The loads and generators must be converted from Constant Power values to Constant Impedance or Current values. This is accomplished through the "CONG/CONL" function in PSS/e (under the "Power Flow" tab). This conversion is necessary due to the extreme voltage swings and fault currents present in Dynamics studies causing Constant Power parameters to produce unrealistic solution values. SIGE converts the generators by utilizing the "ZSORCE" solution option. Typically, SIGE uses a generic and conservative allocation for load conversion of 100% Constant Current for active power (MW) and 100% Constant Impedance/Admittance for reactive power (MVAR). These percentages can vary depending on the type of load, and different values may be used for certain studies.
   ii. The network admittance matrix in PSS/e must be optimally ordered for the solution algorithm to solve properly. This is achieved by utilizing the "ORDR" function in PSS/e (under the "Power Flow >> Solution" tab). There are two options provided by PSS/e for this step, ignore out of service branches or assume all branches are in-service. SIGE uses the "assume all branches are in-service" methodology.
   iii. Once ordered, the network admittance matrix must be factorized. This is another step needed for the PSS/e solution algorithm to function properly by triangularizing the matrix and is performed by utilizing the "FACT" function in PSS/e (under the "Power Flow >> Solution" tab).
   iv. Solve the model by utilizing the Solution for Switching Studies ("TYSL") function in PSS/e (under the "Power Flow >> Solution" tab). This solution method determines instantaneous changes in network voltages as a switching operation occurs, which allows the Steady-State model to solve properly once dynamic disturbances are introduced. There are two solution options provided by PSS/e for this function, flat start or to use

voltage vectors as the starting point. SIGE uses the voltage vectors as the starting point, but flat start could be used if the model is not reaching a valid solution due to voltage deviations.

d. Add Distance Relay models in the "Protection Models" tab in PSS/e and compare the data to the ASPEN Relay Database. SIGE currently uses the generic Distance Relay model "DISTR1".

e. The final model type added is the Dynamic Load Model. SIGE uses the "CLOD" generic complex load model and applies this model on the Bus level. Each load has a CLOD model added through the "Load – Bus" tab in PSS/E. The CLOD model includes the behavior of induction motor loads. Indiana Planning and Protection classifies each load as either Residential, Commercial, or Industrial based on the dominant customer type of the load. The data for each of these load types is as follows:

Residential	
0	% Large Motor (industrial/large commercial)
85	% Small Motor (residential/small commercial)
3	% Transformer Exciting Current (losses)
0	% Discharge Lighting (fluorescent lighting)
12	% Constant Power (power electronics)
1	Kp
0	Branch R
0	Branch X

Commercial	
10	% Large Motor (industrial/large commercial)
75	% Small Motor (residential/small commercial)
3	% Transformer Exciting Current (losses)
0	% Discharge Lighting (fluorescent lighting)
12	% Constant Power (electronics)
1	Kp
0	Branch R
0	Branch X

Industrial	
75	% Large Motor (industrial/large commercial)
15	% Small Motor (residential/small commercial)
0	% Transformer Exciting Current (losses)
0	% Discharge Lighting (fluorescent lighting)

10	% Constant Power (power electronics)
1	Kp
0	Branch R
0	Branch X

2.1.2.2 Contingencies (Faults)

Indiana Planning and Protection selects close-in faults at all in-service power plants for dynamics contingencies. Indiana Planning and Protection uses the contingencies that produced the most severe system impacts in the previous Dynamics study if no material generation changes were made to SIGE's and the surrounding system.

The monitored elements include all of the differing generators in SIGE's control area (if two units are the same, i.e., the Cannelton Hydro units, then only one needs to be monitored) and select nearby units in the neighboring control areas. For each of these generating units, set up Channels in PSS/E to monitor the Machine Angle, Terminal Voltage, Bus Voltage, Machine Speed, and Bus Frequency. Add other channels if deemed necessary.

Studied contingencies include the effects of existing and planned Protection Systems or other automatic controls. The effects of existing and planned protection systems to be studied include:

a. Removal of all elements outaged by that protection system
b. Tripping of generators when the generator bus voltage (or high side of the GSU bus voltage) is less than the known or assumed generator steady state voltage limit (or voltage ride-through capability)
c. Tripping of all appropriate elements when relay loadability limits are exceeded
d. Successful and unsuccessful high speed reclosing (in instances where high speed reclosing is used)
e. Tripping of transmission elements when transient swings cause protection system operation based on generic relay models
f. Any other effects as deemed appropriate by SIGE's Indiana Planning and Protection

Contingencies are included that simulate the expected automatic operation of existing and planned devices designed to provide dynamic control, including exciters.

For the purpose of evaluating the transmission system, the following contingency events are tested per the NERC TPL requirements:

More Probable Contingencies:

a. Sudden outage of any transmission facility (circuit, transformer, generator, shunt device, breaker, or bus section) for normal system configuration per NERC Category P1 and P2 in **Table 1**.

Less Probable Contingencies:

a. Sudden outage of any transmission facility (circuit, transformer, generator, or shunt device) followed by the loss of another transmission facility, a stuck breaker, or relay failure.
b. Additional NERC Category P3 through P7 contingencies as described in **Table 1**.

Extreme Contingencies:

SIGE's extreme contingencies are expected to be caused by a tornado, earthquake, ice storm, or other catastrophic event. Mitigation measures to reduce the possibility of an extreme contingency at a substation may include the following: redesign, modifications to substations, use of ring busses, breaker-and-a-half busses, or primary and secondary alternate busses.

Extreme Contingencies include:

a. Outage of a bus and any associated transformers at any substation with three or more lines at 100 kV or above.
b. Additional NERC Extreme Events contingencies as described in Table 1.

2.1.2.3 Performance

The performance of Dynamics models is measured by the system's ability to remain stable and meet transient voltage response criteria after a contingent event. Indiana Planning and Protection monitors machine angle, terminal voltage, bus voltage, machine speed, and bus frequency to ensure acceptable performance. SIGE uses a Transient Voltage Recovery (TVR) methodology that coincides with MISO's TVR methodology as its voltage response criteria. The TVR limits and generator ride-through capability are listed in the below tables.

Generator Low Voltage Ride-Through Capability	
0.00 to 0.15 seconds	0.00 p.u.
0.15 to 0.30 seconds	0.45 p.u.
0.30 to 2.00 seconds	0.65 p.u
2.00 to 3.00 seconds	0.75 p.u.
Beyond 2.00 seconds	0.90 p.u.

Generator High Voltage Ride-Through Capability	
0.00 to 0.20 seconds	1.200 p.u.
0.20 to 0.50 seconds	1.175 p.u.
0.50 to 1.00 seconds	1.150 p.u.
Beyond 1.00 seconds	1.100 p.u.

Load Bus Low Voltage Recovery Limits	
Within 1.00 to 5.00 seconds after fault clearing	0.70 p.u.
Beyond 5.00 seconds after fault clearing	0.90 p.u.

In addition to the transient voltage response, system stability must be maintained. System stability is determined by ensuring that the monitored channels exhibit acceptable damping of all power oscillations. SIGE adheres to MISO's criteria for acceptable damping by utilizing the same damping ratio of 0.03. This damping ratio corresponds in the time domain as a reduction in oscillation magnitude of 17.2% for the first peak, or 53% over four periods of oscillation.

In addition to the criteria stated above, no generating unit shall pull out of synchronism for NERC Category P1 events. For NERC Category P2 through P7 events, when a generator pulls out of synchronism, the resulting impedance swings shall not result in the tripping of any system elements other than the generating unit and it's directly connected facilities. A generator being disconnected from the system by fault clearing action is not considered pulling out of synchronism.

2.1.3 Short Circuit Models

2.1.3.1 Model Development

Indiana Planning and Protection develops and maintains a base case system model in ASPEN OneLiner to include current system conditions. The base case model includes existing system facilities at or above 69

kV, and also includes some distribution circuits and facilities. Facilities modeled include lines, buses, generators and transformers. System protection devices including ground and phase overcurrent relays, ground and phase distance relays, fuses and reclosers are modeled.

The base case model can be used to study planned system changes prior to implementation. The base case model is used to study the impact of system growth, generator interconnections, transmission interconnections, and other studies as needed.

Study case models are developed as needed to represent proposed upgrades of planned facilities. The study case models are developed to consider future additions of long-term transmission and/or generation.

The required modeling data for all impedance based assets includes:

a. Positive Sequence R and X
b. Zero Sequence R and X
c. Mutual Coupling Line Impedance
d. Transformer Winding Connections, impedances and ratings
e. Auxiliary transformers / equipment connected at the tertiary (i.e. grounding transformers, series reactors, etc.)
f. Normally open (NO)/normally closed (NC) switches and line configuration
g. Equipment MVA ratings
h. Transmission line data
    i. Length in miles
i. Generator impedance data
    i. Transient reactance
    ii. Sub-transient reactance
    iii. Synchronous reactance

Indiana Planning and Protection coordinates modeling parameters for interconnections with neighboring utilities to ensure accurate representations of facilities and equipment. A review is completed for the short circuit model as changes occur to generation and transmission (69kV and above), including changes to generators, transformers, transmission lines, and other impedance based assets.

High Voltage Engineering and Power Supply collaborate with Indiana Planning and Protection to ensure the accurate and timely updates to the ASPEN base case model. Other base case model reviews occur on an as needed basis. As system changes occur, the

base case ASPEN model is update when the equipment is placed in-service.

Annually or as needed, System Protection coordinates or exchanges system short circuit data (Aspen OneLiner model preferred) with neighboring entities. The entities SIGE coordinates with are LGE, HE, BREC, IPL, DEI, AMP Ohio (Cannelton Hydro), and ALCOA Warrick.

When System Planning makes edits/changes to the base case model, a list of as-found and as-left data of the affected element(s) should be provided to System Protection.

The ASPEN OneLiner short circuit model is only accessible by the assigned personnel within the System Relay Protection group and Electric System Planning group. A revision log is used to capture the base case updates.

2.1.3.2 Calculation of Fault Currents

SIGE calculates the fault currents by using the Fault Summary module within the ASPEN OneLiner short circuit model. For all selected facilities within the model, ASPEN OneLiner simulates the classical fault types: three line to ground (3LG), two-line to ground (2LG), single line to ground (1LG), and line to line (LL). The program generates a spreadsheet containing the fault current values for each of the line to ground and line to line faults (3LG, 2LG, 1LG and LL faults) for every selected facility within the model. The magnitude of the simulated fault currents are displayed for every modeled bus in the spreadsheet.

2.1.3.3 Performance

Indiana Planning and Protection annually conducts short circuit analysis as a part of MISO's MTEP process. Indiana Planning and Protection validates previous short circuit analysis corrective action plans and updates the implementation status, if needed.

Short circuit studies are performed to determine if the transmission circuit breakers have sufficient interrupting capability. Studies are performed by using the latest ASPEN OneLiner short circuit model, with all known planned generation and transmission facilities in-service which could impact the system, to calculate the maximum fault current at each transmission bus.

Indiana Planning and Protection completes a screening process by comparing the substation-specific bus fault data against the circuit breaker nameplate interrupting current capability. SIGE's Electric Engineering department maintains the master listing of breaker nameplate data, which includes the interrupting current capability. If the fault current is greater than 80% of a breaker's rated interrupting current capability, that breaker is further analyzed.

For the breakers requiring further analysis, Indiana Planning and Protection applies the K factor to all circuit breakers and fast reclosing deration to oil circuit breakers. The manufacturer provides data for the K factor. The breaker interrupting current capability will be increased by applying the K factor if the operating voltage of the breaker is less than the maximum rated voltage. For example, if a 138 kV breaker is rated for 145 kV, the nameplate interrupting current capability is multiplied by the K Factor to account for the difference in operating voltage. The IEEE standard C37.04-2018 circuit breaker design interrupting current capability criteria provides application guidelines for circuit breaker K factors.

In addition to applying K factor, a breaker interrupting capability derating for oil circuit breakers is applied for any reclosing operation that occurs in less than 15 seconds after the preceding interruption. If the fault current remains above 80% of the rating after applying the K factor and the reclosing derating, additional breaker analysis is performed per the specific bus configurations (either straight, ring or breaker and half bus) to determine the individual breaker's fault current. The fault current will be less than or equal to the value in the initial analysis as the current is distributed between the breakers at the bus.

For identified deficiencies in the short circuit interrupting duty, Indiana Planning and Protection recommends a corrective action plan. For fault currents greater than 90% of the rating, Indiana Planning and Protection recommends replacement of the breaker within Energy Delivery's five-year budget plan. Indiana Planning and Protection recommends replacement as soon as practical for fault currents greater than 100% of rating.

2.1.4 Transfer Study Models

2.1.4.1 Model Development

Models will be developed for transfer capability studies, including Total Transfer Capability, Incremental Transfer Capability, First Contingent Incremental Transfer Capability, the Available Flowgate Capability (AFC) of facilities, and impacts of both Firm and Non-Firm transmission service requests. These study-specific models are to be developed in the same manner as the Steady State models as described in Section 2.1.1. The Steady State models are then updated with a generation dispatch and load level that reflects the transfer study being analyzed. All committed facilities will be included for study periods in the future. Uncommitted facilities will not be included.

Upon request, SIGE will provide flowgates to Transmission Service Providers that work within SIGE's Transmission Planning Area and to adjacent Transmission Planners.

2.1.4.2 Contingencies

Indiana Planning and Protection uses a contingency list composed of all 100 kV and above transmission lines and transformers in SIGE's control area and those facilities three buses into our neighboring systems. Other contingencies can be analyzed as needed based on the specifics of the transfer study being conducted.

Analysis is performed on the model under normal conditions (NERC Category P0) and contingent conditions per the selected contingency list (NERC Category P1) as described in Table 1.

2.1.4.3 Performance

Transmission Interchange Limits Calculation (TLTG) analysis is performed in PSS/E to determine the transfer capability. A distribution factor data file is created utilizing specified SUB, MON, and CON files. The amount of generation to import/export is set in the "study system generation shift" field. A "maximum import/export" value is also identified, which is extrapolated linearly from the actual import/export transfer value set in the study system generation shift field by PSS/E. The intent of the maximum import/export value is to highlight facilities that may be approaching the actual transfer limit, but not surpassing it. A "study system" (the exporting system) and an "opposing system" (the importing system) are also selected. The list of study and opposing systems is prepopulated from the SUB file used for the study, with the

requirement that each identified system must include at least one generator. Default values are typically used for the remaining options and study parameter fields but can be changed if needed depending on the study.

The study results include every limiting facility, for both normal and first contingent scenarios as determined by the CON file, up to the identified "maximum import/export" value. The results also report the limiting facility's distribution factor. The distribution factor is the percentage of the transfer in which that facility participated.

Facilities identified as normal or first contingent limits for maximum transfers of 10,000 MW and have a distribution factor of 5% or greater are submitted as flowgates to MISO by Indiana Planning and Protection. See the MISO Regional Transmission Organization (RTO) Reliability Plan.

2.1.5 SOL and IROL Determination

All components of the BES facilities have a thermal and voltage rating. In addition to these ratings, Indiana Planning and Protection, conjunction with MISO's MTEP process, studies the system to determine if any additional voltage or power stability issues could further limit the system. The studies include the following criteria: facility thermal ratings, transient stability ratings, voltage stability ratings, and system voltage limits. System Operating Limits (SOLs) will be developed to operate facilities within these ratings.

MISO has determined that SIGE does not have any IROLs. SIGE also reviews system studies for potential IROLs through cascading analysis. If a contingency occurs that results in a facility over 125% of its emergency rating, or less than 90% voltage PU for generating facility, that facility will be outaged. The simulation will be solved and again any facilities over 125% of its emergency rating, or under 90% voltage PU for a generating facility, will be outaged. Cascading occurs when more than two facilities, in a series, are outaged using this process. The review continues until no facilities exceed the identified thresholds. This determines the extent of cascading.

If cascading occurs, Indiana Planning and Protection develops an IROL for the initiating facility. Indiana Planning and Protection coordinates IROLs with MISO and other impacted systems.

2.2 Study Results

The study results document all assumptions made during the analysis, including the rationale behind the model system conditions and year selection, and provide a summary of all contingencies studied and the level of performance indicated by the model. The study results include a reactive power resources review to indicate that adequate reactive resources are available to meet system performance. If reactive resources are found to be inadequate, a recommended plan will be provided.

If the performance of the system does not meet requirements throughout the planning horizons, a recommended corrective action plan including any system upgrades will be provided. The written corrective action plan will include a schedule for implementation with required in-service dates of facilities and with consideration for expected lead times for equipment delivery and construction timelines. Corrective action plans are not necessarily created to address deficiencies observed in a single sensitivity study, however they are created if the same deficiency is identified in multiple sensitivity studies throughout the assessment. These corrective action plans are reviewed in subsequent planning assessments for continued validity and implementation status. In instances where simulations were not performed due to lack of system changes, studies from past years are assessed to support the current planning assessment, given that they are less than 5 calendar years old.

If the system fails to meet the steady-state or stability performance requirements described in Sections **2.1.1.4 Steady-State Model, Performance** and **2.1.2.3 Dynamics Model, Performance**, the deficiencies are documented and addressed in corrective action plans. These corrective action plans are reviewed in subsequent planning assessments for continued validity and implementation status.

The short circuit portion of the analysis is used to determine whether circuit breakers have adequate interrupting capability for faults that they will be expected to interrupt. Any instance where a breaker's interrupting capability is found to be inadequate is documented in the corrective action plan along with the actions needed to achieve the required system performance. These corrective action plans are reviewed in subsequent planning assessments for continued validity and implementation status.

The study results and corrective action plans are documented and provided to SIGE's Reliability Coordinator (RC), Transmission Service Provider (TSP) and Transmission Planning Coordinator (PC) as requested. SIGE's RC, TSP, and PC are MISO. Any resulting projects from a corrective action plan are submitted through the MISO Model Manager (MAGE) and Model on Demand for inclusion in the **MISO Transmission Expansion Plan (MTEP)**. The MTEP is posted publicly and provided annually to the RRO. SIGE also provides the study results to RF upon request subject to confidentiality requirements.

The study results and corrective action plans are also provided to TSO on a timely basis for their review and inclusion into the planning process for reliable operation of the transmission system during the study period.

3 Risk Assessment for Instability, Uncontrolled Separation, or Cascading

In order to determine if an event leads to cascading, uncontrolled separation or instability within the Interconnection, an iterative approach is necessary. Each iteration of the process will combine dynamic stability analysis as the first step and steady state analysis as the second step to evaluate the full impact of the simulated event. The first iteration will include evaluating the event in both the dynamic stability and steady state analysis. In instances of violations with steady state criteria as defined in this document, another iteration of analysis will be required. The procedure is defined in further detail below.

3.1 Step 1: Dynamic Stability Analysis

To evaluate the response of the system to the defined event in the transient time frame, dynamic stability simulations will be performed. In the first iteration, a 3-phase (3PH) bus fault at the high-side voltage of the substation will be applied at the defined facility and the fault will be cleared at each connected transmission facility based on the corresponding clearing time. For any subsequent iteration(s), facilities will be tripped offline under a no-fault condition as identified in the steady state results.

For dynamic stability analysis, the following generator and system parameters will be monitored and reviewed for acceptable responses:

a. ANGLE: Machine relative rotor angle
b. SPD: Machine rotor speed
c. ETRM: Machine terminal voltage
d. POWR: Machine electrical power
e. VARS: Machine reactive power
f. VOLT: Voltage at key system buses
g. FLOW: P and Q flow for key lines
h. FREQ: Frequency at key system buses

Each of the parameters are observed for a minimum of twenty seconds, which includes the application and clearing of the defined fault. The monitored parameters will be evaluated for generator angular stability, generator frequency and voltage ride-through capability, load bus voltage recovery capability, and oscillation damping as outlined below.

Monitored generators will be evaluated for angular stability with reference to a large remote generator to the event simulated. Any monitored generator rotor angle that exceeds 180 degrees to the reference generator will be defined as an unstable

response, resulting in the monitored generator being tripped offline based on available protection system information.

Generator frequency and voltage ride-through capability are within the following criteria as defined in Attachments 1 and 2, respectively, of the **PRC-024 NERC Reliability Standard**:

Generator High Frequency Ride-Through Capability	
Frequency Range (Hz)	**Time Duration (sec)**
≥61.8	Instantaneous Trip
≥60.5	$10^{(90.935-1.45713*f)}$
<60.5	Continuous Operation

Generator Low Frequency Ride-Through Capability	
Frequency Range (Hz)	**Time Duration (sec)**
≤57.8	Instantaneous Trip
≤59.5	$10^{(1.7373*f-100.116)}$
>59.5	Continuous Operation

Generator High Voltage Ride-Through Capability	
Voltage Range (p.u.)	**Time Duration (sec)**
≥1.20	Instantaneous Trip
≥1.175	0.20
≥1.15	0.50
≥1.10	1.00
<1.10	4.00

Generator Low Voltage Ride-Through Capability	
Voltage Range (p.u.)	**Time Duration (sec)**
<0.45	0.15
<0.65	0.30
<0.75	2.00
<0.90	3.00
≥0.90	4.00

Any monitored generator exceeding the frequency or voltage ride-through capability will be defined as an unacceptable response, resulting in the monitored generator being tripped offline based on available protection system information.

Voltage recovery at select monitored load buses will be evaluated against the following criteria as defined in MISO's **MTEP Reliability Planning Methodology**:

Load Bus Low-Voltage Recovery Limits	
Voltage Range (p.u.)	**Time Duration (sec)**
0.00-0.70 p.u	0.00 to 2.00 seconds
> 0.70 p.u.	2.00 to 20.0 seconds
> 0.90 p.u.	Beyond 20.0 seconds

Any monitored load bus exceeding the low-voltage recovery limits will be defined as an unacceptable response, resulting in the load at the monitored bus being tripped offline based on available protection system information.

Should the generator parameters from the event analyzed result in an oscillatory response, then the parameters will be evaluated against a damping ratio of 0.03. This damping ratio corresponds in the time domain as a reduction in oscillation magnitude of 17.2% for the first peak, or 53% over four periods of oscillation. Any generator parameter that does not meet an acceptable response (loss of synchronism) will be tripped offline based on available protection system information.

3.2 Step 2: Steady State Analysis

Once the defined event has been initially simulated in the transient timeframe, steady state analysis will be performed through power flow simulations. The defined event will be modified in the power flow analysis to include the generator outages and load shed resulting from the dynamic stability analysis.

The modified event will be simulated in power flow analysis and the system response will be evaluated against the following criteria:

a. Any BES transmission facility exceeding 125% of its emergency rating and/or
b. Generator terminal voltage on the high-side or low-side of the GSU is below 0.90 p.u. and/or
c. Load bus voltage is below 0.90 p.u.

If any of the criteria is exceeded, the applicable facility will be tripped offline. The power flow model will be solved, and the monitored facilities will be evaluated again for exceeding criteria. This iterative process will continue until all monitored facilities meet the defined criteria.

3.3 Criteria

The outcome of the dynamic stability and steady state analysis will be used to determine if the defined event results in cascading, uncontrolled separation, or instability with the Interconnection based on the following criteria:

a. The accumulated total of non-consequential load loss and generation tripped offline due to unacceptable response exceeds 1000 MW.
b. The resulting number of BES transmission facilities which are loaded above the 125% of the facilities emergency rating and opened during simulation will be evaluated for cascading by considering MISOs criteria of four or more elements tripping due to excessive loading, but also accounting for other factors such as voltage of the facility, geographic area effected, and overall quantity of facilities.
c. A voltage collapse condition, not mitigated by an existing automatic under-voltage load shed (UVLS), special protection scheme (SPS), or remedial action scheme (RAS), is indicated by a non-convergent power flow solution and verified using engineering judgment.

4 Referenced Document Table

Document Name
MISO Transmission Expansion Plant (MTEP)
MOD-032 Data for Power System Modeling and Analysis
VEC-014 Transmission and Generation System Facility Ratings

5 Appendices

5.1 Appendix A: TPL-001-5.1; Table 1 – Steady State & Stability Performance Planning Events

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

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Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1.Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1.Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker10 (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency (Fault plus redundant component of	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1.Generator	SLG	EHV	No[9]	No
				HV	Yes	Yes

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a Protection System failure to operate)		2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section				
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments.[9] 1.Transmission Circuit 2. Transformer[5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency (*Common Structure*)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

5.2 Appendix B: TPL-001-5.1; Table 1 – Steady State & Stability Performance Extreme Events

Table 1 – Steady State & Stability Performance Planning Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as:	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.

a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

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5.3 Appendix C: TPL-001-5.1; Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
b. A single communications system associated with protective functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and 67),reported at a Control Center);
c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).and open circuit);
d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

6 Revision Table

Revision Number	Revision Date	Effective Date	Revised By	Summary of Changes
0	07/23/08	07/28/08	Name R. Tabor	Revised document into new format, added sections to address NERC FAC and TPL standards
1	04/09/09	04/10/09	R. Tabor	▪ Updated Annual Review Table ▪ Standardized document formatting.
2	01/12/10	01/26/10	R. Tabor	▪ Added 3H Reference to VEC-014 and ratings. ▪ Added 4.3 SOL & IROL Determination ▪ Updated reference tables to latest reports
3	03/10/10	04/05/10	M. Rose	▪ Added verbiage to cover TPL-001 & TPL-002 for Transmission Performance Planning Models (up to 10 years) under 2 Model Usage, 2.1. ▪ Added Section F under Study Results
4	10/05/10	11/23/10	M. Rose	• Made content changes based on self-certification. See redline(s).
5	10/27/11	11/15/11	R. Collins	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
6	03/01/12	04/10/12	R. Collins	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
7	05/13/13	05/23/13	K. Sims	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
8	08/31/13	08/31/13	J. Biggerstaff	• Revised MISO document link under section 2.1.2
9	10/22/13	11/01/13	J. Biggerstaff	• Revised first paragraph of section 2.3.1. Contingencies based on Director Review.

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10	03/24/14	04/07/14	K. Barr	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
11	07/07//14	12/10/14	K. Barr	• Inserted references based on annual or self-certification review. See redline(s) and summary of document changes.
12	11/06/15	12/18/15	K. Barr	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
13	04/11/16	11/21/16	K. Barr	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
14	09/22/17	12/08/17	K. Barr	• Made content changes based on annual or self-certification review. See redline(s) and summary of document changes.
15	10/30/18	12/18/18	K. Barr	• Made content changes based on annual review. See redline(s) and summary of document changes.
16	04/18/19	11/11/19	K. Barr	• Updated signatory and post-merger references. See redline(s).
17	11/02/20	12/18/20	K. Barr	• Made content changes based on annual review. See redline(s).
18	02/01/21	12/14/21	L. Hamby	• Made content changes based on annual review. See redline(s).
19	07/06/22	12/07/22	L. Hamby	• Non-material format changes • Made content changes based on annual review. See redline(s).
20	03/23/23	05/18/23	L. Hamby	• Made content changes based on TPL-001-5 review. See redline(s).
21	07/24/23	10/05/23	L. Hamby	• Made content changes based on annual review. See redline(s).
22	01/09/24	01/16/24	L. Hamby	• Made content changes based on annual review. See redline(s).

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This document is compliant with NERC Transmission Planning Standards		

Revision Number	Revision Date	Effective Date	Revised By	Summary of Changes
23	01/22/24	04/01/24	L. Hamby	• Reviewed due to FAC-014-3 Implementation and annual review; See redline(s).
24	03/25/24	06/18/24	L. Hamby	• Made content changes based on annual review. See redline(s).
25	04/10/25	05/20/25	K. Pharr	• Made content changes based on annual review. See redlines(s).
26	08/14/25	08/18/25	K. Barr	• Made content changes for MISO submission. See redlines(s).

Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)

SEE ATTACHMENTS: CONFIDENTIAL - 4.1 CEIS 2025 IRP Model with Scenarios & Stochastic Model

Attachment 4.2 Stakeholder Materials

CenterPoint Energy

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 1

March 19, 2025



Stakeholder Meeting Facilitator: 1898 & Co.

WHO: 1898 & Co. is the business, technology and security consultancy part of Burns & McDonnell

WHAT: The Resource Planning & Market Assessments group has been working on Integrated Resource Plans for over 20 years

HOW: Our team will help facilitate stakeholder meetings – we look forward to working with and hearing from you all

Agenda

Time	Topic	Speaker
9:00	Sign-in & Refreshments	
9:30	Facilitators and Meeting Protocols & Participation	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
9:40	Safety Share & Welcome	Shane Bradford, Vice President, Indiana Electric, CenterPoint Energy
9:50	2025 IRP Process, Objectives and Draft Metrics	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
10:30	BREAK	
10:40	All-Source RFP Results	Josh Swanson, Director Power Supply Services, CenterPoint Energy
11:00	MISO Update	Kimberly Dunning, Manager MISO Affairs, CenterPoint Energy
11:15	Environmental Compliance Update	Angie Casbon-Scheller, Director Generation Compliance & Carbon Policy, CenterPoint Energy
11:30	LUNCH	
12:15	Large Load Sensitivity Discussion	Justin Forshey, Director Energy Solutions and Business Development, CenterPoint Energy
12:30	Draft Sales & Demand Forecast	Michael Russo, Forecast Consultant – ITRON
1:00	BREAK	
1:10	Resource Options	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:30	Commodity Inputs	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:50	Scenario Development	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:20	Stakeholder Questions and Feedback	Moderated by Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
3:00	Adjourn	

Meeting Protocols

- Please focus questions, comments, and feedback to the IRP process and today's agenda topics
- CenterPoint Energy Indiana (CEI) South does not authorize the use of cameras, video/audio recording devices, or AI transcription during the meeting
- Following the meeting, feedback (concepts, inputs, methodology, etc.) and questions may be sent to IRP@CenterPointEnergy.com
- CEI South will be recording the meeting to accurately capture notes and questions. The public meetings are not transcribed or recordings posted; however, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp

Meeting Participation

Time is allotted for questions following each presentation – please hold questions until the designated question period

In-person attendees – please raise your hand to be recognized

Virtual attendees will be in listen-only mode – to participate:

- Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
- Enter questions into the “Q&A” feature in Teams

Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

There will be a list compiled for items to be addressed later. Questions that are not able to be answered in this meeting will be answered later.

Safety Share and Welcome

Shane Bradford

Vice President, Indiana Electric

Safety is everyone's responsibility

- **Know your exits**
  - Whenever you are entering a public area or a guest in a facility such as this, always know your exits. Take note of the signs
- **Visualize for safety**
  - When you enter a new space, visualize that an emergency – like a fire, bad weather, or an earthquake – could happen there and consider how you can respond
- **Fire**
  - Evacuate the building and move to the back of the CNP Plaza parking lot, near the YWCA (East side of the building)
- **Bad Weather**
  - During a tornado warning, stay away from windows, glass doors, and outside walls
  - Move in an orderly fashion to the stairwell, just outside of the lobby in the main entrance way
- **Earthquake**
  - Move under the desk where you are sitting, facing away from glass, and cover your head and face
  - Once shaking has subsided, move in an orderly fashion towards the nearest exit and move to the back of the CNP Plaza parking lot, near the YWCA

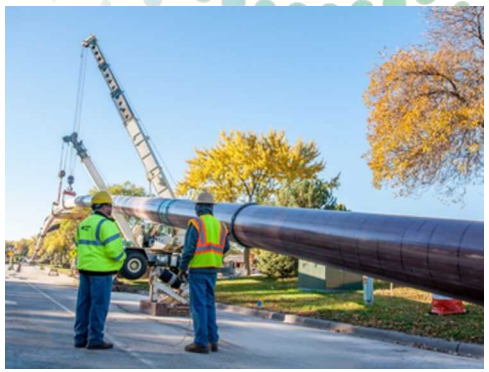
Who We Are

CenterPoint Energy (NYSE:CNP) is an investor-owned electric and natural gas utility, based in Houston, Texas, serving more than **7 million metered customers** across six states -- Indiana, Ohio, Texas, Minnesota, Louisiana and Mississippi.

With the help of our approximately **9,000 employees**, we provide service to our customers, fueling everyday comfort and productivity. CenterPoint and its predecessor companies have been in business for more than **150 years**.

We are unwavering in our commitment to safely and reliably provide electricity and natural gas to millions of people – so they can focus on what matters most to them.









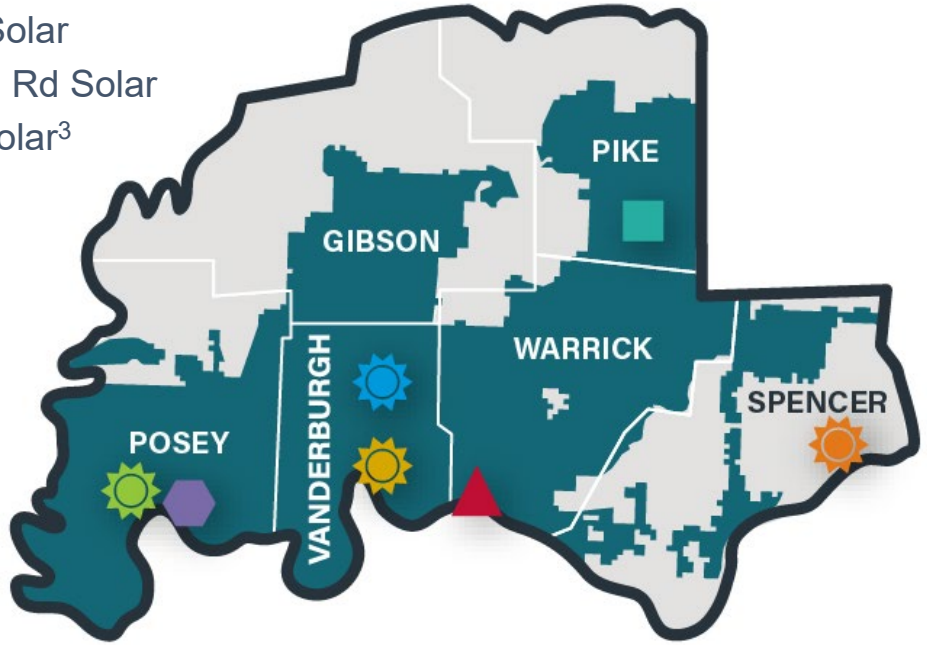
2025 CenterPoint Energy Indiana (CEI) South

In Southwestern Indiana, CEI South Electric:

- Serves more than **150,000** customers
- Owns and operates:
  - **1,039** circuit miles of transmission lines
  - **7,318** circuit miles of distribution lines
  - **109** substations
- Has **1,344 MW** of installed generating capacity, including:
  - **245 MW** of solar
  - **80 MW** of wind
  - **627 MW** of gas-fired units
  - **392 MW** of coal-fired units

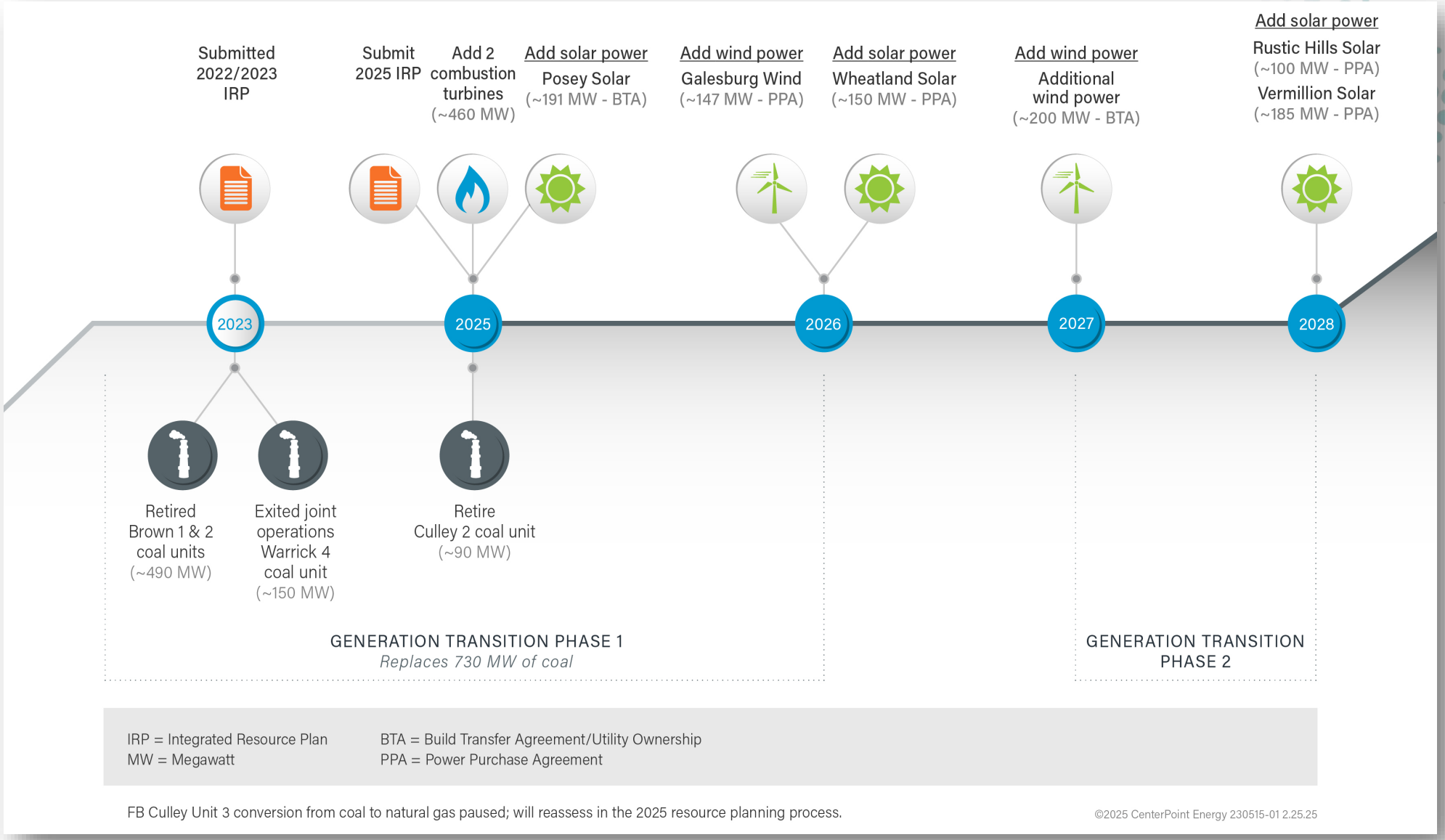
Power plants[1]

- A.B. Brown Gas Turbines[2]
- F.B. Culley
- Blackfoot Clean Energy Plant
- Troy Solar
- Oakhill Solar
- Volkman Rd Solar
- Posey Solar[3]



[1]Fowler Ridge & Benton County Wind Farms not shown.
[2]ABB Gas Turbines 5&6 expected to be in-service 2025.
[3]Posey Solar expected to be in-service 2025.

Generation Transition Timeline



The 2022-2023 IRP preferred portfolio included 600 MWs of wind and 200 MWs of solar through 2032

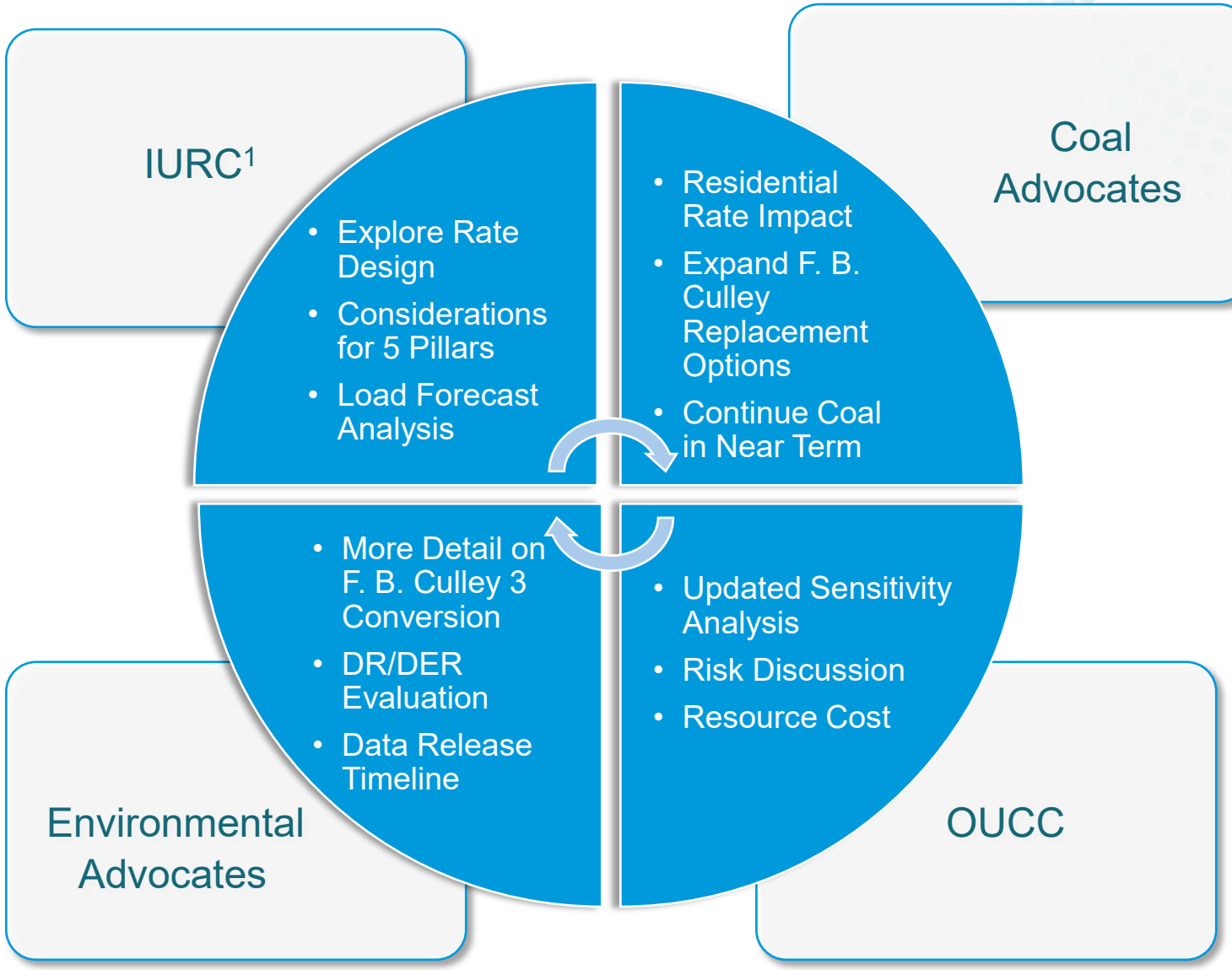
2025 IRP Process, Objectives, & Draft Metrics

Matt Rice

Director, Regulatory and Rates

Feedback From All Parties

- CEI South received written feedback following the 2022-2023 IRP from various stakeholders
- This feedback was utilized to provide the basis for 2025 IRP enhancements
- Please continue to provide feedback as we work through the current analysis



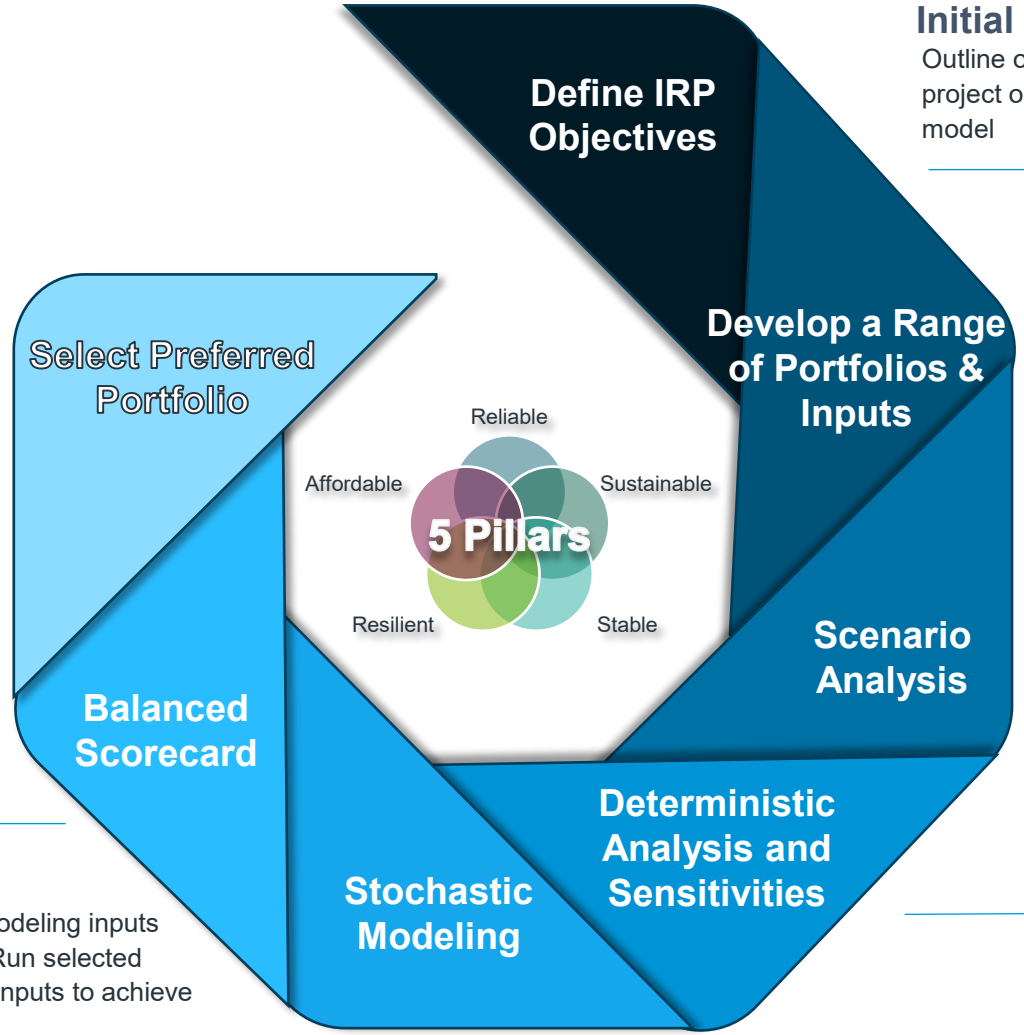
[1] *Based on Draft Director's report as of May 2024* *DR = Demand Response* *DER = Distributed Energy Resource*

2025 IRP Enhancements

- Refreshed IRP layout with enhanced description of analysis and results
- Expanded sensitivity analysis - large load impacts, tax impacts, CO_2, DSM, MISO accreditation
- Increased collaboration with transmission & distribution planning
- Additional analysis of unserved energy
- Provide an expected data release schedule
- 5 pillars-focused score card with expanded view of affordability

DSM = Demand Side Management CO_2 = Carbon dioxide MISO = Midcontinent Independent System Operator

Proposed 2025 IRP Process



Initial Modeling Phase

Outline our requirements and project options/constraints within the model

Deterministic Modeling

Optimize the least cost capacity expansion plan for each portfolio. Run hourly dispatch modeling on all portfolios

Probabilistic Modeling

Develop 200 unique families of modeling inputs through Monte Carlo simulation. Run selected portfolios through 200 families of inputs to achieve a balanced scorecard

IRP Overview

Purpose

- Evaluate CEI South's current energy resource portfolio and a range of alternative future portfolios to meet customers' electrical energy needs for reliable and economical power, while considering risks and uncertainties

Guiding Principles

- Five Pillars as outlined in House Enrolled Act (HEA) 1007
  - Reliability
  - Affordability
  - Resiliency
  - Stability
  - Environmental Sustainability

Engagement

- Objective of Stakeholder meetings is to Listen, Inform, & Consider
- Incorporate feedback from IRP Stakeholders and IURC staff
- Provide data release schedule

Scenarios & Modeling

- Modeling helps inform planning decisions
- Robust modeling inputs from load forecast to transmission impacts
- Utilize sensitivities to evaluate various risks

2025 Stakeholder Process

Proposed 2025 CEI South Stakeholder and Tech to Tech Meetings – *Dates and agendas are subject to change*

Meeting 1
March 19

- IRP Process, Objectives, & Draft Metrics
- All-Source RFP Results
- MISO Update
- Environmental Compliance Update
- Draft Sales and Demand Forecast (Reference Case)
- Commodity Inputs
- Large Load Sensitivity Discussion
- Resource Options
- Scenario Development

Tech to Tech
April 28

Meeting 2
May 14

- Follow Up Information From 1st IRP Stakeholder Meeting
- Final Scorecard and Scenarios
- DSM Market Potential Study Update
- Draft Supply-Side Resource Inputs
- Final Load Forecast and Draft Scenario Forecasts
- Probabilistic Modeling Approach and Assumptions
- Portfolio Development Methodology
- Draft Reference Case Modeling Update

Tech to Tech
July 7

Meeting 3
July 23

- Follow Up Information From 2nd IRP Stakeholder Meeting
- Discussion of Final Portfolios
- Scenario and Probabilistic Modeling Update
- Draft Scenario Optimization Results without DSM
- Draft Deterministic Portfolio Results
- Early Sensitivity Results

Tech to Tech
September 5

Meeting 4
September 23

- Follow Up Information from 3rd IRP Stakeholder Meeting
- Preferred Portfolio
- Risk Analysis Modeling and Portfolios
- Risk Analysis Scorecard

Target Filing Date: November 1, 2025

Stakeholder Engagement is Critical to the IRP Process
CEI South is committed to meaningful information sharing and dialogue

Target Data Release Schedule

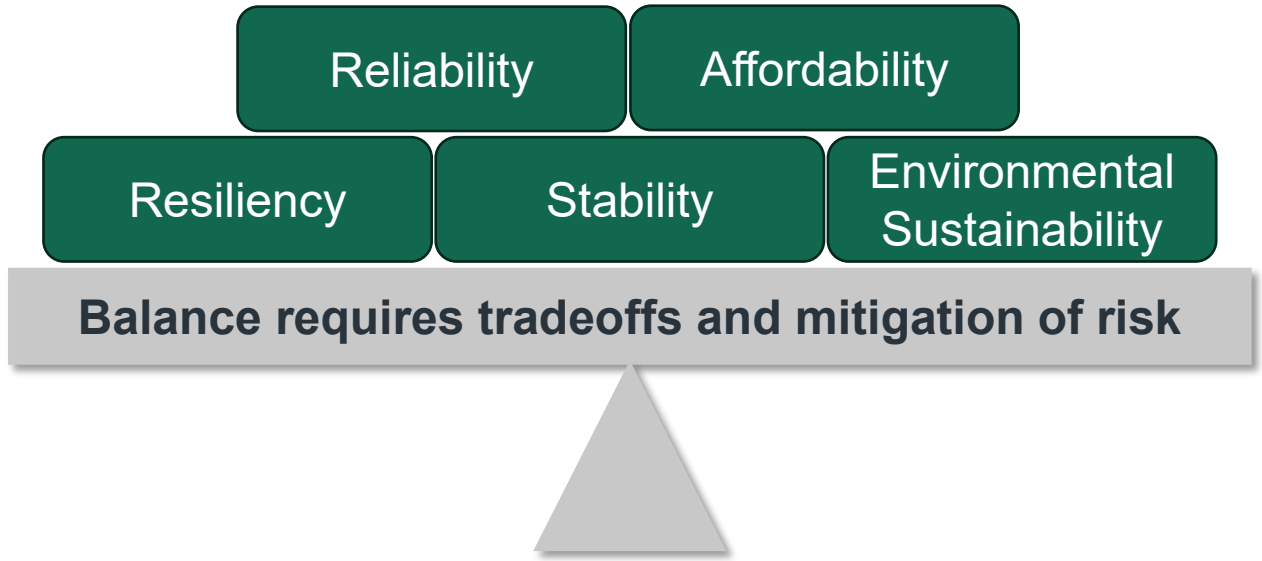
Draft Load Forecast	Draft Base Case Model	Updated Base Case + Scenario Models	Probabilistic + Sensitivity Analysis Models
3/20/2025 1	5/5/2025 2	7/14/2025 3	9/12/2025 4

Note: The released data will be available to the technical stakeholders with a completed Non-Disclosure Agreement

Selection of the Preferred Portfolio

Each portfolio will be tested against:

- Objectives
- Quantitative metrics
- Qualitative analysis



Objectives & Draft Metrics

Objective	Measure	Metrics
Affordability: *Consider portfolios' impact on the retail electric utility service providers ability to provide affordable power across residential, commercial, and industrial customer classes*	➢ 20-year Net Present Value Revenue Requirement ("NPVRR")	➢ $
	➢ 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions	➢ $
	➢ **5th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions**	➢ $
	➢ **5-Year residential rate impact**	➢ $
Environmental Sustainability: *Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation*	➢ CO_2 Intensity	➢ Tons CO_2/kwh
	➢ CO_2 Equivalent Emissions	➢ Tons CO_2e
Reliability: *Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all time and withstand sudden disturbances* **Resiliency:** *Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions* **Stability:** *Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters*	➢ **Unserved energy across 200 dispatch iterations under varying market conditions**	➢ MWh
	➢ Spinning Reserve	➢ Portfolio MW's That Offer Spinning Reserve
	➢ Fast Start Capability	➢ Portfolio MW's That Offer Fast Start
	➢ **Transmission reliability analysis**	➢ Dynamic VAR Support (MVAR) ➢ Short Circuit Ratio
Risk/Other:	➢ Energy Market Purchase and sales	➢ % (average, near/long term)
	➢ **IRA tax credit exposure**	➢ $

Blue text indicates a new measure for this IRP cycle

MWh = Megawatt hour MVAR = Megavolt-Ampere Reactive

Q&A

All-Source RFP Results

Josh Swanson

Director, Power Supply Services

All-Source RFP Overview

- CEI South's 2024 All-Source Request for Proposal (RFP) was conducted from August through December
  - CEI South conducted a non-limiting and accessible All-Source RFP that was objective, fair, and open
- From proposals received, CEI South can better access the current market for resources that best align with CEI South's needs
- RFP Results will be used to help inform CEI South's 2025 Integrated Resource Plan

Summary of RFP Insights

Resource Availability	>>	• Limited wind resources available, specifically in Indiana • Several battery proposals for the re-use of F.B. Culley 2 interconnect
Pricing	>>	• Pricing of proposals was in line with expectations • General increase in pricing, potentially driven by supply chain constraints, increasing demand for renewables, and MISO queue
RFP - IRP Integration	>>	• Proposals received as part of the RFP will help inform input pricing for the IRP • IRP will help to inform resource types to be pursued

RFP General Requirement Overview

Resources

- Renewables
- Storage
- Thermal
- Load Modifying Resources
- Demand Response



Contract Structures

- PPA
- Purchase
- Renewable Project in Development
- Demand-side contracts



Timeline

Preference for resources to be in-service and operational prior to March 1, 2028



Generator Replacement

Within the All-Source RFP CEI South solicited projects for re-use of the 90 MW interconnect at F.B. Culley 2

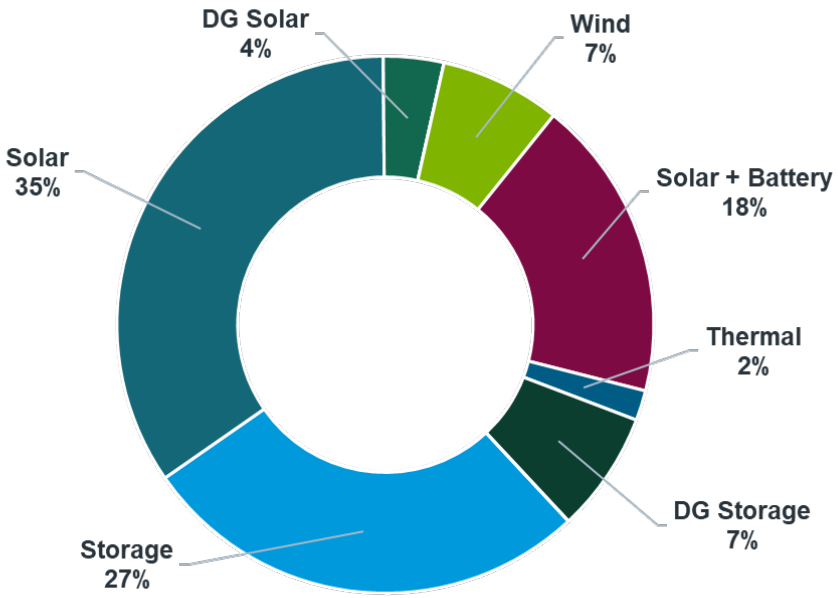


PPA = Purchase Power Agreement

RFP Results

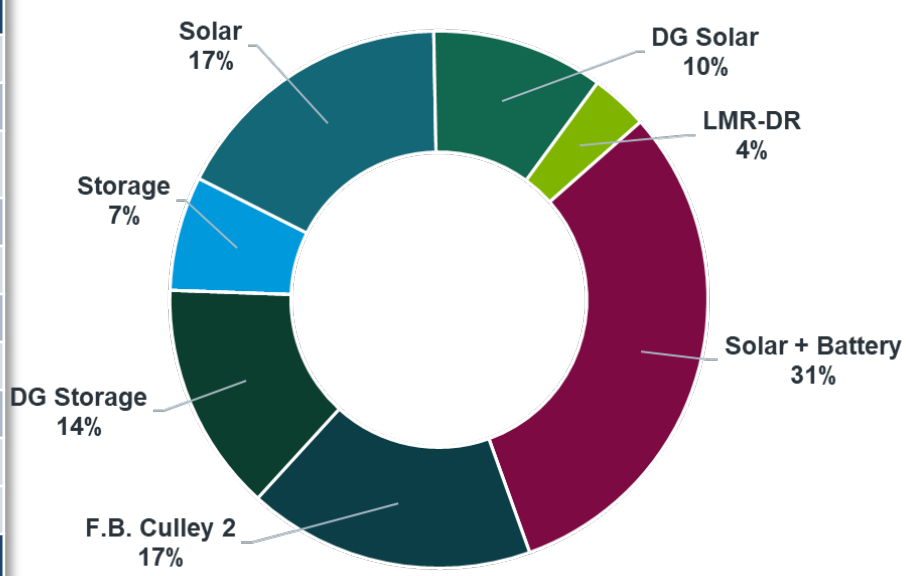
- Total of 95 proposals were received
- Projects will be considered based on outcomes of the 2025 IRP

Summary of PPA Projects by Tech Type



Tech Type	Count of PPA Projects	Count of Purchase Projects	Other
Solar	19	5	-
Storage	15	2	-
Solar + Storage	10	9	-
Wind	4	-	-
DG Storage	4	4	-
DG Solar	2	3	-
Thermal	1	-	-
LMR-DR	-	1	-
FB Culley 2	-	5	-
Unique*	-	-	11
Subtotals	**55**	**29**	**11**
Total	**95**		

Summary of Purchase Projects by Tech Type



**Unique Proposals were projects offered with alternative contract structures (e.g., EPC, pre-NTP sale, etc.)*

RFP Results – Pricing

Tech Type	PPA Proposals			Purchase Projects	
	Count	Average Price ($/MWh)	Average Price ($/kW-mo)	Count	Average Price ($/kW)
Solar	19	$67.60	-	5	$2,351
Storage*	15	-	$14.25	2	$2,272
Solar + Storage	10	$76.40	$12.85	9	$3,425
Wind	4	$75.00	-	0	-
Thermal**	1	-	*Single bid*	0	-
LMR-DR**	0	-	-	1	*Single bid*
F.B. Culley 2 (Storage)	0	-	-	5	$1,573

**Capacity only - not directly comparable to solar and wind*
***Thermal and LMR-DR pricing information is not shown as it is data from only one bid.*

- The reported pricing does not include proposals that were "unique" in contract structure (e.g., pre-NTP sales, EPC, etc.)

Q&A

MISO Update

Kimberly Dunning

Manager, MISO Affairs

Midcontinent Independent System Operator (MISO)

What is it and how does it work?

- MISO is a non-profit, member-based organization
  - Operates the power grid across 15 U.S. states and the Canadian province of Manitoba
  - Primary responsibility is to ensure the reliable delivery of electricity to consumers by managing the generation and transmission of power across its region
- In 2001, MISO was approved as the first Regional Transmission Organization (“RTO”)
  - MISO has operational authority: the authority to control transmission facilities and coordinate security for its region to ensure reliability
  - MISO is responsible for dispatch of lowest cost generation units: MISO’s energy market dispatches the most cost-effective generation to meet load needs
- MISO is divided into three main regions North, Central and South
- MISO is divided into 10 Local Resources Zones (“LRZ”)
  - Indiana is part of Zone 6 in the Central region
  - Each LRZ has its own planning requirements for energy and capacity
  - Each Zone’s ability to rely on neighboring Zones depends largely on transmission infrastructure.

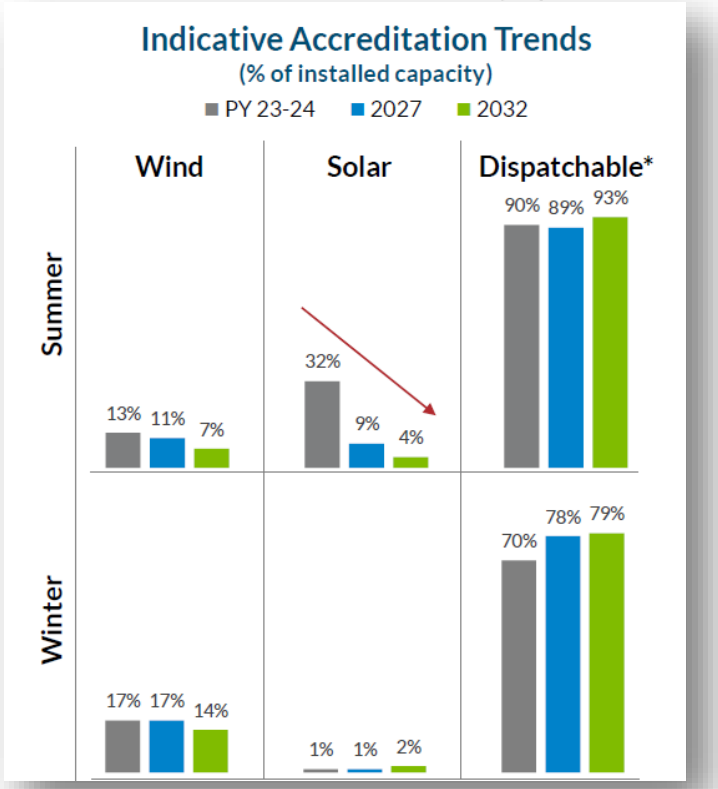




Source: *MISO*

Resource Accreditation Reform - Direct Loss of Load (DLOL)

- The DLOL method examines a resource adequacy contribution of a resource by measuring its availability to serve load during times when reliability risk is the greatest
- MISO will utilize probabilistic modeling to determine DLOL
- MISO's proposed approach is likely to decrease both the accreditation granted to resources as well as the seasonal reserve margin requirement
  - Solar accreditation declines with higher levels of penetration because risk hours are shifted to early evening
- This methodology will accredit resources using a two-step process:
  1. The class-level megawatt will be determined by averaging the availability of each resource during loss-of-load (LOL) hours. This is done within the Loss-of-Load Expectation (LOLE) model. Resource class megawatts are aggregated
  2. Allocate each resource class level megawatts among the individual resources in the class using the individual resources' performance by season using three years of operational experience



Source: *MISO*

Reliability Imperative – Market Redefinition Progress

MARKET REDEFINITION

Completed

✓Attributes Roadmap published
✓Seasonal Resource Auctions (2024-25 PRA)
✓Accreditation - Direct Loss of Load (2028-29 PRA)
✓Reliability Based Demand Curve (2025-26 PRA)
✓Value of Loss Load FERC Filing
✓Shortage Pricing FERC Filing

In-flight or Planned

- Provide Accreditation Data
- Implement Shortage Pricing Across Time Horizons
- Execute Planning Resource Auction with Reliability Based Demand Curve
- Illustrate Energy Adequacy Risks Across Time Horizons and Locations
- Develop and Communicate Risk Metrics
- Implement Dynamic Locational Reserve Products Including Flexibility & Ramping



Source: *MISO*

PRA = Planning Resource Auction *FERC = Federal Energy Regulatory Commission*

CEI South is Monitoring MISO Initiatives

- **Interconnection Queue Volume Cap**:
  - Limit requests to 50% of each planning region's non-coincident peak; effective date January 2025
- **Expedited Resource Addition Studies (ERAS)**:
  - Temporary process to more quickly add generation projects identified as critical in member resource adequacy plans
  - Q1 2025 filing at FERC, proposed effective date June 2025
- **Long-Range Transmission Plan (LRTP) Tranche 2.1:**
  - On December 12, 2024, the MISO Board of Directors approved the MTEP24 report and Appendix A
  - Includes a $21.8 billion investment for 24 projects and 323 facilities across the MISO Midwest subregion.
  - Projects are targeted to go in service from 2032 to 2034
- **Demand Response & Emergency Resource Reform:**
  - Improve operational effectiveness by splitting Demand Response into two categories based on notification time with accreditation based on actual availability
  - Q2 2025 filing at FERC, proposed effective date 2028/2029 Planning Year
- **FERC Order 2222:**
  - Promote competition in electric markets by removing the barriers preventing Distributed Energy Resources (DERs) from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators
  - Awaiting FERC decision on MISO's compliance filing; implementation 2029

MTEP = MISO Transmission Expansion Plan FERC = Federal Energy Regulatory Commission

Q&A

Environmental Compliance Update

Angie Casbon-Scheller

Director, Generation Compliance & Carbon Policy

Clean Air Act 111(b) & (d) Greenhouse Rules

- In May 2024, EPA finalized a regulation for Greenhouse Gas (CO_2) Emissions for new gas-fired combustion turbines; existing coal & gas fired steam generating units; and repeal of the ACE Rule
  - Established emission guidelines for the longest-running existing coal units and performance standards for new baseload combustion turbines based on the use of carbon capture and sequestration/storage (CCS), unless the units retire or convert by 2032. Medium term existing coal units have a natural gas co-firing option.
  - Excluded from this rule is existing natural-gas fired combustion turbines, which includes A.B. Brown units 3 – 6
- Modeling will be performed to the current rule, as well as running a low-reg scenario in consideration of the uncertainty surrounding CO_2 regulations associated with administration change and their current review of the existing regulations

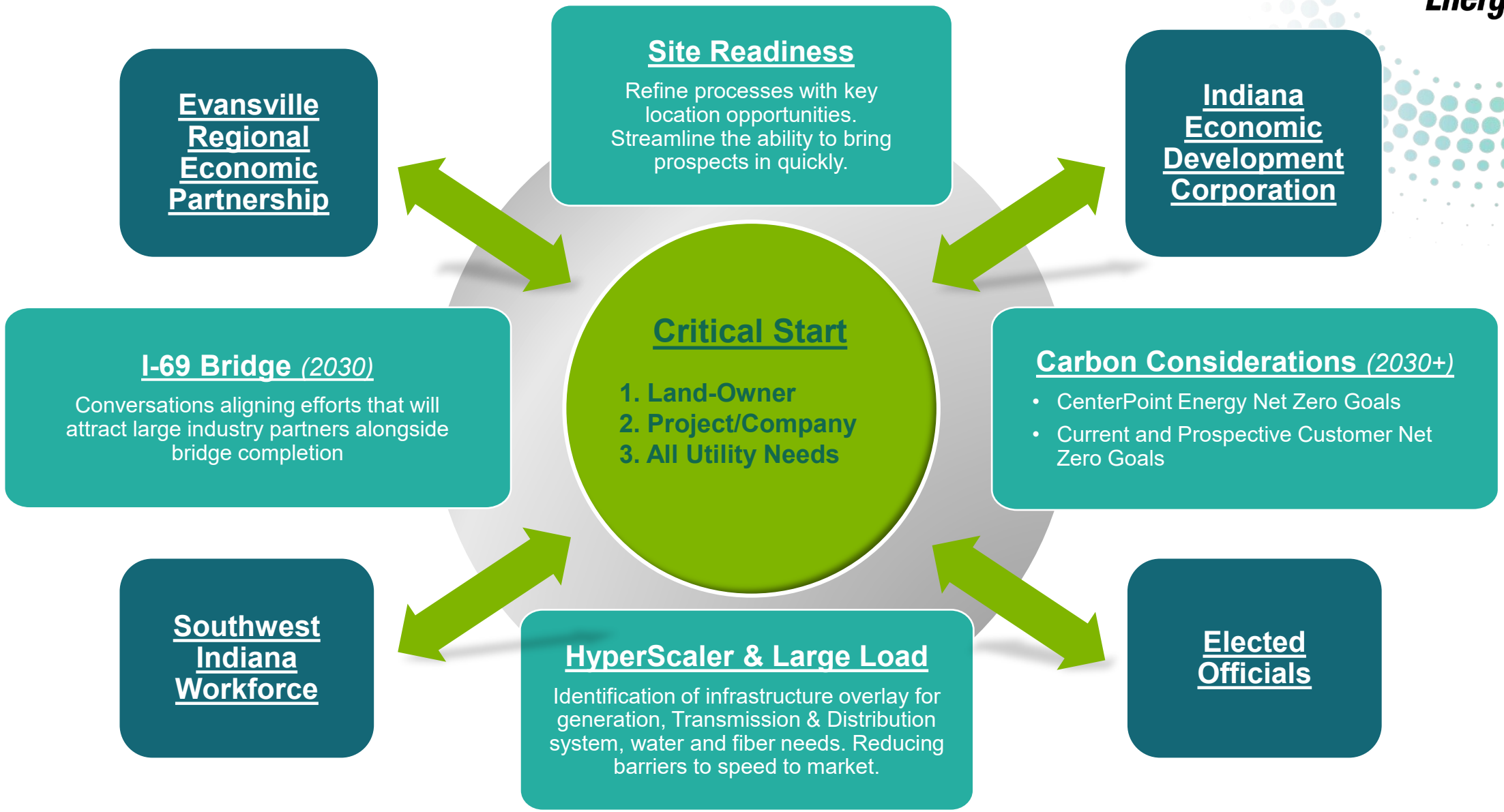
Clean Water Act 316(b) Rule

- In May 2014, EPA finalized its Clean Water Act 316(b) rule which focuses on impingement and entrainment of aquatic species during water intake. The rule has not been revised since being published.
- Best Technology Available (BTA) Selection & Implementation applies to all regulatory scenarios and both fuel options and therefore has to be modeled under the base case and all scenarios.
- In summary, 316(b) compliance / technology is required at F.B. Culley for either continuation or conversion of F.B. Culley 3.
- For purposes of IRP modeling, CEI South is modeling intake screen modifications for the F. B. Culley plant and will assume a 2026 - 2028 deadline for compliance

Q&A

Large Load Sensitivities

Justin Forshey
Director, Energy Solutions and Business Development


Site Readiness
Refine processes with key location opportunities. Streamline the ability to bring prospects in quickly.
Evansville Regional Economic Partnership
Indiana Economic Development Corporation
I-69 Bridge (2030)
Conversations aligning efforts that will attract large industry partners alongside bridge completion
Critical Start
1. Land-Owner
2. Project/Company
3. All Utility Needs
Carbon Considerations (2030+)
• CenterPoint Energy Net Zero Goals
• Current and Prospective Customer Net Zero Goals
Southwest Indiana Workforce
HyperScaler & Large Load
Identification of infrastructure overlay for generation, Transmission & Distribution system, water and fiber needs. Reducing barriers to speed to market.
Elected Officials

Large Load Sensitivity

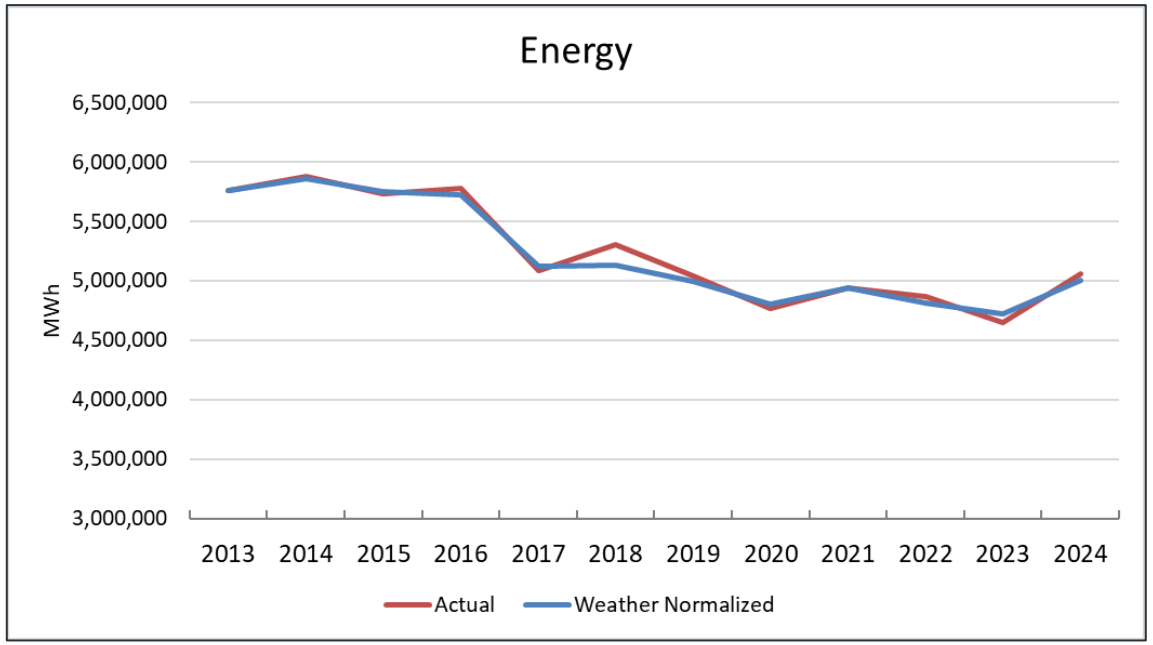
- Speculative load interest continues to evolve, and CEI South is responding alongside customer expectations
- Focused on large load users, not only data centers
  - New growth, expansion and retention of current customers
- Large load considerations - Methodology:
  - Initial consideration - analysis of up to 3 load sizes (ex. 100 MW, 300 MW, 1,000 MW)
  - Focusing on two types of resource mix (heavier gas vs heavier renewables)
  - Understanding transmission & distribution needs
  - Considerations for behind the meter options
- No large load addition is included in the base forecast

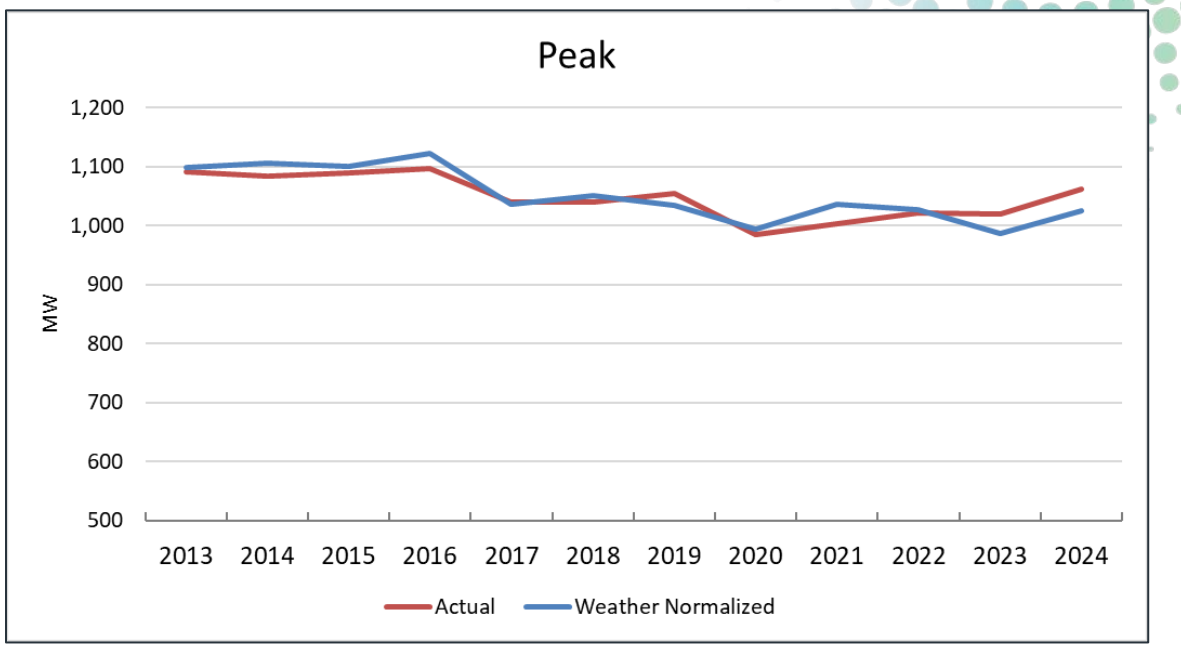
Q&A

Draft Sales & Demand Forecast *(Reference Case)*

Michael Russo
Forecast Consultant – ITRON

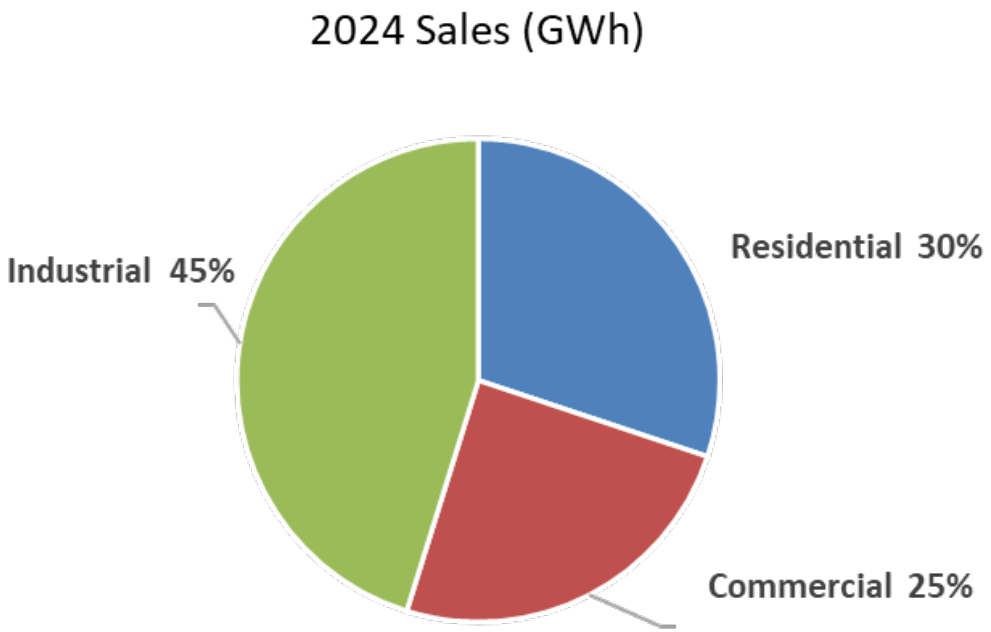
Historical Energy and Peak Trends

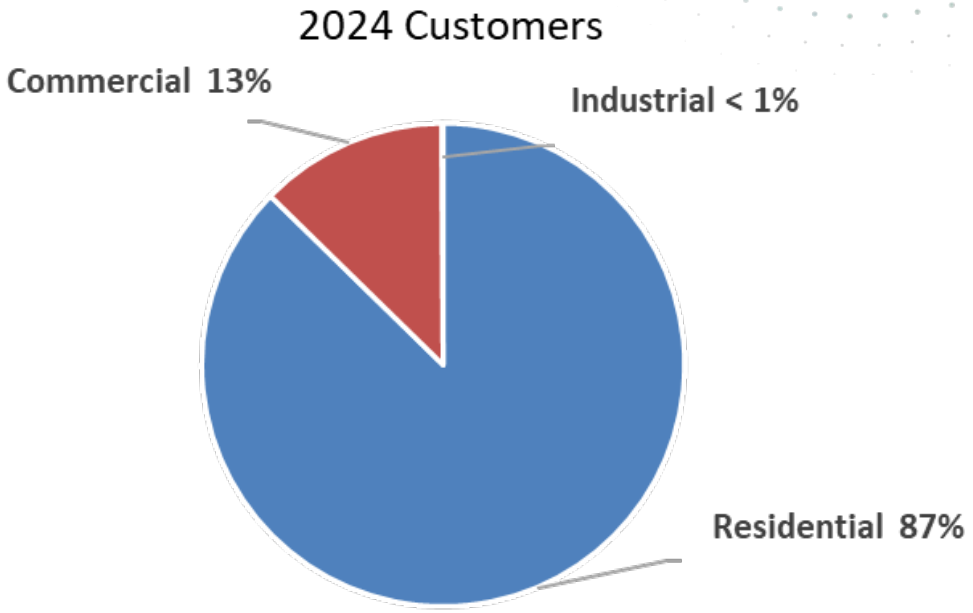




- 0.3% annual decline in energy and 0.1% decline in peak since 2017
- Strong efficiency gains reflecting new and existing federal codes and standards as well as utility sponsored energy efficiency program savings.

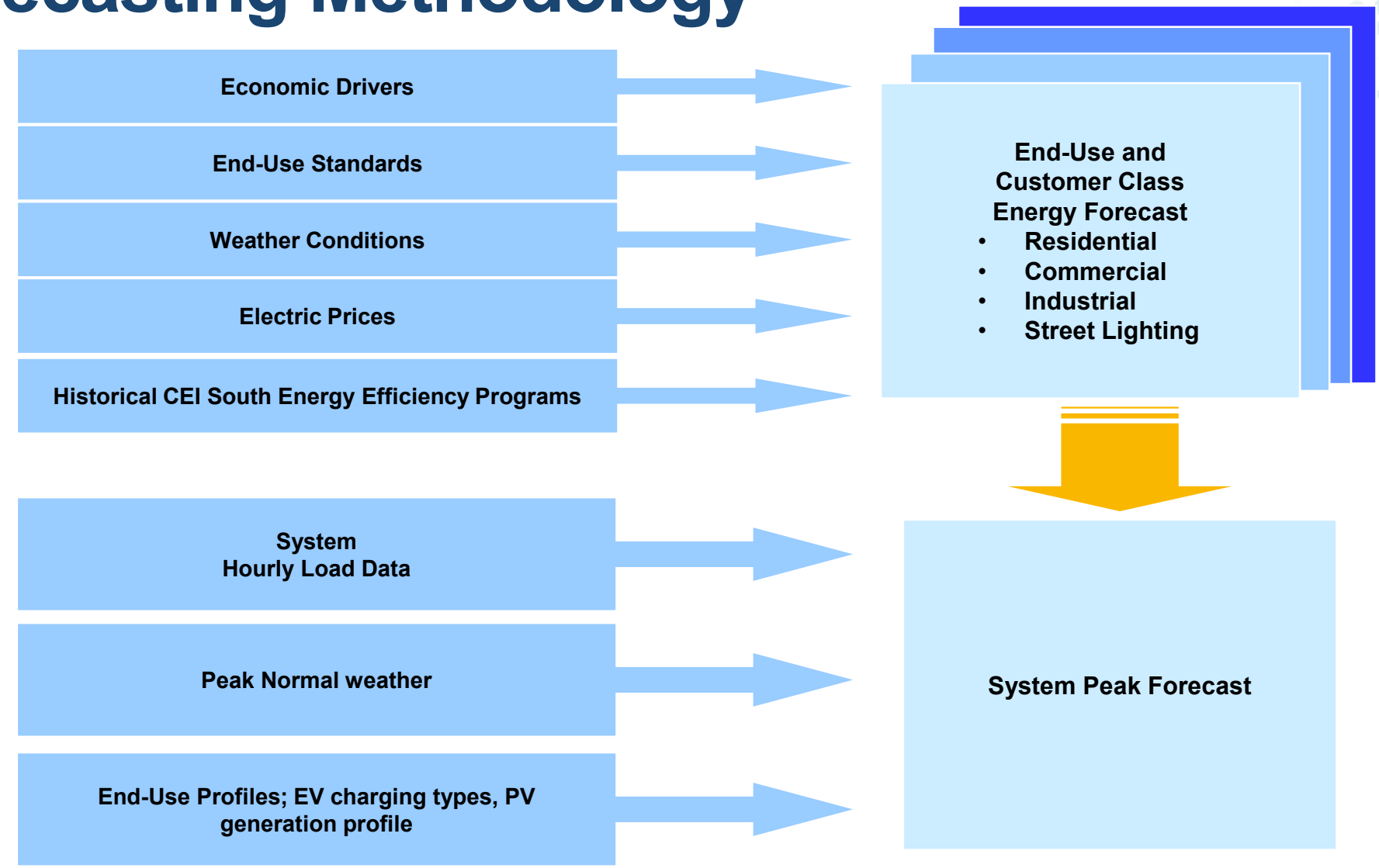
Customer Class Mix





CEI South currently serves more than 150,000 customers

Forecasting Methodology



EV = Electric Vehicle *PV = Photovoltaic*

Statistically Adjusted End-Use Approach (SAE)

Objective:

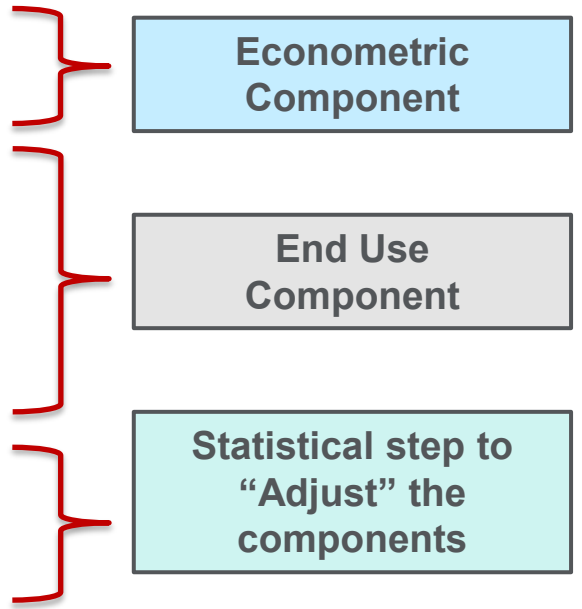
- Develop an econometric approach that incorporates the best characteristics of an econometric and end-use modeling framework

Captures:

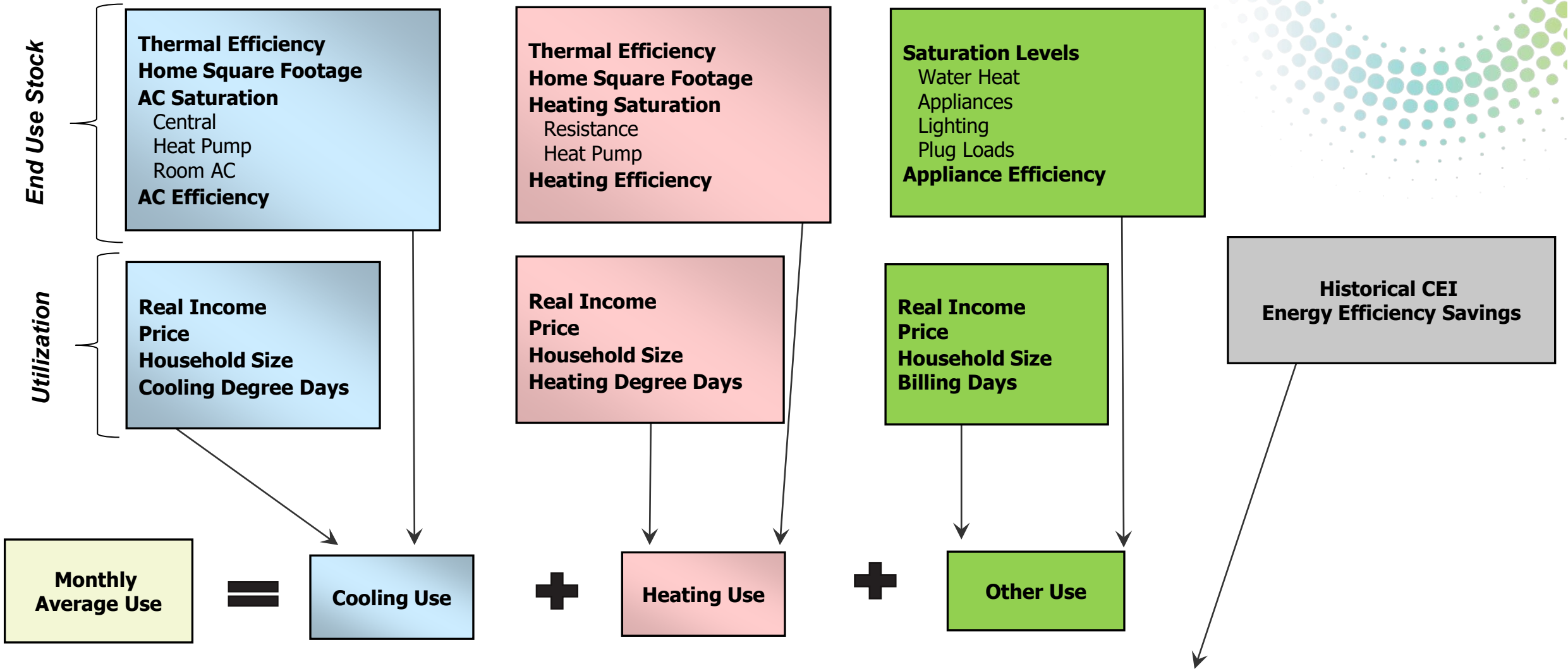
- Economic impacts (e.g., household income and size, price impacts)
- End-Use Structural changes (e.g., saturation and efficiency trends, housing square footage, thermal shell integrity improvements)
- Weather impacts

Statistical Adjustment:

- Model coefficients adjust up or down to calibrate to historical sales

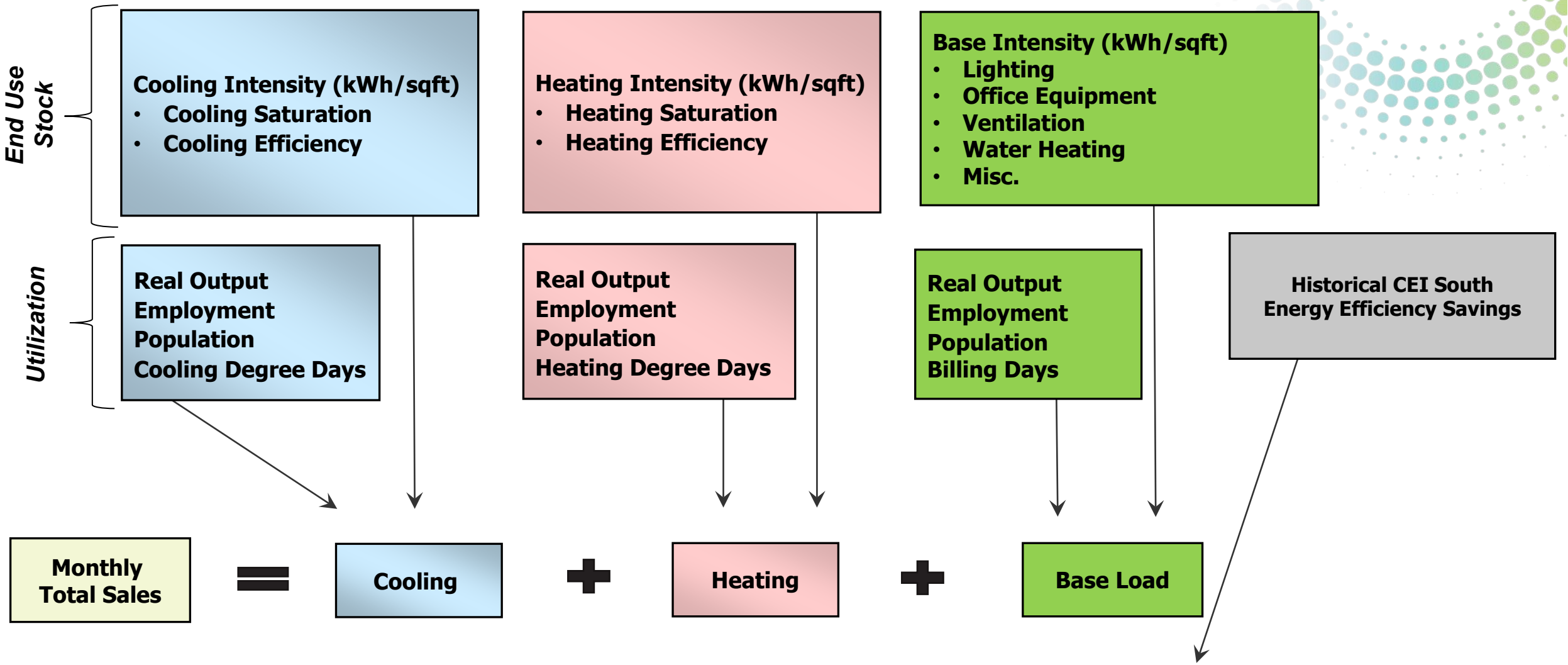


SAE Residential Model Framework



$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d \times EEm + e_m$$

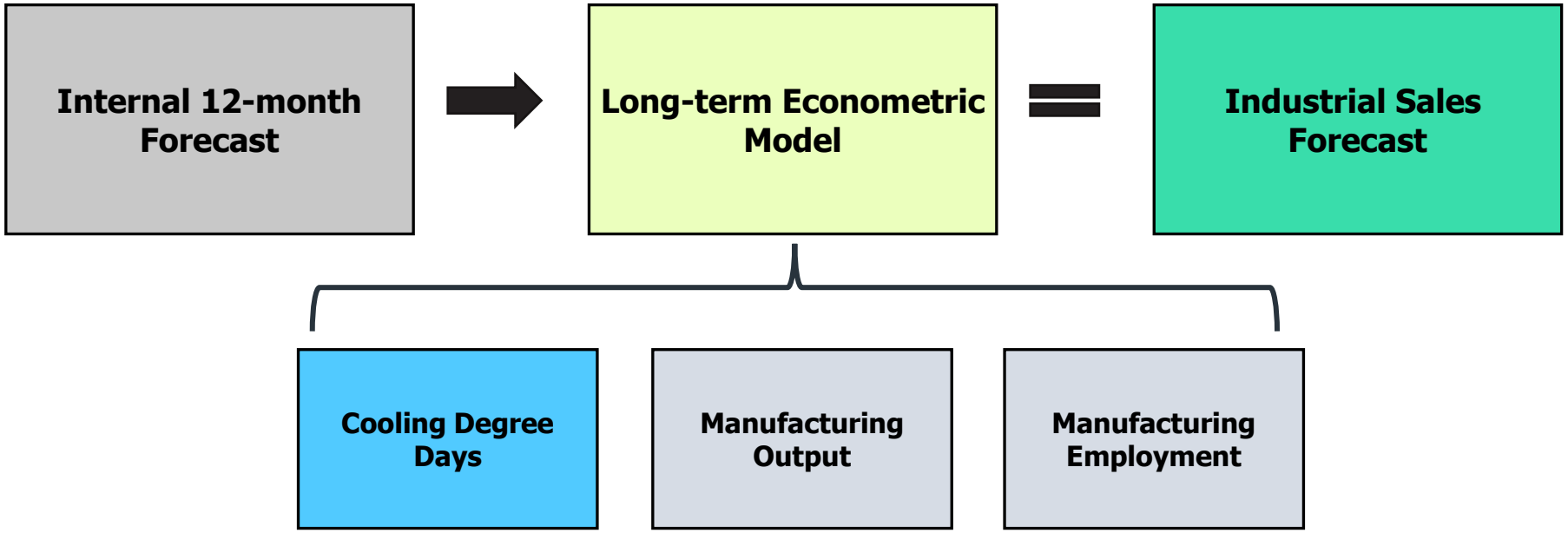
SAE Commercial Model Framework



$$MWh_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d \times EEm + e_m$$

Industrial Model Framework

- The industrial (large customer) forecast is a two-step approach
  - The first 12 months are based on CEI South's internal forecast
  - The long-term growth rate is developed using the econometric model framework



Model Estimation Period

- Models estimated using rate class billed sales and customer data
- Monthly models, estimated for the period January 2013 to December 2024
- Rate class models:
  - Residential average use (kWh)
  - Residential customers
  - Commercial total sales (MWh)
  - Industrial total sales (MWh)
  - Street lighting total sales (MWh)
  - System peak (MW)

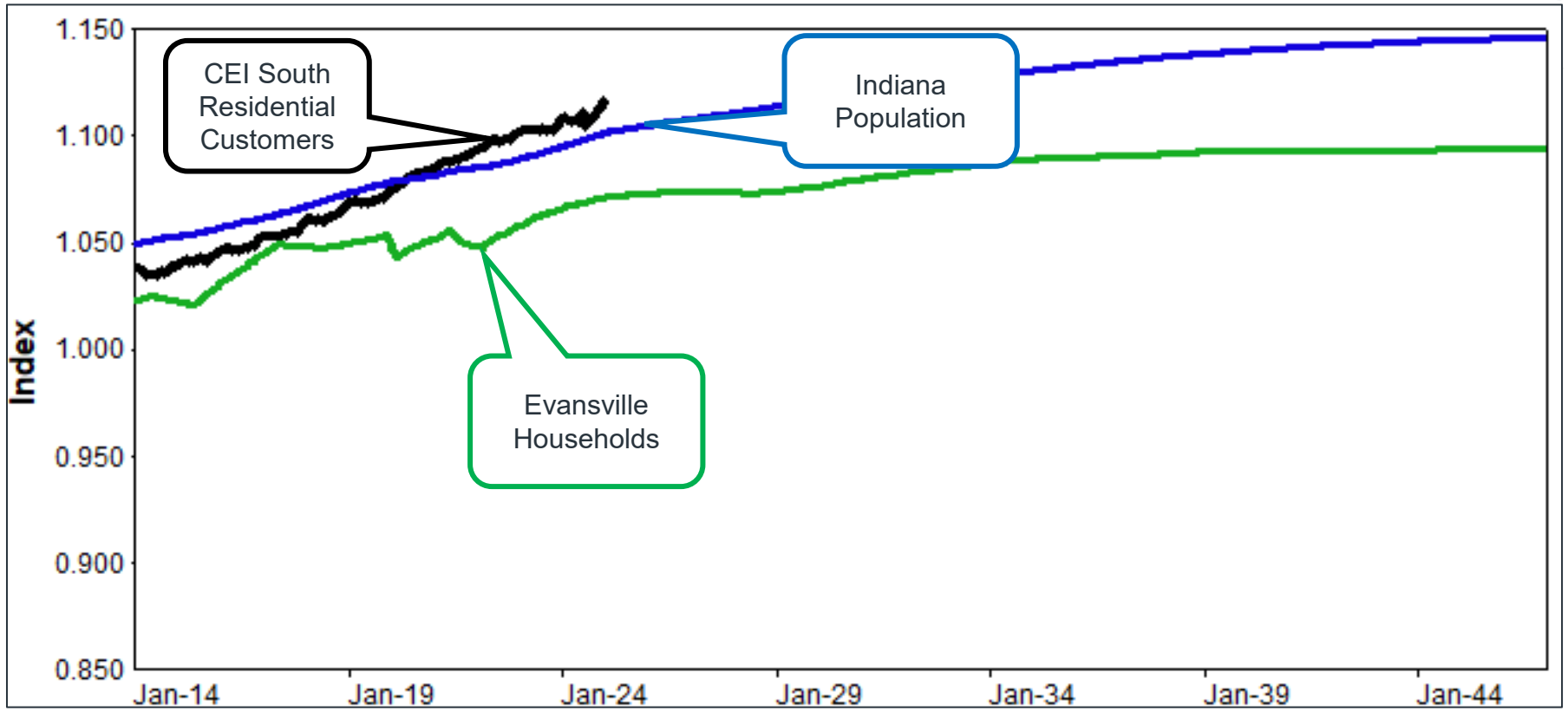
Residential Economic Drivers

S&P Global forecast for Indiana

- Population: 0.1% CAGR
- Real Household Income: 1.8% CAGR
- Household Size: -0.2% CAGR

*CAGR= Compound average growth rate from 2026-2045

Residential Customer Forecast Drivers



- CEI South residential customers are more highly correlated with Indiana population than Evansville metropolitan statistical area (MSA) households

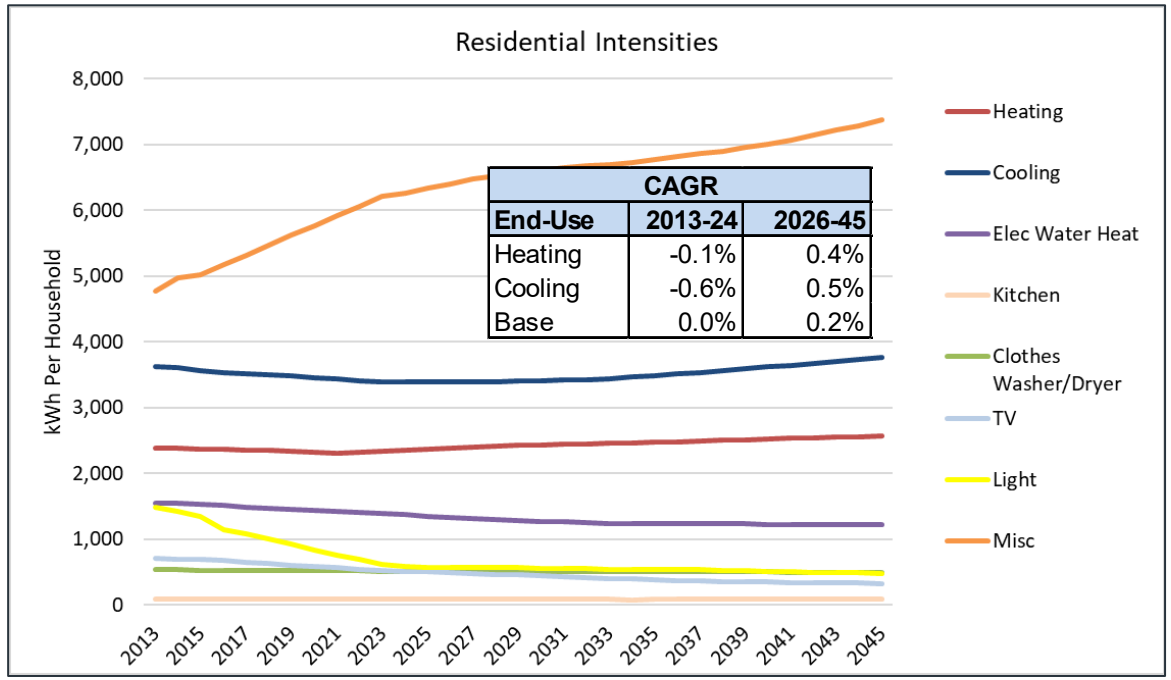
Non-Residential Economic Drivers

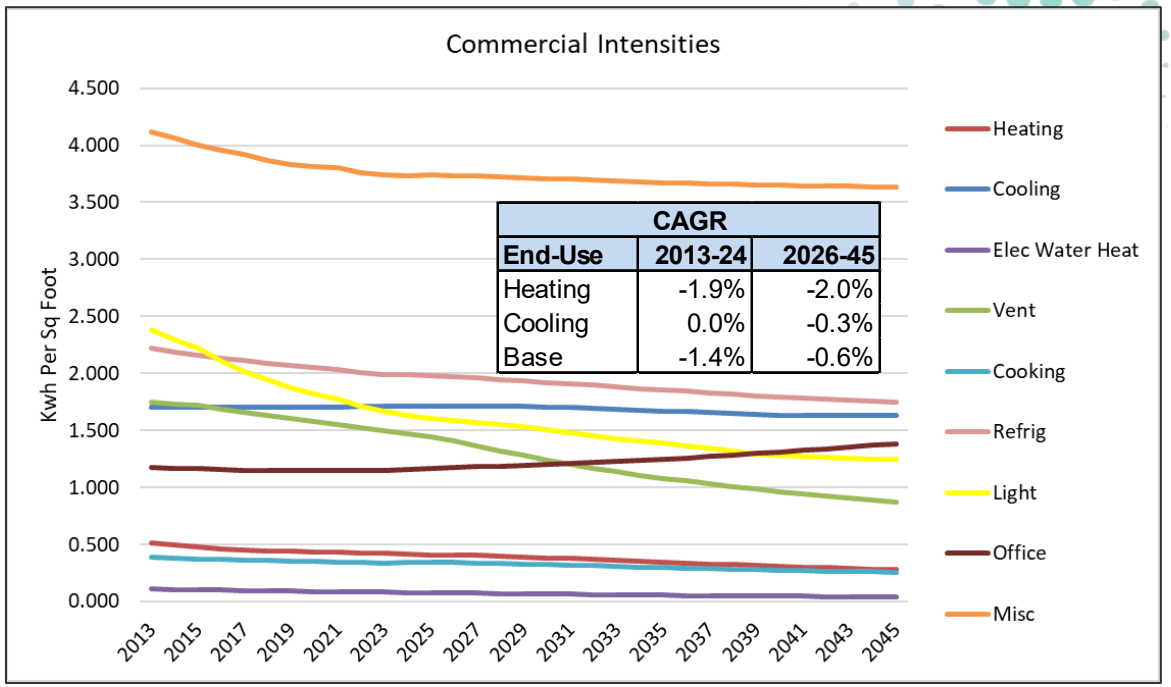
S&P Global forecast for the Indiana

- Commercial Sector
  - Non-Manufacturing Output: 0.7% CAGR
  - Non-Manufacturing Employment : 0.2% CAGR
  - Population 0.1% CAGR
- Industrial Sector
  - Manufacturing Output: 1.1% CAGR
  - Manufacturing Employment: 0.1% CAGR

*CAGR= Compound average growth rate from 2026-2045

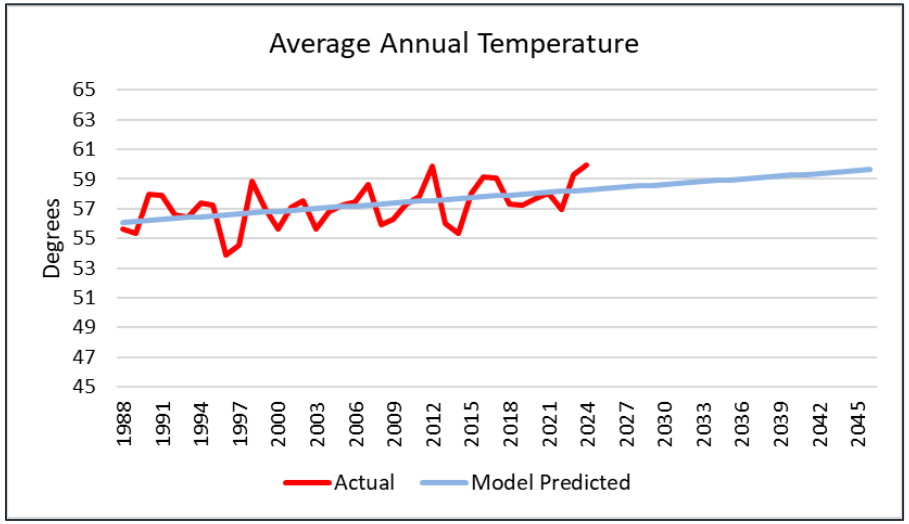
End-Use Intensity Trends



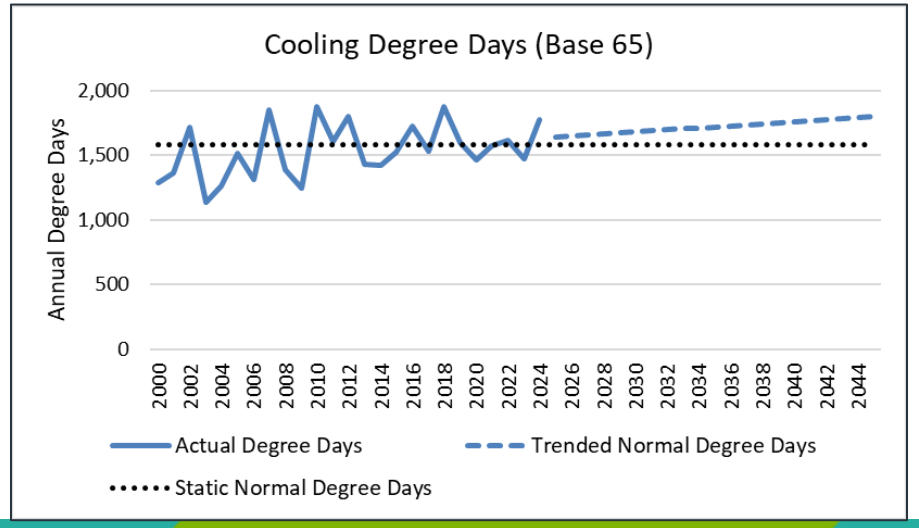


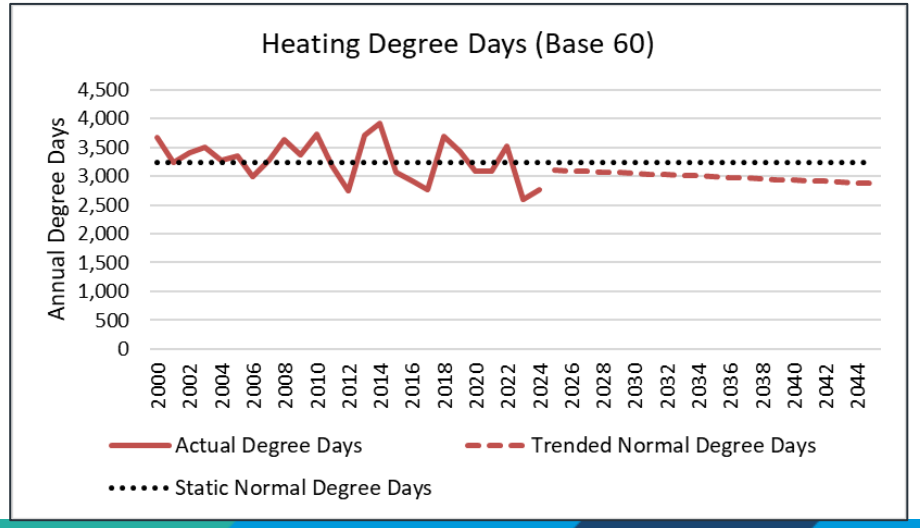
- Intensities based on the 2023 Annual Energy Outlook from the Energy Information Administration (EIA)
- Reflects changes in end-use ownership, efficiency trends, and home thermal shell efficiency

Trended Normal Weather

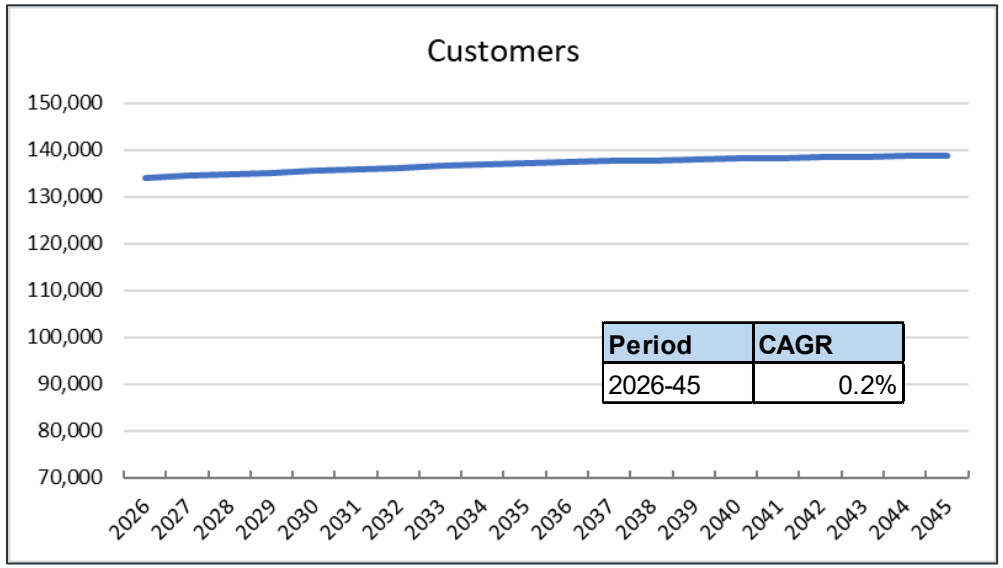


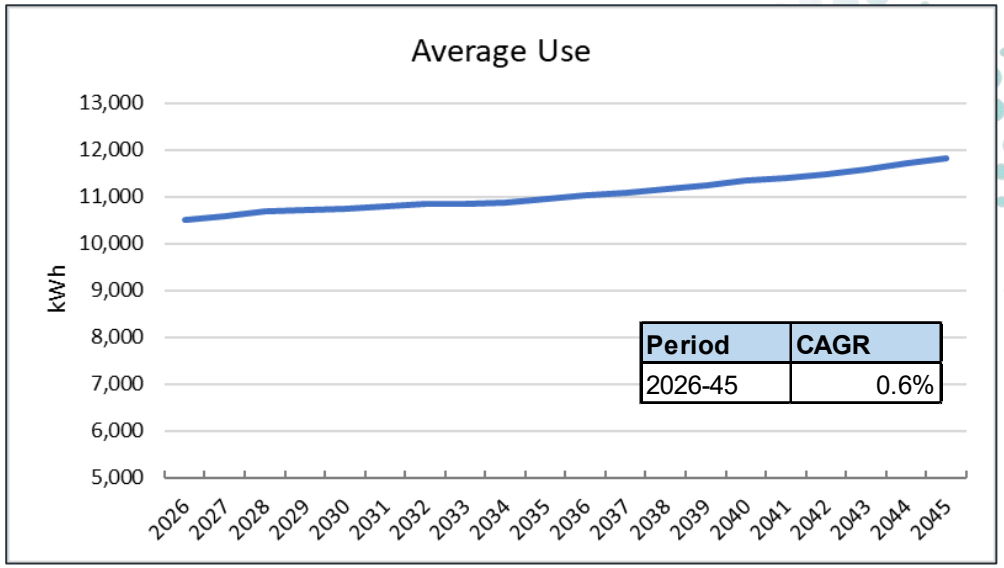
- Trend based on statistical analysis of historical weather data (1988 to 2024)
- Average annual temperature increasing 0.6 degrees per decade
- Decline in HDD (0.4% annual decline)
- Increase in CDD (0.4% annual increase)

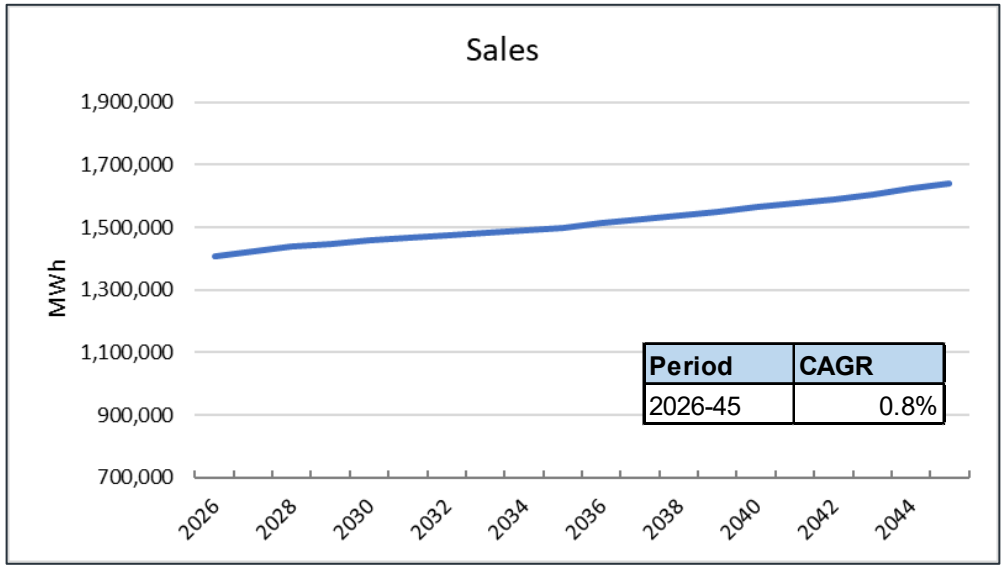




Residential Forecast

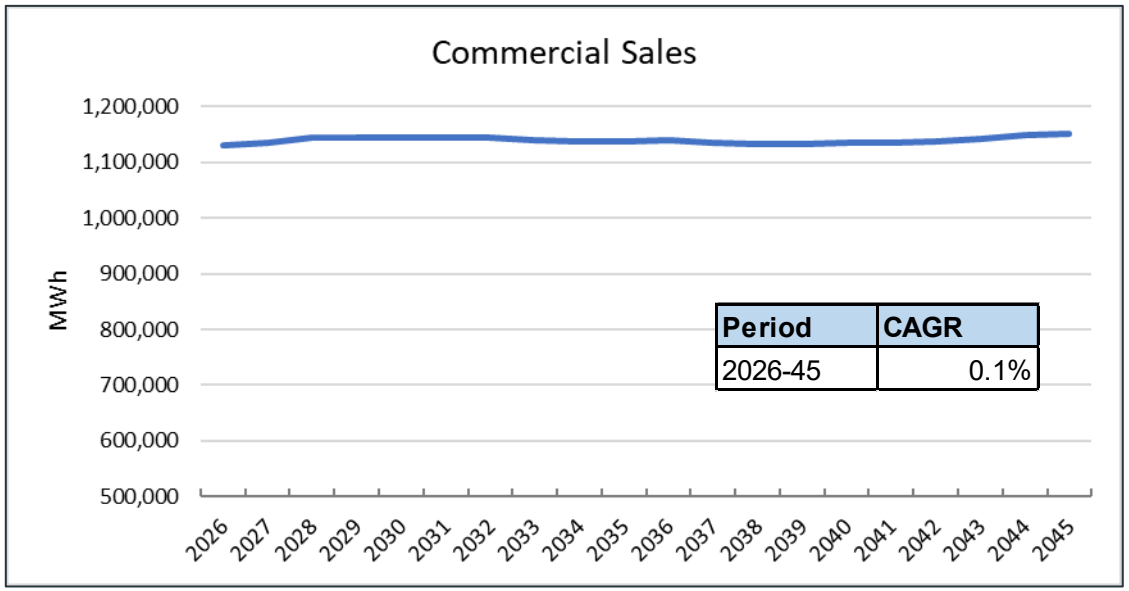


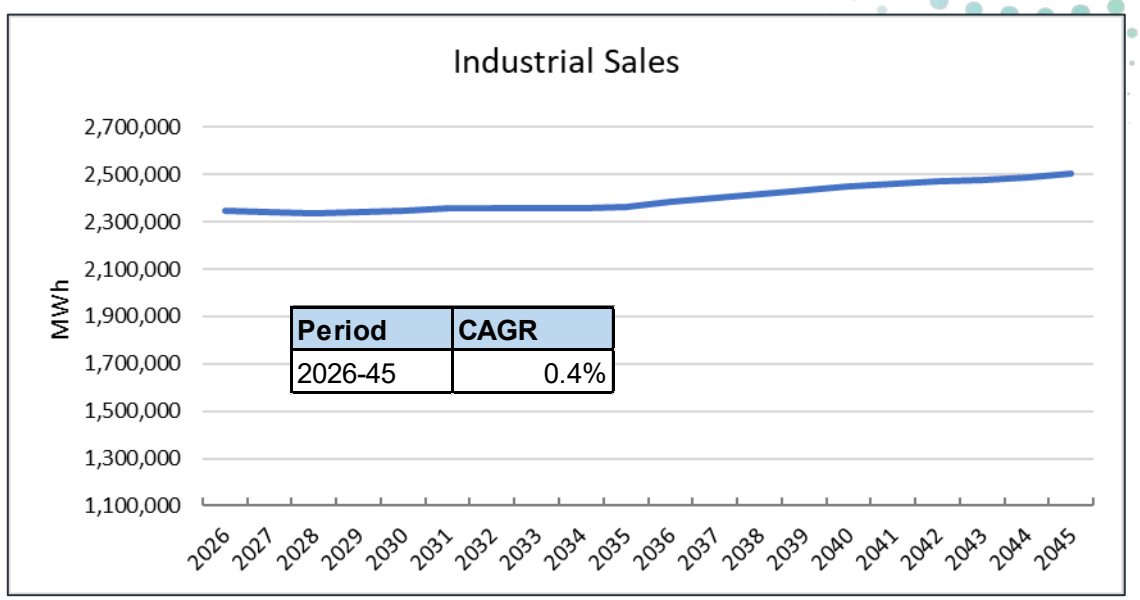




- Does not include the impact of future CEI South efficiency program savings
- Does not include the impact of EV or PV

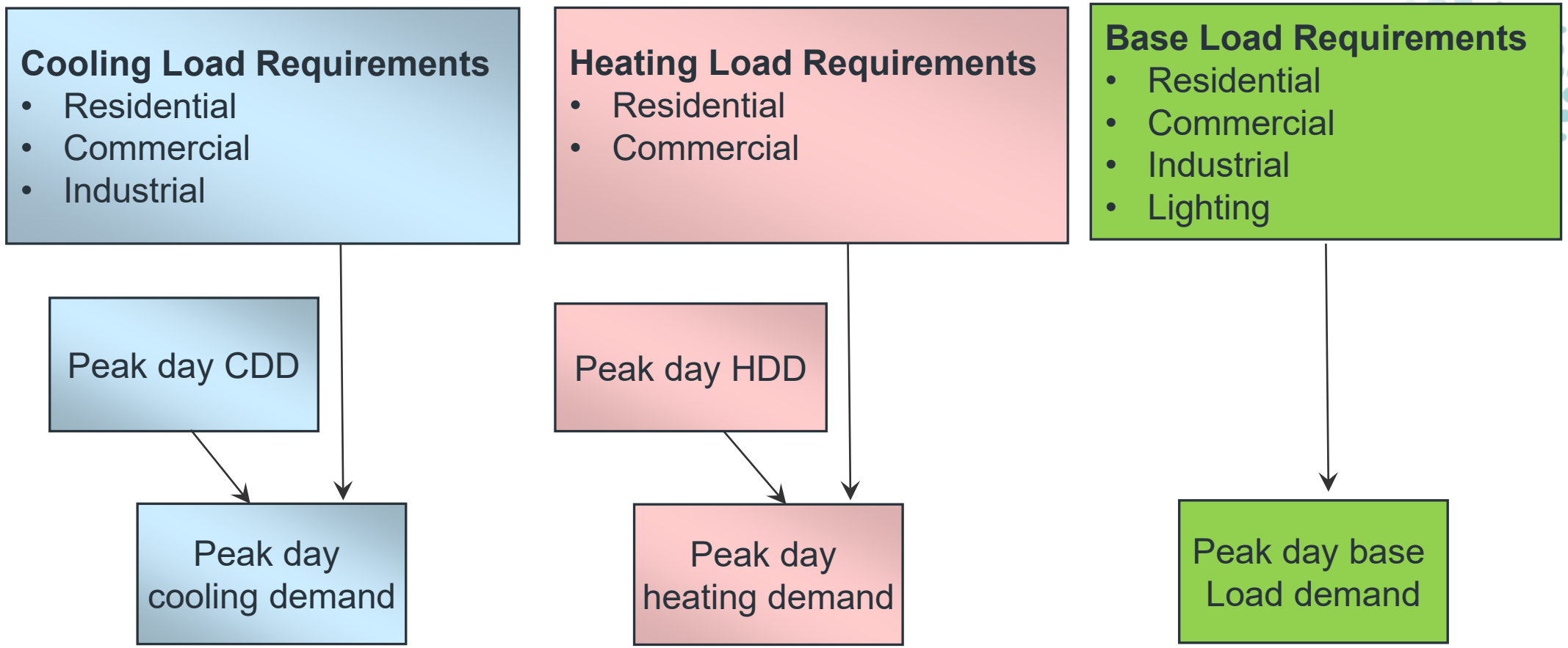
Commercial & Industrial Forecast





- Does not include the impact of future CEI South efficiency program savings
- Does not include the impact of EV or PV

Peak Model Framework



- Model produces a baseline peak forecast, not including the impact of EV or PV

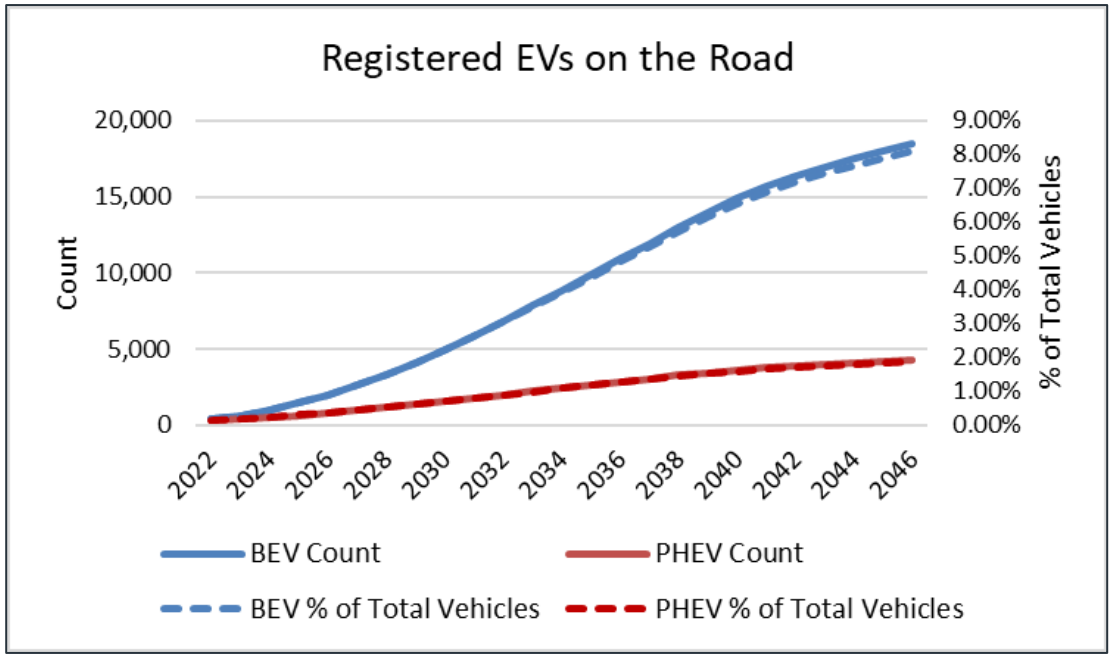
Electric Vehicle (EV) Forecast Methodology

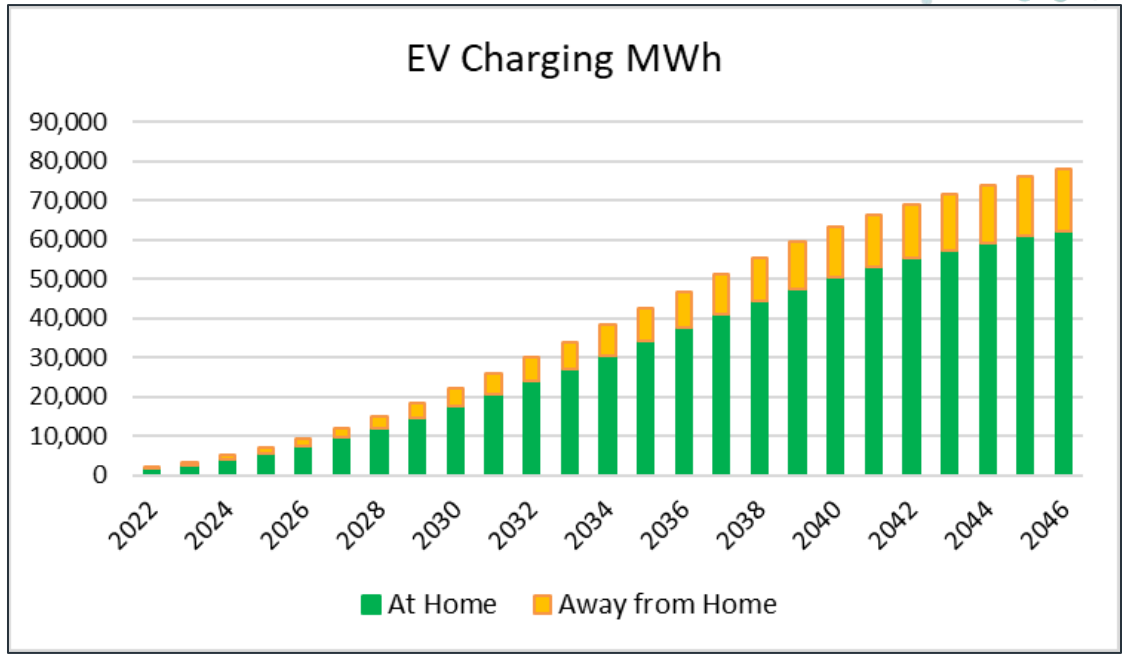
- Energy Information Administration (EIA) forecast based on share of new vehicle sales; differentiating between all electric (BEV) and plug-in hybrid electric (PHEV).

- Starting electric vehicle numbers based on the number of currently registered electric vehicles in CEI South's service territory.

- Annual kWh per vehicles based on the current mix of BEV and PHEV and 12,000 miles per year.

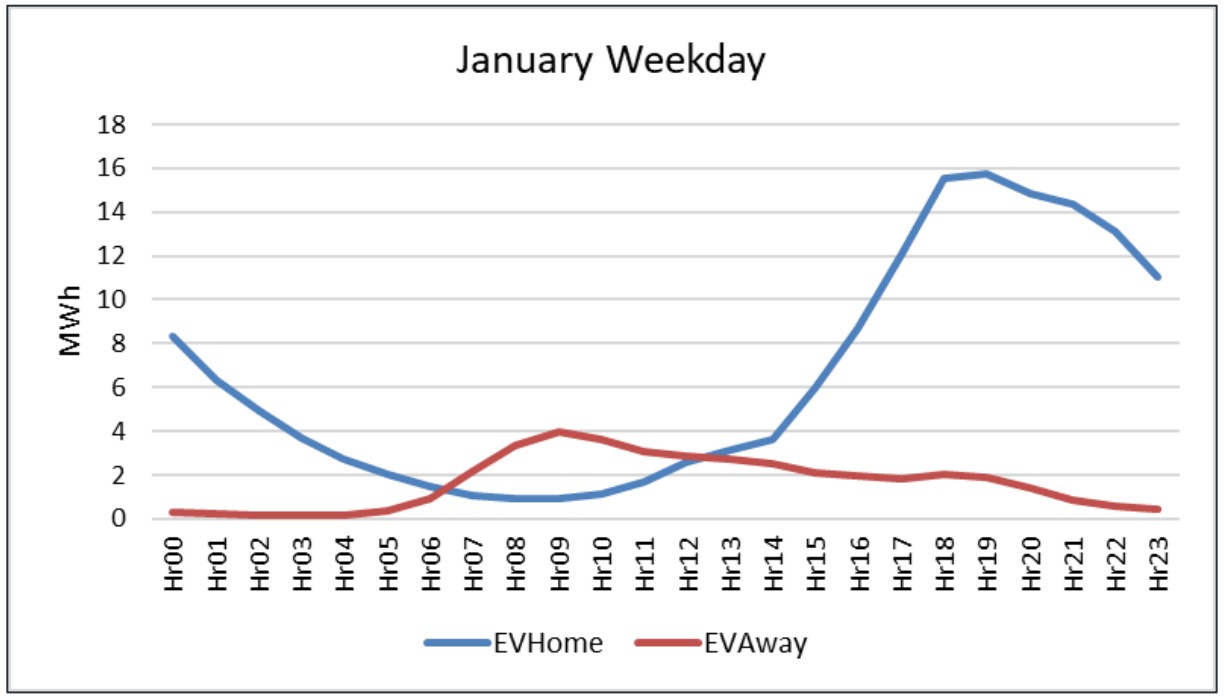
Electric Vehicle (EV) Forecast





- Currently there are approximately 1,000 BEV and 520 PHEV in CEI South's service territory

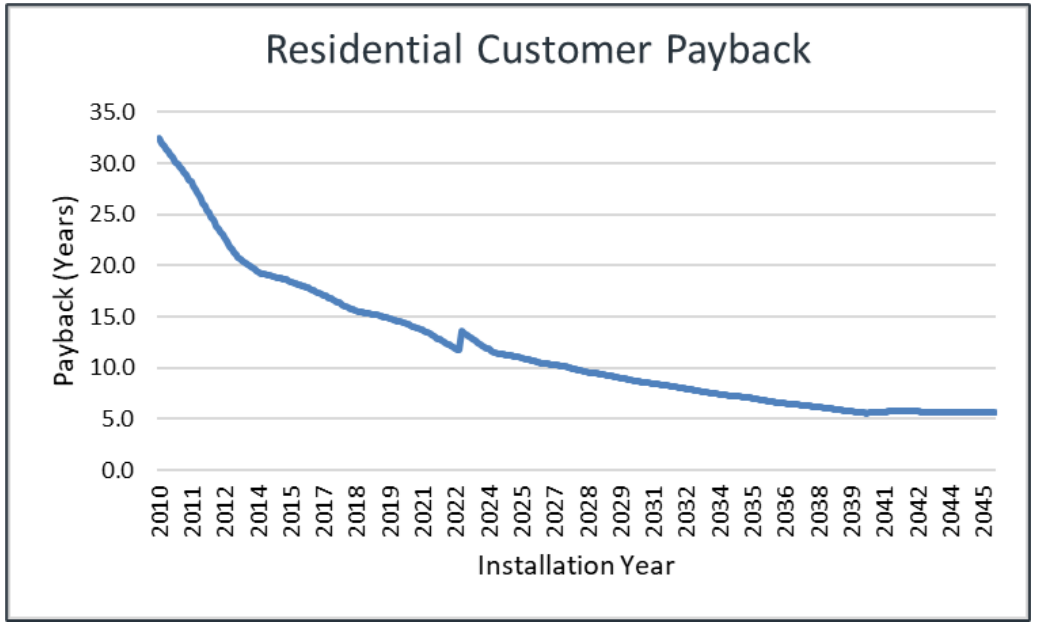
Electric Vehicle Charging Profiles



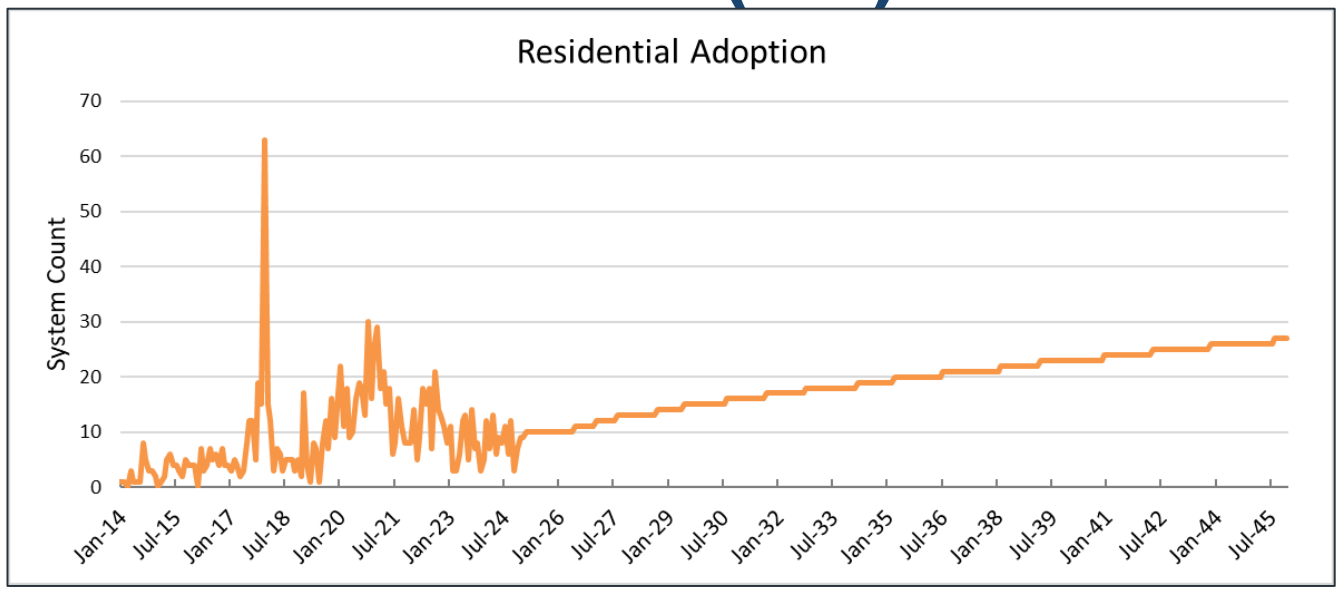
- Separate charging profiles based on home and public/workplace charging
  - Assumes that 80% of charging occurs at home and 20% away from home
- Seasonal differences based on temperature assumptions
- Profiles derived from the National Renewable Energy Laboratory's EVI-Pro Lite tool

Customer Owned Photovoltaic (PV) Forecast Methodology

- Monthly adoption modeled as a function of simple payback
  - Incorporates declining solar system costs, electric price projections, changes in net metering laws, and federal incentives
    - Switch from net metering to Excess Distributed Generation (EDG) policy
    - Continued decline in solar costs
    - Future projections of electric prices

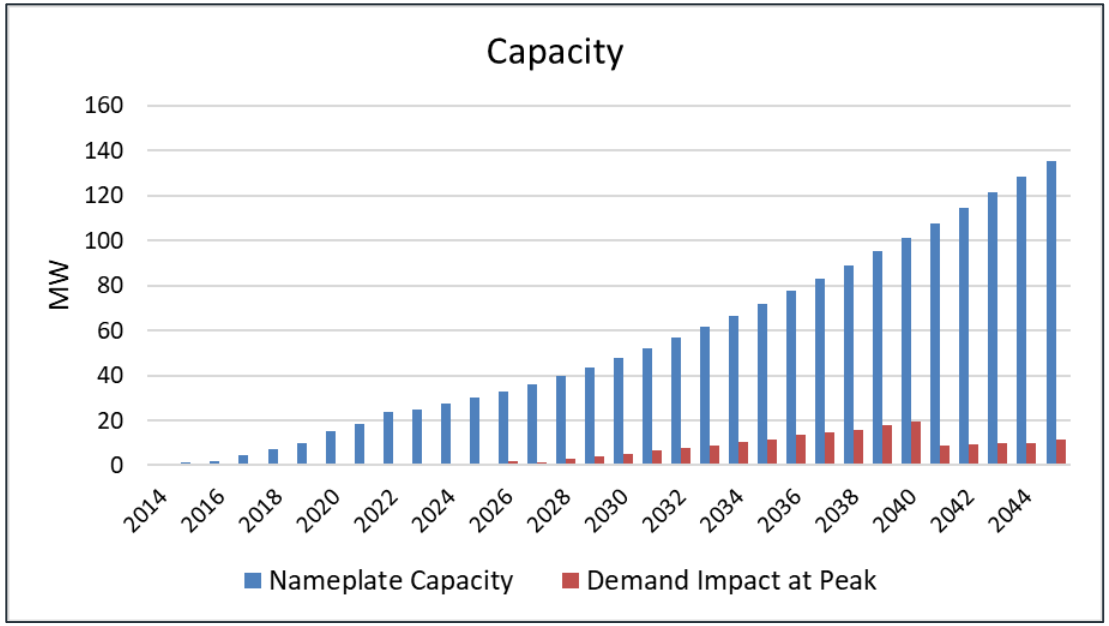


Photovoltaic (PV) Forecast

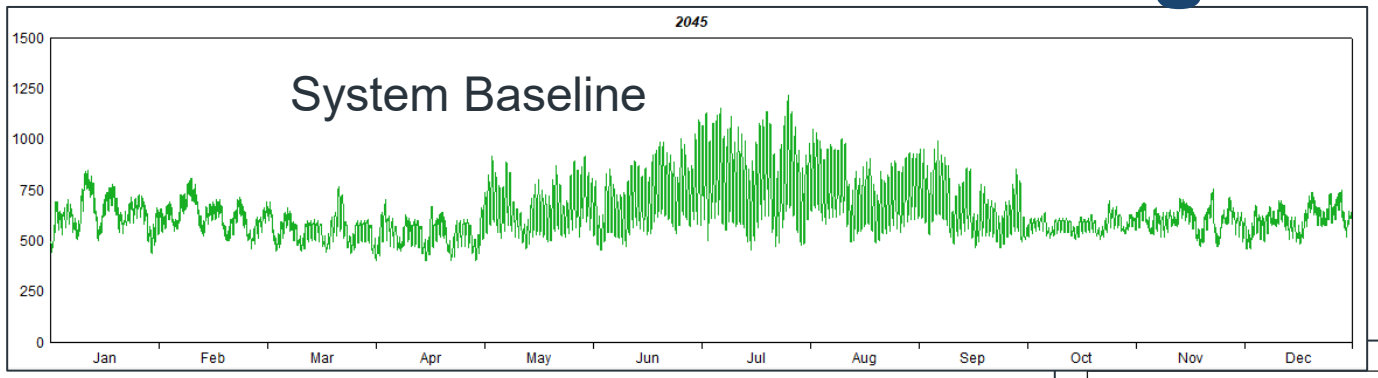


- Total installed capacity derived by combining monthly adoptions with average (kW) system size
- NREL PVWatts hourly solar profile is used to calculate monthly load factors and estimate monthly solar generation

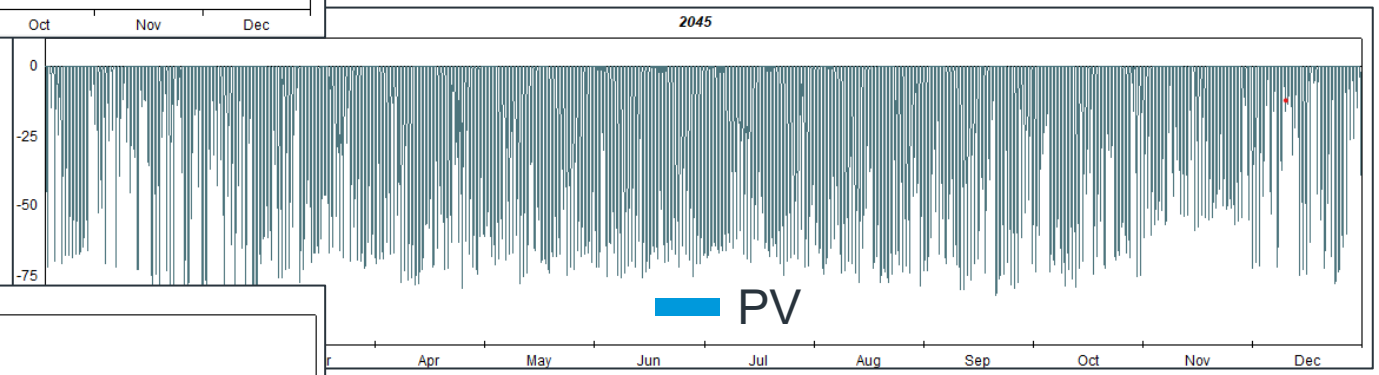
- Commercial adoption based on historical relationship between residential and commercial installations.

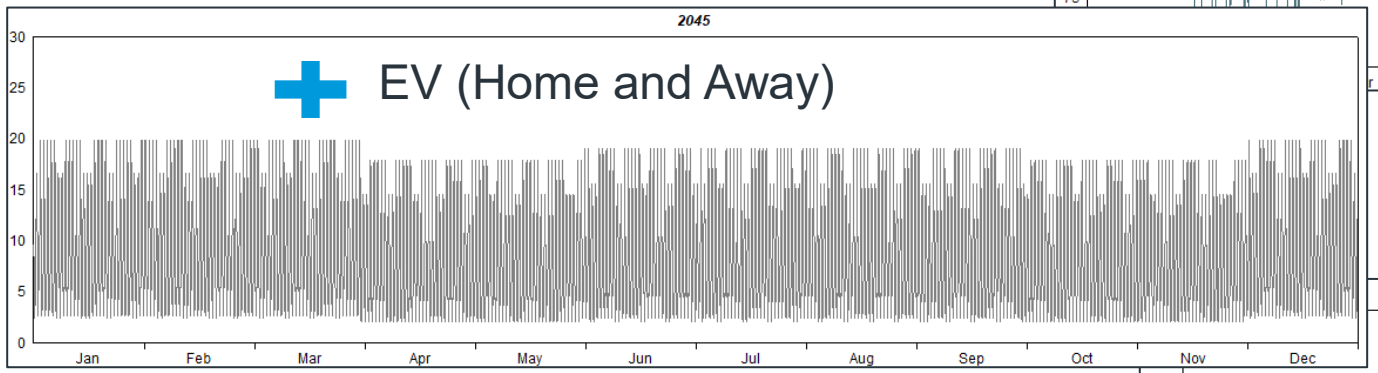


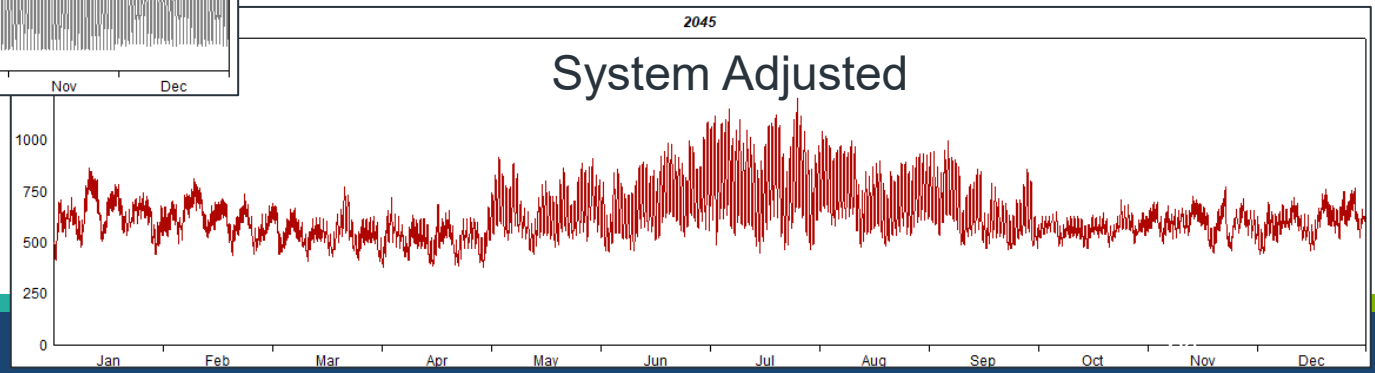
Peak Forecast: Accounting for EV & PV



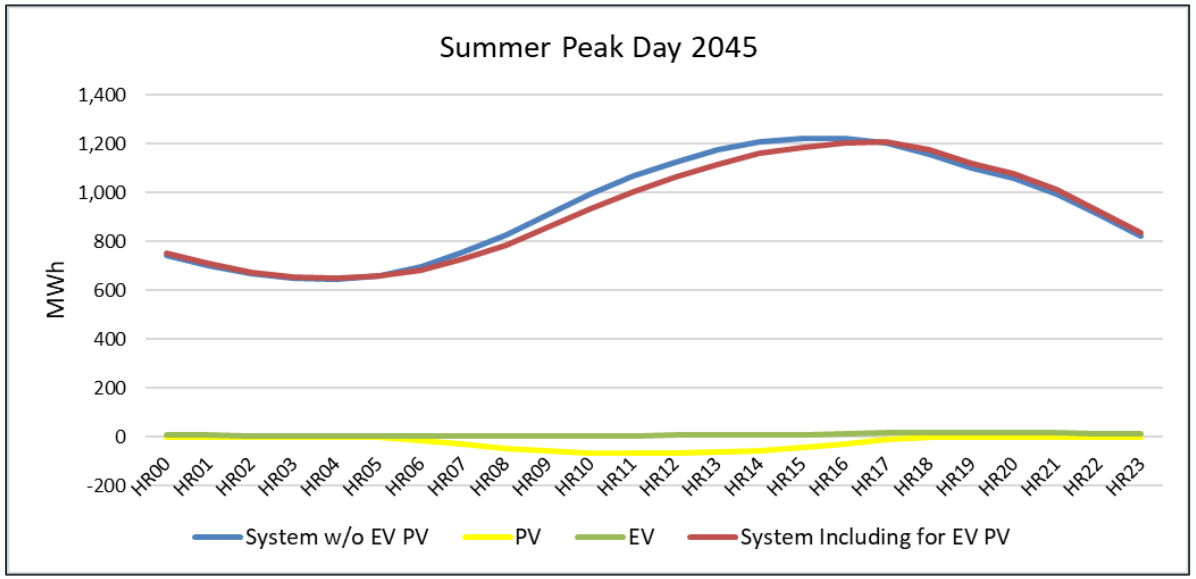
- Combine monthly or annual MWh forecasts with hourly profiles forecasts





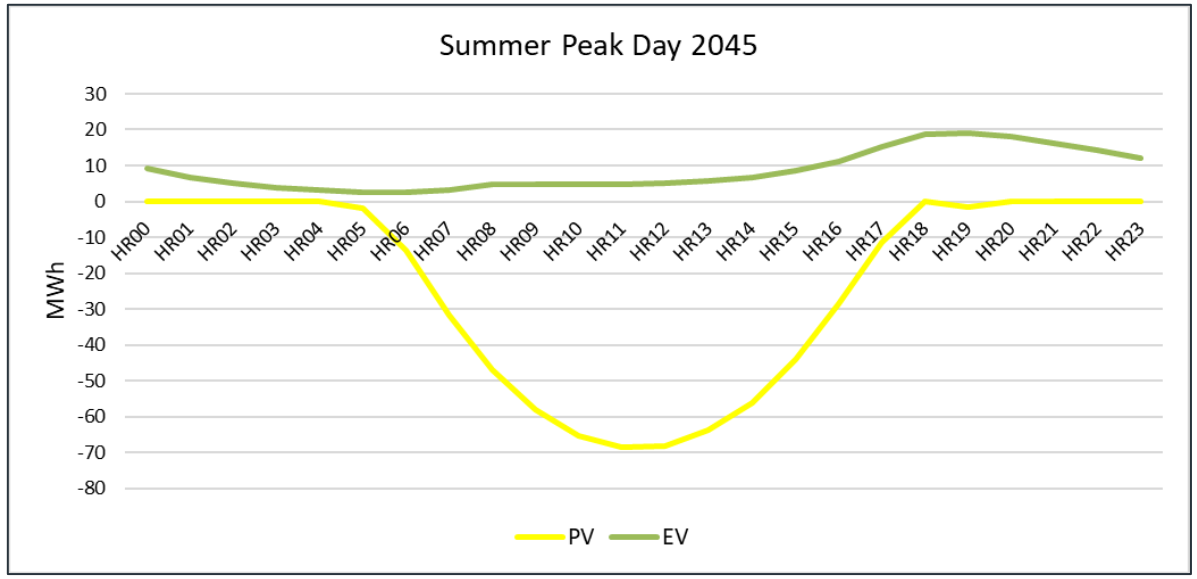


Peak Day Impact of EV & PV: Summer

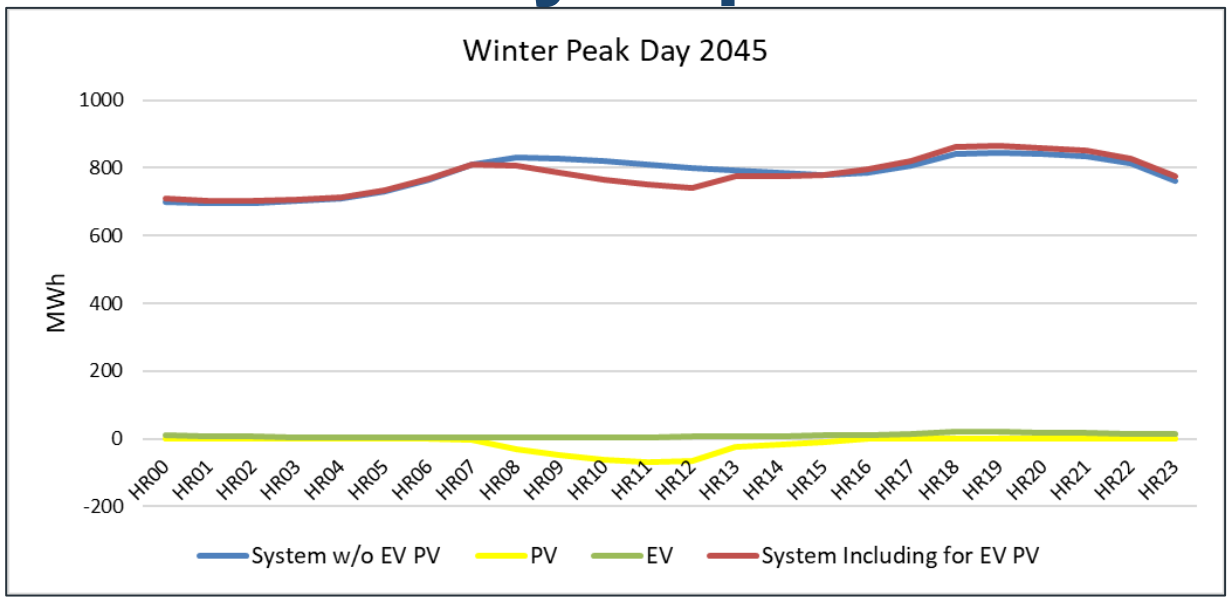


- The impact of EV and PV causes the system peak to move two hours later into the evening

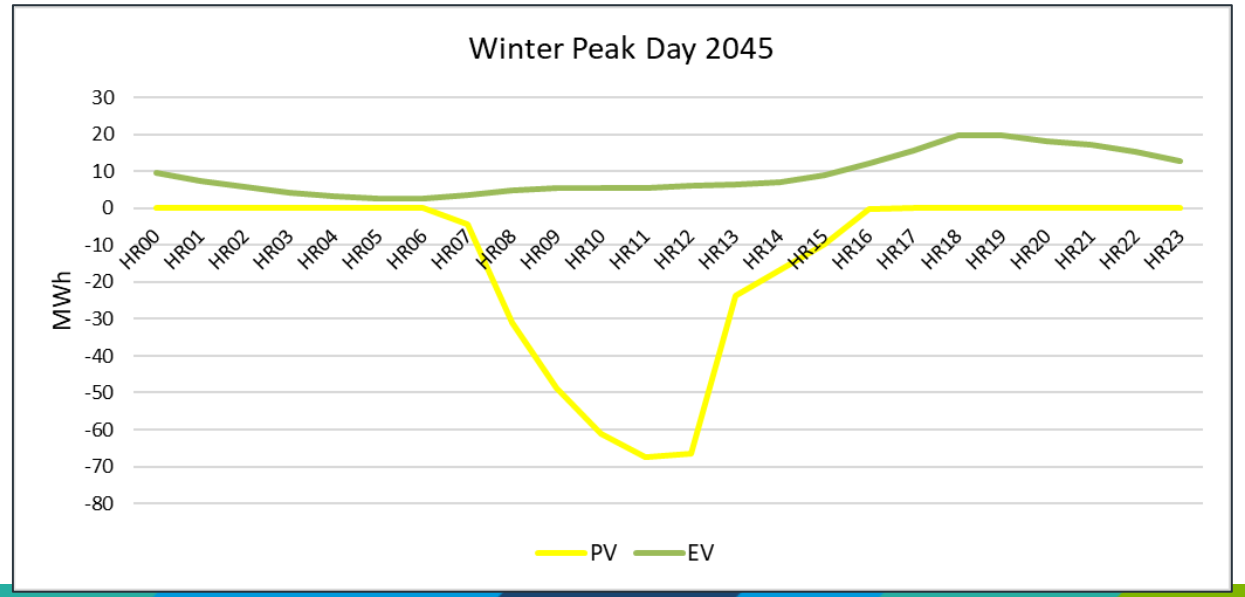
- As the peak shift the impact of addition PV decreases and EV increases



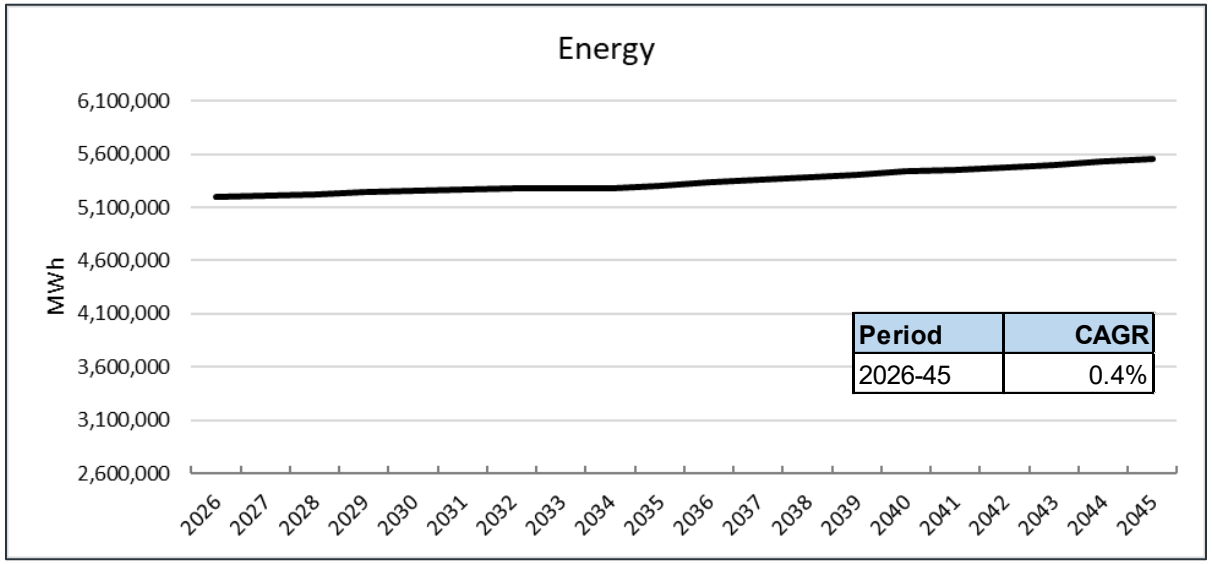
Peak Day Impact of EV & PV: Winter

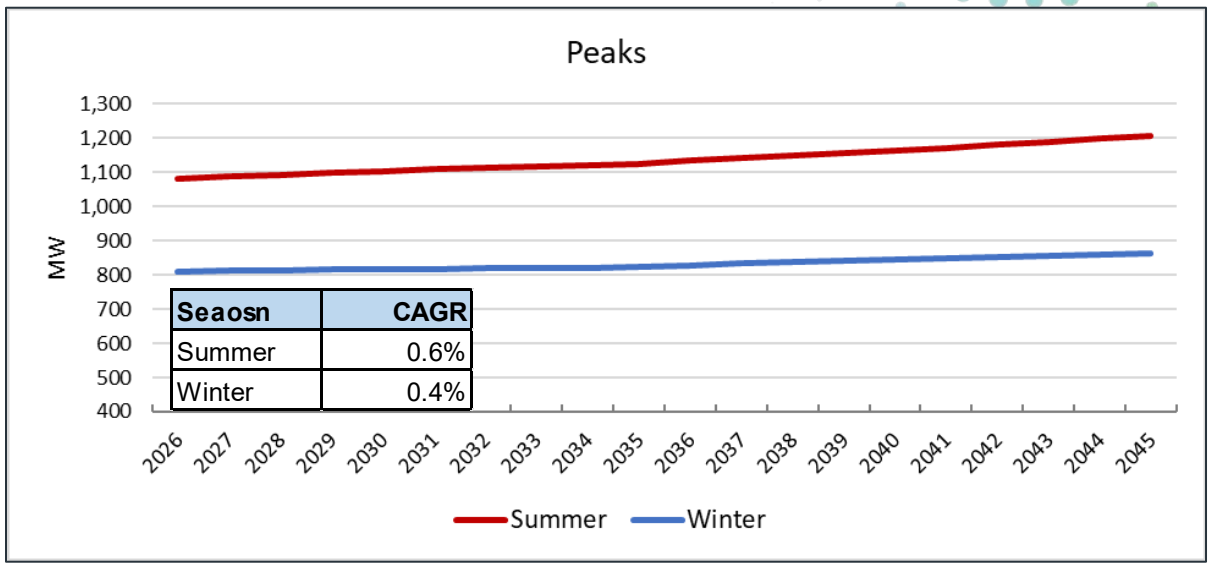


- Winter peak now occurs in the evening
- Solar has no impact on winter peaks



Energy & Peak Forecast





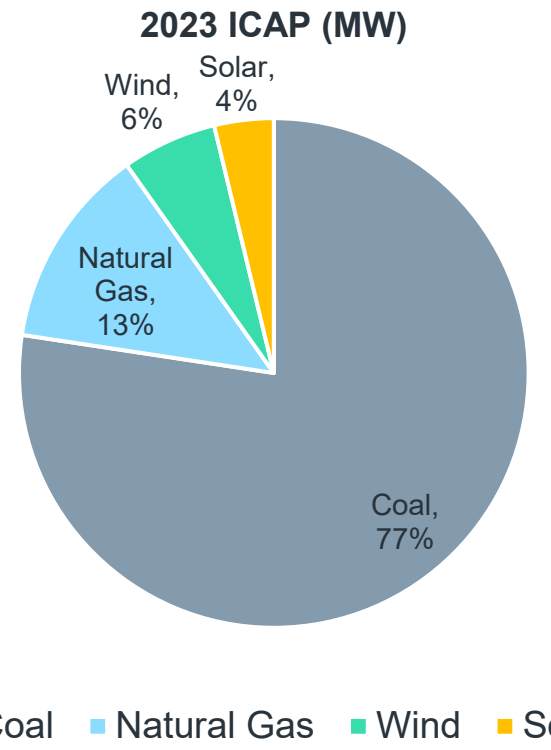
- Does not include the impact of future CEI South efficiency program savings
- Includes the impact of photovoltaics and electric vehicles

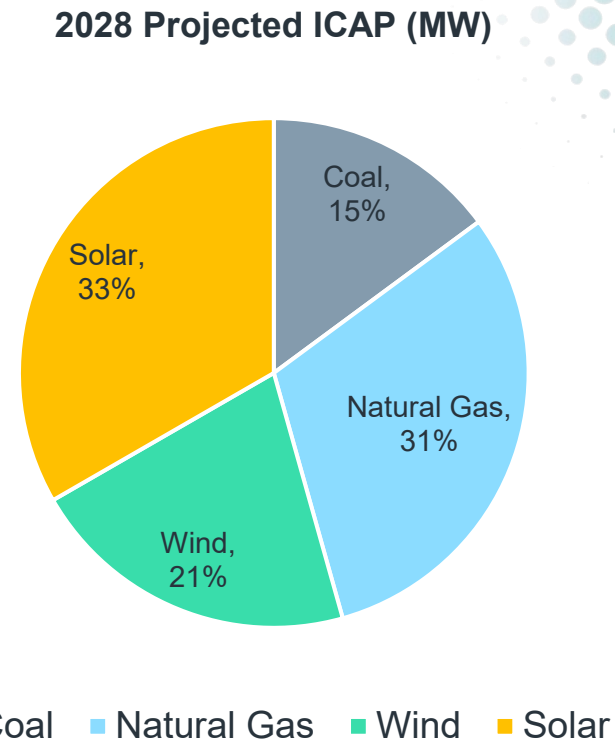
Q&A

Resource Options

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

CEI South Resource Mix





CEI South's resource mix has been evolving. The 2025 IRP will evaluate the current and future resource needed to meet customers' electrical energy needs for reliable, resilient, stable, affordable and sustainable power, while considering risks and uncertainties

ICAP = Installed Capacity

CEI South Thermal Resources

Existing Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
F.B. Culley 2	Coal	90	1966	2025
F.B Culley 3	Coal	270	1973	
OVEC	Coal	32	1950s-60s	
A.B. Brown 3	Natural Gas	80	1991	
A.B. Brown 4	Natural Gas	80	2002	

Planned Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
A.B. Brown 5	Natural Gas	232	2025	
A.B. Brown 6	Natural Gas	232	2025	

OVEC = Ohio Valley Electric Corporation

CEI South Wind Resources

Existing Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
Benton County	Wind	50	2008	2028
Fowler Ridge	Wind	30	2009	2030

Planned Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
Galesburg	Wind	147	2026	2051
Additional Wind Power*	Wind	200	2027	

**Projects are not named due to confidentiality limitations*

CEI South Solar Resources

Existing Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
Troy	Solar	50	2021	

Planned Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
Posey	Solar	191	2025	
Vermillion	Solar	185	2028	2042
Wheatland	Solar	150	2026	2046
Rustic Hills	Solar	100	2028	2052

New Alternative Resources: Thermal



Simple Cycle Natural Gas

- F class
- J class



Combined Cycle Natural Gas*

- Fired and Unfired
- F class**
- G/H class
- J class



Peaking Natural Gas

- Reciprocating Engines
- Aeroderivative SCGT



Nuclear

- Small Modular Reactors



Existing Unit Conversions

- A.B. Brown SCGT to CCGT
- F.B. Culley 3 Coal to NG Conversion/ Co-Fire

** Only select CCGT models will be considered for the base capacity expansion simulations, while additional options may be considered during the large load sensitivity runs. 1x1 and 2x1 configurations may be considered.*

***CCS as a selectable option is currently only being considered on the F class CCGT*

New Alternative Resources: Non-Thermal



Wind

- Wind
- Wind with Storage



Solar

- Single Axis Tracking
- Single Axis Tracking with storage



Storage

- Short Duration Lithium Ion
- Long Duration Lithium Ion
- Long Duration Non-Lithium Ion



Hydroelectric

- At existing Newburgh dam
- At existing J.T. Myers dam



Demand-Side Management / Innovative Rates

- Demand Response
- Energy Efficiency
- Time of Use Rate

Q&A

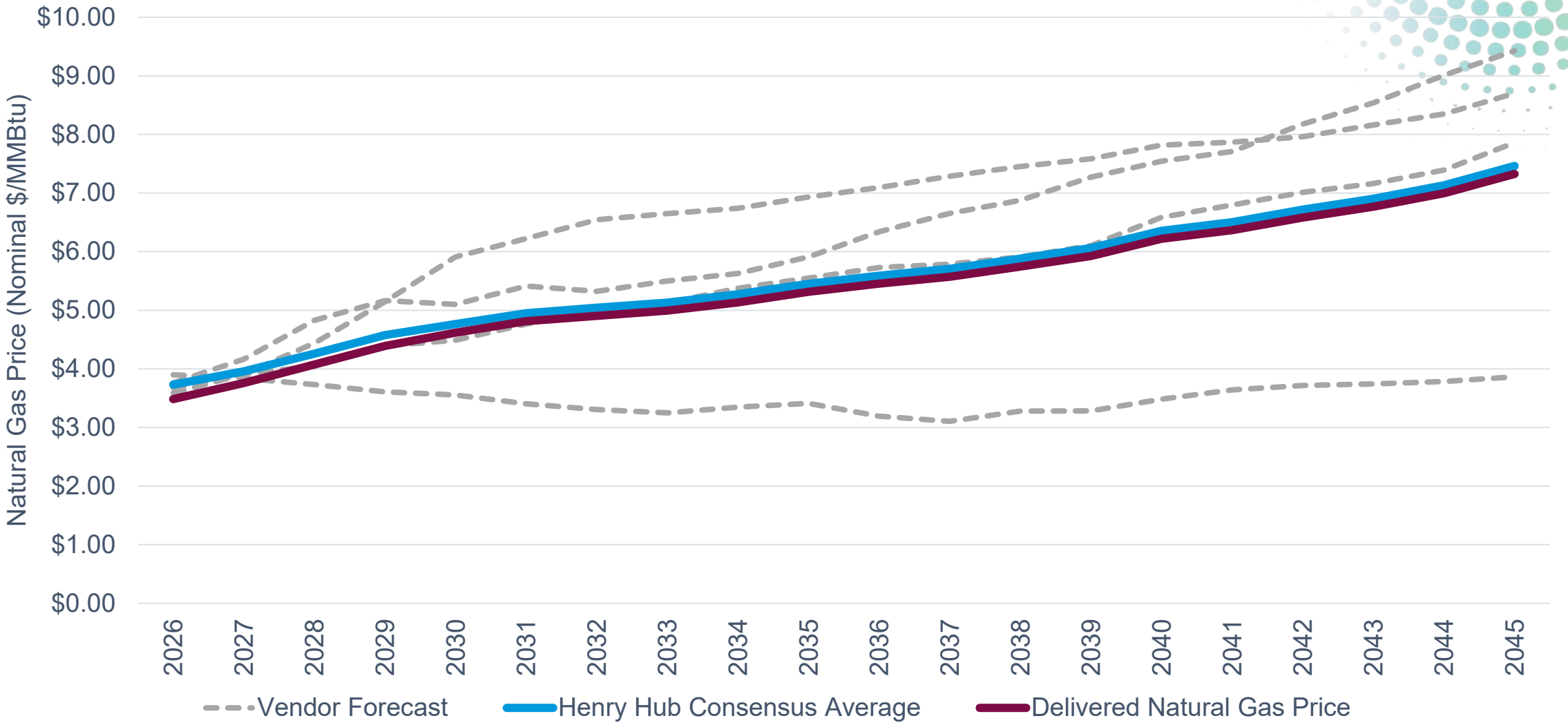
Commodity Inputs

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

Commodity Input Methodology

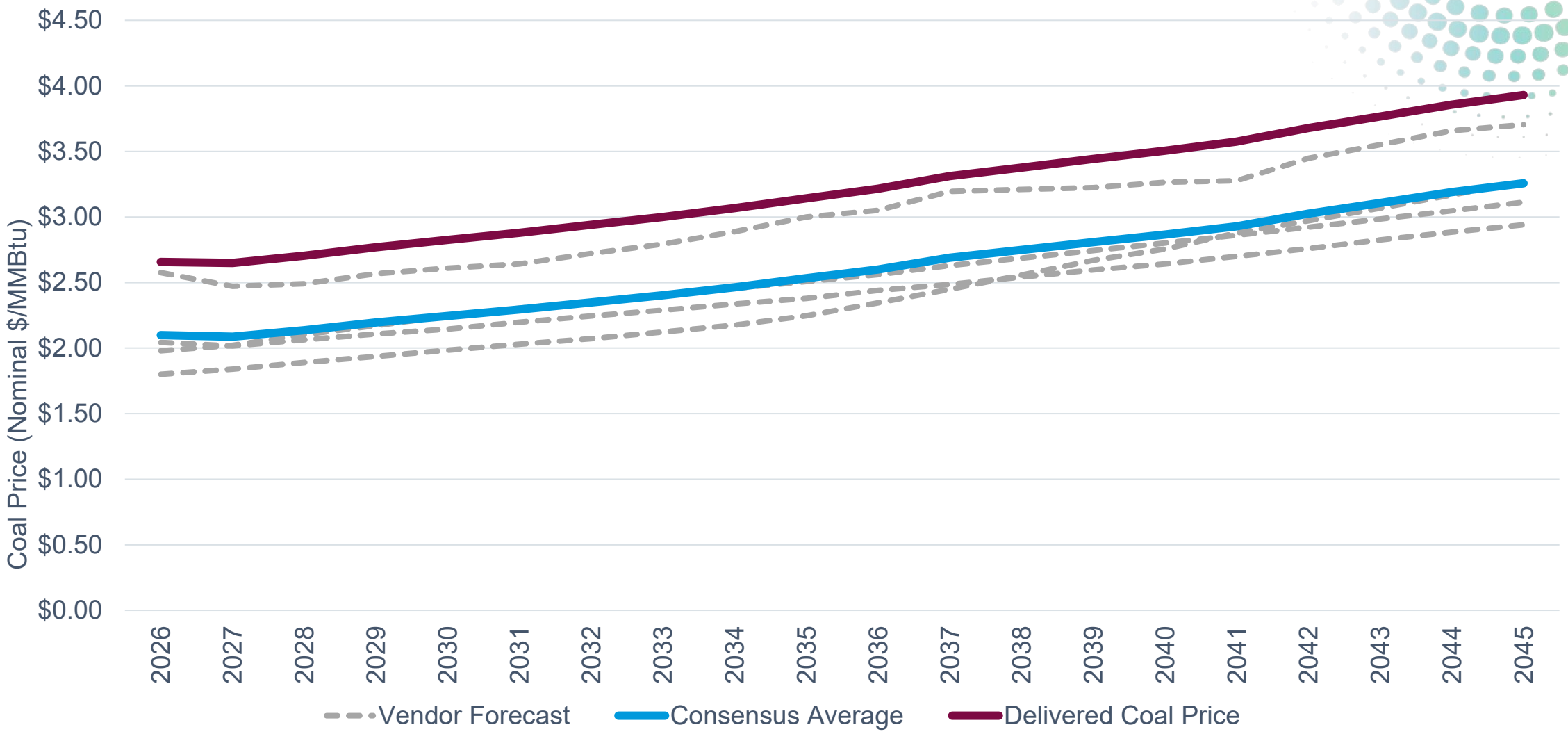
- CenterPoint Energy Indiana (CEI) South surveyed and incorporated a wide array of sources in developing its Reference Case Commodity inputs, which reflect a current consensus view of key drivers in power and fuel markets
  - This methodology protects against reliance on a single forecast
- Commodity Inputs include:
  - Henry Hub and delivered natural gas prices
  - Illinois Basin mine mouth and delivered coal prices
  - MISO capacity costs

Natural Gas (Henry Hub) Forecast



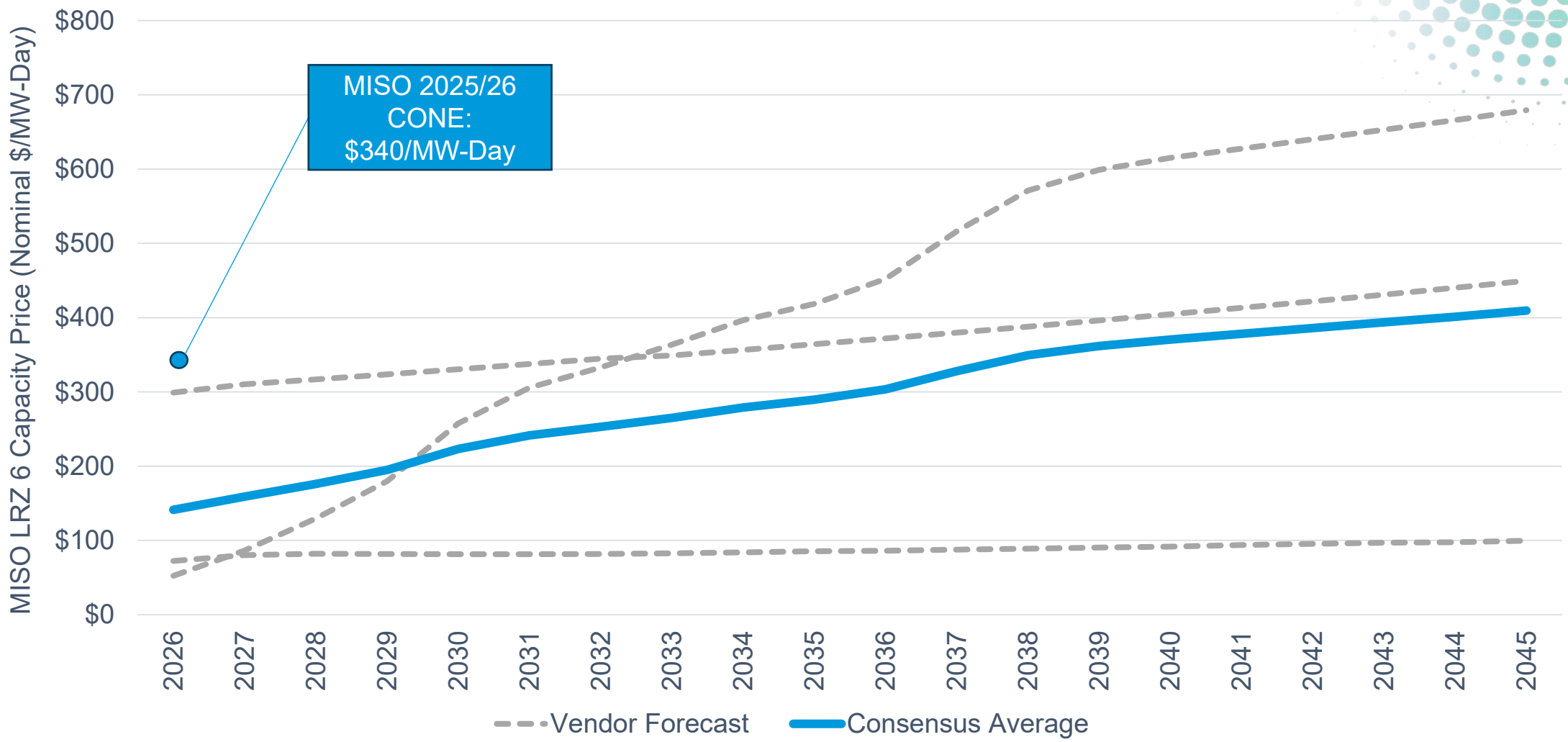
$/MMBtu = Dollars per Million British Thermal Units

Coal Forecast



$/MMBtu = Dollars per Million British Thermal Units

MISO Capacity Forecast



LRZ = Local Resource Zone *CONE = Cost of New Entry*

Q&A

Scenario Development

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

Scenario Development

- **Scenario ("Plausible Future"):** a simulation with a specific set of input assumptions
  - Scenarios are used to capture different goals or views of the future
  - Scenarios are commonly structured such that they represent plausible future states that provide high and low boundaries relative to the reference case
  - Forecasts within each scenario are internally consistent
- **Sensitivity:** a single variable that drives results
  - Sensitivities may be used to change only one variable at a time to understand the impact of that single risk factor

Reference Case Scenario

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Reference Case	Clean Air Act 111 (b & d)	IRA	None	Base	Base	Base	Base	Base

- As per Rule 170 IAC 4-7-4, the base case [reference case] is to be the most likely future scenario. As such, it is designed to be an extension of the status quo
- The Reference Case includes base commodity forecasts and assumptions for the following key drivers:
  - Policy Factors
    - Clean Air Act 111 (b & d)
    - Inflation Reduction Act (IRA)
    - CO_2 Policy
  - Load
  - Commodity Prices
    - Consensus natural gas price
    - Consensus coal price
  - Capital costs
    - Generation (informed by technology assessment and All Source RFP market data)
    - Energy efficiency (based on market potential study)

Narrative - High Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher

- In the High Regulatory Scenario, the Clean Air Act 111(b & d) is enforced as well as expanded to include existing gas resources and a CO_2 Tax is added
- **Load (↓)** – additional regulation drives lower demand growth for electricity
- **Commodity Prices (↑)** – additional environmental regulations increase costs for producing NG and coal, thus driving prices up
- **Generation Capital Costs (↓)** – continuation of the IRA, technology advancements, and lower demand for new generation results in lower capital costs
- **EE Costs (↑)** – lower load leads to less opportunity for cost-effective energy efficiency. In addition, a high regulatory environment leads to more codes and standards for equipment; This in turn results in higher incentives for more efficient equipment

Narrative - Low Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	None	Higher	Lower	Lower	Higher	Lower

- Under the Low Regulation Scenario, several environmental policies are eventually revised, including CAA 111. No new carbon emission regulations are created
- **Load (↑)** – reduced regulation encourages expansion of industrial/other large load users
- **Commodity Prices (↓)** – lower regulatory encourages the use of fossil fuels, increasing supply and lowering prices
- **Generation Capital Costs (↑)** – reduced incentives for renewables and increased pressure from tariffs drive costs up for new generation. Additional load growth also leads to an increase in demand, and higher costs
- **EE Costs (↓)** – higher load leads to greater opportunity for cost-effective energy efficiency and thus decreasing incentive costs

Scenario Summary

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	Clean Air Act 111 (b & d)	IRA	None	Base	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	None	Higher	Lower	Lower	Higher	Lower

Q&A

Stakeholder Questions and Feedback

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

Q&A

- In-person attendees – please raise your hand to be recognized
- Virtual attendees will be in listen-only mode – to participate:
  - Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
  - Enter questions into the “Q&A” feature in Teams

- Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

CenterPoint 2025 IRP
1st Stakeholder Meeting Minutes Q&A
March 19, 2025, 9:00 am – 3:00 pm CDT

Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Introduced the meeting facilitator and covered meeting protocols and participation.

Shane Bradford (Vice President, CenterPoint Energy) – Welcome, Safety Message, Introduction to CenterPoint Energy, Generation Transition Timeline Overview.

- General Questions
  - Question: The Demand Response ("DR") proposals are still subject to conversation and change with the Demand Side Management ("DSM") Oversight Board. Is that still the case?
    - Response: Yes. [We will still discuss DR with the DSM Oversight Board Members.]
  - Question: How long of a timeframe are you referring to when you speak about sustainability over time? If you make an investment now, especially in technology such as renewables, that may lead to sustainability in the long term.
    - Response: The Integrated Resource Plan looks over a 20-year period from 2026-2045. Additionally, CenterPoint Energy has an internal goal of being net-zero by 2035. Please refer to the Generation Transition Timeline (Slide 10) for more information regarding CenterPoint Energy's adoption of renewable energy technologies.
  - Question: Is there a plan or need to use securitization for F.B. Culley Unit 2 retirement?
    - Response: Not at this time. The securitization law, as it currently is written, set up a pilot program with specific requirements for a project to qualify for securitization. The F.B. Culley Unit 2 retirement does not meet those specific requirements.
  - Question: For the new wind and solar projects shown on the Generation Transition Timeline, do the projects have Indiana Utility Regulatory Commission (IURC) approval and is the interconnection worked out for those?
    - Response: Every project on the Generation Transition Timeline has been IURC approved. The projects shown as coming online in 2027 or later are in the MISO 2020 Queue, and DPP Phase 3 results are currently being finalized.
  - Question: The conversion of F.B. Culley 3 from coal to natural gas in 2027 was a finding from CenterPoint's last IRP. Why are you reevaluating that decision as part of this IRP?
    - Response: Following the last IRP, CenterPoint developed a more refined cost estimate of converting F.B. Culley Unit 3 from coal to natural gas, including our gas transportation cost. This information revealed the near-term impact on customer rates would increase bills for customers in the short term. While the conversion of Culley 3 to natural gas remains under consideration, this IRP provides an opportunity to reevaluate the decision using the most current and comprehensive information available, with the

goal of determining the most cost-effective and reliable path forward for customers in the near and long term.

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Discussed updates from the last stakeholder meeting including feedback and enhancements and presented an overview of the 2025 IRP process with the target date release schedule and draft objectives and measures.

- Slide 16 2025 Stakeholder Process
  - Question: Who do I contact about signing an NDA for the 2025 IRP process?
    - Response: Please send a request to IRP@CenterPointEnergy.com.
  - Question: Will a draft IRP be released to stakeholder group before November 1, 2025 to allow stakeholders to make comments on the draft?
    - Response: During the 4th Stakeholder Meeting, the full analysis and results will be shared. During this meeting, CenterPoint Energy will welcome stakeholder feedback before filing the final IRP document.
  - Question: Other utilities are having separate meetings with technical experts in correlation with the public IRP stakeholder meetings. CenterPoint had these last IRP, do you plan to have these technical meetings again this IRP cycle?
    - Response: Between each stakeholder meeting, CenterPoint will have technical conversations with those representing organizations who have signed the NDA. Please reach out to the IRP email IRP@CenterPointEnergy.com to receive the NDA.
- Slide 19 Objectives & Draft Metrics
  - Question: Regarding the draft metrics for environmental sustainability, we would like to suggest removing CO_2 intensity, keeping CO_2-e tons, and adding both SO_2 and NOx emissions as separate metrics.
    - Response: We will consider that feedback when detailing the final measures.
  - Question: There is a risk of environmental compliance costs associated with NOx emissions that I do not believe are captured by current metrics. I suggest that CO_2 emission intensity should be dropped, keeping total CO_2-e as the metric for GHG emissions.
    - Response: We will consider adding NOx and SOx metrics. NOx and SOx emissions can be considered in the modeling, from both an emissions and cost perspective [where applicable], similar to what we included in the last IRP analysis.
  - Question: What distribution resources and planning are you considering for this IRP?
    - Response: Incentives for rooftop solar will be investigated during this IRP. We can add more metrics or specificity as the process continues. Please let us know if there are additional items you would like to see included in the analysis.
  - Question: What is CenterPoint doing to protect the IRA Tax Credits?
    - Response: CenterPoint Energy is part of the Edison Electric Institute (EEI); EEI has been and continues to be supportive of the IRA tax credits. CEI South recently supplied EEI with information on specific projects to

help them in their efforts of supporting the IRA tax credits. We think those tax credits are important for our customers.

- Question: How do you calculate affordability? Is there consideration for the median income in Southern Indiana? Are you considering that rate of wages in 20 years is unknown?
  - Response: Historically, wages have grown proportionately with inflation, increasing by about 2.5% per year. Additionally, in the IRP, CenterPoint will consider the all-in cost impact for infrastructure, operating costs, etc. over 20 years for our generation portfolio, as well as the 5-year residential rate impact, which is meant to evaluate the near-term impact on customers.
- Question: Referring to the Affordability metric, would CenterPoint consider adding an energy burden calculation?
  - Response: CenterPoint will consider adding energy burden analysis as part of the IRP process and including it as a metric.
- Question: Does the IRA Tax Credit Exposure measure relate to future projects or current projects?
  - Response: Tax credit exposure is a concern for both current and future resources. We will have a metric that shows each portfolio's exposure to tax credits associated with new resources.
- Question: For the Reliability metric looking at unserved energy, does "varying market conditions" mean that CenterPoint will look at turning off access to the MISO market for this analysis?
  - Response: Yes, CenterPoint is considering varying the connection between MISO and CenterPoint for energy purchases as part of this analysis.
- Question: Regarding the "5-Year residential rate impact" measure, is the intent to have a compound annual growth rate on how much rates will go up every year? It would be good to get more granular.
  - Response: The 5-year residential rate impact will be a point-in-time value of what the impact on residential bills is expected to be at that time for each portfolio of generating resources.

- General Questions:
  - Question: In reference to FERC 1920, is CenterPoint Energy considering grid enhancement technologies, including those on the transmission system?
    - Response: CenterPoint Energy is currently utilizing grid enhancement technologies, such as Ambient Adjusted Ratings (AARs) on transmission, in accordance with FERC 881. Additionally, MISO is currently working on the Regional Transmission Expansion Plan, which includes grid enhancing technology. CenterPoint will continue to evaluate new and existing technologies in and outside the IRP process.
  - Comment: Indiana Senate Bill 422 requires a transmission analysis. We're starting an official Grid Enhancing Technologies (GETs) analysis with another Indiana utility soon. We encourage CenterPoint Energy to consider this type of study as well.

        - Response: Thank you for your comment. CenterPoint will take it into consideration.
    - Question: Is your grid equally reliable? If not, will you prioritize the most vulnerable grid areas?
        - Response: As generation portfolios are being considered, transmission analyses will occur in parallel to ensure that there is adequate reactive power on the system to maintain reliability.

Josh Swanson (Director, Power Supply Services, CenterPoint Energy) – Discussed the 2024 All-Source Request for Proposal (ASRFP) including bid requirements and results.

- Slide 26 RFP Results - Pricing
    - Question: Did you group together Distributed Generation solar and storage with utility-scale solar and storage? Would you share the pricing separated out?
        - Response: The prices displayed in the chart are only for utility-scale solar. To access the RFP bid data, stakeholders [without a competitive interest] will need to sign the NDA.
    - Question: Why is the pricing ($/MWh) for solar Power Purchase Agreements (PPAs) lower than pricing for solar plus storage PPAs?
        - Response: The prices for solar plus storage PPAs are additive. Thus, the component costs cannot be directly compared to those of standalone technology.
    - Question: Why are some of the bid prices in $/MWh versus $/kW-month?
        - Response: Due to the differences in contract structure, the units for purchases and PPAs are expressed in different units. For energy resources bid as a PPA, price is typically represented in a $/MWh amount. Storage resources bid as a PPA are typically represented in $/kW-mo as they offer capacity and do not produce any electricity. For purchase options, resources are typically represented in $/kW.
    - Question: Is there a way to get a price range for the thermal bids?
        - Response: Stakeholders [without a competitive interest] who complete an NDA with CenterPoint can receive more detailed information regarding the 2024 ASRFP. Please reach out to the IRP email IRP@CenterPointEnergy.com.
- General Questions:
    - Question: Similar to previous RFPs, technical stakeholders would appreciate an opportunity to review future RFPs before they are issued.
        - Response: During the 2022 RFP, CenterPoint Energy implemented many suggestions from stakeholders. As this RFP was not fundamentally different, many of those changes and other suggestions were carried into the 2024 RFP. We appreciate the feedback and will keep this in mind in the future.
    - Question: Regarding Small Module Reactors, I am concerned about the pricing of these resources.
        - Response: CenterPoint plans to consider a wide range of technologies as part of this IRP, and affordability metrics for different portfolios will be included in the scorecard analysis.

- Question: Did CenterPoint, or its affiliates, submit any project self-build bids into the RFP?
  - Response: No.
- Questions: How did you treat any bids that had both distributed generation solar and storage?
  - Response: We did not receive any solar plus storage distributed generation bids.

Kimberly Dunning (Manager, MISO Affairs, CenterPoint Energy) – Presented an overview of the Midcontinent Independent System Operator (MISO), including new initiatives such as Direct Loss of Load.

- Slide 29 MISO
  - Question: Can you elaborate on cost-effective generation? Are there specific formulas?
    - Response: MISO utilizes a day-ahead market in which generator owners bid in the cost that it will be to dispatch their resources. Every day, the lowest-cost resources will "clear" the market (i.e., generate electricity) before higher cost resources, at the necessary level to sufficiently meet demand. This enables the most cost-effective resources to be dispatched, ultimately lowering the cost of energy across the MISO footprint.
  - Question: What does the dispatch of the lowest-cost generators look like in MISO? I am concerned about the decision not to retire F.B. Culley 3 based on the market structure.
    - Response: Lowest-cost generation and the dispatch stack only are looking at the energy component of unit dispatch across all of MISO. The portfolios considered in this IRP will comprehensively evaluate energy and capacity to provide a broader, more all-inclusive view of the cost-effectiveness of all existing and new resources. Regarding the decision at F.B. Culley 3, CenterPoint will evaluate the impact of conversion to natural gas, as well as other alternatives.
- Slide 30 Resource Accreditation Reform – Direct Loss of Load (DLOL)
  - Question: Will you be using the most up-to-date indicative accreditation values under DLOL? The PY 23-24 values shown are outdated, as 25-26 values have been published: Link[1].
    - Response: Yes, CenterPoint plans on using the latest available information around DLOL and unit accreditation.
  - Question: Does DLOL allow the flexibility to properly evaluate and accredit storage hybrid projects?
    - Response: In the modeling of hybrid projects, we will have different accreditations for hybrid resources than standalone renewable or storage projects. In future stakeholder meetings, CenterPoint will be sharing more detailed information on the accreditation process.
- Slide 31 Reliability Imperative

[1] [MISO Indicative Direct Loss of Load (DLOL) Results, Planning Year 2025-2026]

    - Question: Could you describe the reliability-based demand curve and how that differs from before?
        - Response: The Reliability Based Demand Curve (RBDC) is a sloped demand curve which was put in place to improve price signals, incentivize capacity investments, and reduce market volatility[2]. [MISO's Tariff revision filing, 2023-09-29 Docket No. ER23-2977-000, details the implementation of the RBDC].
    - Question: Can you provide more information on the Value of Loss Load FERC Filing?
        - Response: MISO filed the Value of Loss Load (VOLL), which is intended to capture what a customer will pay when electricity is scarce. It sets the maximum price for energy in a given hour. They are increasing the VOLL from $3,500/MWh to $10,000/MWh[3]. [MISO's Tariff revision filing, 2024-11-26 Docket No. ER25-579-000, details revisions to update the rules governing VOLL].
- General Questions:
    - Question: Given that there is energy that flows from Canada to MISO, how does the current tariff situation affect energy into MISO and will that impact southern Indiana?
        - Response: In a public response, MISO stated that the flow of energy from Canada to the MISO footprint is less than 2%, so they do not see issues with the tariff.

Angie Casbon-Scheller (Director, Generation Compliance & Carbon Policy, CenterPoint Energy) – Discussed relevant environmental regulation, including the Clean Air Act and Clean Water Act.

- Slide 35 Clean Air Act 111(b) & (d) Greenhouse Rules
    - Question: Are A.B. Brown 5 & 6 excluded from the Clean Air Act 111(b)?
        - Response: Yes. They are considered existing due to when construction began.
    - Question: Why would CenterPoint look at a Low Regulatory Scenario, where there are lower environmental regulations?
        - Response: The statute for the IRP analysis requires CenterPoint model plausible scenarios. Moreover, it is prudent to determine the impact of these plausible scenarios for CenterPoint's customers.
- Slide 36 Clean Water Act 316(b) Rule
    - Question: There was mention of scenario analysis where changes to regulation will be considered. Will there be scenarios that include changes to 316(b)?
        - Response: The 316(b) costs will be included in every scenario. This regulation has not changed since it was published in 2014.
    - Question: Will you consider the retirement of F.B. Culley 3 and a replacement of solar or renewables as part of this IRP. Would 316(b) upgrades be avoided if F.B. Culley 3 were retired?

[2] [MISO Resource Adequacy Subcommittee, RASC-2019-9, September 8, 2023]
[3] [MISO Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve]

        - Response: [No, we do not plan to retire F.B. Culley 3 before the 2026-2028 compliance deadline for 316(b) (see Slide 36).]
    - Question: Can you provide a high-level overview of intake screens?
        - Response: F.B. Culley facility currently has intake screens for the water intake from the Ohio River. These screens would be upgraded to have smaller openings and a fish return system to better protect the aquatic life.
- General Questions:
    - Question: Is CenterPoint taking affordability metrics such as insurance costs, health costs, air conditioning costs, etc. into account as part of the IRP?
        - Response: Typically, all of those costs are considered in the development of environmental regulations. New legislation, including a CO_2 tax, will be added to the high regulatory scenario.
    - Question: Will available Coal Combustion Residuals (CCR) disposal capacity be a limiting factor for how long F.B. Culley 3 will be able to operate on coal?
        - Response: CenterPoint does not believe this will be a limiting factor in this decision, though will continue to monitor for any changes that could have an impact.

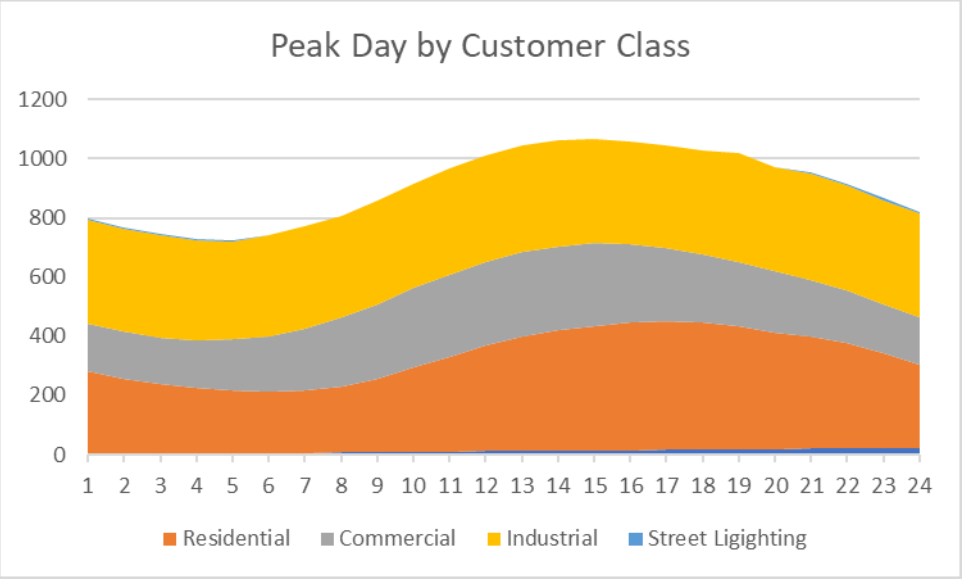
Justin Forshey (Director, Energy Solutions and Business Development, CenterPoint Energy) – Discussed the motivation and methodology for considering large load additions in the 2025 IRP.

- General Questions:
    - Comment: CenterPoint should continue to consider equitable access to renewable energy across different customer classes.
        - Response: Thank you for your comment.
    - Question: Buildings are a huge part of economic development, and they have operations and maintenance costs. The IRP needs to address the operations and maintenance costs over the years, and it would be beneficial to look at reducing operations and maintenance costs. I am suggesting getting more involved with those building committees.
        - Response: CenterPoint partners with regional economic development organizations and elected officials to help drive positive economic development for the region. Additionally, as we think about Energy Efficiency, CenterPoint has robust energy efficiency programs and has recently kicked off a new building optimization program that is intended to address and target inefficient buildings to drive energy reduction and savings.
    - Question: Can you provide more info about where CenterPoint is in discussions / negotiations with new large load customers? Are these all in very early stages? Have engineering studies been performed? Are any close to signing an electric service agreement at this point?
        - Response: CenterPoint does not currently have any additional large loads under contract. There are several in the queue that are at varying stages in negotiation. It would be hard to provide a concrete answer, but this is the most active queue for speculative load in CenterPoint's recent history.
    - Question: What percentage of the large load is being driven by data centers?

        - Response: We have conversations with both manufacturing facilities and data centers, but an exact answer on percentage is not known at this time.
    - Comment: Perhaps in the next tech-to-tech meeting CenterPoint could share more details about its current large load customer queue (e.g., MW in each stage of the queue, number of customers) and process it goes through to add such a customer.
        - Response: [Thank you for your suggestion].

Michael Russo (Forecast Consultant, ITRON) – Discussed the methodology for developing energy and demand forecasts, including impacts from Electric Vehicle and behind-the-meter solar photovoltaic adoption.

- Slide 43 Historical Energy and Peak Trends
    - Question: Could you break out peaks by customer classes?
        - Response: CenterPoint can pull some data from the rate case on this topic. [Please see the graph below for a breakout of load by class for a peak day].



- Slide 44 Customer Class Mix
    - Question: Is it fair to use 150,000 customers instead of households?
        - Response: There are approximately 150,000 unique accounts that CenterPoint services. Alternatively, this figure can be viewed as 150,000 meters that CenterPoint serves.
- Slide 45 Forecasting Methodology
    - Question: Looking at the column on the left, some of those items aren't independent of each other. Are you looking at those independently or stand alone?

        - Response: Most of the drivers are not developed in conjunction with the other inputs.
- Slide 46 Statistically Adjusted End-Use Approach
    - Question: The price you charge a residential customer is not based on the household income, and it appears that the slide indicates that it is.
        - Response: Household income is used as one of the drivers of sales with the underlying assumption that greater household income leads to more power consumption. The price per unit electricity charged to consumers is not dependent on quantity of use.
- Slide 47 SAE Residential Model Framework
    - Question: Can you explain why billing days are not always consistent? Our monthly bills can range from 28 days to 35 days.
        - Response: The meter read schedule is dictated by holidays and weekends. Depending on when your meter was read last, the next read day is likely not a Saturday, Sunday, or holiday. Therefore, the cycle could vary just based on when the meter is read.
- Slide 49 Industrial Model Framework
    - Question: Who provides the Internal 12-month Forecast? If your rate to industrial customers is based on usage, is their rate variable?
        - Response: CenterPoint provides the Internal 12-Month Forecast to Itron, and they determine that forecast by talking to their large industrial customers about their plans to expand or reduce operations. The price of electricity is not an input for the Industrial Model Framework. Whether a price is variable for large customers depends on the customer class, and they are charged on maximum demand.
- Slide 54 End-Use Intensity Trends
    - Question: For the MISC trend, what would fall under that for residential?
        - Response: This category includes tablets, computers, etc. The EIA also has an unknown end-use category which is included in Miscellaneous, which is forecasted as a function of personal income.
- Slide 55 Trended Normal Weather
    - Question: Regarding the temperature, why are you using historical rather than forecast?
        - Response: CenterPoint has chosen to use a linear projection of temperature based on historical data. CenterPoint is open to looking at the impact of using a more accelerated temperature trend over time.
    - Question: Do heating and cooling days balance each other out over a season, especially considering southern Indiana vs northern?
        - Response: Yes, the impact of an increasing number of Cooling Degree Days and decreasing number of Heating Degree Days balance each other out for an overall energy forecast. The historical weather data used is for Evansville, not for the state of Indiana.
    - Comment: The way normal temperature adjustment is calculated on the gas bill. That mechanism is always going to cost the customer more money with a warmer trend.
        - Response: Thank you for your comment.

- Slide 59 Electric Vehicle Forecast Methodology
  - Question: I wanted to voice concern for estimating 12,000 miles for EVs. I suggest finding a larger data set.
    - Response: There are a few studies that say less and a few that say more. CenterPoint can look revisit this estimate. Also, please note that plug-in hybrid vehicles are assumed to operate in electric mode for only 50% of the miles.
- Slide 61 Electric Vehicle Charging Profile
  - Question: Do you know if the data that you were relying on takes into account remote work and if it took into account different times at home (charging at home during lunch)?
    - Response: The data that is being used is from an NREL tool, EVI-Pro. In this tool there are a number of scenarios to toggle, such as access to home charging, preferences for home charging, etc. We are not sure if Work from Home charging settings are included.
  - Question: CenterPoint should consider incentivizing EV charging at businesses. On that note, does CenterPoint offer employee charging?
    - Response: CenterPoint does not currently offer EV charging.
- Slide 63 Photovoltaic (PV) Forecast
  - Question: On the demand impact at peak, there is a small drop in 2041 for the demand impact at peak. What is the justification? What is the significance of 2041?
    - Response: The peak is shifting one hour in the evening, so solar generation is lower one hour later. Solar generation drops off significantly as it gets later in the evening. Throughout the forecast, the peak is slowly shifting later and later and 2041 is the tipping point where peak first occurs at the next hour.
- Slide 67 Energy & Peak Forecast
  - Question: Why is the peak not earlier in the day?
    - Response: Based on recent years data, around hour 15, 16 or 17 is when CenterPoint is most likely to have highest demand.
- General Questions:
  - Question: How do energy efficiency, energy savings, and associated lost revenues factor into the IRP analysis?
    - Response: As we have energy savings, we have lost revenues and lost margins. Those costs do not go into the IRP process but are a part of the rate making process.
  - Question: Will cost trends associated with batteries and different resources be factored into this analysis?
    - Response: Yes, this will be addressed further in the next section and future meetings.
  - Question: Are there any plans to electrify CenterPoint's fleet?
    - Response: CenterPoint currently has some Electric Vehicles in their fleet. [As a follow-up, CenterPoint does have plans to electrify its fleet. Please see the following link https://sustainability.centerpointenergy.com/energy-transition-goals/fleet/].

Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the resource options being considered in the 2025 IRP along with CenterPoint's current resource mix.

- Slide 70 CEI South Resource Mix
  - Question: Are all the resources in the resource mix charts owned by CenterPoint?
    - Response: This is installed capacity, which includes resources owned by CenterPoint as well as resources that are under contract via PPA or other contract method.
  - Question: Is there a breakout of a potential resource incentive to see what would be the resource mix if CenterPoint reinstated full 1-to-1 net meter, or increase the EDG rate to 90 to 95% of retail? Does the legislature set the Excess Distributed Generation (EDG) rate as a maximum?
    - Response: The EDG rate is set by statute, and net metering is closed out. The EDG rate is set to 125% of the average market cost of energy from the prior year. CenterPoint can look into what it will take to incentivize distributed solar within the IRP.
  - Question: Why are the values here shown in ICAP versus UCAP?
    - Response: Future meetings will provide more detail into the ICAP and UCAP of resources. Installed capacity was specifically called out during this meeting to introduce stakeholders to CenterPoint's' generation fleet.
- Slide 72 CEI South Wind Resources
  - Question: Have you considered renewing the contracts for Benton County or Fowler Ridge wind projects?
    - Response: CenterPoint has reached out to the owners of Benton County and Fowler Ridge to look at extending the contract or potential purchase options, and at this point have not been successful.
- Slide 74 New Alternative Resources: Thermal
  - Question: Are the gas resources on this slide not included in the previous slides?
    - Response: The alternative resource list shows what new resources will be available for the model to select for new builds. This is different from the existing resources in CenterPoint's fleet, although some may have the same technology type.
  - Comment: A.B. Brown 5 and 6 are coming online in 2025; I have concerns about converting it to a combined cycle.
    - Response: Thank you for your comment. We are considering a wide range of alternatives as part of this analysis.
  - Question: Will CenterPoint present the costs for the new thermal resource options at the next IRP meeting?
    - Response: CenterPoint will be providing additional details on the resource options in future meetings.
  - Comment: I have concerns about the affordability of SMRs. I would discourage any pre-construction spending for this resource.
    - Response: Thank you for your comment. The affordability will be captured via the 20-year net present value and the 5-year impact on residential

rates to quantify different portfolios' short- and long-term impacts. No resource or portfolio has been selected at this point in the IRP.

- Slide 75 New Alternative Resources: Non-Thermal
  - Question: What types of technologies did you have in mind under non-Lithium-Ion battery storage?
    - Response: The cost and technical information used to model long-duration storage is currently based on compressed air. However, CenterPoint wants to be sure to consider all commercially viable utility-scale technologies, so please provide suggestions if there are technologies you wish to be considered.
- General Questions:
  - Comment: I would like to suggest the pause at F.B. Culley 3 conversion to natural gas be as short as possible.
    - Response: Thank you for your comment.

Drew Burczyk – Discussed modeling inputs for commodities, including Natural Gas, Coal, and MISO Capacity costs.

- Slide 79 Natural Gas (Henry Hub) Forecast
  - Question: Does this natural gas forecast assume the increased drilling that the current administration is interested in?
    - Response: CenterPoint cannot speak to what is included in each specific forecast but could follow up with the vendors. [Our vendors consider multiple factors when developing commodity forecasts. CEI South uses a consensus forecast methodology. Incorporating various perspectives allow us to capture the diversity in opinions for future market prices.]
- Slide 80 Coal Forecast
  - Question: How much of CenterPoint's current coal is imported from out of state versus sourced from in-state?
    - Response: CenterPoint uses all Indiana coal.
- General Questions:
  - Question: What metrics are being considered that could quantify the value of resources that use less fuel and may have less exposure to commodity price volatility? Is the affordability metric designed to capture price stability?
    - Response: During the modeling process, the impact of varied fuel prices will be captured by running multiple scenarios and evaluating portfolio performance. Additionally, a stochastic analysis will be performed, where 200 different draws for each portfolio will work to limit the variability of fuel prices. In terms of metrics, the 95th and 5th percentile of NPVRR will capture some of the risk of fuel price instability. Additional sensitivities can also provide insights into how individual drivers can impact portfolio costs.
  - Question: Is buying capacity from MISO expensive? Why does CenterPoint consider this as an option in the IRP modeling?
    - Response: The amount of capacity that can be purchased from capacity markets will be limited, so the model does not purchase all capacity from

capacity markets. This allows the model to purchase small quantities to fill in gaps from year to year [in the long term], without requiring the addition of a new resource that may be larger than the capacity needed.

- Question: Who are the vendors that are providing these forecasts?
  - Response: Wood Mackenzie, ABB, S&P, and EVA provided the commodity forecast information.
- Question: Is there something that could be implemented to prevent extreme weather events the effect gas bills such as winter storm Uri?
  - Response: This topic is not directly covered in the IRP process.

Drew Burczyk – Discussed scenarios and scenario drivers that will be considered during the 2025 IRP Modeling.

- Slide 86 High Regulatory
  - Question: What are you assuming for requirements on existing gas turbines under the High Regulatory scenario?
    - Response: We will look at the CAA 111 final rule, as well as the draft rules, and try to use those to inform potential future regulation of existing natural gas plants.
- Slide 87 Low Regulatory
  - Question: Why are you considering the IRA would not exist under low regulatory?
    - Response: When you look at policies and the way the administration is moving, there is a chance the IRA could go away in the future. It is important in the IRP to study a multiple of potential scenarios.
- General Questions:
  - Question: One scenario option would be to consider high regulation but also assumes load growth and lower energy efficiency costs. I am assuming that the regulations are onshore manufacturing and electrification, and I am not sure if those are captured in the reference case.
    - Response: We appreciate the comment. With these scenarios, we are trying to come up with an internally consistent view as well as boundaries on each end. We will consider your feedback as part of the scenario development process.

General Q&A Section

- General Questions:
  - Question: Will you be sending out the notes for this meeting and the agenda for the next meeting at least a week in advance?
    - Response: Yes. Meeting notes will be posted to the 2025 IRP website. The slides, including the agenda, will be posted a week in advance of the meeting.
  - Question: Will we be able to follow-up with CenterPoint folks?
    - Response: Please reach out to the IRP email address, IRP@CenterPointEnergy.com.

Stakeholder Feedback and/or Data Request

Reliable Energy's (REI) Comments on the First 2025 Integrated Resource Plan (IRP) Meeting for CenterPoint Energy, Inc. (CEI) on March 19, 2025

REI Comments Received: May 16, 2025

CEIS REsponse: 6/9/2025

Reliable Energy (REI) appreciates the opportunity to participate in the development of the 2025 CEI IRP. It was disappointing, however, that CEI stereotyped REI as simply a "coal advocate."[1] REI's members are not just coal companies. REI is a trade association with diverse membership that is committed to ensuring an abundant supply of available, a ordable, and dependable energy in the Hoosier state and nationwide. To the extent that these e orts are best achieved by keeping some existing baseload coal generation plants operational, REI promotes this outcome through legislative, regulatory, and grassroots advocacy.[2] We believe that Indiana utilities promote the fallacy that their coal plants are "too expensive" to operate in order to justify their early retirement and replacement before the end of their useful lives. This only results in higher costs to ratepayers and a less reliable and resilient grid.

The intention of slide 12 of CEI South's first stakeholder presentation on March 19, 2025, titled "Feedback from All Parties", was to provide a general overview of the balanced feedback that we received from multiple types of stakeholders, from those that advocated on environmental issues to continue operating coal in the near term.

General Comments on Public Stakeholder Meeting #1

1. CEI prepared a lengthy presentation (the Presentation) which had limited information supporting the graphics. Further, the quality of the audio for those participating on Zoom was spotty. Certain presenters were particularly difficult to understand. Hopefully, this can be corrected for future meetings.

   Thank you for your feedback. We recognized there were challenges with the audio in the first stakeholder meeting and subsequently took action to address those issues prior to the second stakeholder meeting held on May 14, 2025. The quality was noticeably improved for those that joined the 5/14 meeting virtually.

2. REI supports CEI's addition to the "affordability" metric that will take into account ratepayer costs. To fully represent the true cost of CEI's generation decisions, when retiring plant, it is particularly important that this calculation include *undepreciated capital from stranded assets*. REI looks forward to working with CEI to review how it is calculated. Pretending that these stranded costs do not result in real ratepayer costs is misleading to the public.

   CEI South appreciates REI's support of CEI's near term affordability metric.

   CEI South modeling methodology does include potential stranded asset cost when evaluating a potential retirement, as it has in the prior IRP. Modeling inputs will be provided to stakeholders for review.

[1] Presentation page 12.
[2] https://reliableenergyinc.org/about/

3. CEI understated the impact of the environmental policy forwarded by President Trump's new administration. In particular, CEI failed to even mention the President's declaration of a National Energy Emergency (NEE) under the National Emergencies Act (50 U.S.C 1601 et seq) and section 301 of Title 3 U.S.C. 3(a). While the full consequences of the declaration are not yet known, the Trump Administration has made clear it is looking to revamp the regulatory landscape, foster growth in new fossil generation to support expected load growth, and expand the production of fossil fuels for both domestic and international markets. Further, it appears that the Administration could use this Declaration to allow operating coal plants to continue to run. It is important for CEI to monitor these actions, but it is more important for CEI to consider how these actions might affect the results in CEI's IRP. When considering the key elements of the President's energy policy (details below), the Low Regulatory Scenario[3] is inadequate to fully address the potential range of regulatory changes that could occur.

   CEI South monitors state and federal regulatory initiatives, policy discussions and activities, as well as considers possible impacts of regulatory policy changes after each election cycle. We appreciate REI's provided U.S. Energy Policy list and recognize the current dynamic regulatory environment at the state and federal level as well as the significant uncertainties that can follow from sweeping attempts to change federal policy and roll back final regulations.

   Scenarios are meant to represent plausible boundaries. We believe that the low regulatory scenario, which allows coal generation plants to continue to run through the planning timeframe, is a plausible boundary condition, while also considering the possible impacts of current policy changes.

   As requested in the second stakeholder meeting on May 14, 2025, if there is a specific scenario and associated drivers you would like us to evaluate, please provide those for review and consideration.

4. Given the potential range of possible regulatory changes, CEI should commit to not pursue any Certificate of Public Need and Necessity (CPCN) until there is some clarity from the Trump Administration regarding how it will support coal-fired energy production.

   We have paused the F.B. Culley 3 conversion. The conversion will be evaluated again in this IRP. As discussed in stakeholder meeting 2 on May 14, 2025, existing EPA Clean Air Act ("CAA") 111 requires that CEI South evaluate conversion of F.B. Culley 3 to natural gas by 2030, co-fire natural gas by 2030, or retirement in 2032. Precisely because of the uncertainty that Reliable Energy is pointing out, and the relatively near term in which these current requirements fall, we are unable to commit to not pursuing a CPCN at this time.

5. CEI suggests that by using stochastics, CEI will be able to have sufficient results to draw conclusions for its IRP. REI's experience is stochastics helps in some areas but not others. Fuel price forecasts and regulatory requirements require more definitive forecasts.

[3] Presentation page 87.

CEI South IRP process incorporates both probabilistic modeling (stochastics) and deterministic modeling which includes scenario analysis that takes varying fuel forecasts developed utilizing four industry expert opinions and regulatory requirements into consideration. Additionally, CEI South has committed to performing sensitivities.

6. The fuel cost assumptions, as presented, are problematic. With respect to CEI's coal forecast, CEI should provide additional information regarding the sourcing of the coal, transportation costs, and quality constraints of the Culley #3 power plant. Moreover, an extension of the operational life of Culley #3 is unlikely to be more than 10 years, which suggests pricing could be determined, at least in party, with *actual* bids. With respect to natural gas, CEI should provide information on the expected forecast shapes of the natural gas prices and related pipeline agreements. REI is happy to work with CEI on the construction of the fuel price scenarios.

   CEI South utilizes four independent price forecasts from industry experts to create its reference case forecast. This approach provides transparency and includes alternate perspectives on the future. CEI South plans to discuss the coal price forecast as it compares to our current contract, pursuant to the existing NDA, in the next Tech to Tech meeting. Additionally, CEI South will provide the expected forecast shape of natural gas prices.

7. CEI indicated that it assumed a net zero CO_2 target for 2035 in all scenarios.[4] This assumption is intended to force false IRP results, because it reflects a corporate goal (from which CEI's executives will obtain large personal profit), *not* a current state or federal mandate. In addition, if there is an environmental target, in order to provide accurate results on the impact of the IRP scenarios on carbon emissions, those assumptions should include what is commonly referred to as Scope 3 emissions which are the CO_2 equivalent (CO_2(e)) associated with methane emissions from natural gas production and transport.

   To clarify, slide 39 of Meeting #1 is illustrating the framework CEI South uses to evaluate large load. The reference "CenterPoint Energy Net Zero Goals" was intended to highlight that it is a consideration when evaluating large load. This slide had nothing to do with CEI South scenarios; it was in reference to "Large Load Sensitivities." The net zero goal is a consideration within the analysis but not determinative.

   With regards to Scope 3 emissions, CEI has conducted a life cycle CO_2 analysis in the past, which did not provide meaningfully different results than our current approach. For example, methane emissions are also associated with coal mining.

8. Unlike other Indiana utilities, CEI is downplaying the future role of large load additions, including data centers. In fact, CEI states no large loads are included in the base forecast.[5] Other Indiana utilities in the midst of their IRP process are assuming there will be some

[4] Presentation page 39.
[5] Presentation, page 40.

impact from large loads. More importantly, the issue of large loads is relevant to IRP's, particularly with respect to how existing ratepayers are protected from cost shifts.

CEI South acknowledges there has been an increase in speculative large load; however, CEI South does not currently have any additional large loads under contract. Until we have more certainty, speculative load will not be included in the reference case. To assess the possible impact large load, we are running a large load sensitivity that is not specific to any one industry. We will continue to monitor and adjust as needed.

9. CEI is also downplaying the importance of considering small modular nuclear reactors (SMRs) in its IRP. While there are no nuclear facilities currently operating in Indiana, this technology is not new. The U.S. nuclear submarine fleet has been utilizing a form of SMR technology for decades to generate power and propulsion. France derives about 70% of its electricity generation from nuclear. Over 50% of electricity generation in the Province of Ontario comes from nuclear. About 20% of U.S. electricity generation is from nuclear. It is a fundamental flaw in the IRP process for CEI to assume nuclear generation will not come to Indiana in the next 20 years.

   Even closed nuclear plants are reopening. The Palisades plant in Michigan which was closed in May 2022 is expected to reopen in October 2025. Holtec International, the current owner has announced plans to construct two SMRs by 2030 at the site as well, which will double the energy generation capacity at Palisades. One unit at the infamous Three Mile Island in Pennsylvania which is now owned by Constellation Energy is expected to reopen in 2028 to power Microsoft's data centers.[6]

   A number of utilities are including SMR's in their portfolios. For example, Appalachian Power announced plans to bring SMRs to Virginia and has started the site application process for a site in Campbell County Virginia. Tennessee Valley Authority (TVA) is pursuing an SMR for the Clinch River Site near Oak Ridge, Tennessee looking for commercial operation in 2033.[7]

   Extending the life of existing generation allows CEI to aggressively pursue the SMR option, which would reduce the exposure to stranded costs for new gas. Ultimately, a genuine concern about the environment supports the SMR alternative.

   CEI South is monitoring the administration's desire for nuclear in the state. The IRP will evaluate both CEI South's current and possible future resource mix. As discussed in Meeting #1 (see Slide 74), we are including nuclear as one of the options for the portfolios to select. We'll be discussing portfolios in more detail during the July stakeholder meeting (Meeting #3).

[6] In 2025, NextEra filed a notice with the Nuclear Regulatory Commission to request a licensing change for the Duane Arnold nuclear plant which was closed in 2020. This is a first step in establishing the regulatory pathway to potentially restart plant operations.

[7] https://www.gevernova.com/news/press-releases/us-utilities-team-accelerate-deployment-ge-vernova-bwrx-300-small-modular-reactor

Of note, the October 2024 Study on Small Modular Reactor Technology and its Impact for Indiana report, commissioned by the Indiana Office of Energy Development, included assessments of current and recently retired coal plants as possible sites for SMR. The results of the assessment are captured in Table 16, "Site List and Screening or Prioritization Factors at Play". AB Brown and FB Culley were flagged as not suitable for SMR based on high seismic activity and too populated, respectively.

U.S. Energy Policy in the Trump Administration

The Trump Administration has made clear that its energy policy will focus on the following:

- National and economic security, not decarbonization.[8]
- Supporting the present fleet of firm, dispatchable generation using NEE authorities.
- Providing EPA the flexibility to waive 2020 ELG Rule notification and compliance requirements.
- Revoking, remanding or otherwise making the Clean Air Act Sections 111(b) and 111(d) rules (often referred to as the GHG rules) non-enforceable.
- Revoking, remanding or otherwise making the new mercury and air toxic standards (MATS), new coal combustion residual (CCR) and new effluent limitation guidelines (ELG) Rules non-enforceable.
- Permitting previously shuttered coal plants to re-energize without re-initiating the ISO/RTO interconnection process.
- Reversing the Endangerment Finding that GHG are a threat to public health and welfare.
- Eliminating the target that electric vehicle market penetration reach 50% by 2030.[9]
- Revising EPA emission targets and fuel economy requirements from the National Highway Traffic Safety Administration.

CEI's single Low Regulatory Scenario that assumes only the withdrawal of the Clean Air Act (CAA) Sections 111(b) and 111(d) and the elimination of the IRA is insufficient to cover the impact of these numerous policy changes.

Thank you for your feedback. CEI South is considering how to incorporate the potential for some coal units to remain on-line longer than expected in the low regulatory scenario. More information will be shared in the next stakeholder meeting.

[8] This includes withdrawing from the Paris Climate Accords
[9] A change in this mandate will reduce electricity demand from EVs.

Impact of Trump Policies on Energy Markets

In addition to the environmental agenda, the Trump administration is pursuing policies that are likely to impact energy markets.

- The halt on leasing offshore wind and the halt on permitting both onshore and offshore wind on Federal lands are likely to reduce wind development.

- Restructuring/eliminating the Infrastructure Bill and the Inflation Reduction Act (IRA) Grant Programs.[10]

- The imposition of higher tariffs, which is likely to increase costs for renewables, new gas generation, and batteries.[11]

- An economic recession is a likely result of a decline in economic activity due to the tariffs, high unemployment, rising costs, reduced consumer spending, and financial crises. The duration of any recession is difficult to predict. What became known as the Great Recession lasted several years.[12]

Thank you for your feedback.

Request that CEI Coordinate with REI

1. REI is pleased to hear that CEI is willing to work with stakeholders on a number of issues.

2. REI specifically requests to work with CEI on the following:

    a. Formulation of additional scenarios to reflect the expanded list of potential changes to environmental regulations put forward by the Trump Administration.

    In stakeholder meeting #2 on May 14, 2025, CEI South included an additional scenario per stakeholder request to reflect the possibility of an alternate high regulatory scenario. CEI South has requested that stakeholders provide a set of drivers that are logically consistent. It would be helpful for REI to provide their view on a plausible potential future with directional driver impacts for consideration.

[10] There is considerable debate as to the extent to which already allocated funds can be redirected.
[11] FirstEnergy 10-K filed February 27, 2025: "New or increased tariffs could also negatively affect U.S. national or regional economies, which also could negatively impact our business and results of operations."
[12] The period that ultimately became known as the Great Recession started when the decade-long expansion in U.S. housing market activity peaked in 2006 and residential construction began to decline. In 2007, losses on mortgage-related financial assets caused strains in global financial markets, and in December 2007 the U.S. economy entered a recession. That year several large financial firms experienced financial distress, and many financial markets experienced significant turbulence. In the fall of 2008, the economic contraction worsened with the U.S. economy bottoming out in the middle of 2009. It took several years for economic growth to recover.

b. Formulation of additional scenarios to address the potential economic impacts of tariffs and an economic recession.

As described in the stakeholder meeting #2 on May 14, 2025, CEI South is factoring in a scenario that includes reduced economic output[13]. Additionally, per stakeholder feedback, CEI South will include a low regulatory sensitivity where load is reduced. Based on results, CEI South may consider an alternate low regulatory scenario.

c. Development of fuel price scenarios that include reasonable coal assumptions and transportation logistics for Culley #3 and, for natural gas, the likely shape of the price curves, and pipeline agreements.

CEI South plans to continue to utilize its consensus fuel price forecast methodology, which provides transparency and a diverse set of expert opinions on where fuel prices may go in the future. CEI South plans to discuss the coal price forecast as it compares to our current contract, pursuant to the existing NDA, in the next Tech to Tech meeting. Additionally, CEI South will provide the expected forecast shape of natural gas prices.

d. The methodology for evaluating the quantification of rate impacts as part of the affordability pillar.

Near term residential rate impacts of each portfolio will be included within the scorecard as part of the electric energy burden calculation. The calculation will be provided as part of the IRP submission.

[13] S&P Global's pessimistic outlook assumes strict trade and immigration policy will create near-term financial stress, increase inflation, and reduce economic growth.

CenterPoint Energy

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 2

May 14, 2025



Stakeholder Meeting Facilitator: 1898 & Co.

WHO: 1898 & Co. is the business, technology and security consultancy part of Burns & McDonnell

WHAT: The Resource Planning & Market Assessments group has been working on Integrated Resource Plans for over 20 years

HOW: Our team will help facilitate stakeholder meetings – we look forward to working with and hearing from you all

Agenda

Time	Topic	Speaker
9:00	Sign-in & Refreshments	
9:30	Meeting Protocols & Participation	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
9:40	Safety Share & Welcome	Shane Bradford, Vice President, Indiana Electric, CenterPoint Energy
9:50	IRP Process Recap & Stakeholder Feedback from Meeting #1	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
10:20	Final Scenarios	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
10:35	BREAK	
10:45	Draft Supply-Side Resource Inputs	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
11:00	DSM Market Potential Study Update	Jeffrey Huber, Principal, Energy Efficiency, GDS Associates
11:30	LUNCH	
12:30	Sales & Demand Scenario Forecasts	Michael Russo, Forecast Consultant – Itron
1:00	Probabilistic Modeling Approach & Assumptions	Brian Despard, Senior Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:20	Draft Scenario Forecasts	Brian Despard, Senior Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:40	BREAK	
1:50	Portfolio Development Methodology	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:10	Draft Reference Case: Modeling Update	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:30	Stakeholder Questions & Feedback	Moderated by Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
3:00	Adjourn	

Meeting Protocols

- Please focus questions, comments, and feedback to the IRP process and today's agenda topics
- CenterPoint Energy Indiana (CEI) South does not authorize the use of cameras, video/audio recording devices, or AI transcription during the meeting
- Following the meeting, feedback (concepts, inputs, methodology, etc.) and questions may be sent to IRP@CenterPointEnergy.com
- CEI South will be recording the meeting to accurately capture notes and questions. The public meetings are not transcribed or recordings posted; however, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp

Meeting Participation

Time is allotted for questions following each presentation – please hold questions until the designated question period

In-person attendees – please raise your hand to be recognized

Virtual attendees will be in listen-only mode – to participate:

- Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
- Enter questions into the “Q&A” feature in Teams

Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

There will be a list compiled for items to be addressed later. Questions that are not able to be answered in this meeting will be answered later.

Safety Share

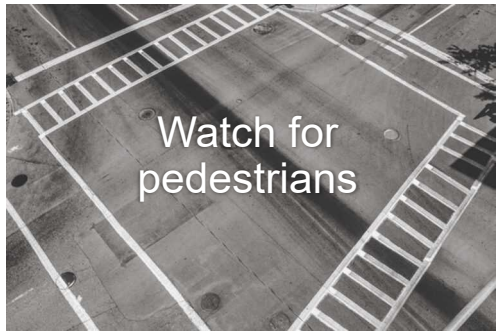


Increase your following distance, turn on your headlights, and drive slowly during heavy spring rains



Try not to swerve to avoid potholes, but brake gently before and navigate them with caution



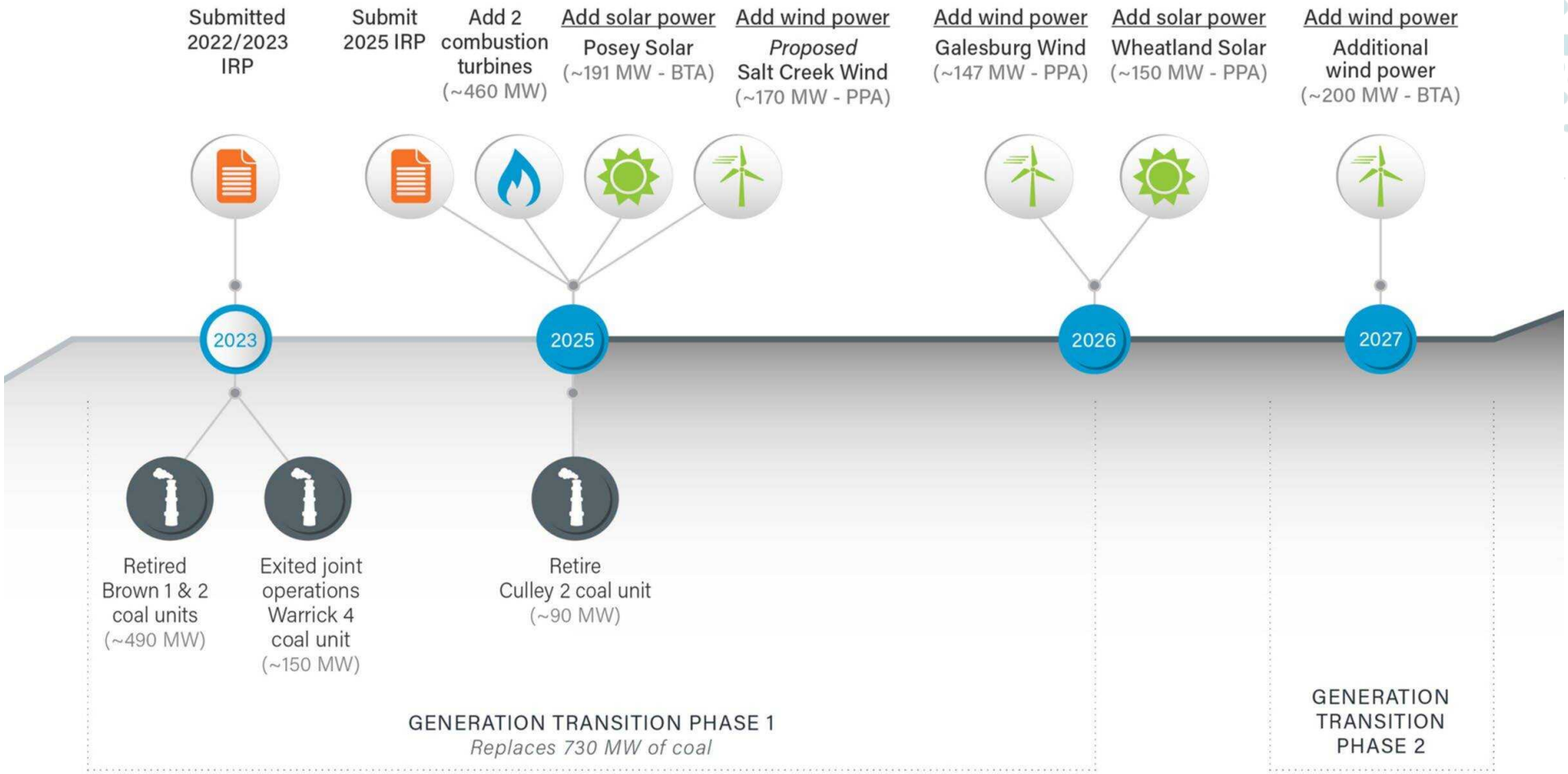


Slow down in your neighborhood and pay extra attention to crosswalks



Be on alert at dusk and in rural areas where animals are most active

Generation Transition Timeline: Revised



IRP = Integrated Resource Plan
MW = Megawatt
BTA = Build Transfer Agreement/Utility Ownership
PPA = Power Purchase Agreement

IRP Process Recap & Stakeholder Feedback

Matt Rice

Director, Regulatory and Rates

2025 Stakeholder Process

Proposed 2025 CEI South Stakeholder and Tech to Tech Meetings – *Dates and agendas are subject to change*

Meeting 1
March 19

- IRP Process, Objectives, & Draft Metrics
- All-Source RFP Results
- MISO Update
- Environmental Compliance Update
- Draft Sales and Demand Forecast (Reference Case)
- Commodity Inputs
- Large Load Sensitivity Discussion
- Resource Options
- Scenario Development

Tech to Tech
April 28

Meeting 2
May 14

- Follow Up Information From 1st IRP Stakeholder Meeting
- Final Scorecard and Scenarios
- DSM Market Potential Study Update
- Draft Supply-Side Resource Inputs
- Final Load Forecast and Draft Scenario Forecasts
- Probabilistic Modeling Approach and Assumptions
- Portfolio Development Methodology
- Draft Reference Case Modeling Update

Tech to Tech
July 7

Meeting 3
July 23

- Follow Up Information From 2nd IRP Stakeholder Meeting
- Discussion of Final Portfolios
- Scenario and Probabilistic Modeling Update
- Draft Scenario Optimization Results without DSM
- Draft Deterministic Portfolio Results
- Early Sensitivity Results

Tech to Tech
September 5

Meeting 4
September 23

- Follow Up Information from 3rd IRP Stakeholder Meeting
- Preferred Portfolio
- Risk Analysis Modeling and Portfolios
- Risk Analysis Scorecard

Target Submission Date: November 1, 2025

Stakeholder Engagement is Critical to the IRP Process
CEI South is committed to meaningful information sharing and dialogue

Target Data Release Schedule

Draft Load Forecast	Draft Reference Case Model	Updated Reference Case + Scenario Models	Probabilistic + Sensitivity Analysis Models
3/20/2025 (1)	5/5/2025 (2)	7/14/2025 (3)	9/12/2025 (4)

- *Released data and Tech to Tech meeting attendance will be available to the technical stakeholders with a completed Non-Disclosure Agreement (NDA).*
- *Send NDA requests to IRP@Centerpointenergy.com*

Summary of Stakeholder Feedback From Meeting #1

Topic	Stakeholder Comments/Feedback	CEI South Updates/Responses
Modeling Sensitivity	What distribution resources planning is CEI South considering for the IRP	CEI South will discuss upgrades on the system that help enable DER integration and its long-range distribution plan.
Modeling Sensitivity	Consider sharing more details about CNP's current large load customer process and queue	CEI South shared additional confidential Large Load information during the 4/28/2025 Tech to Tech meeting.
Request	Include consideration of Senate Enrolled Act 422 advanced transmission technologies in IRP	CEI South is collaborating with MISO on the implementation of Ambient Adjusted Ratings and will include a write up in the IRP report.
Modeling Scenarios	Consider if available Coal Combustion Residuals (CCR) disposal capacity will be a limiting factor for FB Culley 3 operation on coal	CEI South does not believe this will be a limiting factor in this decision, we will continue to monitor for any changes that could have an impact
Modeling Scenarios	Consider a high regulation scenario that assumes load growth and lower energy efficiency costs.	CEI South agrees to include an alternate high regulation scenario. The Alt High Scenario will be discussed during the 5/14/2025 Stakeholder Meeting

Summary of Stakeholder Feedback From Meeting #1

Topic	Stakeholder Comments/Feedback	CEI South Updates/Responses
Load Forecast	Provide a break out of peaks by customer class	See graph in 3/19/2025 Stakeholder meeting notes posted at www.centerpointenergy.com/irp
Load Forecast	Why is CEI South using historical rather than forecast temperature, e.g., Purdue University temperature forecast?	CEI South used a linear projection of temperature based on historical data; it is not significantly different from the Purdue University for the IRP period.
Load Forecast	Requested CEI South to revisit the estimated 12,000 miles for EVs used in the forecast	Itron EV assumption for reference forecast. The 12,000 miles per year for EVs was revised to 9,500 miles per year. This revision is noted in the 5/14/2025 Stakeholder meeting slides
Load Forecast	Does the EV charging profile used for CEI South's load forecast account for remote work at home?	The NREL tool, EVI-Pro, documentation does not specifically state any assumptions regarding work from home. The "EVHome" charging profile on slide 61 of the 3/19/2025 stakeholder slides includes some level of charging between 11am-2pm. (slides posted at www.centerpointenergy.com/irp)
Load Forecast	Does CenterPoint have plans to electrify its fleet?	CenterPoint does have plans to electrify its fleet - please see the following link https://sustainability.centerpointenergy.com/energy-transition-goals/fleet/

Summary of Stakeholder Feedback From Meeting #1

Topic	Stakeholder Comments/Feedback	CEI South Updates/Responses
Scorecard	Under the Environmental Sustainability Objective: Remove CO_2 intensity, keep CO_2-e tons	CEI South believes that there is value in keeping CO_2 intensity, as well as CO_2-e metrics. CO_2 intensity allows the reader to compare CO_2 levels across scenarios.
Scorecard	Include metrics for SOx and NOx	CEI South has added metric that includes combined tons of SOx and Nox.
Scorecard	Under the Affordability Objective: consider adding an energy burden calculation	CEI South proposes to add electric energy burden, defined as the 5-Year residential rate impact + residential average bill as of July 1, 2025 divided by the Vanderburgh County Median HH Income.
Resource Options	Are the Demand Response proposals subject to discussion/change with Demand Side Management (DSM) Oversight Board	CEI South continues to discuss Demand Response with members of the DSM Oversight Board
Resource Options	Is CEI South considering what the resource mix could be if a resource incentive (updated EDG rate) is included in the IRP?	CEI South is conducting a sensitivity considering a $500 per kW incentive for Distributed Generation solar resource.

Summary of Stakeholder Feedback From Meeting #1

Topic	Stakeholder Comments/Feedback	CEI South Updates/Responses
Commodity Inputs	Does the natural gas forecast assume increased drilling under the current administration?	At this time, CEI South is uncertain how the current administration's policies will affect natural gas prices. Our vendors consider multiple factors when developing commodity forecasts. Utilizing a consensus forecast is an approach CEI South has taken in previous IRPs. These various perspectives allow us to capture the diversity in opinions for future market prices.

Objectives & Draft Metrics

Objective	Measure	Metrics
Affordability: *Consider portfolios' impact on the retail electric utility service providers ability to provide affordable power across residential, commercial, and industrial customer classes*	➢ 20-year Net Present Value Revenue Requirement ("NPVRR")	➢ $
	➢ 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions	➢ $
	➢ **5th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions**	➢ $
	➢ ~~5-Year residential rate impact~~	➢ ~~$~~
	➢ **Electric energy burden**	➢ **% HH income**
Environmental Sustainability: *Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation*	➢ CO_2 Intensity	➢ Tons CO_2/kwh
	➢ CO_2 Equivalent Emissions	➢ Tons CO_2e
	➢ **SOx and NOx Emissions**	➢ **Tons**
Reliability: *Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all time and withstand sudden disturbances* **Resiliency:** *Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions* **Stability:** *Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters*	➢ **Unserved energy across 200 dispatch iterations under varying market conditions**	➢ MWh
	➢ Spinning Reserve	➢ Portfolio MW's That Offer Spinning Reserve
	➢ Fast Start Capability	➢ Portfolio MW's That Offer Fast Start
	➢ **Transmission reliability analysis**	➢ Dynamic VAR Support (MVAR) ➢ Short Circuit Ratio
Risk/Other:	➢ Energy Market Purchase and sales	➢ % (average, near/long term)
	➢ **IRA tax credit exposure**	➢ $

Blue text indicates a new measure for this IRP cycle

Red text indicates a new measure/revision following recent stakeholder meeting

MWh = Megawatt hour MVAR = Megavolt-Ampere Reactive

Q&A

Final Scenarios

Matt Rice

Director, Regulatory and Rates

Scenario Development

- **Scenario ("Plausible Future"):** a simulation with a specific set of input assumptions
  - Scenarios are used to capture different goals or views of the future
  - Scenarios are commonly structured such that they represent plausible future states that provide high and low boundaries relative to the reference case
  - Forecasts within each scenario are internally consistent

- **Sensitivity:** a single variable that drives results
  - Sensitivities may be used to change only one variable at a time to understand the impact of that single risk factor

Reference Case Scenario

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Reference Case	Clean Air Act 111 (b & d)	IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base

- As per Rule 170 IAC 4-7-4, the base case [reference case] is to be the most likely future scenario. As such, it is designed to be an extension of the status quo
- In the Reference Case Scenario, the Clean Air Act 111(b & d) is enforced; does not include existing gas resources or a CO_2 Tax
- **Load (-)** – Peak demand growth of 0.5% per year in the Summer and 0.3% per year for Winter for electricity (Does not include impact of CEI South EE program savings).
- **Commodity Prices (-)** – Consensus forecasts for gas, coal, and MISO capacity
- **Generation Capital Costs (-)** – continuation of the IRA. Informed by the All-Source RFP and the Technology Assessment
- **EE Costs (-)** – Based on Updated Market Potential Study

Narrative - High Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher

- In the High Regulatory Scenario, the Clean Air Act 111(b & d) is enforced as well as expanded to include existing gas resources and a CO_2 Tax is added
- **Load (↓)** – additional regulation drives lower demand growth for electricity
- **Commodity Prices (↑)** – additional environmental regulations increase costs for producing NG and coal, thus driving prices up
- **Generation Capital Costs (↓)** – continuation of the IRA, technology advancements, and lower demand for new generation results in lower capital costs
- **EE Costs (↑)** – lower load leads to less opportunity for cost-effective energy efficiency. In addition, a high regulatory environment leads to more codes and standards for equipment; This in turn results in higher incentives for more efficient equipment

Narrative – Alternate High Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	**No additional CO_2 regulation**	**Higher**	Higher	Higher	**Higher**	**Base**

- The Alternate High Regulatory Scenario includes the same policy in the high regulatory scenario
  - The Clean Air Act 111(b & d) is enforced as well as expanded to include existing gas resources
- **Load (↑)** – additional regulation surrounding electrification of buildings and transportation drives significant electricity demand growth
- **Commodity Prices (↑)** – strict environmental regulations increase costs for producing natural gas and coal, while electrification-driven demand increases fuel consumption, driving prices up
- **Generation Capital Costs (↑)** – Demand for additional generation to match load growth as well as stringent regulation leads to increasing capital costs of generation technology
- **EE Costs (-)** – higher load creates greater opportunity for utility sponsored EE, balanced by federal/state incentives for adoption of cost-effective energy efficiency incentives which increases cost for utility sponsored EE

Narrative - Low Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

- Under the Low Regulatory Scenario, several environmental policies are eventually revised, including CAA 111. No new carbon emission regulations are created
- **Load (↑)** – reduced regulation encourages expansion of industrial/other large load users
- **Commodity Prices (↓)** – lower regulatory encourages the use of fossil fuels, increasing supply and lowering prices
- **Generation Capital Costs (↑)** – reduced incentives for renewables and increased pressure from tariffs drive costs up for new generation. Additional load growth also leads to an increase in demand, and higher costs
- **EE Costs (↓)** – higher load leads to greater opportunity for cost-effective energy efficiency and thus decreasing incentive costs

Scenario Summary

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	Clean Air Act 111 (b & d)	IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	**No additional CO_2 regulation**	**Higher**	Higher	Higher	**Higher**	**Base**
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

Q&A

Draft Supply-Side Resource Inputs

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

Supply Side Resources

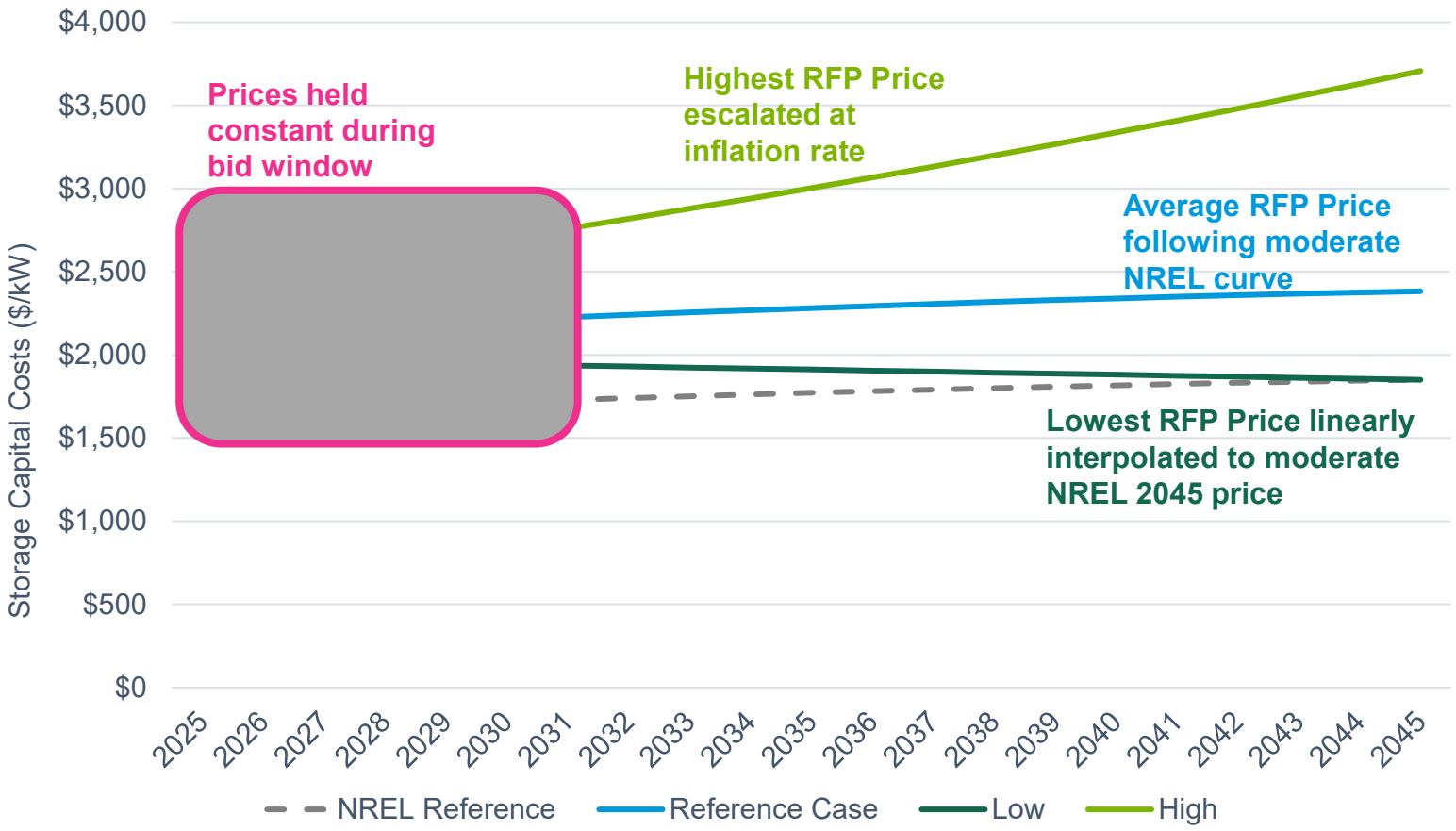
- As part of this IRP, we are evaluating a wide range of new supply-side resources. These options will be used to create different resource portfolios, which will be analyzed against the 5-pillars (Affordability, Reliability, Stability, Resilience, Sustainability).
- Potential resource options and their associated cost and performance are sourced primarily from:
  - All-Source RFP
  - Generic Unit Technology Assessment
- Resource options included in portfolio modeling:
  - Solar (multiple options)
  - Wind (multiple options)
  - Storage (multiple options)
  - Simple cycle natural gas turbines (multiple options)
  - Combined cycle natural gas units (multiple options)
  - Peaking natural gas units (multiple options)
  - Nuclear
- These inputs will inform the development of diverse portfolios and support robust decision-making.

Capital Cost Curve Approach – RFP Bids

- For technologies that had a purchase option submitted with the 2024 All-Source RFP:
  - **Low curve:** starts with the lowest RFP bid and trends linearly to the NREL reference case cost in 2045
  - **Moderate curve:** starts with the average RFP bid price and escalates using the NREL reference case curve
  - **High curve:** starts with the highest RFP bid and escalates at the assumed inflation rate
- For wind bids, a combination of submitted PPA bids and technology assessment costs were used to create the curve

NREL = National Renewable Energy Laboratory *RFP = Request for Proposals* *PPA = Power Purchase Agreement*

Storage Cost Curve

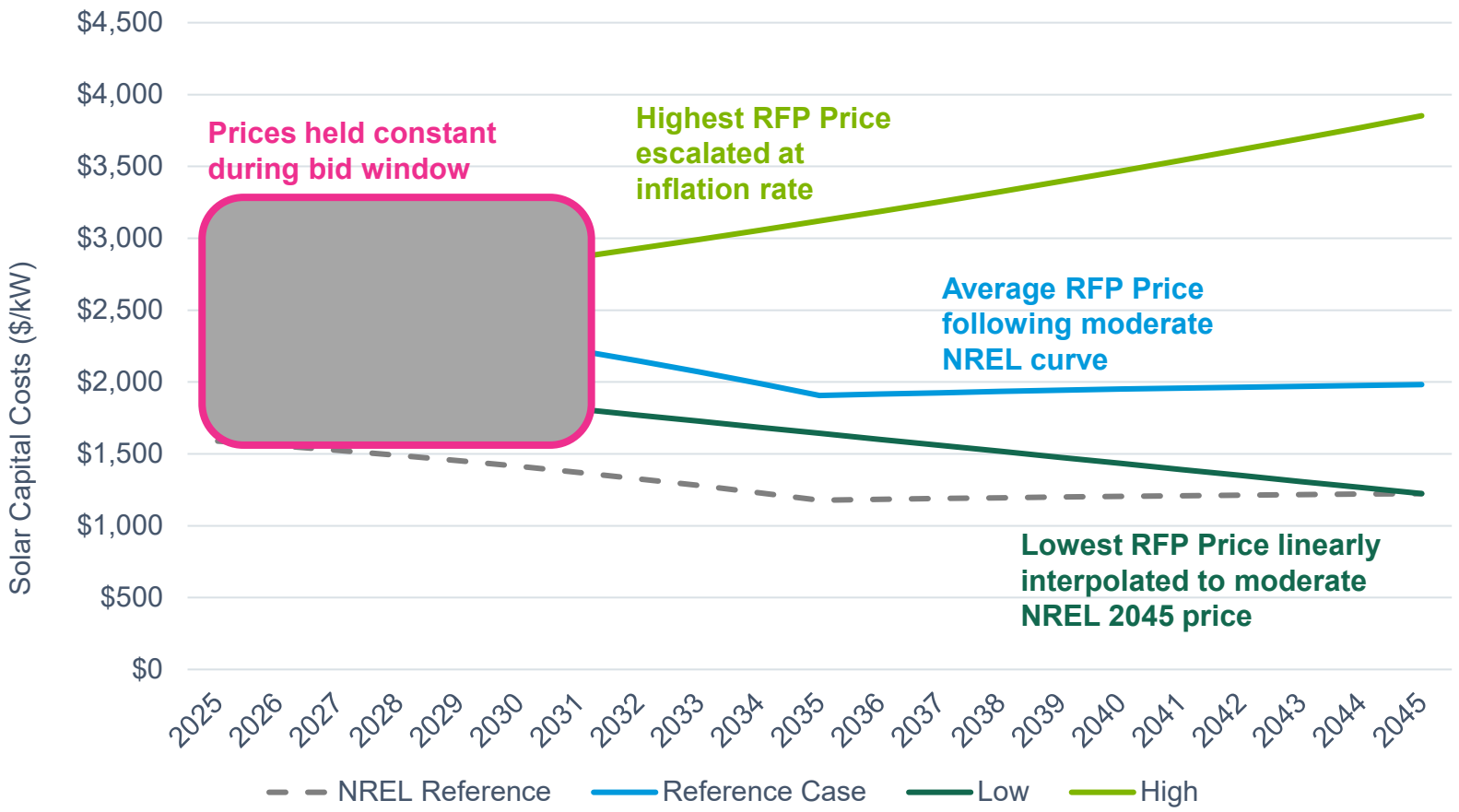


4-Hour Li-on Summary	
Capacity (MW)	100
Capital Costs ($/kW)	$2,273
Fixed O&M ($/kW-yr)	$35.00
Variable Costs ($/MWh)	–
2035 DLOL Accreditation*	
Summer	94%
Winter	68%
Spring	85%
Fall	94%

**Additional information on accreditation methodology is provided in the appendix.*

NREL = National Renewable Energy Laboratory *RFP = Request for Proposals*

Solar Cost Curve

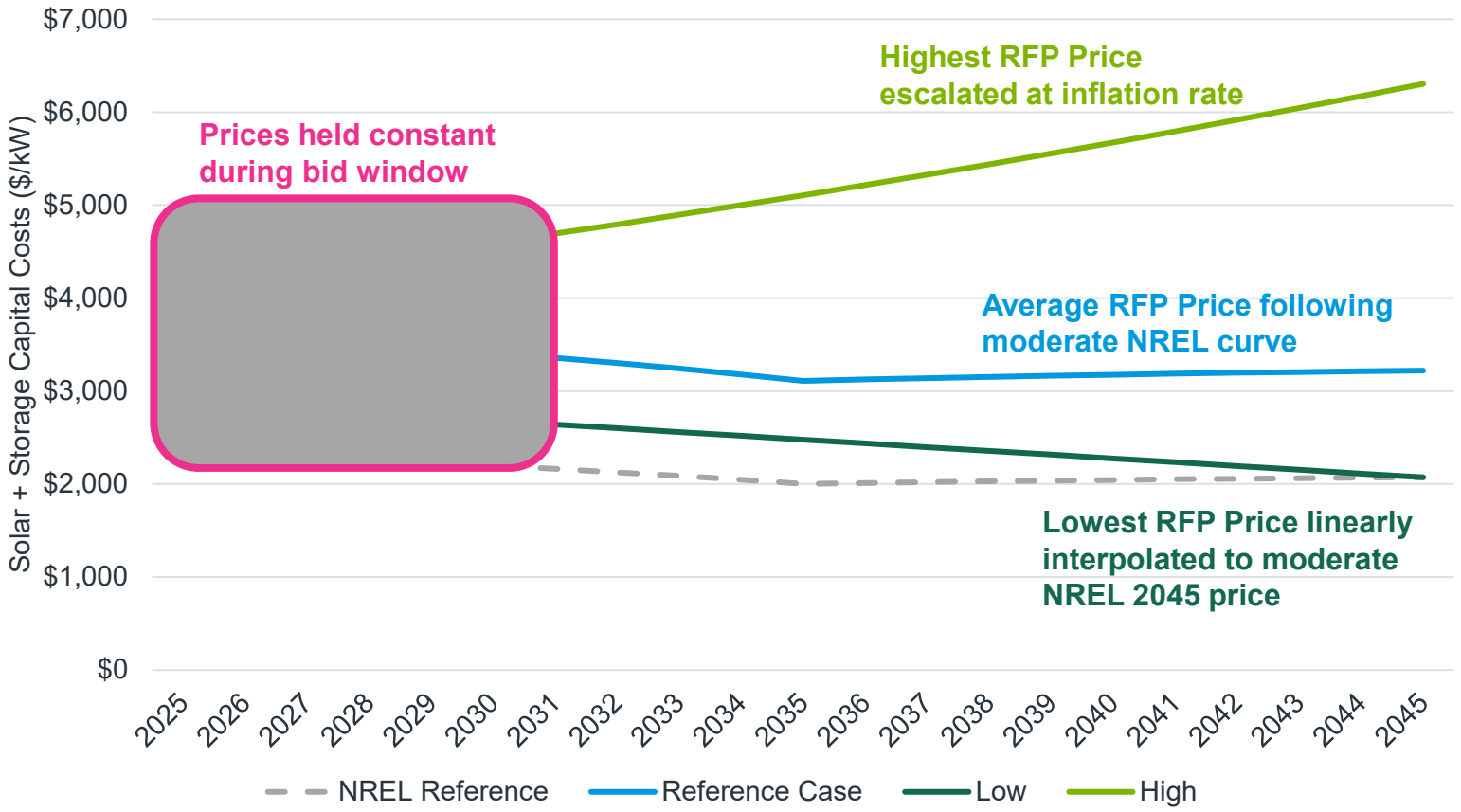


Solar Summary	
Capacity (MW)	100
Capital Costs ($/kW)	$2,351
Fixed O&M ($/kW-yr)	$12
Variable Costs ($/MWh)	–
2035 DLOL Accreditation*	
Summer	4%
Winter	0%
Spring	2%
Fall	3%

**Additional information on accreditation methodology is provided in the appendix.*

NREL = National Renewable Energy Laboratory *RFP = Request for Proposals*

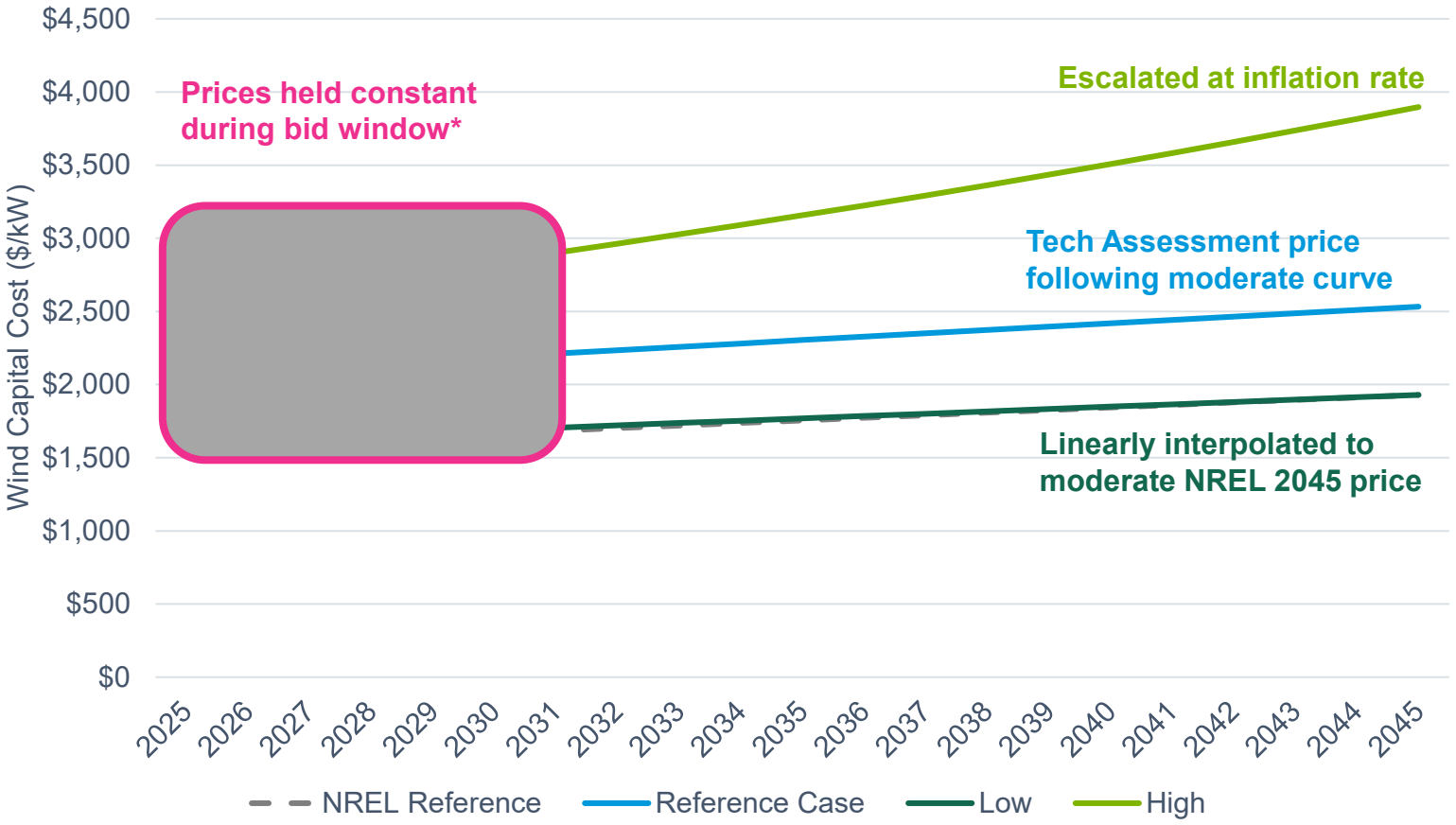
Solar + Storage Cost Curve



Solar + Storage Summary	
Capacity (MW)	100 MW Solar + 50 MW Storage
Capital Costs ($/kW)	$3,491
Fixed O&M ($/kW-yr)	$46.90
Variable Costs ($/MWh)	–

NREL = National Renewable Energy Laboratory *RFP = Request for Proposals*

Wind Cost Curve



Wind Summary	
Capacity (MW)	200
Capital Costs ($/kW)	$2,194*
Fixed O&M ($/kW-yr)	$34.50
Variable Costs ($/MWh)	–
2035 DLOL Accreditation**	
Summer	11%
Winter	15%
Spring	10%
Fall	14%

***Additional information on accreditation methodology is provided in the appendix.*

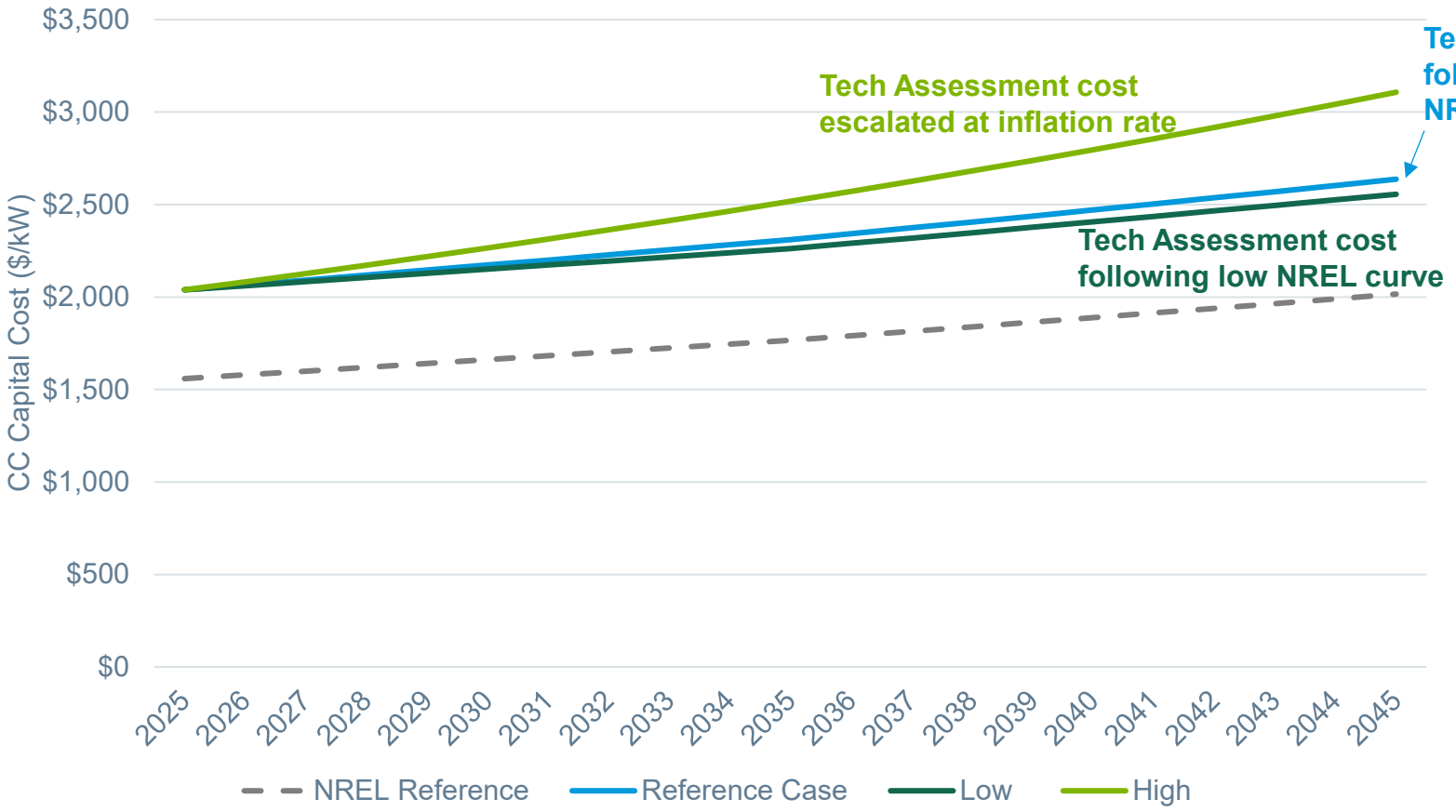
**Wind did not receive purchase as part of the RFP; a combination of Tech Assessment and PPA data was used to create capital cost curves.*

NREL = National Renewable Energy Laboratory *TA = Technology Assessment* *PPA = Power Purchase Agreement*

Cost Curve Approach – Tech Assessment

- For technologies that had no purchase options submitted in the 2024 All-Source RFP:
  - **Low curve**: starts with the capital cost from the technology assessment and follows the low NREL cost curve
  - **Moderate curve**: starts with the capital cost from the technology assessment and follows the moderate NREL cost curve
  - **High curve**: starts with the capital cost from the technology assessment and escalates at the assumed inflation rate

Combined Cycle Cost Curve



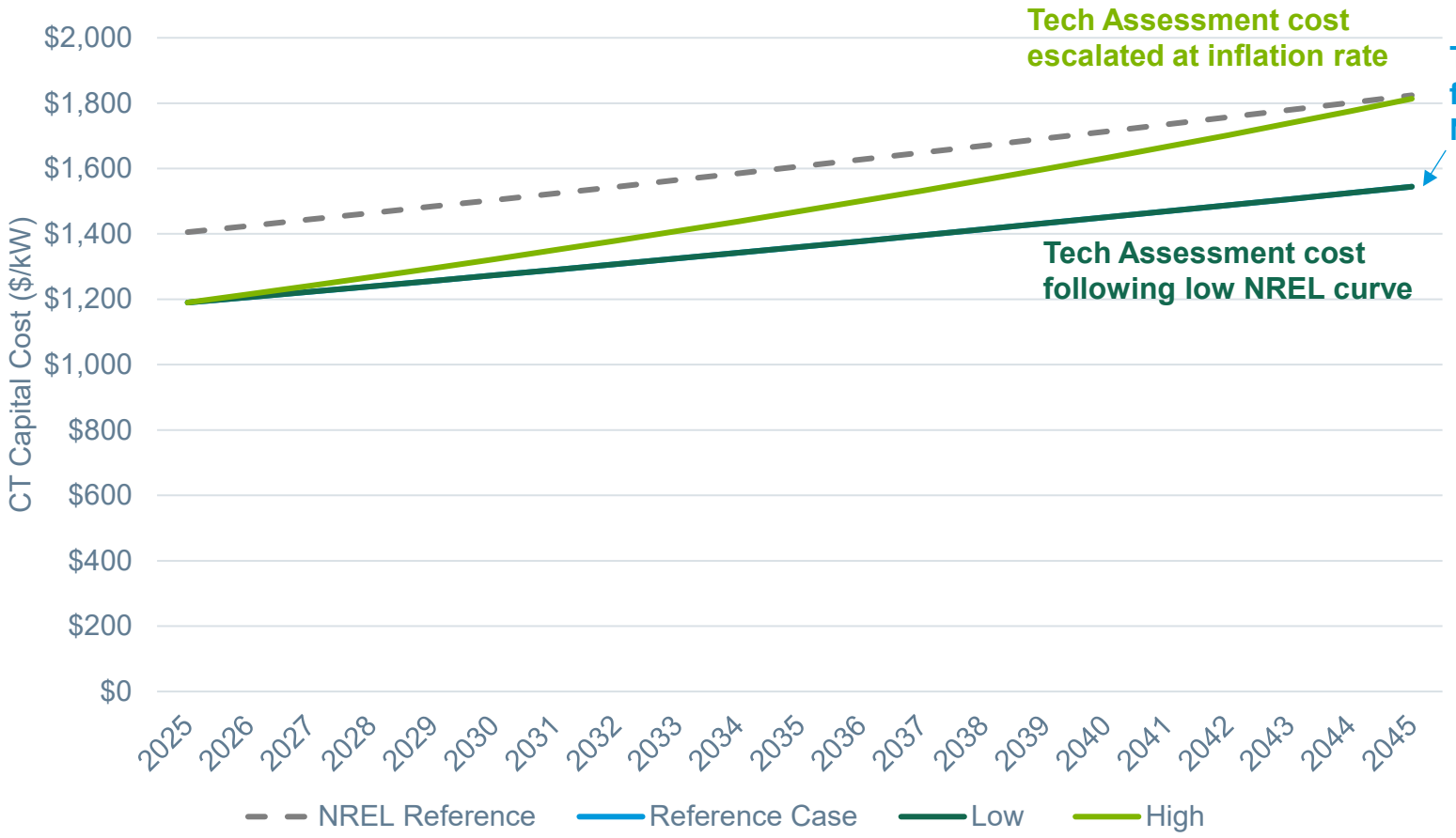
Combined Cycle Summary*	
Capacity (MW)	619.6
Capital Costs ($/kW)	$2,039
Fixed O&M ($/kW-yr)	$9.80
Variable Costs ($/MWh)	$2.79
Gas Transportation Cost ($MM/yr)	$26.33
2035 DLOL Accreditation**	
Summer	87%
Winter	93%
Spring	68%
Fall	78%

***Additional information on accreditation methodology is provided in the appendix.*

**Cost summary represents a 1x1 J Class Unfired CCGT, whereas the NREL curve represents a 2x1 F-Class*

NREL = National Renewable Energy Laboratory

Combustion Turbine Cost Curve



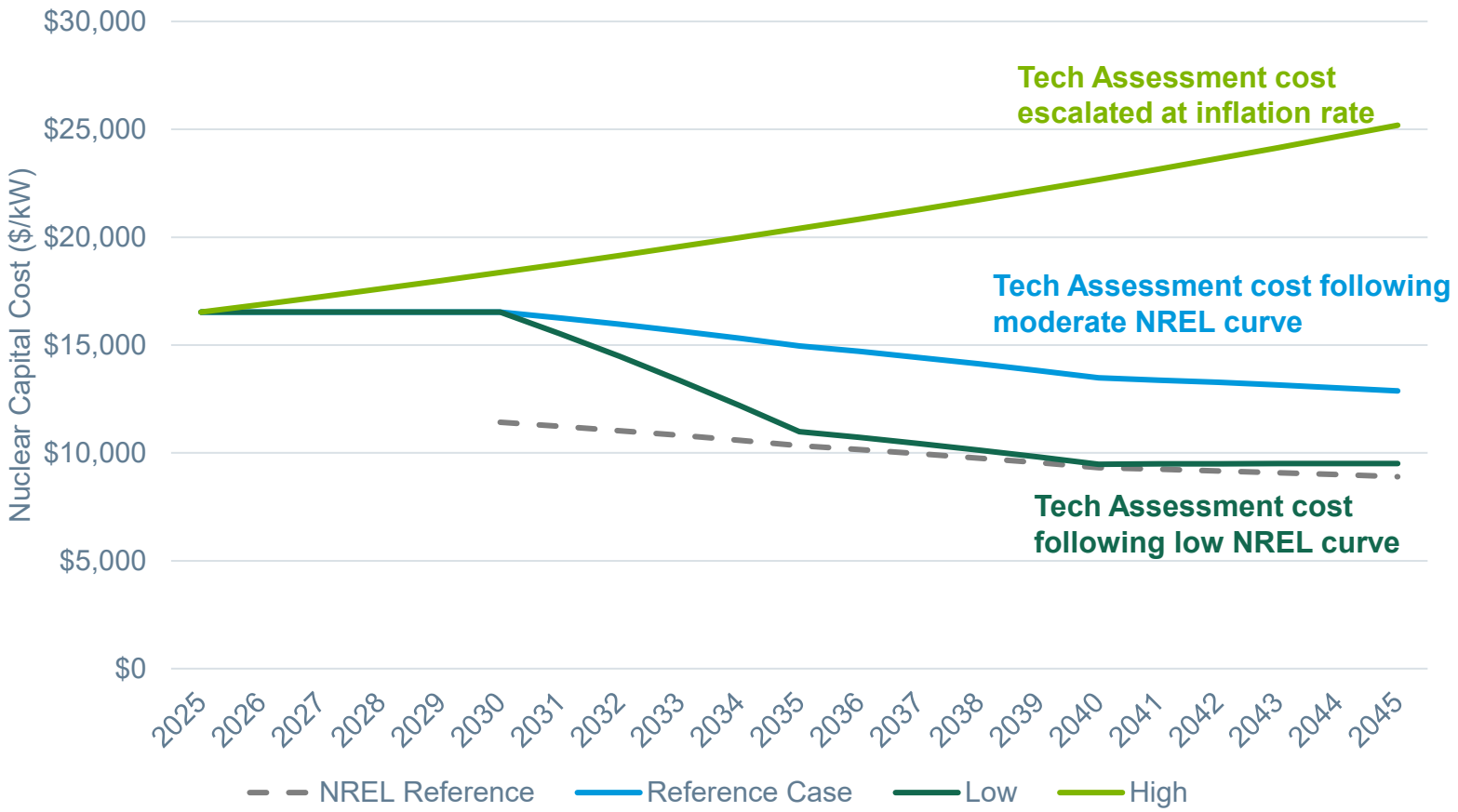
Combustion Turbine Summary*	
Capacity (MW)	426.4
Capital Costs ($/kW)	$1,190
Fixed O&M ($/kW-yr)	$6.10
Variable Costs ($/MWh)	$3.10
Gas Transportation Cost ($MM/yr)	$18.12
2035 DLOL Accreditation*	
Summer	87%
Winter	84%
Spring	74%
Fall	81%

Additional information on accreditation methodology is provided in the appendix.

Cost summary represents a J-Class CT, whereas the NREL cost curve represents a F-Class CT

NREL = National Renewable Energy Laboratory

Nuclear Cost Curve



Nuclear Summary	
Capacity (MW)	300
Capital Costs ($/kW)	$16,528
Fixed O&M ($/kW-yr)	$216
Variable Costs ($/MWh)	$2.80
2035 DLOL Accreditation*	
Summer	91%
Winter	95%
Spring	71%
Fall	90%

**Additional information on accreditation methodology is provided in the appendix.*

NREL = National Renewable Energy Laboratory

Q&A

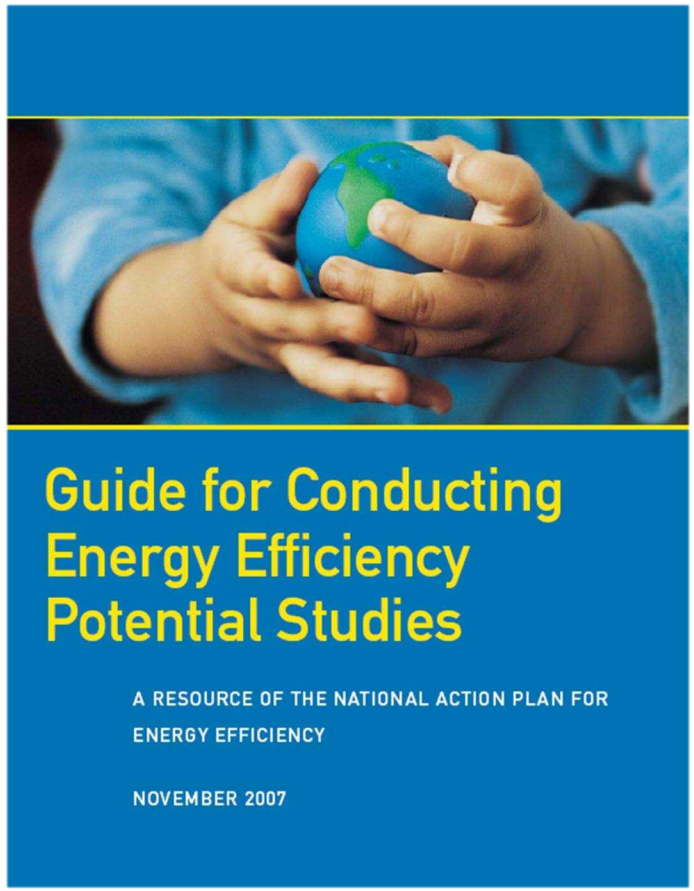
DSM Market Potential Study Update

Jeffrey Huber, Principal, Energy Efficiency, GDS Associates

TOPIC OVERVIEW

- Market Potential Study Overview
  - What is a Market Potential Study (MPS)?
  - Past Studies and Scope Overview
- Energy Efficiency (EE) Market Potential Study Overview
  - Market & Measure Characterization
  - Modeling
- Demand Response (DR) Market Potential Study Overview
  - Programs Considered
  - Methodology & Modeling
- IRP Inputs

WHAT IS A MARKET POTENTIAL STUDY?



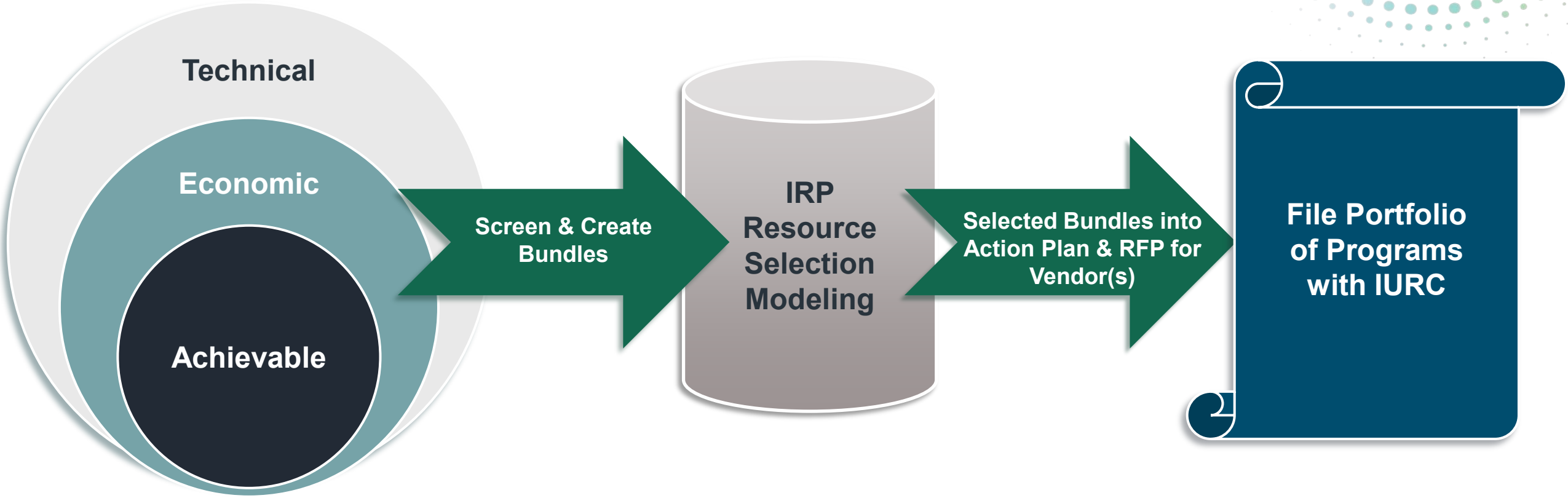
Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies.

-National Action Plan for Energy Efficiency

THE MPS & 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."



MARKET POTENTIAL STUDY

PAST STUDIES & CURRENT SCOPE

PAST STUDIES

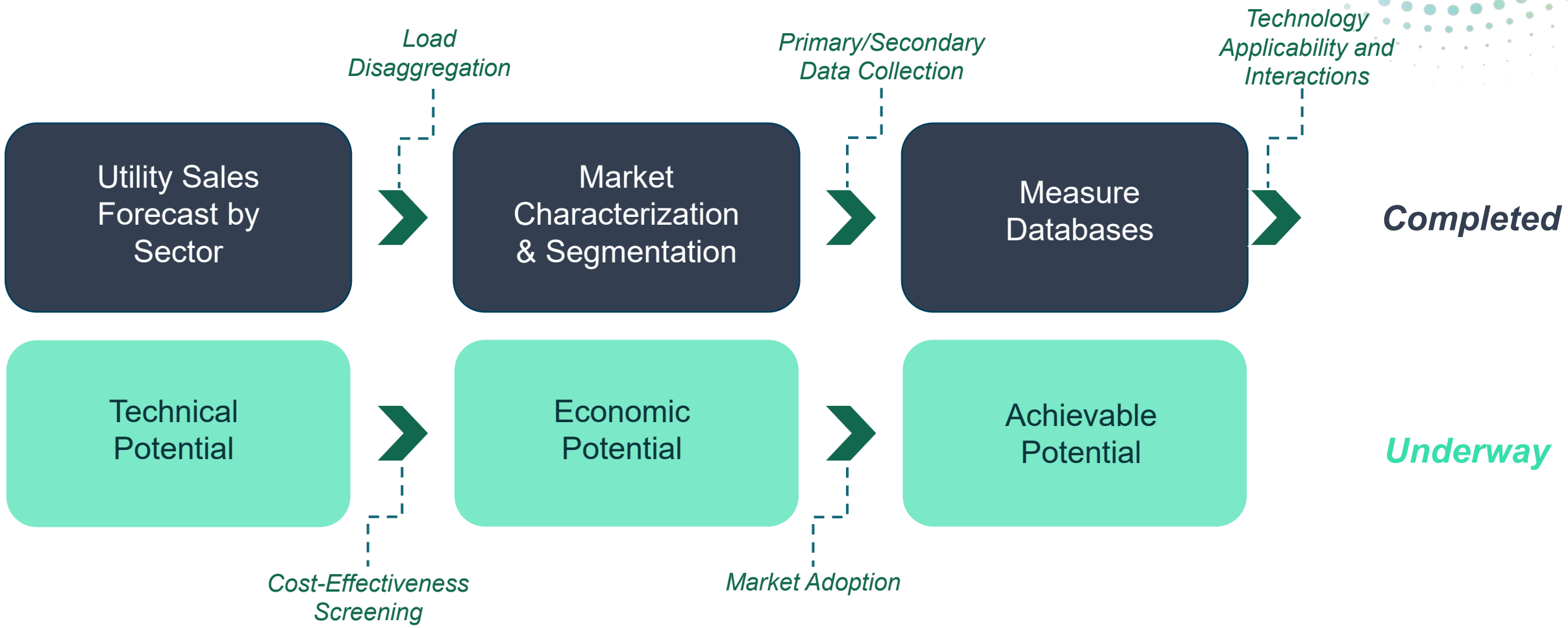
- GDS completed prior market potential studies in coordination with the 2019/2020 and 2022/2023 IRPs

CURRENT SCOPE

- Electric Energy Efficiency & Demand Response Potential Analysis
  - Estimates both energy savings and associated program costs
  - Used to inform DSM Inputs in IRP
  - DSM Action Plan
- Natural Gas Potential Analysis
  - DSM Action Plan

DSM = Demand Side Management

EE OVERVIEW: FLOW CHART



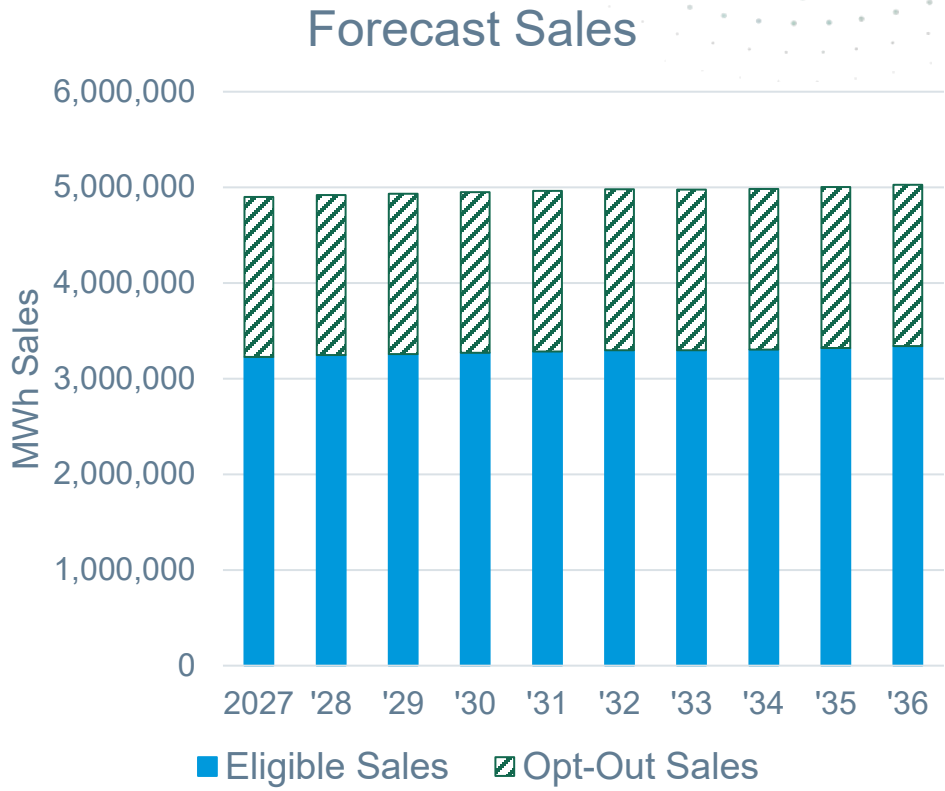
EE OVERVIEW: DATA INPUT NEEDS

- CEI South Load Forecast*
- Forecasts of Avoided Costs
- Global Economic Inputs
- End-Use Load Shapes
- Market Characteristic Data*
- Energy efficiency and demand response measure costs, kWh and kW savings, useful lives
- Historical Performance Data
- Relevant DSM Policy Considerations

** To be discussed in more detail*

EE OVERVIEW: MARKET CHARACTERIZATION

- LOAD FORECAST
  - Review of Sales and Customer Counts
    - Residential (single family/multifamily ; market rate/income qualified)
    - Commercial (by building type)
    - Industrial (by industry type)
  - Review Eligible Sales
    - 48% of all C&I sales are from customers who have opted-out of EE programs
    - Percentage of sales from other “atypical” facilities with limited traditional EE opportunities
  - Estimating Consumption by End-Use



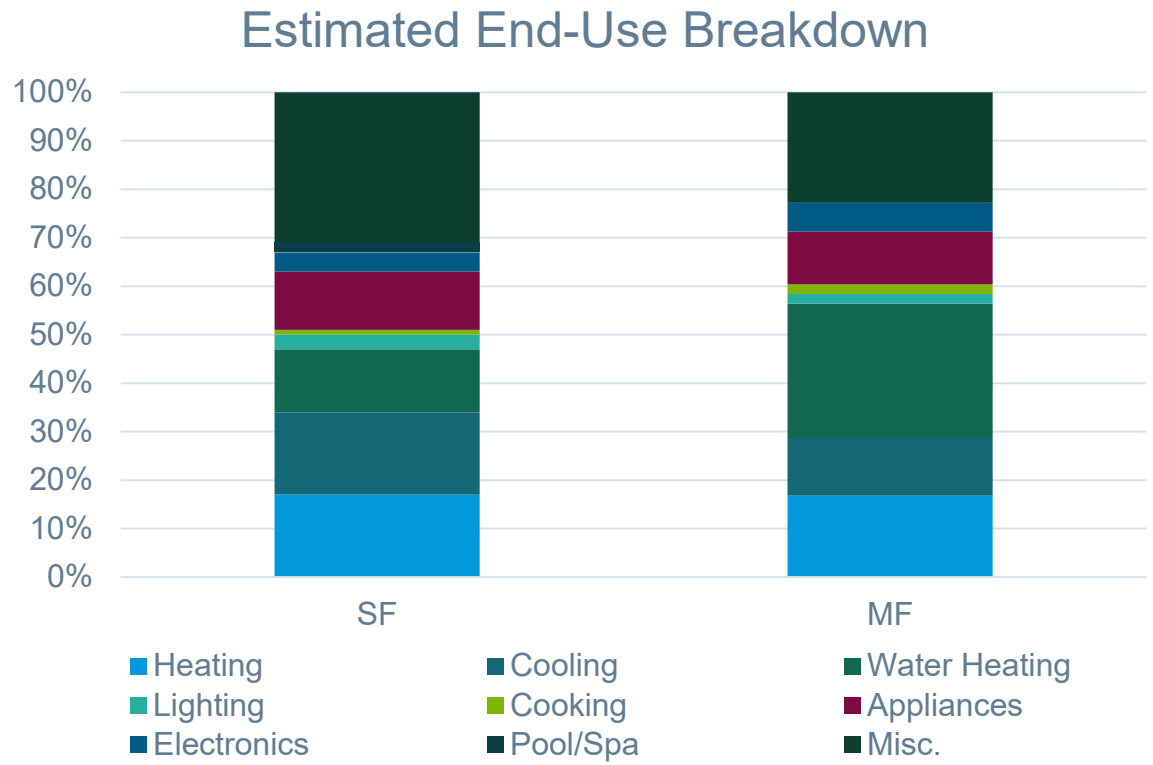
C&I = Commercial & Industrial

EE OVERVIEW: MARKET CHARACTERIZATION

- RESIDENTIAL ELECTRIC ACCOUNTS

	%
Single Family (SF)	85%
Multifamily (MF)	15%
SF-New Construction (NC)	72%
MF-NC	28%
Income Qualified (IQ*)-SF	21.6%
IQ-MF	45.5%

**200% of Federal Poverty Guidelines or less*

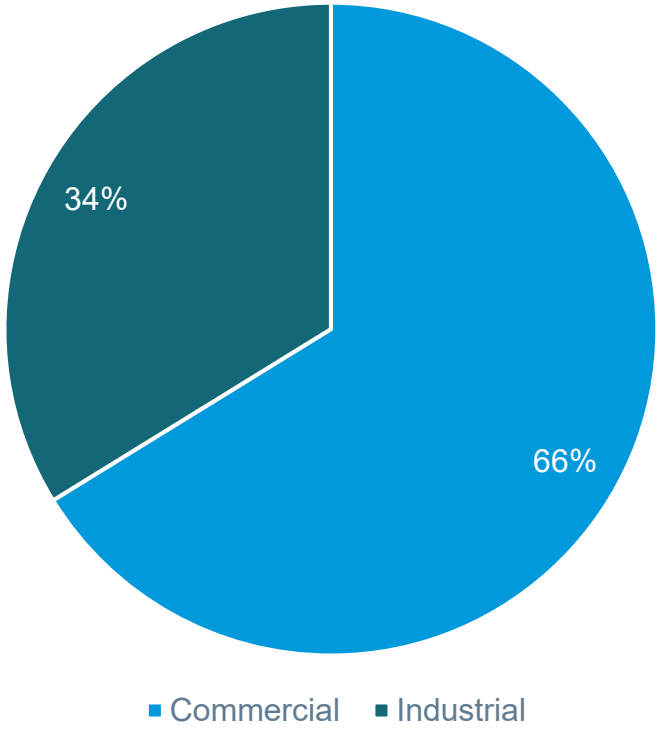


Source: 2023 Annual Energy Outlook – East South-Central Region

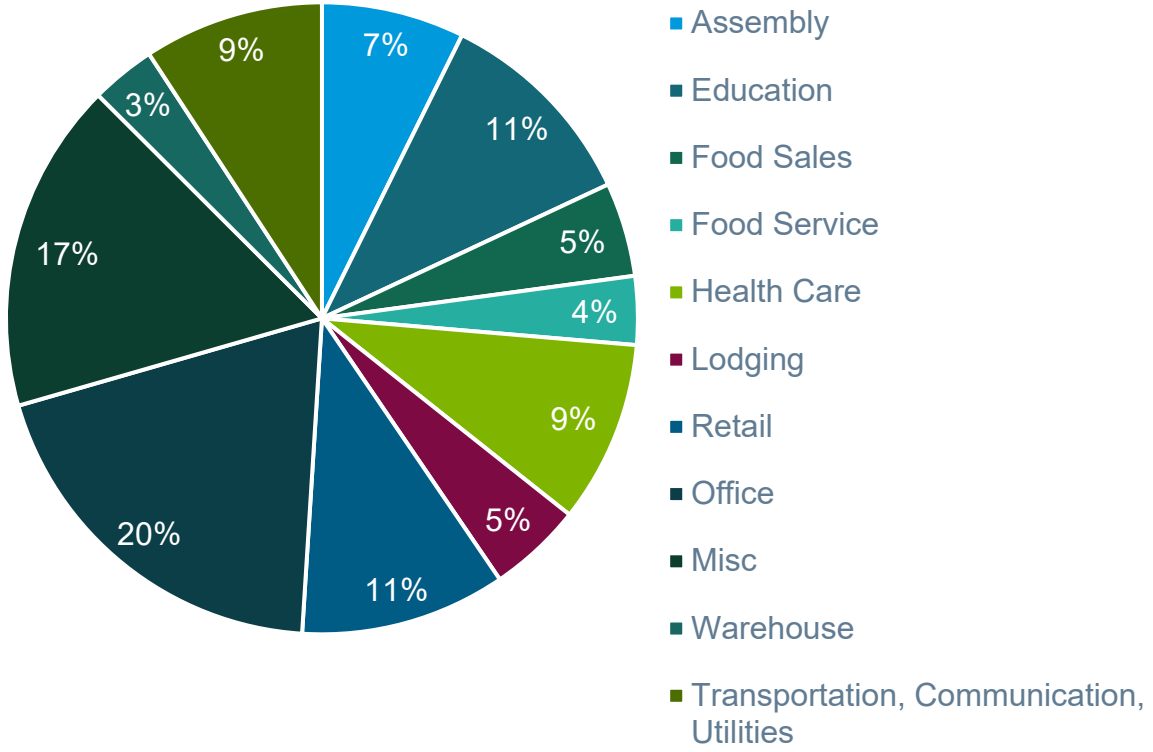
EE OVERVIEW: MARKET CHARACTERIZATION

- C&I SEGMENTATION

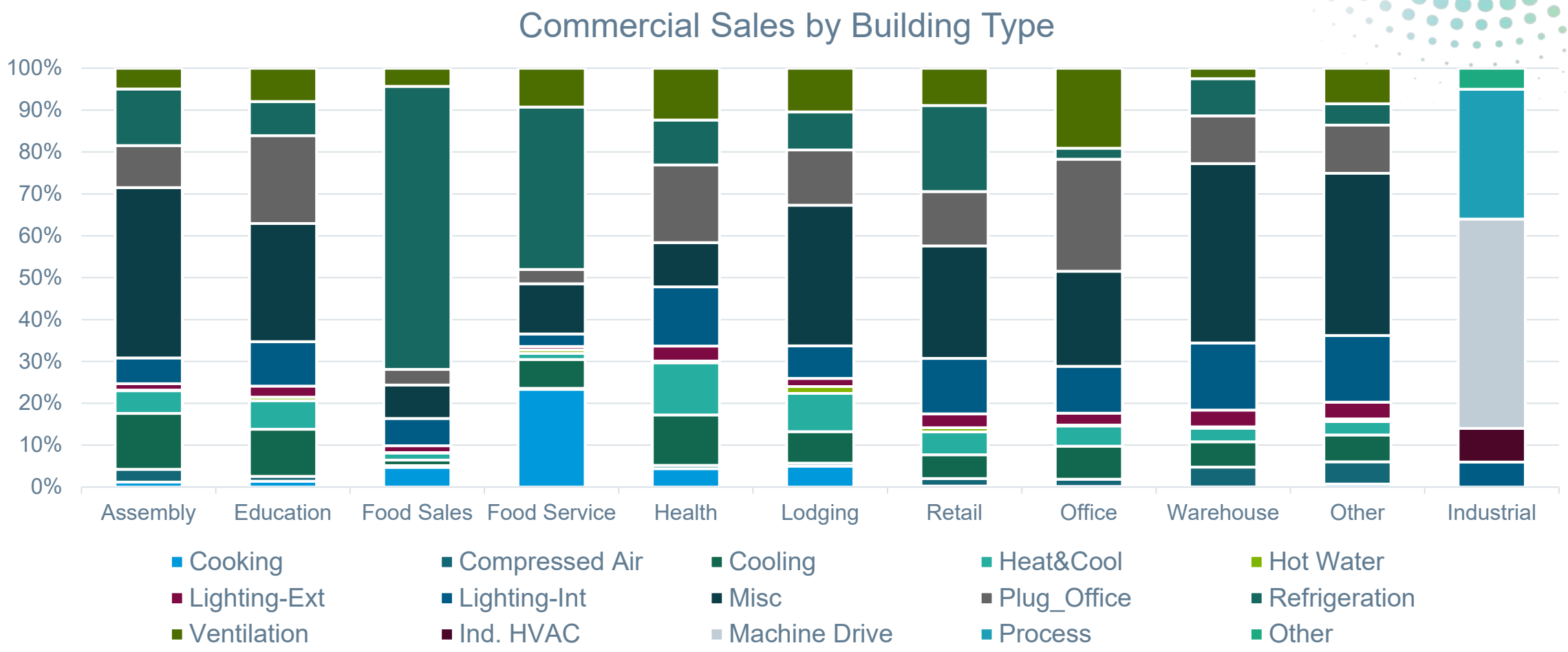
Sales by Sector



Commercial Sales by Building Type



EE OVERVIEW: MARKET CHARACTERIZATION



EE OVERVIEW: MEASURE CHARACTERIZATION

- Develop a CenterPoint Indiana specific measure database of:
  - Measure Savings (Annual Savings and Peak Demand Savings)
  - Measure Effective Useful Life (EUL)
  - Measure Costs (either full costs or incremental costs)
  - Measure Incentives

Derived primarily from the Indiana TRM w/ support from additional regional resources

  - Base Saturation Estimates (i.e., % of homes with a specific type of equipment)
  - EE Saturation Estimates (% of equipment that is already efficient)

Derived from a blend of recent primary market research and regional/national data sources

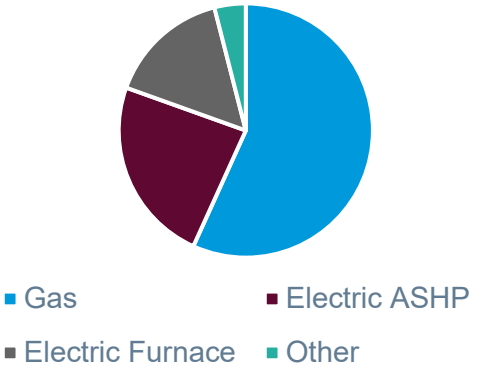
TRM = Technical Reference Manual

EE OVERVIEW: MARKET RESEARCH

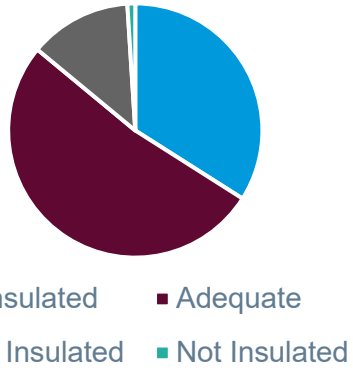
- CenterPoint Indiana conducted a residential survey on energy consuming equipment and customer perspectives in early 2025, with over 1,000 responses.

Results Examples:

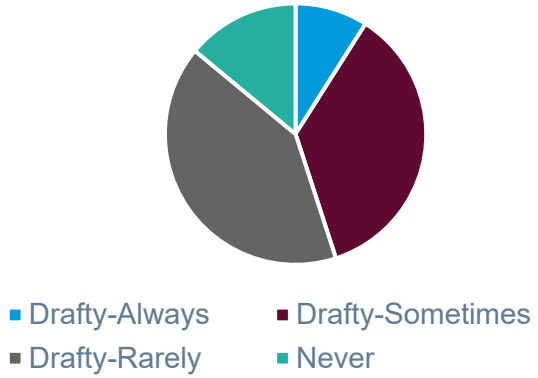
Heating Fuel Type

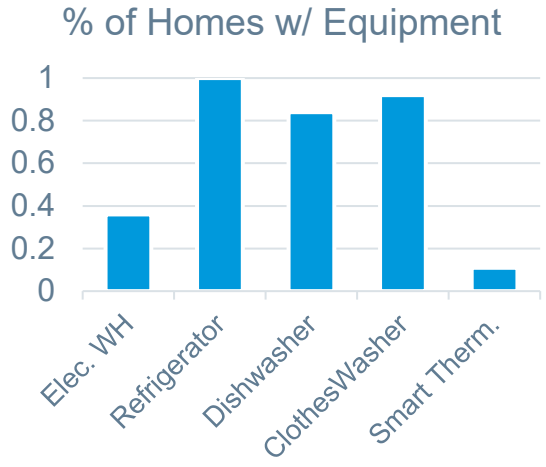


Insulation



Air Sealing





EE OVERVIEW: TYPES OF POTENTIAL OVERVIEW

TECHNICAL POTENTIAL

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

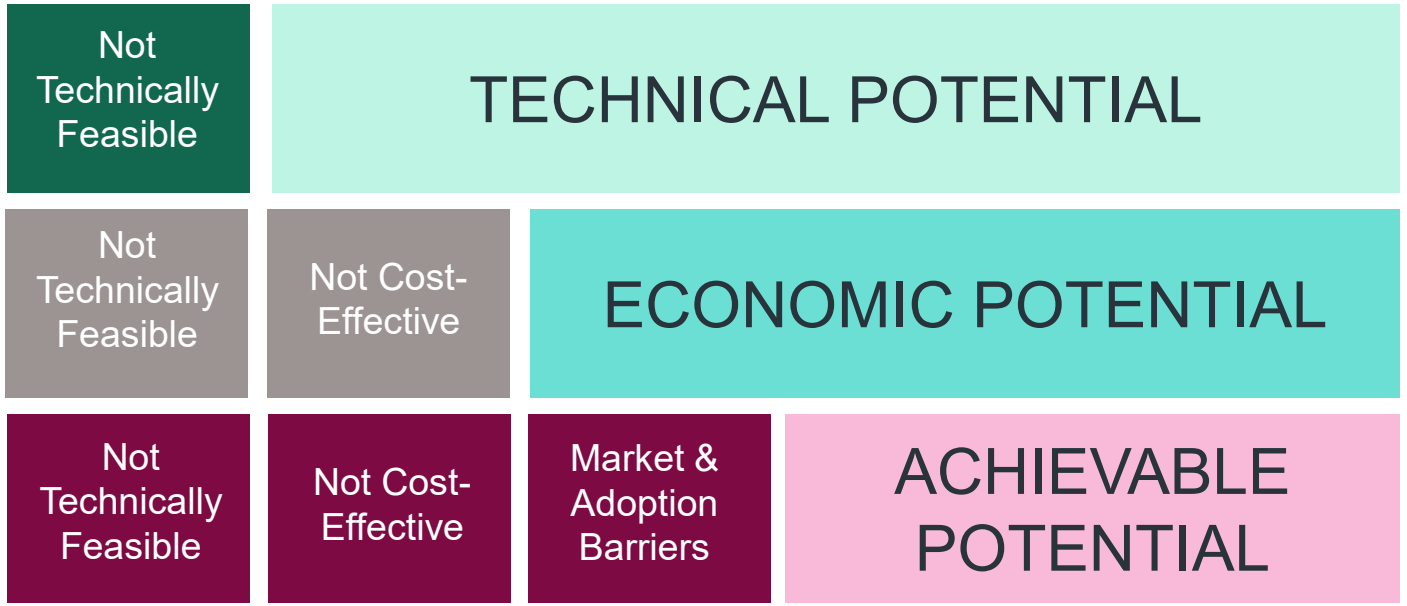
ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the **Utility Cost 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



EE OVERVIEW: ON-GOING COORDINATION

- On-going coordination between GDS, CenterPoint Indiana, and the CenterPoint Energy Oversight Board
- Discussing select methodology considerations for modeling
  - Addressing future C&I lighting opportunities
  - Measure refill
  - Willingness to Participate/Adoption Rates
  - Additional Achievable Potential Scenarios

EE OVERVIEW: MODEL OUTPUTS

- Energy Savings by Potential Type
  - Technical, Economic, Achievable, etc.
- Gross and Net Savings
- Incremental Annual & Cumulative Annual Savings (MWh) by:
  - Sector
  - Home/Building Type
  - Income type
  - End-Use
  - Program
- Incremental and Cumulative Annual Demand Savings
  - By Season
- Annual Incentives
- Annual Non-Incentives
- Annual NPV Benefits and UCT Ratios
- Levelized Costs of Energy Efficiency
- Top Program Measures

NPV = Net Present Value

UCT = Utility Cost Test

DR OVERVIEW: OVERVIEW

- Goal of the DR MPS is to develop IRP inputs, but will also share some common assumptions with IRP where possible
  - Peak load forecast by season and rate class
  - Electric vehicle adoption forecast
  - Behind-the-meter solar penetration forecast
- DR MPS will also consider results of the EE MPS
  - Use consistent end-use saturation estimates
  - Consider select EE technology adoption estimates/efficiency trends and EE rebates
- Prioritizes current demand response offerings and rate structures

DR OVERVIEW: STARTING POINT

- Historical DR Program Offerings
  - DLC Central AC (Switch and Thermostat)
  - DLC Water Heating (Switch)
- Programs Under Consideration (by 2028)
  - Time of Use (TOU) with Critical Peak Pricing (CPP) Rate
  - DR Aggregation* *(Potential impacts previously analyzed by CenterPoint Indiana South outside of MPS)*
- Additional Programs for MPS
  - DLC Water Heating (Grid-Enabled)
  - DLC Electric Vehicle (EV)
  - Battery Storage

DLC = Direct Load Control

DR OVERVIEW: METHODOLOGY

- Programs are screened for cost-effectiveness using the Utility Cost Test (UCT)
  - UCT = ratio of Net Present Value (NPV) benefits to NPV cost per program over 20-year lifespan
  - NPV benefits include avoided generation capacity (based on a combined Cyle natural gas plan) and avoided transmission and distribution capacity
  - DR offerings with a UCT ratio less than 1.0 may still be presented as resource options in the IRP model
- MPS will contain two DR potential scenarios:
  - RAP (Realistic Achievable Potential): projections of future DR potential at typical incentive rates and marketing levels
  - MAP (Maximum Achievable Potential): more “aggressive” projection of future DR potential, achieved by offering more generous incentives and/or top-performing jurisdiction benchmarking.

DR OVERVIEW: PROGRAM LEVEL CONCEPTS

DLC Central AC

- Control of Central ACs
- 80% of existing switches being transitioned to thermostats; remaining 20% can stay in program until switch failure
- Also offer a BYOT option for thermostats
- Switch program runs only in summer; thermostat option runs spring through fall

DLC Water Heating

- Control of electric storage water heaters
- Legacy switches not being replaced after failure
- Also considering grid-enabled water heaters as a participation option instead of switches
- Switch program runs only in summer; grid-enabled option runs year-round

BYOT = Bring Your Own Thermostat

DR OVERVIEW: PROGRAM LEVEL CONCEPTS

TOU + CPP Rate

- CenterPoint Indiana South is starting pilot in 2026 for residential customers
- Rate will be modeled for C&I customers in future years
- Most days will have TOU on/off-peak pricing
- Critical peak days will have a higher rate during on-peak hours
- Rate will be offered year-round

DR OVERVIEW: PROGRAM LEVEL CONCEPTS

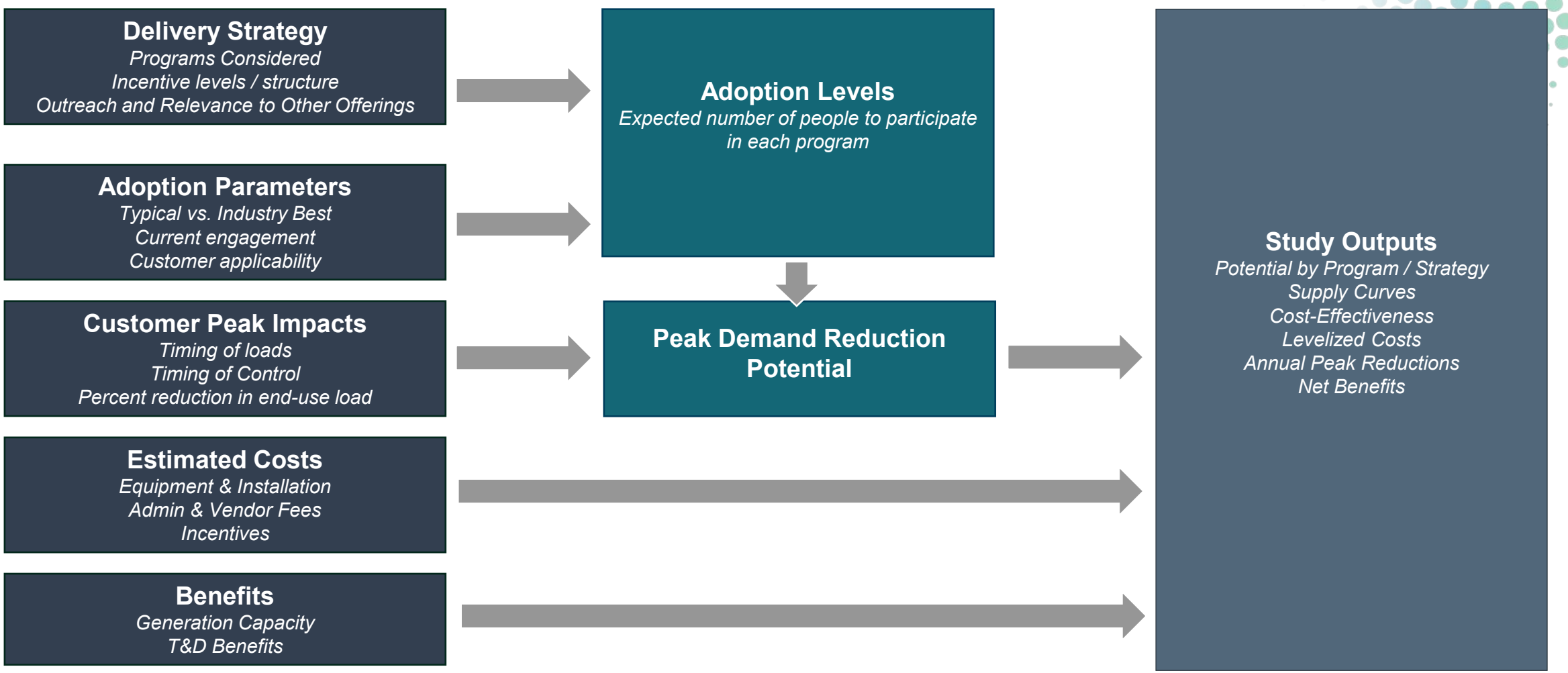
DLC Electric Vehicle

- Control of EV chargers during peak hours
- Program offered year-round
- Uses EV adoption forecast for CenterPoint Indiana South's territory

Battery Storage

- Program uses customers' batteries during times of high demand
- Assumes CenterPoint Indiana South could use 60% of battery, reserving 40% for customer in case of power outage
- Program offered year-round
- Uses solar adoption forecast for CenterPoint Indiana South's territory
- Assumes customer would bring their own battery

DR OVERVIEW: FLOW CHART



DSM IN THE IRP: EXPECTED INPUT STRUCTURE

- DSM Inputs are currently expected to be:
  - Sector based (residential, income-qualified, and nonresidential)
    - Residential and nonresidential will be selectable resources ; income-qualified will be a “going-in” resource
  - Three time-vintages (2028-2030, 2031-2033, and 2034-2045)
  - Based on RAP and/or “Enhanced” RAP (to be defined later)
  - Based on net savings
  - Costs will reflect utility incentive and non-incentive costs (less NPV T&D benefits)
  - Include hourly profiles for each bundle

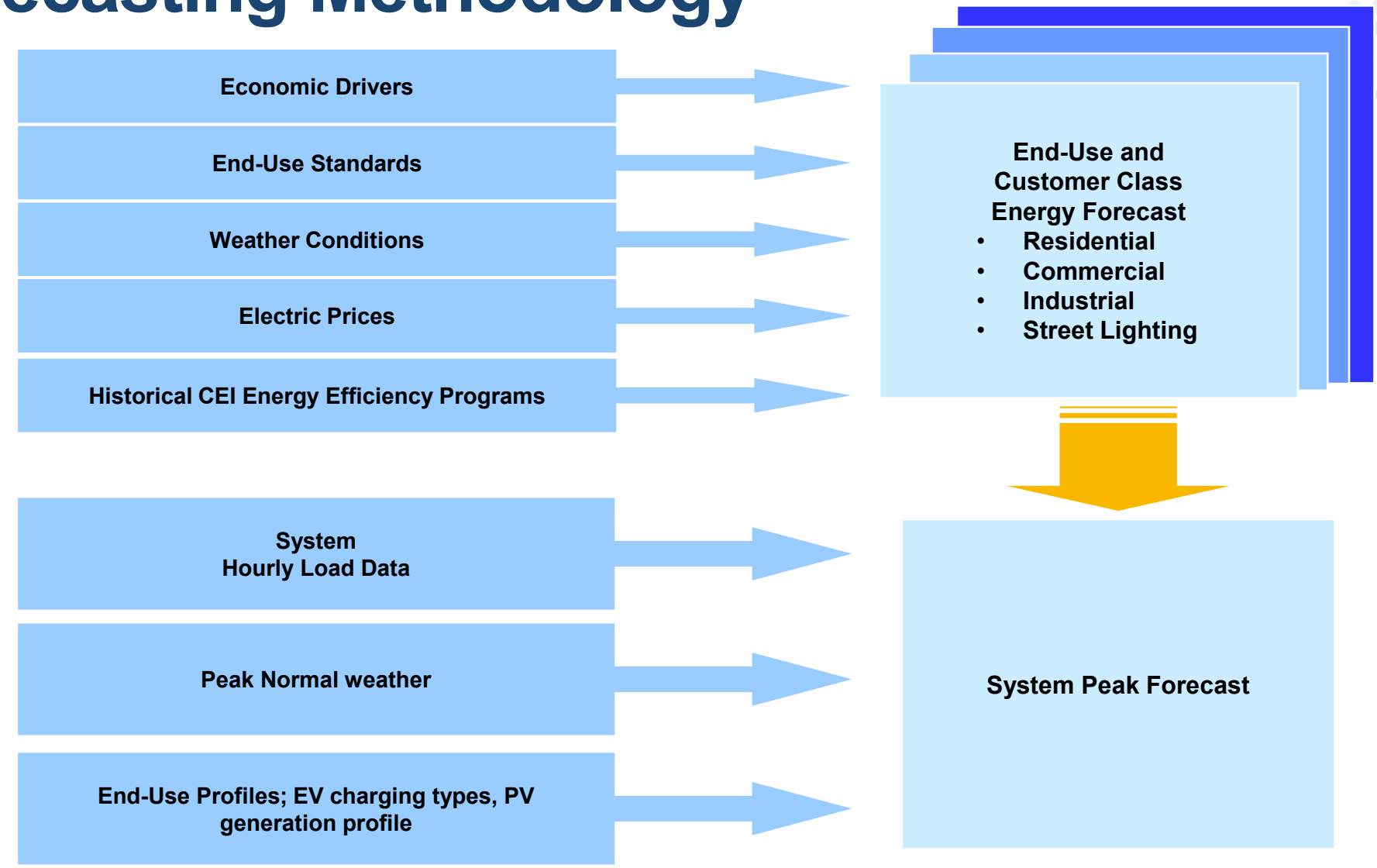
NPV T&D = Net Present Value Transmission & Distribution

Q&A

Sales & Demand Scenario Forecasts

Michael Russo
Forecast Consultant – ITRON

Forecasting Methodology

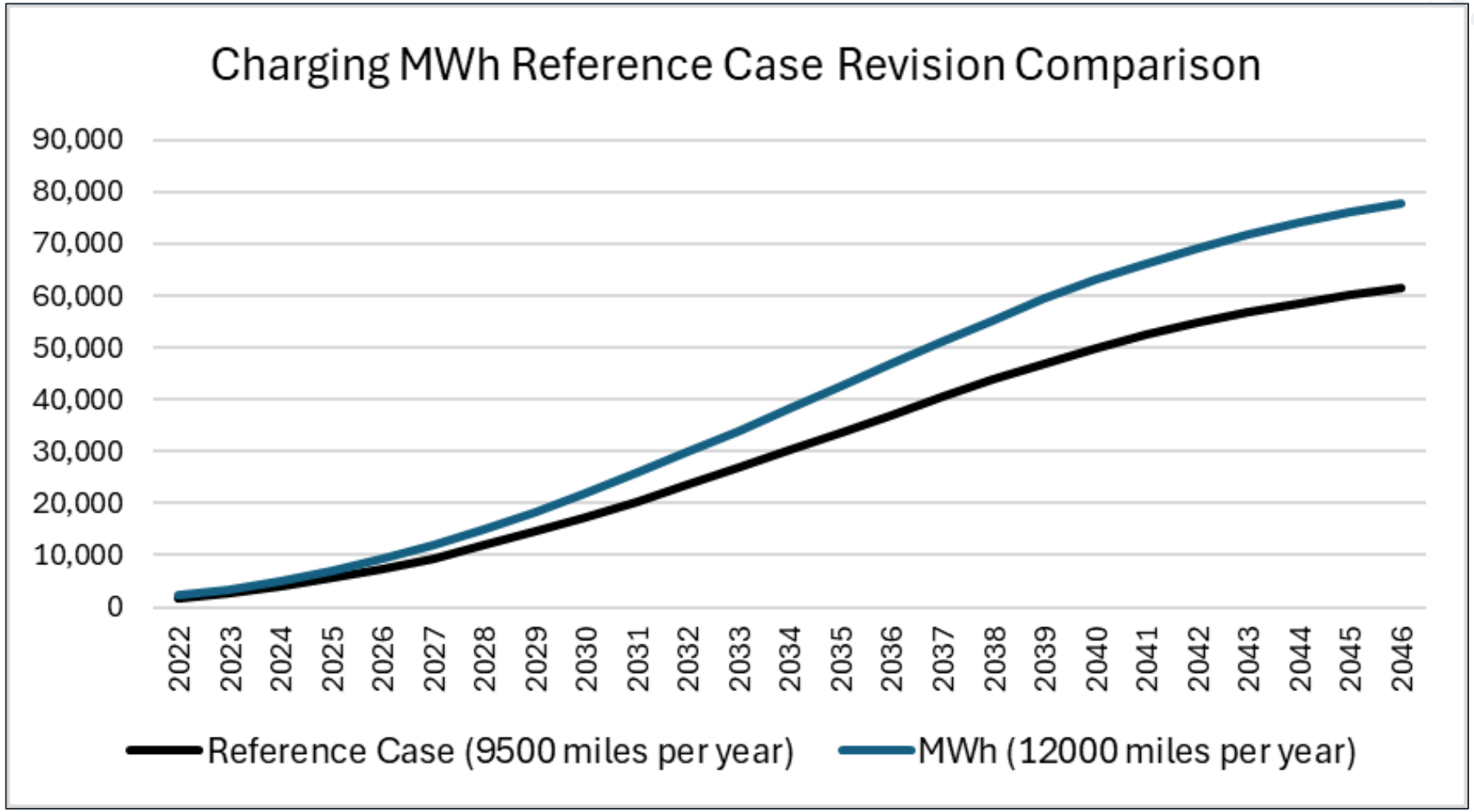


Stakeholder Feedback: Electric Vehicle (EV) Forecast Methodology Revision to Reference Case

- Annual kWh per vehicles based on the current mix of BEV and PHEV and 9,500 miles per year.
  - Based on an average from multiple studies conducted from 2014-2022 for the U.S. and California.
  - Annual milage varied from 6,300 miles in a 2017 National Household Travel survey to 12,522 miles in a 2020 UC Davis study.

- Energy Information Administration (EIA) forecast based on share of new vehicle sales; differentiating between all electric (BEV) and plug-in hybrid electric (PHEV).
- Starting electric vehicle numbers based on the number of currently registered electric vehicles in CenterPoint's service territory.

Electric Vehicle (EV) Forecast Revision



Forecast Scenarios

- CEI South utilized Itron to develop its scenario forecasts, rather than past stochastic methodology, based on feedback from the prior IRP.
- Developed 3 alternate forecasts
  - Low Regulatory
  - High Regulatory
  - Alternate High Regulatory (with Electrification)
    - Based on stakeholder feedback
- Forecasts developed by altering model inputs
  - EV Forecast
  - End Use Saturations & Efficiencies
  - DG forecast
  - Economics
- The Alternate High Regulatory Forecast (with Electrification) drives a significantly higher winter load

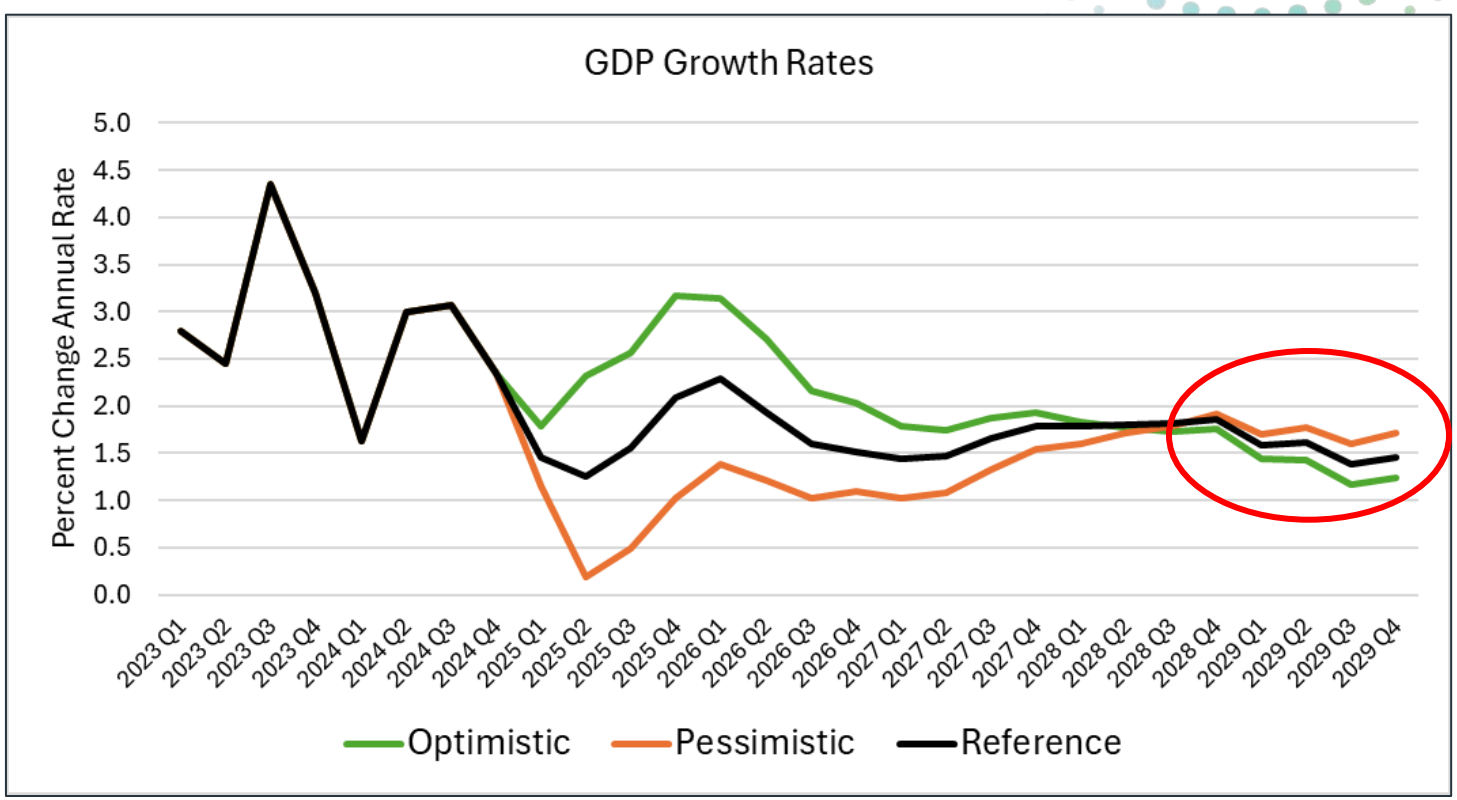
Forecast Scenarios

- **High Regulatory**: Lower load forecast driven by increased efficiency assumptions and weaker economic forecast
  - Assumes end-use efficiency projections increase by 10%-20% over the forecast period in comparison to the reference case.
  - S&P Global's pessimistic outlook assumes strict trade and immigration policy will create near-term financial stress, increase inflation, and reduce economic growth.
  - Extension of federal solar tax credits at 30%.
- **Low Regulatory** : High load forecast driven by stronger economic forecast and lower solar forecast
  - S&P Global's optimistic outlook assumes economic policy will moderate inflation and increase economic growth.
  - Assumes solar installation costs decline at a slower rate compared to the reference case.
- **Alternative High Regulatory (with Electrification)**: Higher load driven by increased adoption of electric vehicle and greater miles driven per year. Building electrification increases the saturation of electric water heaters, clothes dryers, and cooking, and heat-pumps for heating.

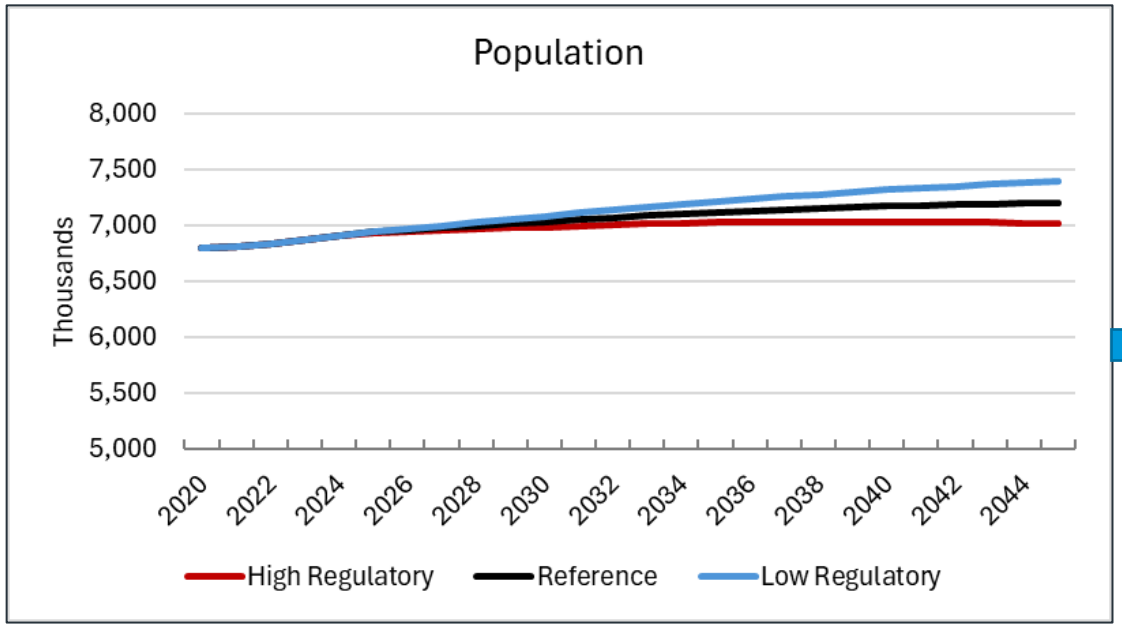
Economic Scenarios

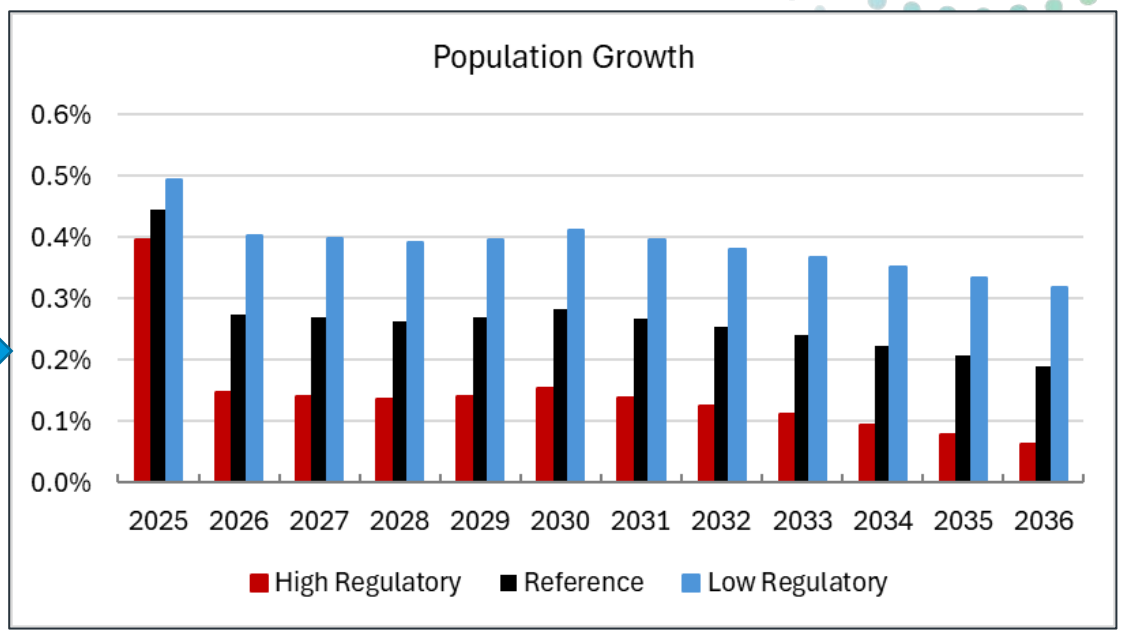
- S&P scenarios are noticeably different though 2028, after which point the forecasts begin to revert to the reference forecast.

- Due to this issue, alternative economic drivers were created which rely on the S&P scenarios through 2028, then are based on the standard deviation of the historical growth of the concept.



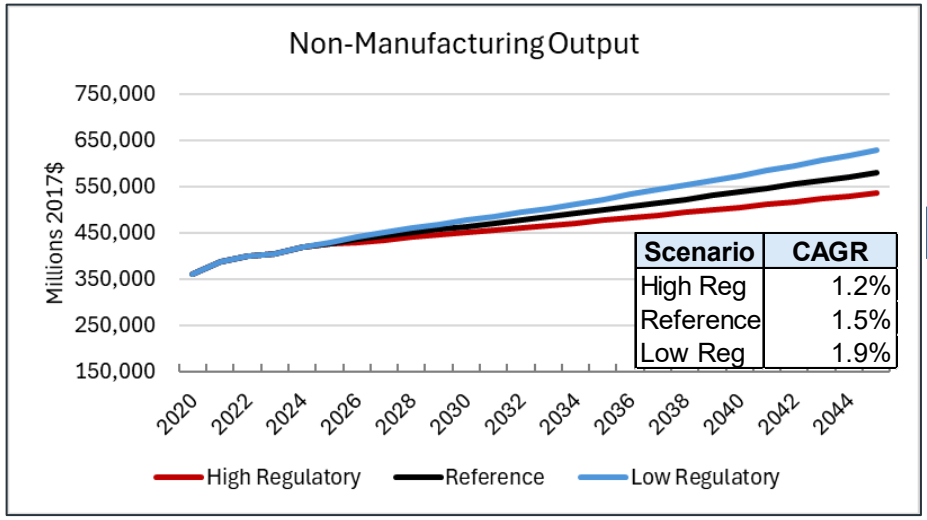
Residential Economic Concepts

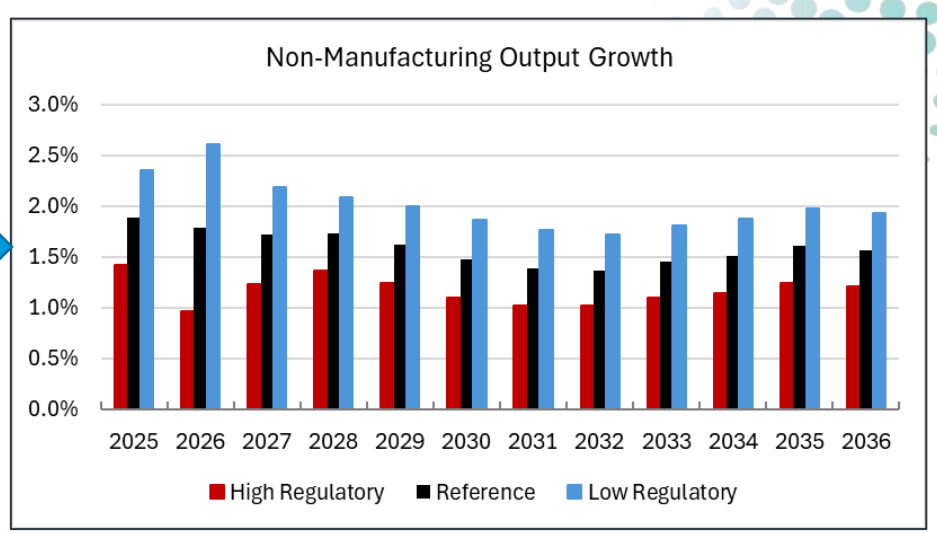


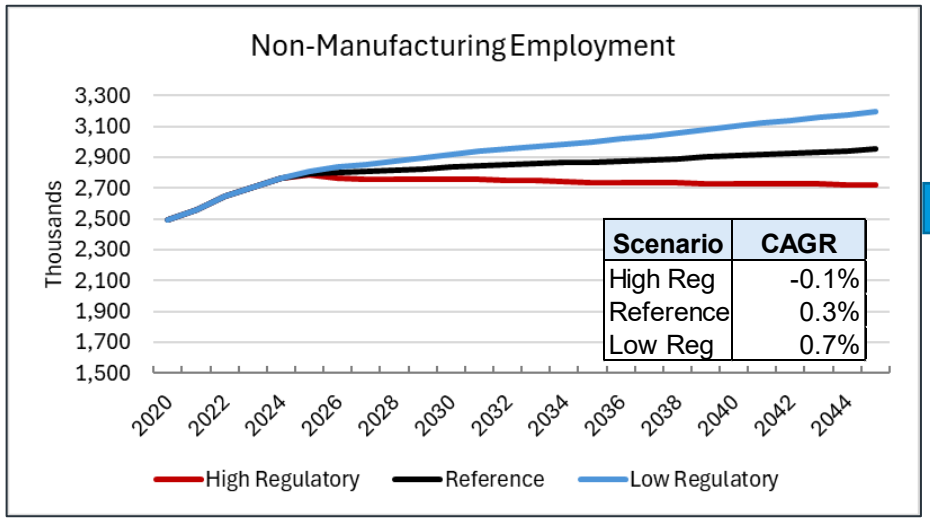


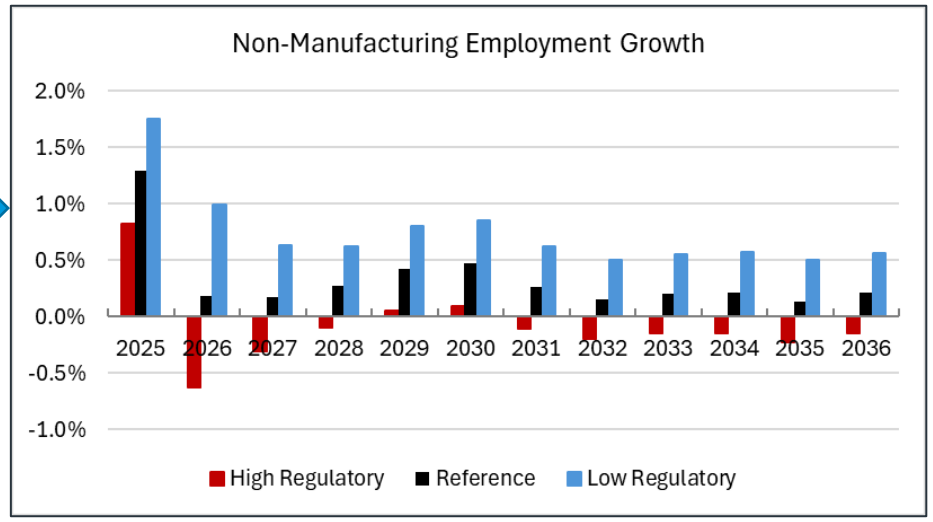
- Population CAGR is 0.1% in the low case and 0.3% in the high case, compared to 0.2% in the reference case.

Commercial Economic Concepts

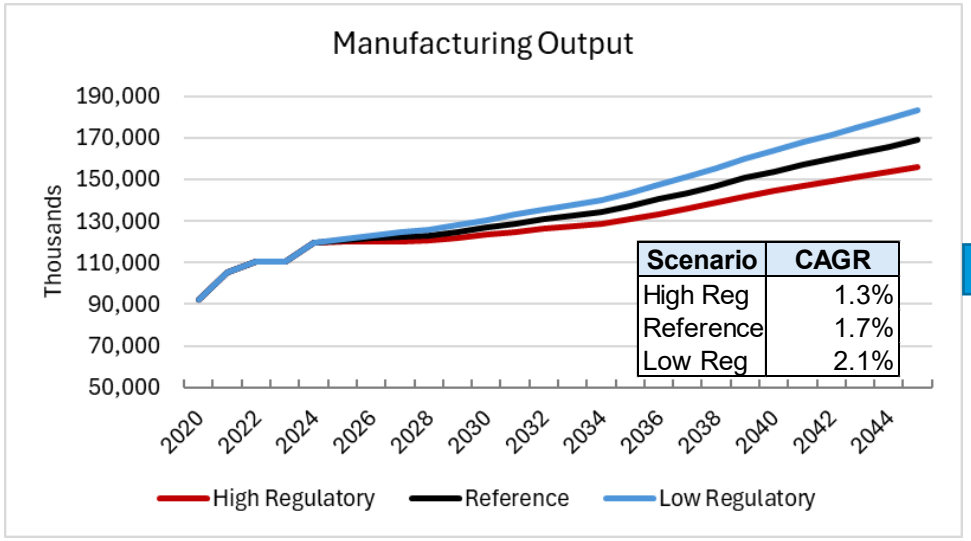


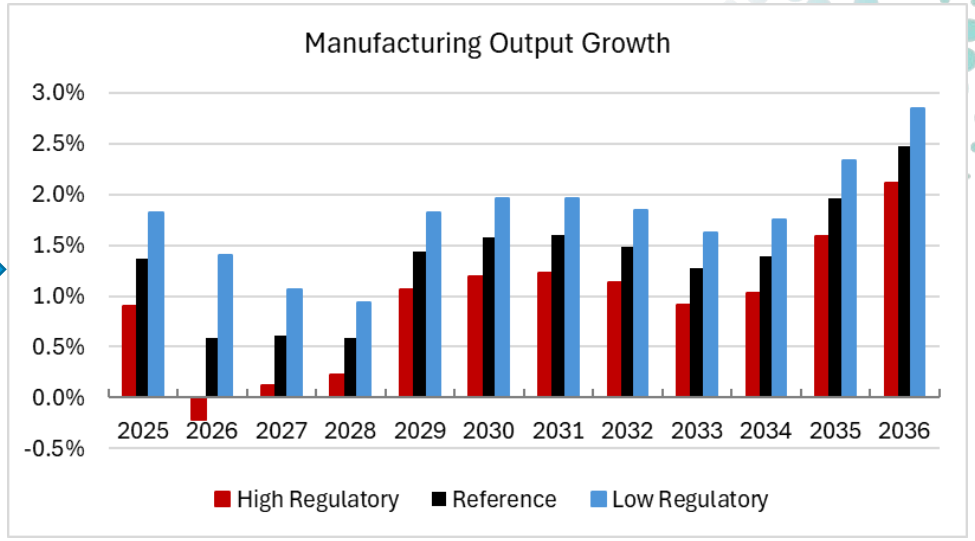


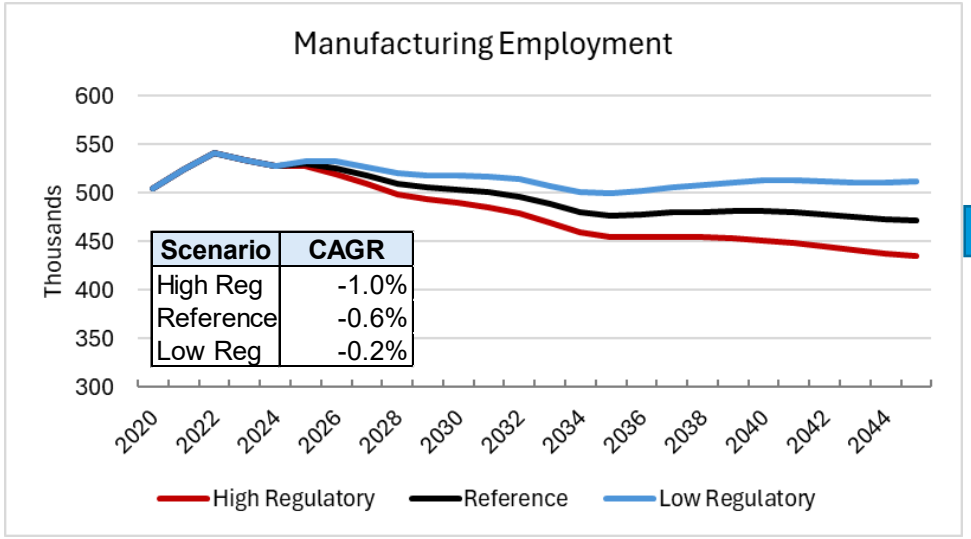


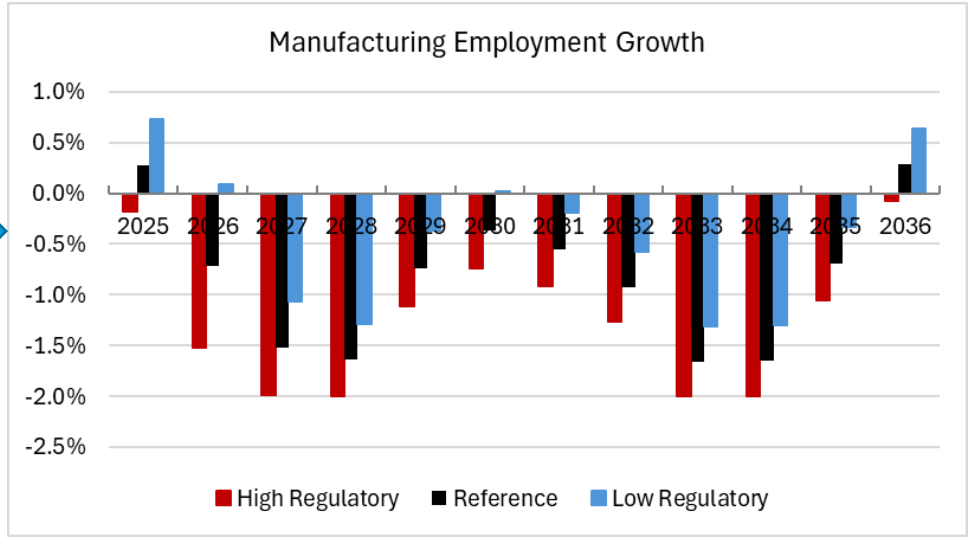


Industrial Economic Concepts









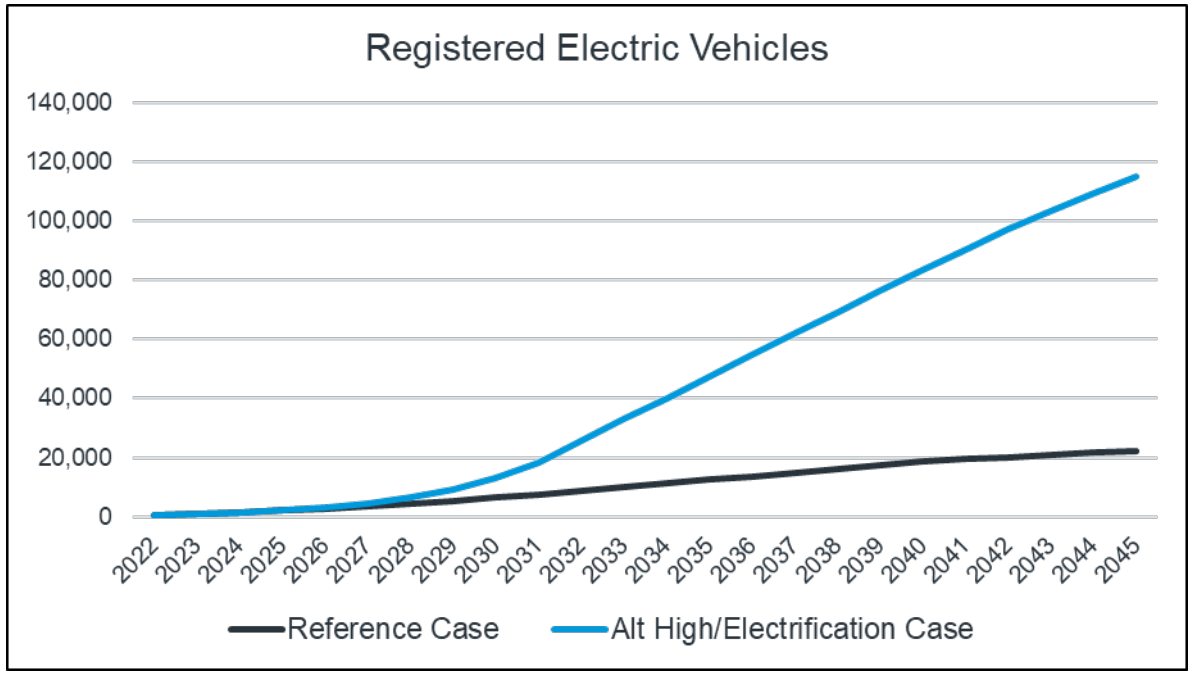
Electric Vehicle (EV) Forecast Methodology: Alt High Electrification Case

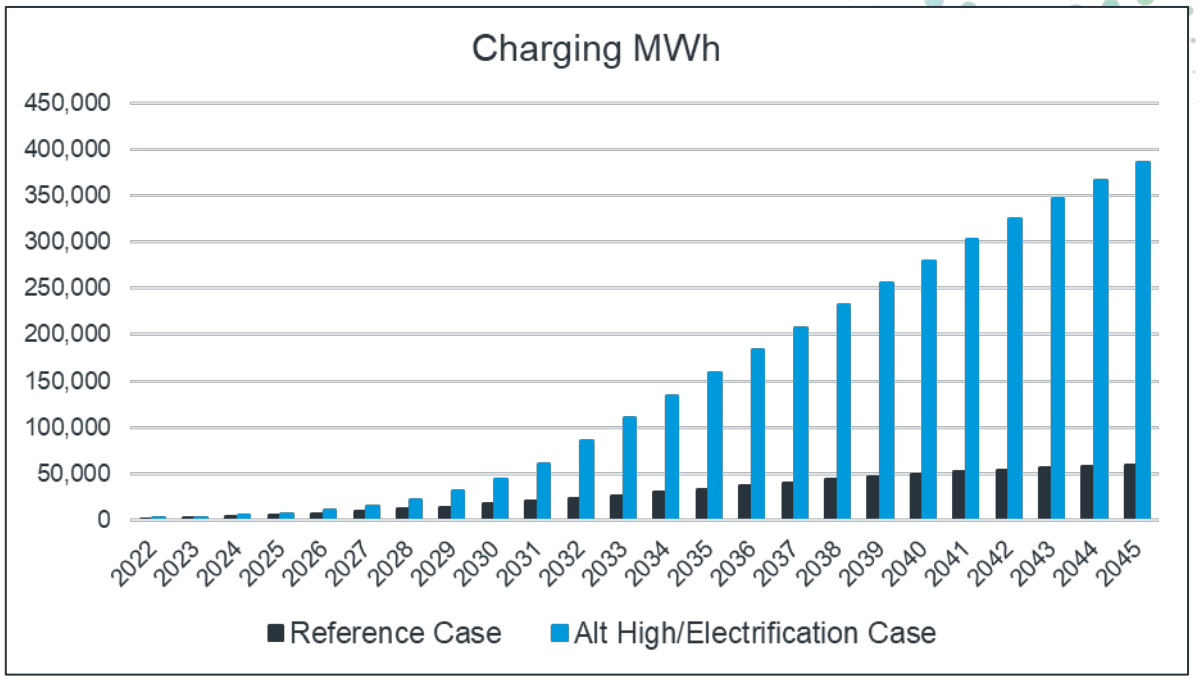
- Based EPA percent of new vehicle sales targets
  - 56% of all new vehicle sales will be electric by 2032

- Starting electric vehicle numbers based on the number of currently registered electric vehicles in CenterPoint's service territory.

- Annual kWh per vehicles based on the current mix of BEV and PHEV and **12,000** miles per year.

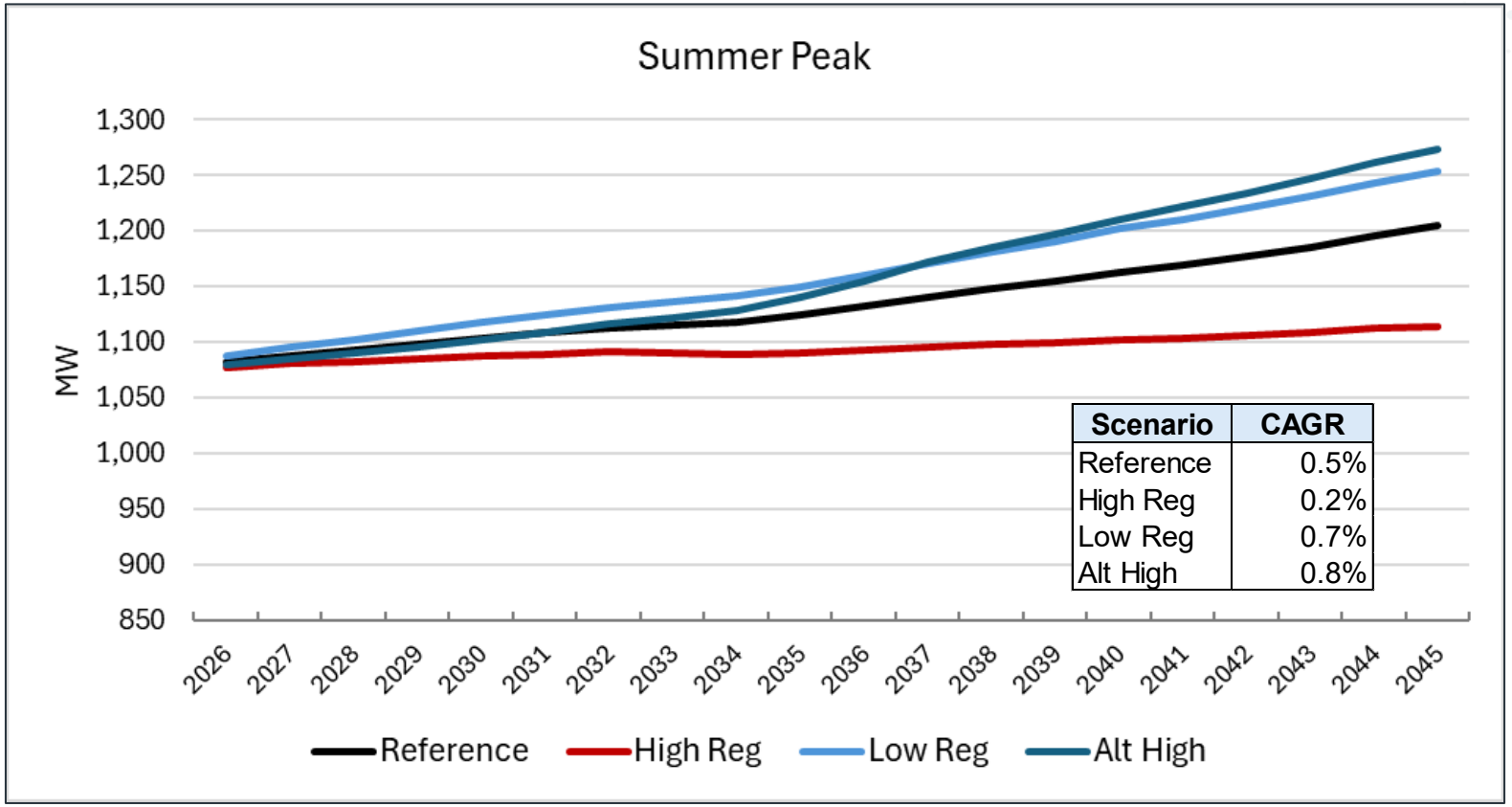
Electric Vehicle (EV) Forecasts





- Currently there are approximately 1,000 BEV and 520 PHEV in CenterPoint's service territory

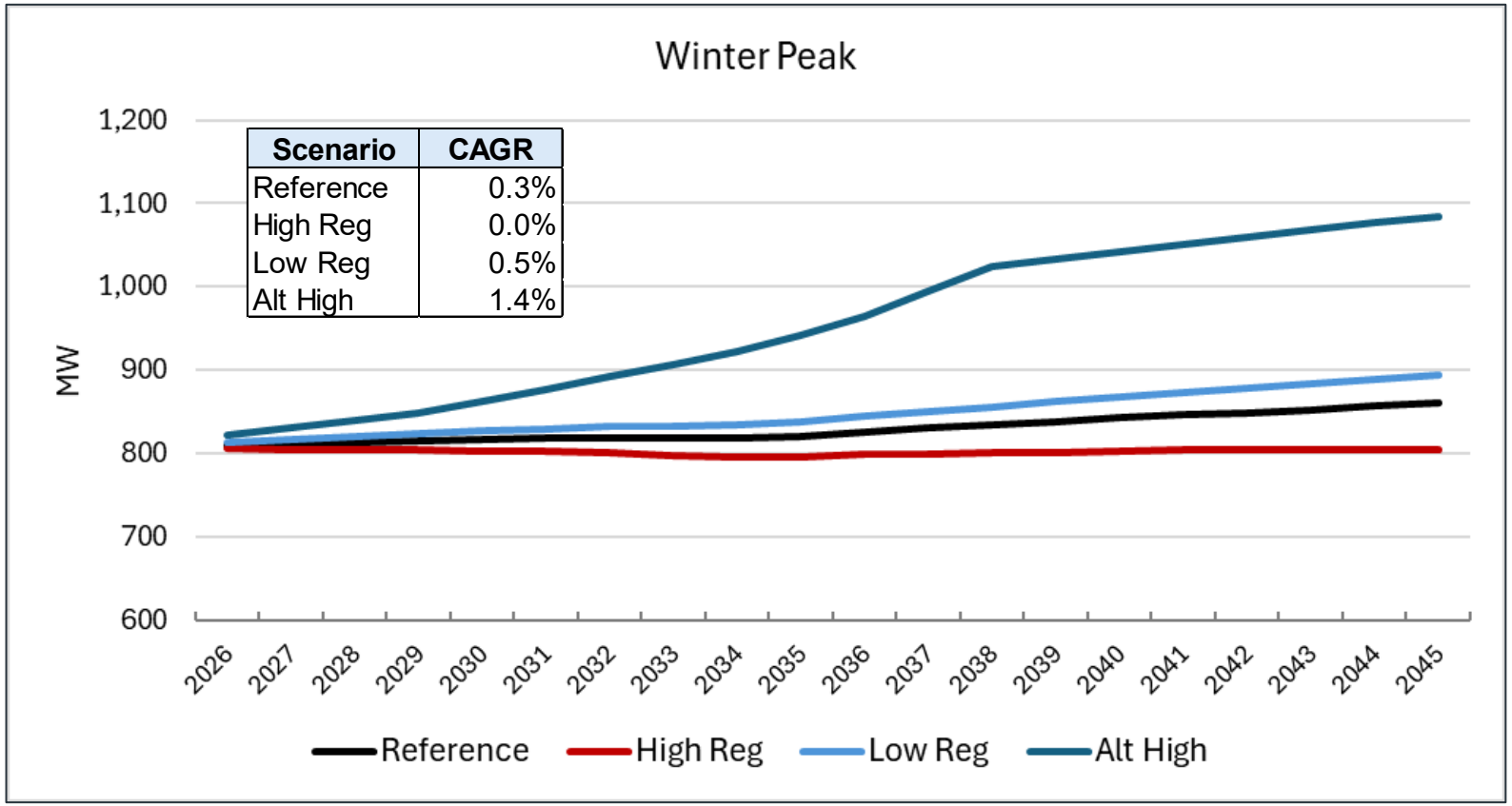
Scenario Forecasts: Summer Peak



Scenario	CAGR
Reference	0.5%
High Reg	0.2%
Low Reg	0.7%
Alt High	0.8%

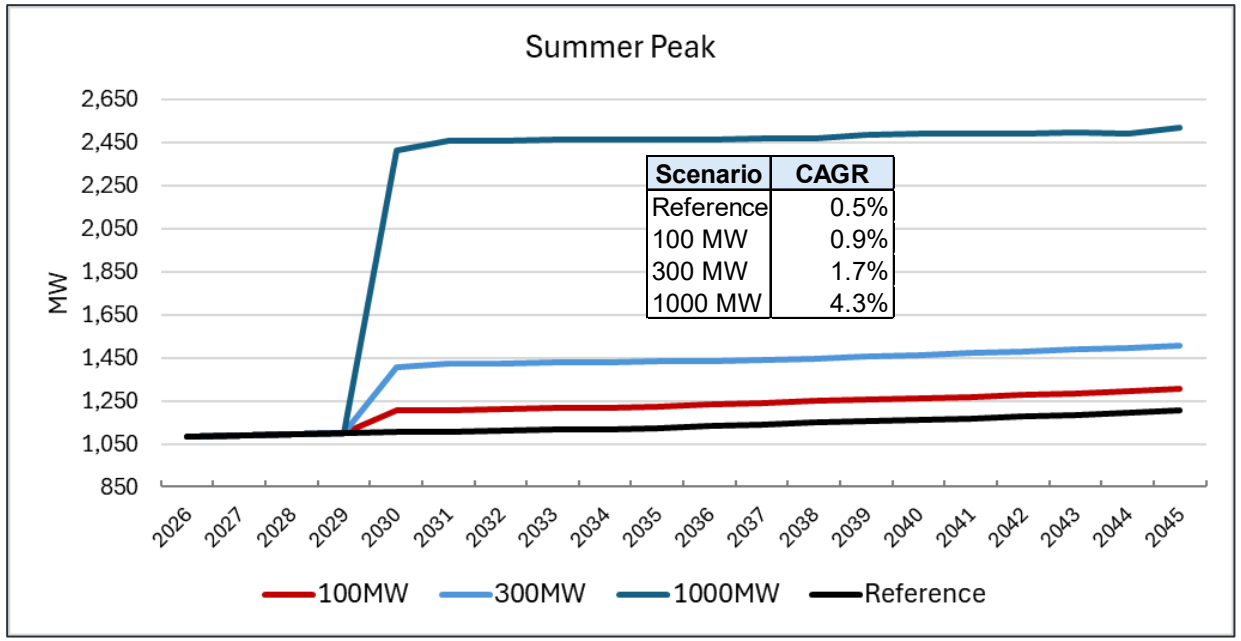
- Does not include the impact of future CenterPoint efficiency program savings
- Includes the impact of photovoltaics and electric vehicles

Scenario Forecasts: Winter Peak

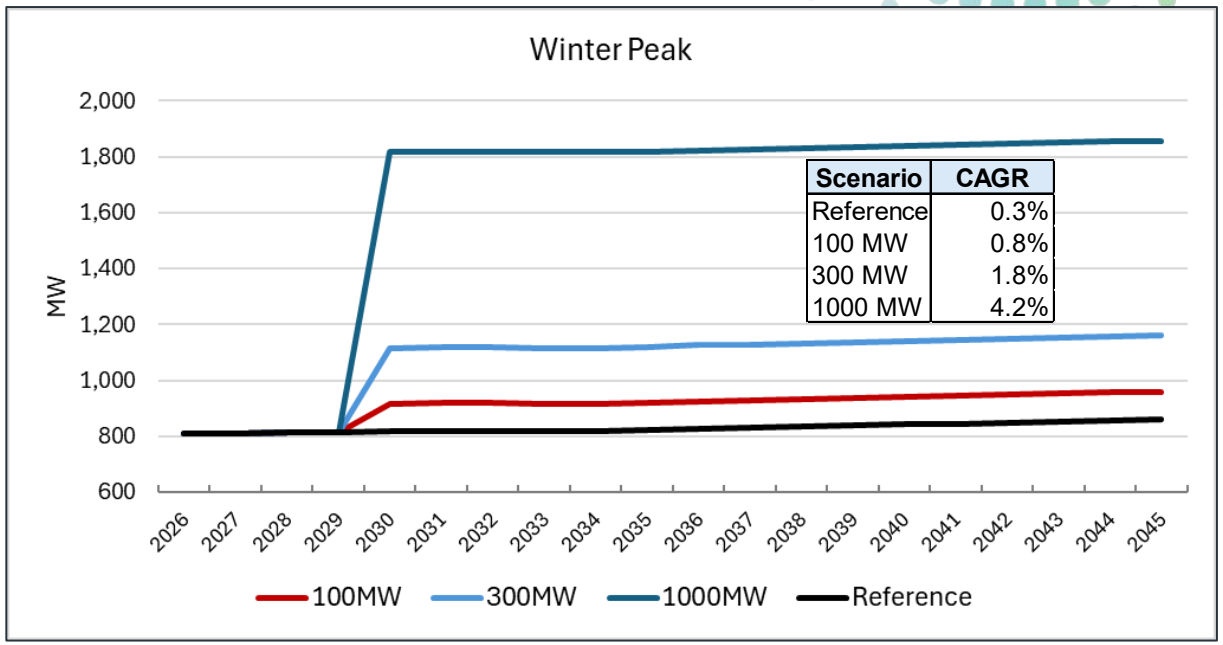


- Does not include the impact of future CenterPoint efficiency program savings
- Includes the impact of photovoltaics and electric vehicles

Large Load Sensitivity



Scenario	CAGR
Reference	0.5%
100 MW	0.9%
300 MW	1.7%
1000 MW	4.3%



Scenario	CAGR
Reference	0.3%
100 MW	0.8%
300 MW	1.8%
1000 MW	4.2%

- Does not include the impact of future CenterPoint efficiency program savings
- Includes the impact of photovoltaics and electric vehicles
- Large load sensitivities assume a 90% load factor starting in 2030

Q&A

Probabilistic Modeling Approach & Assumptions

Brian Despard
Sr. Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Approach Overview

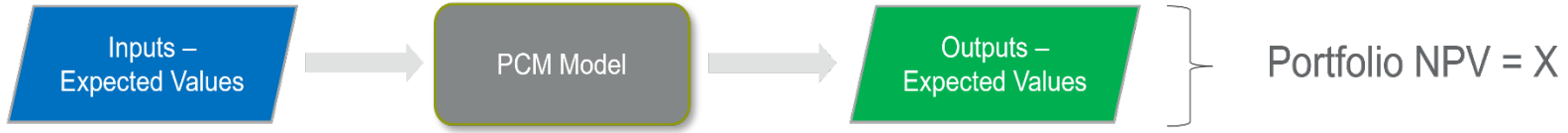
Objective: Utilize stochastic analysis around key IRP inputs to measure uncertainty around power supply portfolio costs.

Two Purposes:

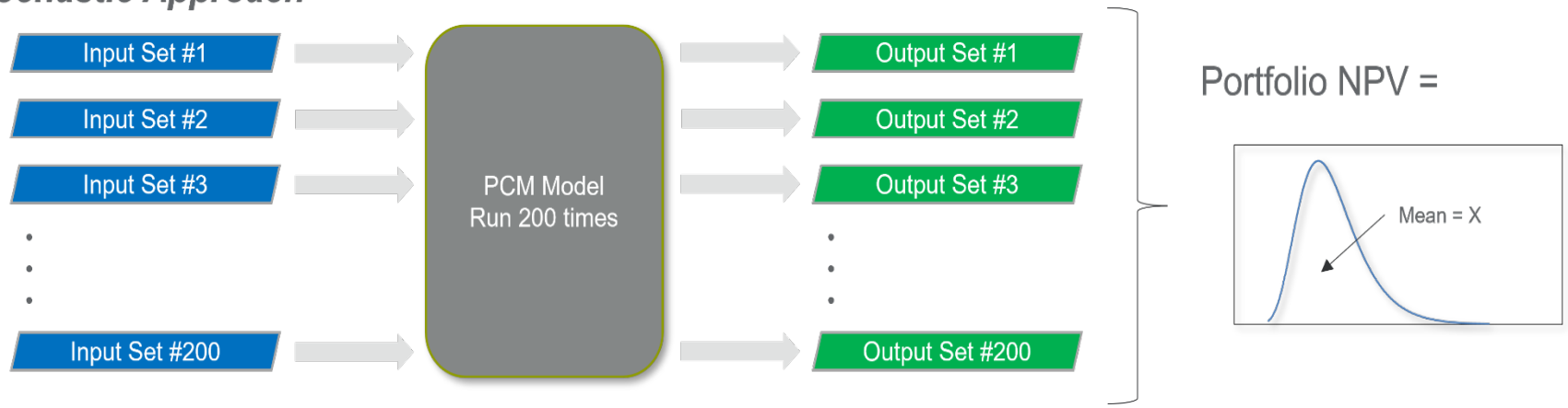
1. Evaluate results of stochastic inputs analysis to inform on what inputs to use for various scenarios; and
2. Stochastically develop 200 “families” of correlated inputs to run through PCM – result will be probability distribution around power supply costs

Production Cost Modeling
Stochastics Process Overview

Typical Deterministic Approach



Stochastic Approach



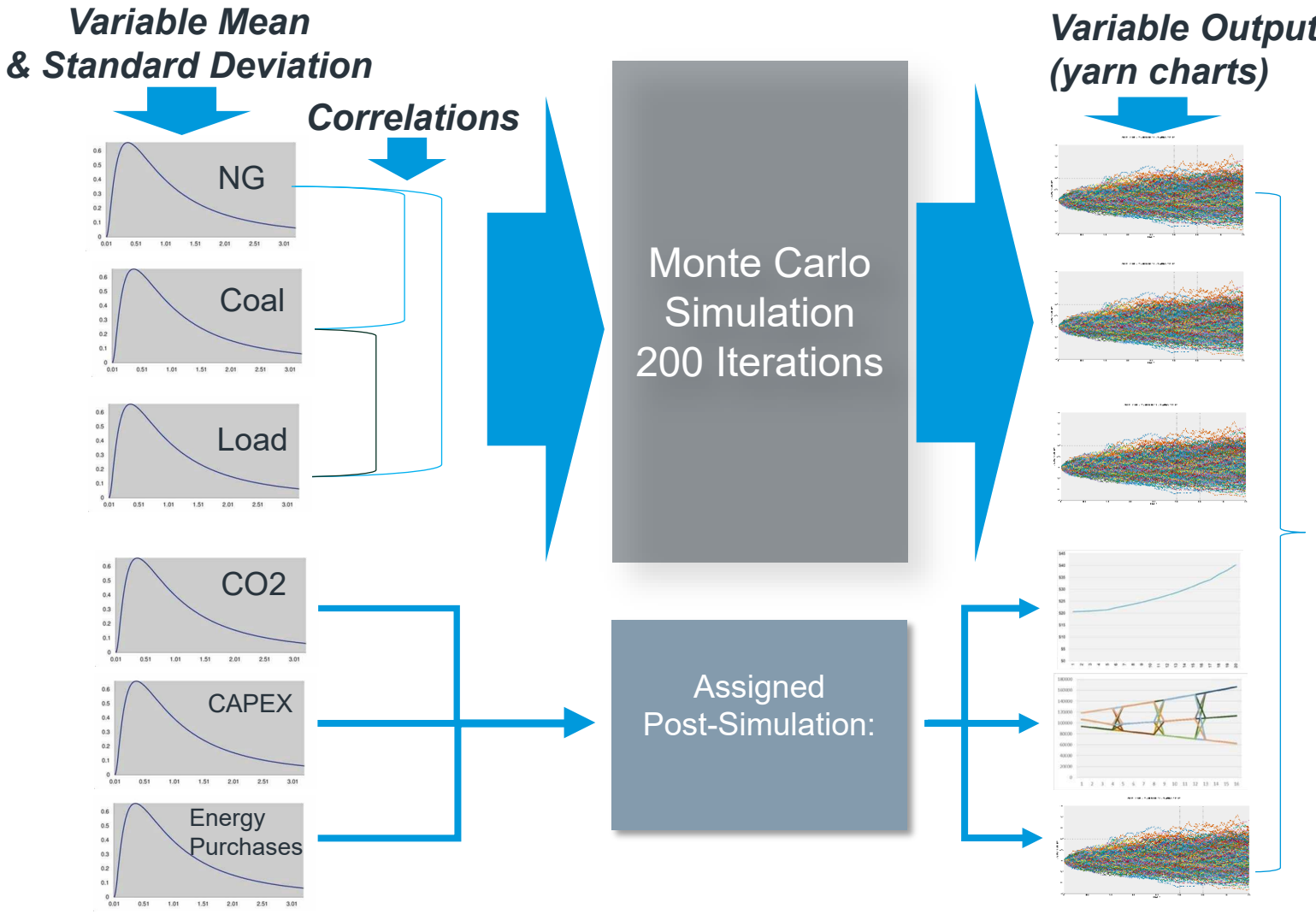
Uncertainty Variables

- Peak Demand
- Natural Gas Prices
- Coal Prices
- CO_2 Costs
- Capital Costs
- Energy Purchase & Sales

Stochastics Process Overview

1. Develop uncertainty variable parameters by month – expected value, volatility, correlations
2. Input variables into Monte Carlo simulation model
3. Run simulations with uncertainty variables being the output
4. Evaluate output implied distributions for each variable
5. Identify 200 sets of uncertainty variable “families”

Stochastics Process Overview (Cont.)



200 families of inputs where each iteration (family) reflects variable levels and paths that are tied together by correlations

Graphic and charts for illustrative purposes only

Stochastically Developed Uncertainty

Expected Values (mean values): Reference case forecasts for each variable

Volatilities (standard deviations):

- **Natural gas pricing**: From base/high/low ABB forecast
- **Coal pricing**: From EIA's 2025 Annual Energy Outlook
- **Demand**: From various Itron demand scenarios

For **CO2 Costs, Capital Costs,** & **Energy Purchases**, the variations are assigned post-simulation. The stochastic process for **CO2 Costs and Capital Costs** are explained in detail on the next slides.

CO_2 Methodology

- A CO_2 tax will be implemented only for the high regulatory scenario
- For the risk analysis, the following process is used to create variation in the CO_2 forecast
  - Assigned 200 EnCompass draws based on:
    - First 160 draws use Reference Case forecast ($0/Ton)
    - Last 40 draws implement a carbon tax

Capital Cost Methodology

- For the risk analysis, the following process is used to create variation in the capital cost forecast
  - Assigned 200 EnCompass draws based on:
    - First 50 draws use the Low forecast
    - Next 100 draws use the Reference Case forecast
    - Last 50 draws use the High forecast
  - Every 4 years, draws randomly reshuffles and the above assignments are made
  - The Low, Reference, and High forecasts align with the capital cost curves discussed earlier in today's presentation

Uncertainty Variable Parameters Expected Correlations

Variable	Demand	NG Price	Coal Price	CO_2 Cost	Dev CAPEX
Demand		Slightly Positive	Zero	Zero	Zero
NG Price	Slightly Positive		Slightly Positive	Negative	Positive
Coal Price	Zero	Slightly Positive		Negative	Zero
CO_2 Cost	Zero	Negative	Negative		Positive
Dev CAPEX	Zero	Positive	Zero	Positive	

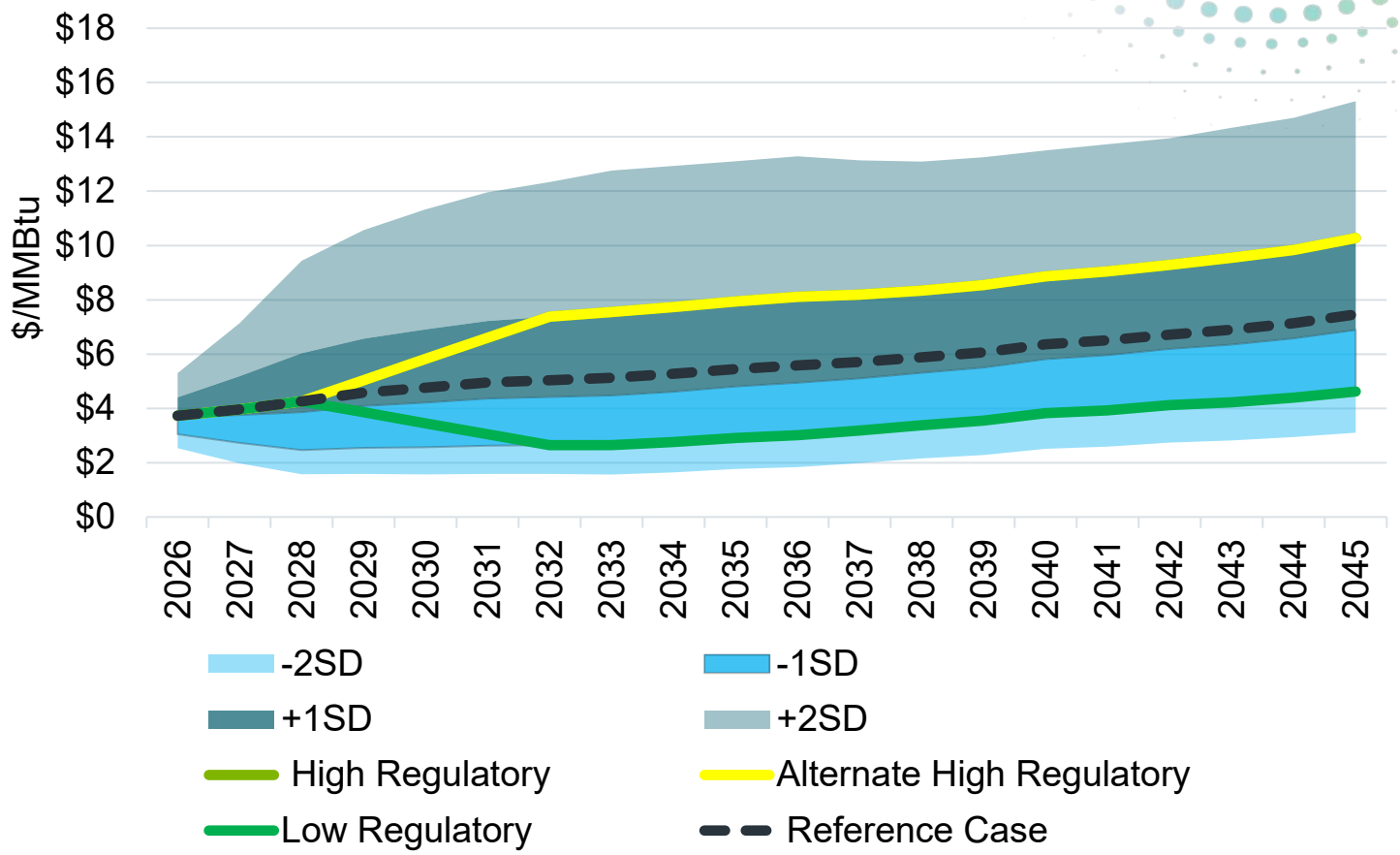
Q&A

Draft Scenario Forecasts

Brian Despard
Sr. Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Scenario Inputs: Natural Gas Henry Hub ($/MMBtu)

Year	Reference Case	High Regulatory	Alternate High Regulatory	Low Regulatory
2026	$3.73	$3.73	$3.73	$3.73
2027	$3.96	$3.96	$3.96	$3.96
2028	$4.26	$4.26	$4.26	$4.26
2029	$4.58	$5.04	$5.04	$3.86
2030	$4.76	$5.82	$5.82	$3.45
2031	$4.95	$6.60	$6.60	$3.05
2032	$5.04	$7.38	$7.38	$2.65
2033	$5.13	$7.55	$7.55	$2.65
2034	$5.27	$7.73	$7.73	$2.76
2035	$5.45	$7.94	$7.94	$2.91
2036	$5.59	$8.11	$8.11	$3.02
2037	$5.71	$8.19	$8.19	$3.18
2038	$5.88	$8.34	$8.34	$3.38
2039	$6.06	$8.54	$8.54	$3.55
2040	$6.36	$8.86	$8.86	$3.82
2041	$6.50	$9.05	$9.05	$3.93
2042	$6.72	$9.29	$9.29	$4.12
2043	$6.90	$9.55	$9.55	$4.23
2044	$7.13	$9.84	$9.84	$4.40
2045	$7.46	$10.27	$10.27	$4.62

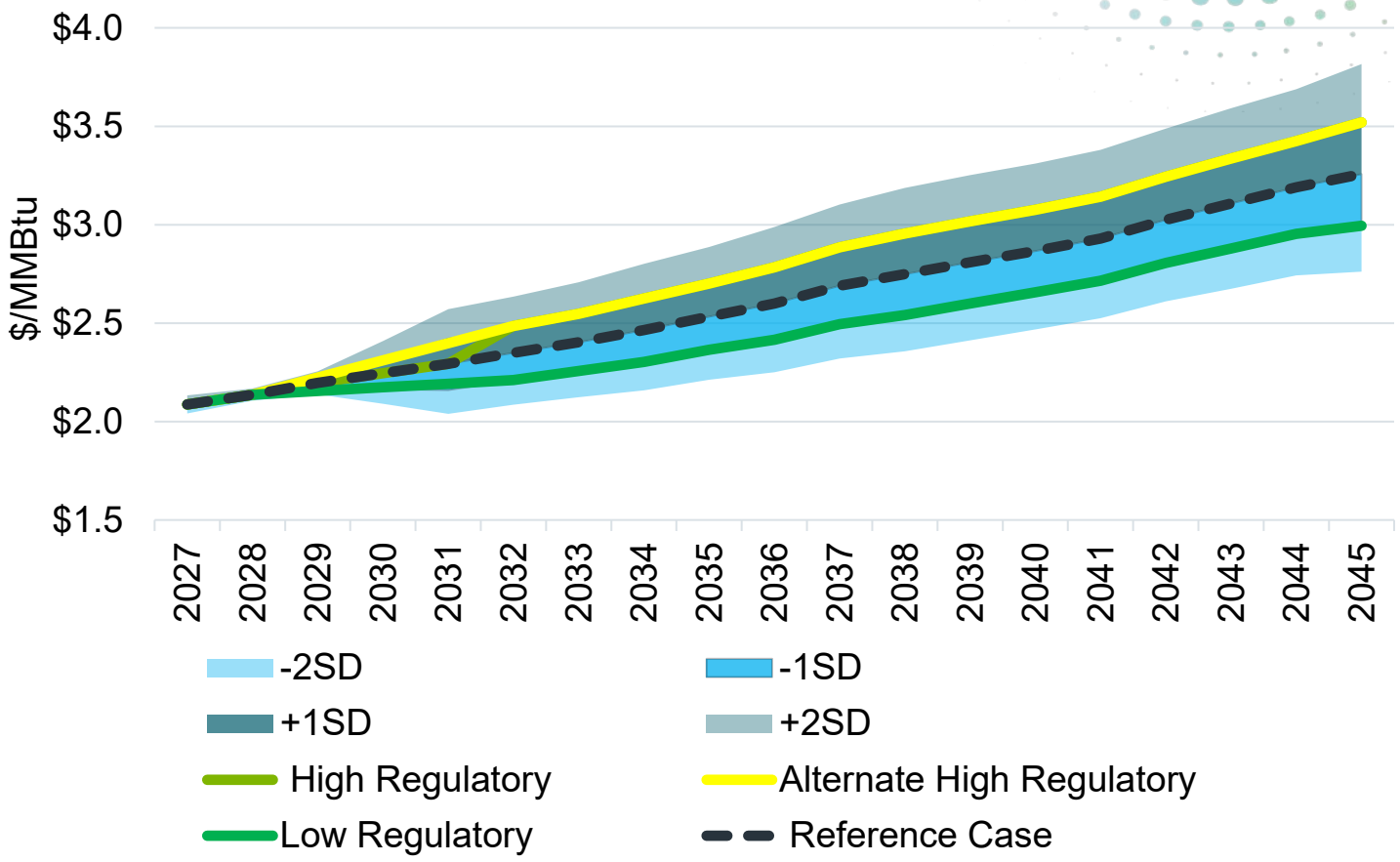


*Data does not include fuel delivery adders.

SD = Standard Deviation from the mean

Scenario Inputs: Coal Illinois Basin fob Mine ($/MMBtu)

Year	Reference Case	High Regulatory	Alternate High Regulatory	Low Regulatory
2026	$2.10	$2.10	$2.10	$2.10
2027	$2.09	$2.09	$2.09	$2.09
2028	$2.14	$2.14	$2.14	$2.14
2029	$2.20	$2.20	$2.22	$2.16
2030	$2.25	$2.25	$2.31	$2.17
2031	$2.29	$2.29	$2.40	$2.19
2032	$2.35	$2.49	$2.49	$2.21
2033	$2.40	$2.55	$2.55	$2.26
2034	$2.46	$2.62	$2.62	$2.30
2035	$2.53	$2.70	$2.70	$2.37
2036	$2.60	$2.78	$2.78	$2.42
2037	$2.69	$2.89	$2.89	$2.49
2038	$2.75	$2.96	$2.96	$2.54
2039	$2.81	$3.02	$3.02	$2.60
2040	$2.87	$3.08	$3.08	$2.66
2041	$2.93	$3.14	$3.14	$2.72
2042	$3.03	$3.24	$3.24	$2.81
2043	$3.11	$3.34	$3.34	$2.88
2044	$3.19	$3.43	$3.43	$2.95
2045	$3.26	$3.52	$3.52	$2.99

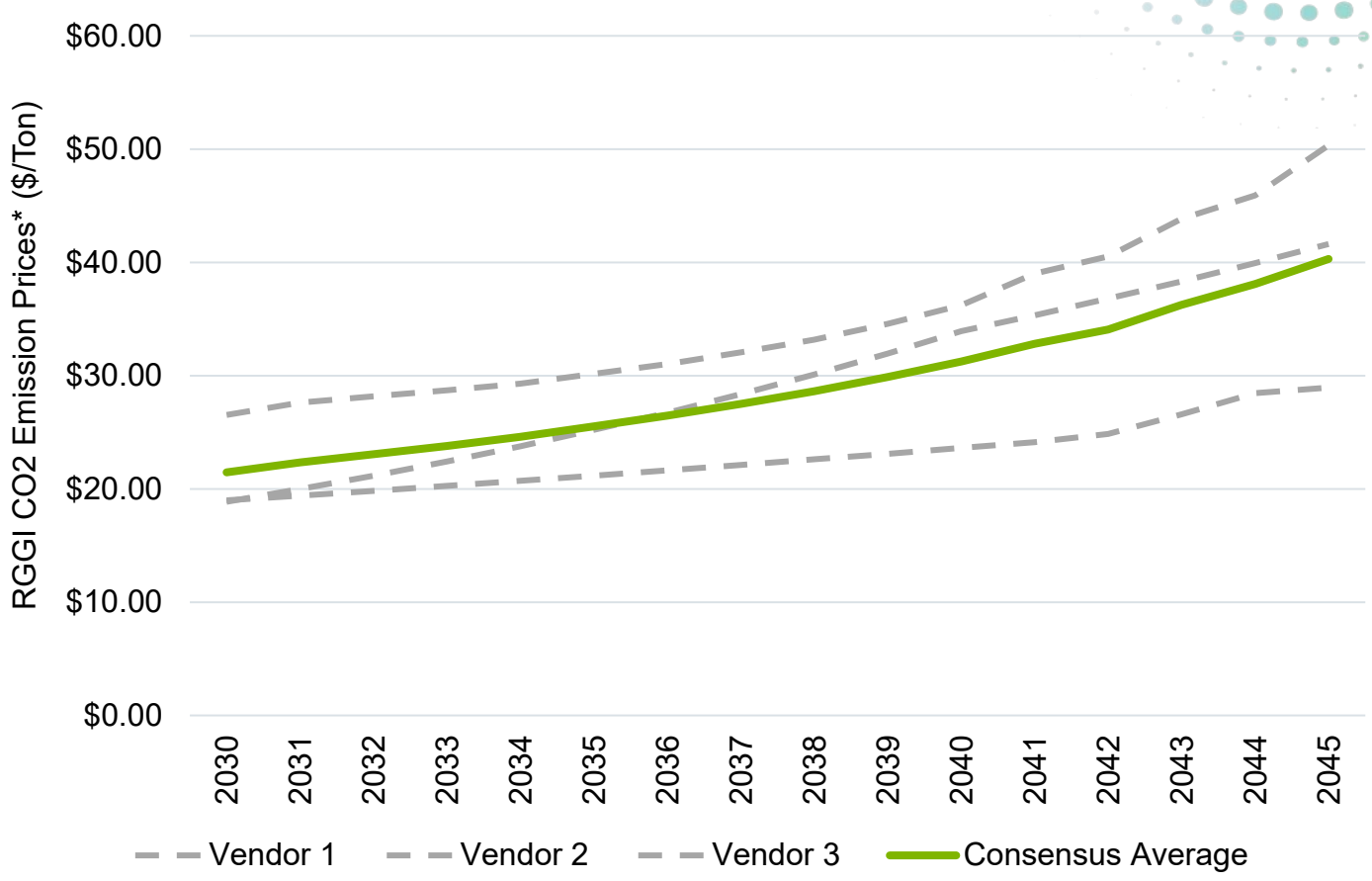


*Data does not include fuel delivery adders.

SD = Standard Deviation from the mean

CO_2 Price Forecast ($/ton)

Year	Reference Case	High Regulatory	Alternate High Regulatory	Low Regulatory
2026	$0	$20.64	$0	$0
2027	$0	$20.76	$0	$0
2028	$0	$20.94	$0	$0
2029	$0	$21.18	$0	$0
2030	$0	$21.46	$0	$0
2031	$0	$22.34	$0	$0
2032	$0	$23.06	$0	$0
2033	$0	$23.80	$0	$0
2034	$0	$24.59	$0	$0
2035	$0	$25.52	$0	$0
2036	$0	$26.46	$0	$0
2037	$0	$27.51	$0	$0
2038	$0	$28.63	$0	$0
2039	$0	$29.88	$0	$0
2040	$0	$31.25	$0	$0
2041	$0	$32.83	$0	$0
2042	$0	$34.06	$0	$0
2043	$0	$36.25	$0	$0
2044	$0	$38.10	$0	$0
2045	$0	$40.30	$0	$0



*Data based on Q3 2024 RGGI CO_2 price forecasts.

SD = Standard Deviation from the mean

Q&A

Portfolio Development Methodology

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

Portfolio Development Methodology Overview

1) Begin with Existing Portfolio

- Establish the current resource mix as the foundation of the analysis.

2) Define Critical IRP Decision Points

- Identify key planning questions and decision points to be addressed in the IRP.

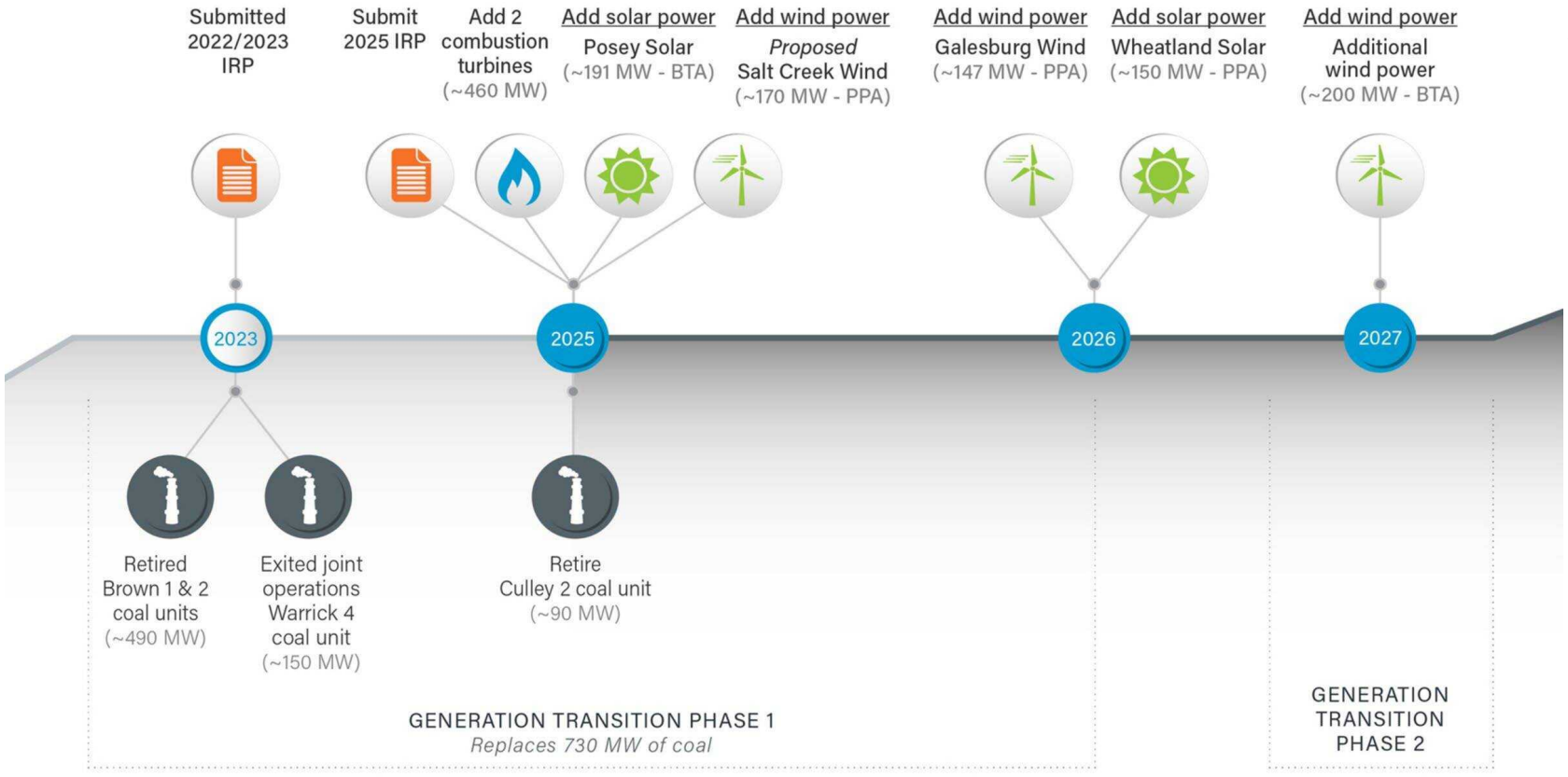
3) Identify Alternative Resources

- Explore new and emerging resource alternatives to supplement the existing resources.

4) Develop a Modeling Framework to Evaluate Options

- Analyze trade-offs of resource selections.
- Create diverse portfolios to assess resource and portfolio trade-offs against the 5 pillars.

Portfolio Development Methodology
Step 1: Existing Resource Portfolio



IRP = Integrated Resource Plan
MW = Megawatt
BTA = Build Transfer Agreement/Utility Ownership
PPA = Power Purchase Agreement

Portfolio Development Methodology
Step 2: Key Near-Term IRP Decisions

FB Culley 2

- CEI South plans to suspend FB Culley 2 operations in December 2025
- Approximately 3-year timeline to reuse the existing interconnection.
- Due to site area and condition of the unit, the resources being studied are:
  - Battery Storage
  - Aeroderivative
  - Reciprocating Engines

FB Culley 3

- For the Reference Case scenario, we implement CAA 111 compliant strategies:
  - Convert to natural gas
  - Co-Fire on gas and coal until 2039 and then retire
  - Retire in 2032
- For the Low Regulatory scenario, FB Culley 3 will continue on coal

Demand Side Management

- Finalize DSM inputs with new MPS
- Determine what levels and programs are frequently selected under optimization simulations.
- Additional programs and optionality being studied in this IRP

Portfolio Development Methodology
Step 3: Resource Alternatives



Simple Cycle Natural Gas



Combined Cycle Natural Gas



Peaking Natural Gas



Nuclear



Existing Unit Conversions



Wind



Solar



Storage



Hydroelectric



DSM / Innovative Rates

Portfolio Development Methodology
Step 4: Modeling Framework and Diverse Portfolios

CEI South envisions carrying forward about 10 portfolios into the stochastic risk analysis and final portfolio scorecard.

- Optimized Scenario Portfolios
  - Reference Case
  - High Regulatory
  - Alternate High Regulatory
  - Low Regulatory
- Portfolios needed to examine existing resource/program decisions
  - FB Culley 2 interconnect reuse options
  - FB Culley 3 optionality
  - AB Brown 5/6 CT to CCGT conversion
  - Energy efficiency and demand response options
- Additional portfolios needed to examine new unit alternatives

This will be an iterative process over the coming months, learning from different phases of the analysis, modeling, and feedback.

Q&A

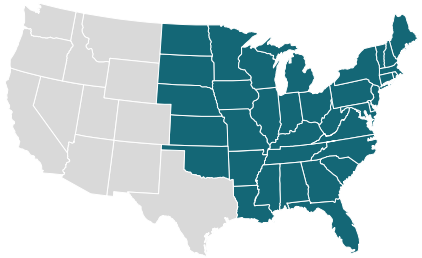
Draft Reference Case: Modeling Update

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

Capacity Expansion Modeling Overview

- Capacity expansion models are used to determine the most cost-effective mix of future resource options over the IRP planning horizon.
- All portfolios must meet CEI South's seasonal capacity requirements, including required reserves in each season.
- The model incorporates a variety of constraints and scenario-specific inputs, including:
    - CEI South Customer energy requirements
    - Environmental regulations
    - Unit dispatch parameters and other operational constraints
  - Outputs from the modeling will be used to generate the draft IRP Scorecard, which evaluates each portfolio against key planning metrics.
- EnCompass software is being used to perform the capacity expansion modeling as part of this IRP.

Modeling Methodology

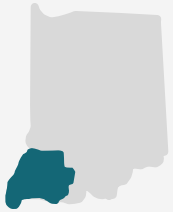


1) Model National Database

Adjust national model inputs to be consistent with IRP scenario assumptions. Generate LMPs for each IRP scenario:

- Base
- High Reg
- Low Reg
- Alt High Reg

Focus of Today's Modeling Discussion



2a) CEIS IRP Capacity Expansion Model

Local model of CEI South's service territory and generation fleet. Capacity expansion to optimize generation additions, replacements, and retirements, under each Scenario.



2b) Production Cost Model

Each portfolio is dispatched in a more granular 8760 chronological dispatch model.

Iteration and Generation Portfolio Strategy



3) Stochastic & Sensitivity Analysis

Stress test portfolios and outcomes:

- Stochastically against 200 random draws with varying inputs
- Single variable impact analysis

Capacity Expansion Model Set Up

- IRP Capacity Expansion Model (local model)
- CEI South's existing and new resources will be used to serve CEI South's energy and capacity needs.
- There will also be a connection to the MISO market, allowing for small amounts of capacity purchases as well as energy purchases and sales.



**Scenario-specific energy prices are derived by 1898 for input into the IRP Model.*

Draft Working Model Outputs

- The following charts are early-stage outputs from the IRP draft working model. Their purpose is to:
  - Set the stage for discussions as modeling evolves
  - Provide a snapshot of the current resource portfolio
  - Familiarize stakeholders with how future modeling results may be presented
- Important context for interpreting the results:
  - We are still early in the modeling process - several assumptions and inputs will change
  - Existing resource flexibility and timing options are not yet reflected in the model
    - FB Culley Unit 3 is shown as converting to natural gas in 2030 in this version as a placeholder until full CAA 111 optionality[1] is included in the model
  - New resource additions are not included in the outputs shown on the next slide, as preliminary results are likely to change when modeling inputs are complete
- **These are not final results or preferred portfolios** - they serve as a foundation for future meeting discussions.

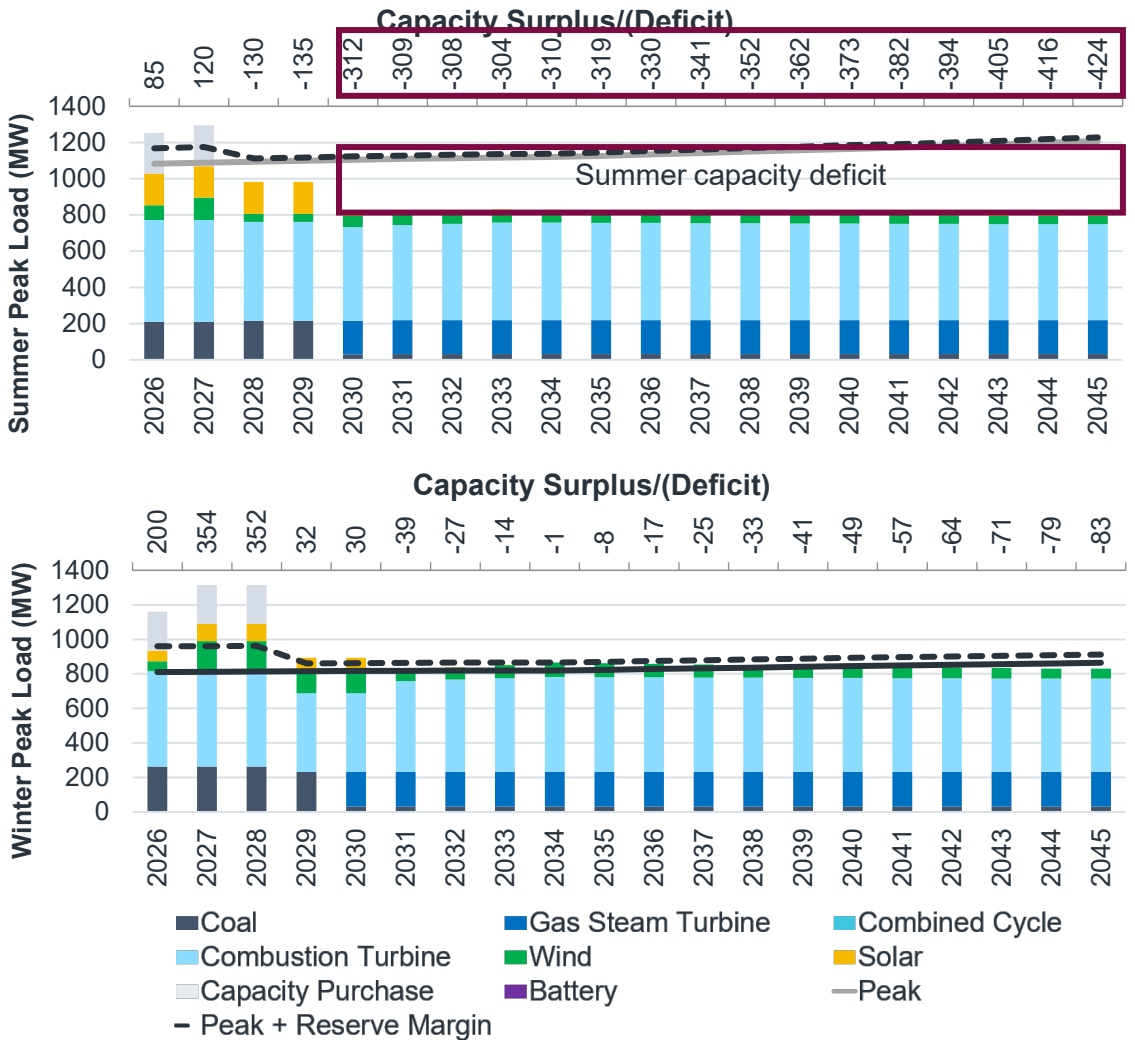
[1] Conversion to natural gas by 2030, Co-fire natural gas by 2030, or retire in 2032 will be evaluated in future modeling

Draft Working Model

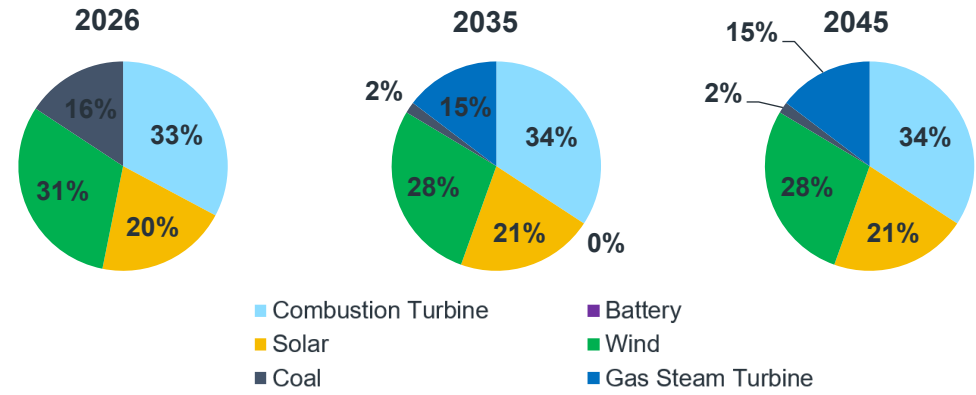
NOT FINAL RESULTS OR PREFERRED PORTFOLIO

CenterPoint Energy

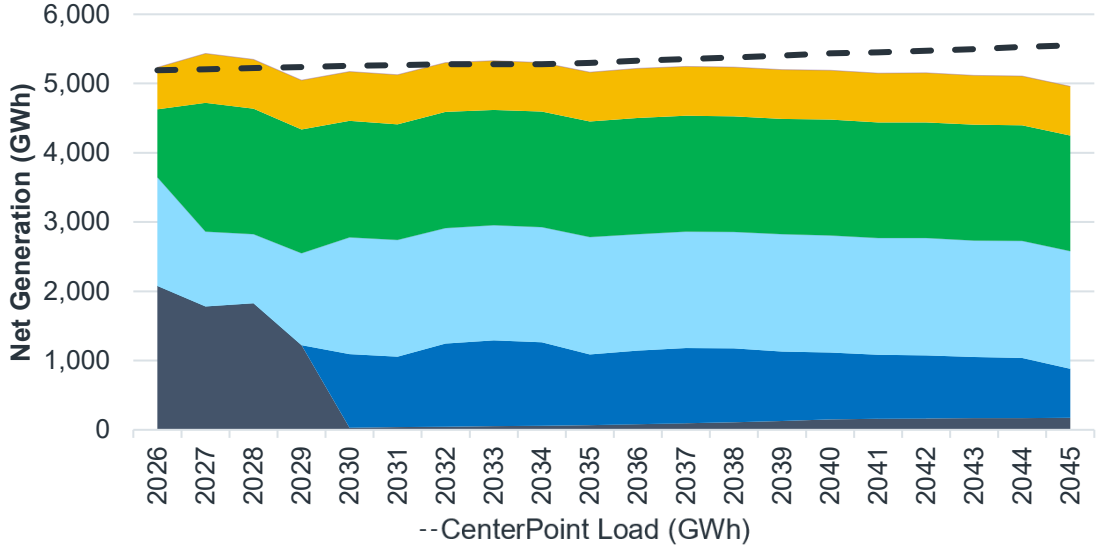
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



Q&A

Stakeholder Questions & Feedback

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

Q&A

- In-person attendees – please raise your hand to be recognized
- Virtual attendees will be in listen-only mode – to participate:
  - Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
  - Enter questions into the “Q&A” feature in Teams

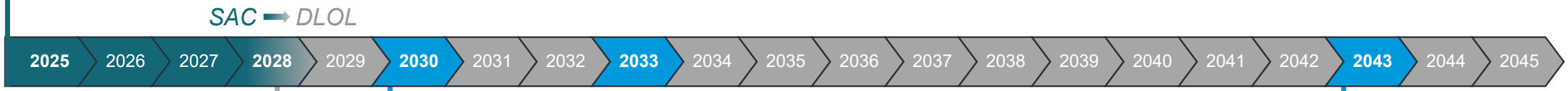
- Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

Appendix

Resource Accreditation and DLOL

MISO provided updated seasonal planning reserve margins (PRM) values for both pre- and post-DLOL implementation

SAC Methodology
- Solar & wind: MISO 2025/2026 PY ELCC
  - *Source: MISO PY 2025/26 LOLE Report, March 2025*
- Other technologies: MISO 2023/2024 PY ELCC
  - *Source: MISO RASC Meeting, February 2024*

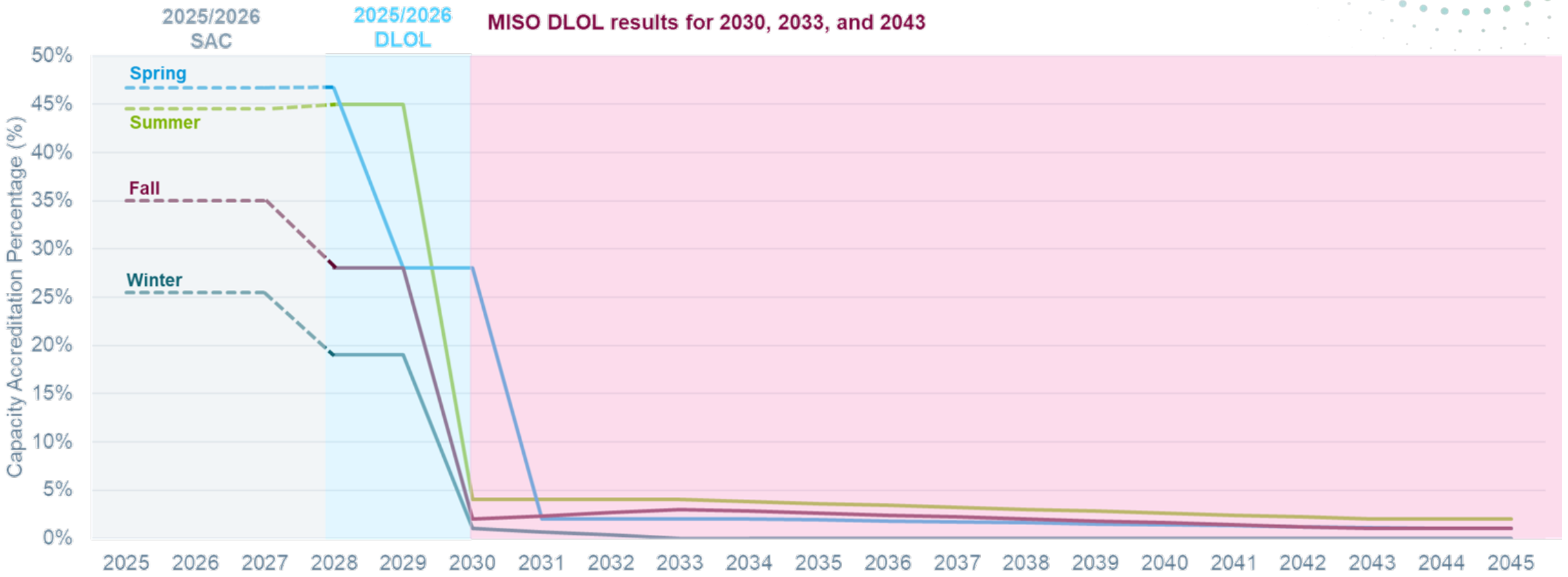


MISO provided DLOL values for 2030, 2033, and 2043 and values were interpolated in between years
Source: MISO RRA Technical Appendix, November 2024

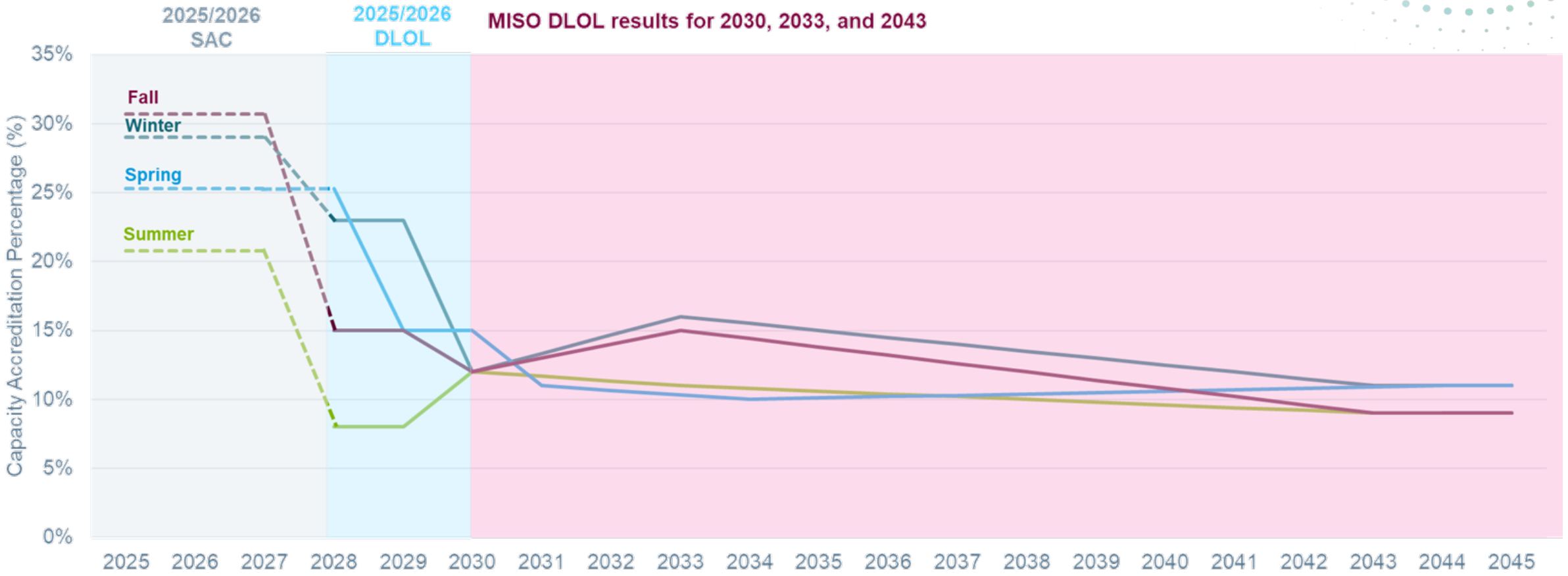
2025/2026 PY DLOL results were utilized from Summer 2028 – 2030
Source: MISO PY 2025/26 Indicative DLOL Results, April 2025

DLOL values held constant from 2043

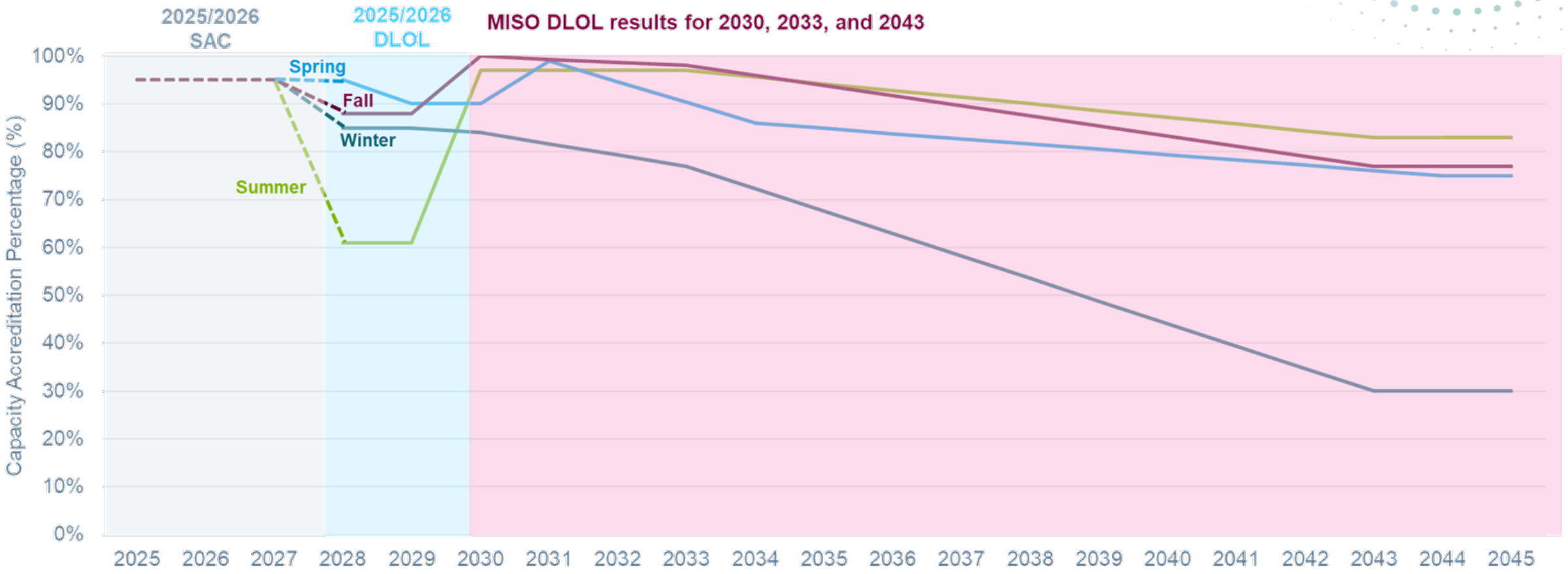
Draft Solar Capacity Accreditation Forecast



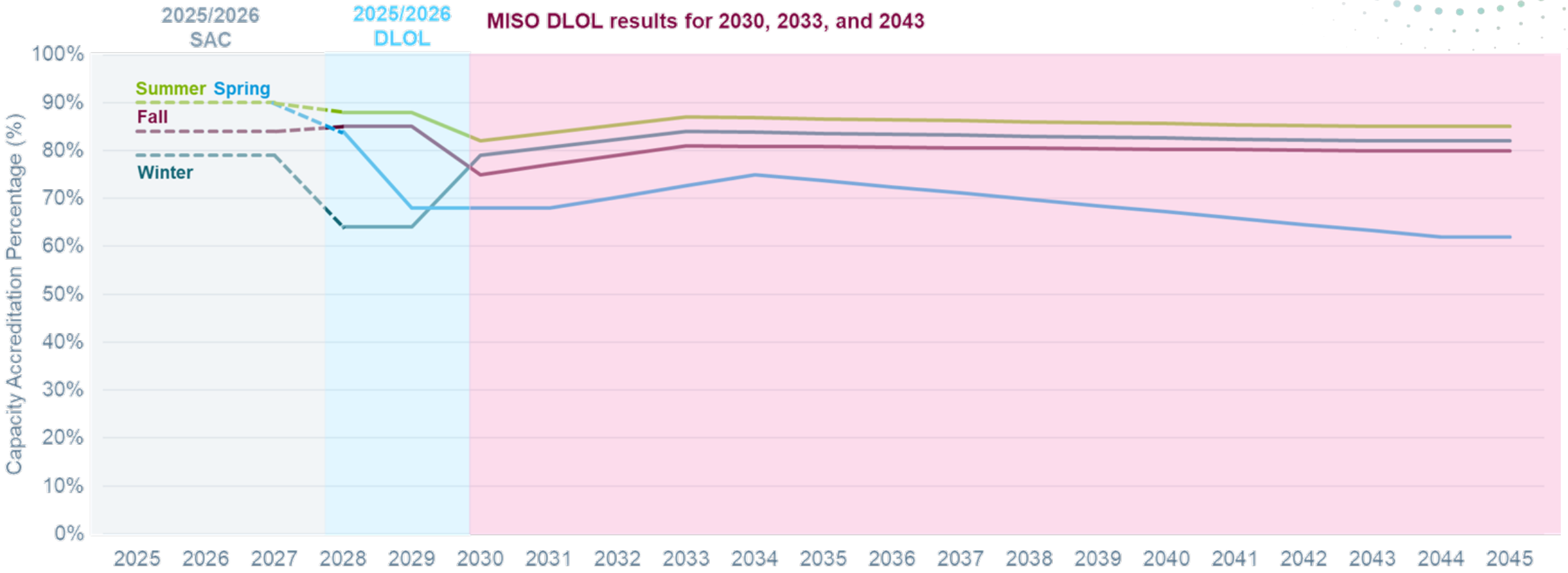
Draft Wind Capacity Accreditation Forecast



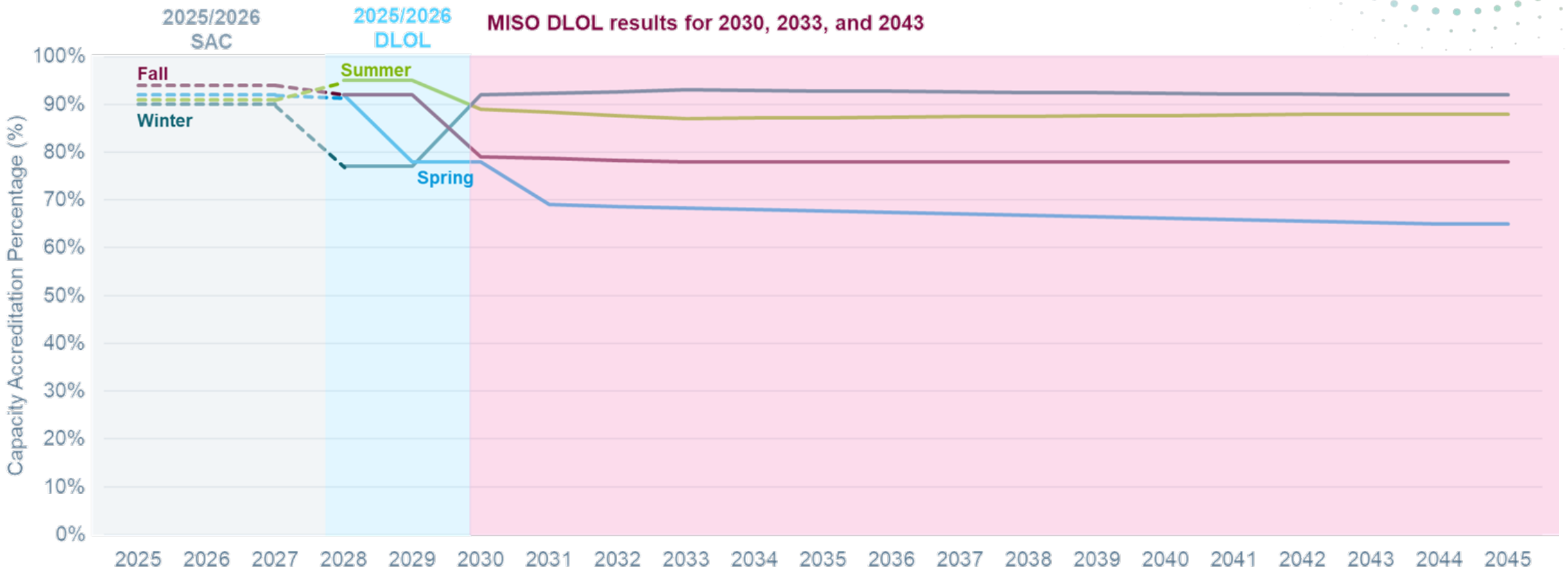
Draft Storage Capacity Accreditation Forecast



Draft CT Capacity Accreditation Forecast



Draft CC Capacity Accreditation Forecast



Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Introduced the meeting facilitator and covered meeting protocols and participation.

Shane Bradford (Vice President, Indiana Electric, CenterPoint Energy) – Shared the safety message for the meeting and the updated generation timeline.

- Slide 7: Generation Transition Timeline: Revised
  - Question: Why were the solar PPAs [Power Purchase Agreements] canceled? Did the tariffs play a part in that decision? What's the potential for restarting negotiations for those projects?
    - Response: The main reason for the termination of the PPAs was increased pricing for each project. The price increases were due to rising MISO [Midcontinent Independent System Operator] interconnection costs, contractor costs, and material costs. Tariffs were not a direct cause for the price increase, but CenterPoint would expect tariffs could potentially increase the prices more. CenterPoint will most likely not revisit those projects.
  - Question: Are there any termination costs related to the termination of the solar PPAs?
    - Response: No. However, there are some legal costs related to the termination of the PPAs and embedded costs from getting project approval from the IURC [Indiana Utility Regulatory Commission].
  - Question: On the Generation Transition Timeline, does this include the wind farm in MISO Zone 4? Has CenterPoint received commission approval for that project?
    - Response: There are two wind projects on the timeline in Zone 4: Galesburg Wind in 2026 and Additional Wind Power in 2027. CenterPoint has received approval for both wind projects from the IURC.
  - Question: Could you please confirm that FB Culley 2 is on track to retire in 2025? Please remind me of the specific timing of that process.
    - Response: Yes, FB Culley 2 is on track to close at the end of December 2025.
  - Question: Regarding Salt Creek Wind, is this project going to serve CenterPoint customers or just provide power to the MISO grid as accredited power? If it's going to be serving to CenterPoint customers, what kind of transmission loss are you expecting since the power is coming from Iowa?
    - Response: [Please see Witness Swanson's public testimony in Cause No. 46218[1]].
  - Question: In the first meeting, the Generation Transition Timeline included an asterisk that the FB Culley 3 conversion was paused, so does the "add 2 combustion turbines" on the Generation Transition Timeline relate to FB Culley 2 or FB Culley 3?

[1] https://iurc.portal.in.gov/docketed-case-details/?id=43b79da2-5219-f011-998a-001dd8084fd9

        - Response: The 2 combustion turbines are currently being constructed at the AB Brown site. FB Culley 2 is slated for closure at the end of this year, and the FB Culley 3 conversion to natural gas is still being evaluated in this IRP. [There has been no change related to those units since meeting 1]
    - Question: Can you please restate the capacity of the two solar PPAs that have been canceled?
        - Response: Rustic Hills PPA was 100 MW, and Vermillion Rise PPA was 185 MW.

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Provided an overview of the IRP process and summarized stakeholder feedback.

- Slide 12: Summary of Stakeholder Feedback from Meeting #1
    - Question: On the subject of EVs, does the load forecast take into account regulatory and policy changes at the federal level on potential impacts to EV adoption?
        - Response: No. The forecast utilizes the Energy Information Administration's prior forecast of electric vehicles adoption, and it would not include any updates from the new administration. The alternative high case scenario utilizes Environmental Protection Agency's EV adoption goal prior to the new administration.
- Slide 15: Objectives & Draft Measures
    - Question: The energy burden metric should look at the entire portfolio period (20 years), with maybe an additional view at the 10-year (half-way) mark. A 5-year window is too short to provide a meaningful view given generation investments are evaluated over the long term. Could CenterPoint please reconsider this time period?
        - Response: The intention of the 5-year look is to provide a near-term impact since there can be more certainty in near-term analysis. When we finalize the IRP, the next step is to potentially ask for a CPCN [Certificate of Public Convenience and Necessity] for resources that enable the energy transition, or a request for PPAs. The 5-year look is meant to give the near-term impact in addition to what we traditionally show, the 20-year look. We will still include a 20-year net present value of revenue requirements, and we also consider the cost risk on a 20-year basis.
    - Question: Why did you not include a 10-year retail rate impact on the scorecard?
        - Response: The intention of the 5-year look is to provide insight into the tangible near-term impact on customers. The long-term impact is captured in the 20-year metrics and will still be considered in this IRP analysis.
    - Comment: I disagree with the short-term (5-year) impact look. We will just have to evaluate it again, and it will cost more in the end. The main focus of IRPs should be long-term.

        - Response: We have historically and will continue to emphasize long-term results during from the IRP. We are adding an additional metric to also consider the short-term impacts, providing a more balanced view.
    - Question: Is the electric energy burden going to be a point in time metric? Also, for model simplicity, when are resources assumed to come online?
        - Response: Electric energy burden will be a point in time metric, 5 years out. New resources options are added on the first of the year, while named projects with a planned online date will be in-service on that date.
    - Question: For cost recovery, for model simplicity, will cost be recovered as they are incurred?
        - Response: The model recovers costs as they are incurred.
    - Question: The proposed calculation for energy burden does not align with what I was hoping it would capture. Can you add a low and high energy burden metric? I am most interested to see what impact this has on the already high energy burden customers.
        - Response: For the purposes of this IRP, we are most interested in the relative difference among portfolios. Thus, we are using Vanderburgh County median income to calculate energy burden since it is a representative value.
- General Questions
    - Question: Will the electric energy burden separate electrically heated homes from gas heated homes, or will those be combined in the aggregate?
        - Response: We could look separately at both the customers with electrically heated homes and the customers with gas heated homes. However, either view will show the same relative difference among portfolios.

Matt Rice – Discussed the addition of a fourth IRP scenario, the Alternate High Regulatory Scenario, following stakeholder feedback from the first stakeholder meeting.

- Slide 22: Narrative – Low Regulatory
    - Question: Your low regulatory scenario only removes Clean Air Act [CAA] 111(b) and 111(d) but there are other regulations that are being discussed that would affect future costs for coal plants, such as ELG [Effluent Limitations Guidelines].
        - Response: Our FB Culley 3 plant is fully compliant with ELG, so it would not meaningfully change the results. If you can send what you'd like to see incorporated in the modeling to irp@centerpointenergy.com, we would consider incorporating these changes into the model.
- Slide 23: Scenario Summary
    - Question: Could we add a scenario that is if Clean Air Act 111 is rescinded during this administration, but then a similar CO_2 policy is added back within the next 5 years (i.e., sort of a delayed carbon policy scenario)?
        - Response: Please send an email to irp@centerpointenergy.com with how that scenario would play out with associated drivers.
    - Question: The current scenarios are skewed towards a higher load. We have seen that the load has not really increased that greatly even with low regulatory.

With the low regulatory scenario, I would suggest adding an option where load stays at base. In this scenario, generation capital costs could still be high. How easy is it to change these variables in the sensitivity study?
    - Response: We can consider adding this alternative low regulatory scenario. However, if we only change one variable (load) in this alternative scenario, it may be better evaluated as a sensitivity analysis.
- Question: For the high regulatory scenario, would the decreased demand for coal actually lead to lower coal commodity prices? Conversely, would the rolling back of regulation in the low regulatory scenario lead to higher coal commodity prices?
    - Response: Our perspective is that the high regulatory scenario leads to additional burdens on the cost of producing coal which would get passed onto the utilities. In the low regulatory scenario, the cost burdens would be removed, thus creating a lower cost for coal.
- Question: Are the coal prices a publicized index, or can you incorporate real coal price offers made to CenterPoint?
    - Response: Our commodity forecast is a blend of forecasts from 4 vendors: Hitachi [ABB], EVA, S&P, and WoodMac. This is described in the IRP Stakeholder Meeting #1 slide deck, which can be found at centerpointenergy.com/irp.
- Comment: There's no reason not to include coal bid numbers. The uncertainty variable is not the mining cost as much as the demand.
    - Response: We can discuss further in the tech-to-tech meeting.

Drew Burczyk – Discussed the draft supply-side resource inputs into the IRP model.

- Slide 28: Storage Cost Curve
    - Question: Did you model cost curves for long duration options or other storage types (not just 4-hour Lithium-Ion)?
        - Response: Yes. We plan to have cost curves for all the different storage options presented in the first IRP stakeholder meeting, including one long duration non-Lithium-Ion battery.
    - Question: How many bids did you receive for storage?
        - Response: This is provided in the first stakeholder meeting presentation, which can be found at centerpointenergy.com/irp. [There were 17 standalone storage bids.]
    - Question: Are you familiar with iron oxide batteries?
        - Response: Yes, and we have discussed that resource option. We do have a long duration storage option in the model. If you have additional feedback or information, please email irp@centerpointenergy.com.
- Slide 29: Solar Cost Curve
    - Question: The cost-benefit for solar over time is going to be better than any other option. If you incentivize rooftop solar again then you won't have to spend the capital costs to get the benefits.
        - Response: We will be running a sensitivity that considers an additional incentive for rooftop solar. With the additional rooftop solar, we will look at how much additional solar is selected and how it impacts the portfolio.

    - Question: Are you accounting for all costs and benefits, including considerations such as health costs? Will these other benefits be incorporated into the IRP?
        - Looking at the costs and benefits of all resources will be the core analysis of the IRP. This section covered only the cost inputs into the model. [Health costs are considered by EPA when regulations are being considered and drafted, thereby incorporating those costs into each scenario by way of including the applicable regulations.]
- Slide 35: Nuclear Cost Curve
    - Question: Why do we call the resource "Nuclear" instead of "Small Modular Reactor"?
        - Response: We used generic language in this section since there are multiple resources of each type.
    - Question: What does CenterPoint consider a realistic timeline for adding a new small modular reactor?
        - Response: The timeline is still being developed as we derive the inputs for the model, but it likely won't be able to be selected in the model until the mid-to-late 2030's.
    - Question: Do you know why the moderate NREL curve is decreasing in the outer years?
        - Response: The information is provided by the 2024 NREL Annual Technology Baseline (ATB) and is publicly available. [NREL states their assumption is that as the technology is standardized, supply chains are established, and costs decrease.]
    - Question: Have you considered the water pressure nuclear option, such as the Westinghouse AP1000?
        - Response: We can evaluate if this option would be well represented by the nuclear option currently in our technology assessment. If you have information regarding technology performance or costs that you would like to see in the model, please email irp@centerpointenergy.com.
    - Question: How do you include nuclear in your model? Will you be including nuclear in your model?
        - Response: For each of the different resource types, we can set boundaries for the number and timing of new resource additions in the model, which will then select the optimized portfolio for the given inputs. At some point, every resource we presented today will be considered in the model.
    - Question: What is the technology assessment cost?
        - Response: The technology assessment is an analysis that evaluates the different resource options and develops the associated costs for a generic project site in or around CenterPoint's service territory.
    - Question: In Indiana, which has a recent bill that was approved with regard to SMRs [Small Modular Reactors], taxpayers are paying for the development of SMRs. Is the cost to taxpayers for SMR development captured in the costs that were summarized and presented?

        - Response: The costs that are summarized represent the total estimated costs that CenterPoint would pay for these new resources.
- General Questions
    - Question: Were any resources screened out?
        - Response: There are no resources that have been screened out. The technology assessment does not include a new coal option.
    - Question: How are the DG [Distributed Generation] Storage and DG Solar bids included or not included in these curves?
        - Response: This section only presented a snapshot of resources over 100 MW. There are other resources we are modeling, including smaller solar resources and we intend to inform our modeling with RFP cost data. We will perform a sensitivity on rooftop solar.
    - Question: Are there any restrictions on the timing of when resources can be added by the model (e.g., combustion turbines might not be available until 2030+) and how much can be added from one resource in a year?
        - Response: Yes. We can add boundaries to the model on the number and timing of new resource additions but have not gotten to that point in the modeling process yet. We will use the best available data from the market and technology assessments to set these constraints.
    - Question: For FB Culley 3, is there an option for natural gas conversion or co-firing the unit?
        - Response: Both natural gas conversion and co-firing will be considered at FB Culley 3 in the IRP modeling.

Jeffery Huber (Principal, Energy Efficiency, GDS Associates) – Presented an introduction to Market Potential Studies and discussed the energy efficiency and demand response modeling methodologies.

- Slide 42: EE Overview: Flow Chart
    - Question: Can you expand on the "Cost Effectiveness Screen" between the economic potential and technical potential?
        - Response: In the Utility Cost Test, for each measure on the EE [Energy Efficiency] or DR [Demand Response] program side, it is quantifying the lifetime benefits of avoiding energy or capacity and the costs of the incentive to CenterPoint.
- Slide 44: EE Overview: Market Characterization
    - Question: What are the Forecast Sales, and what does it include? Does this include people who have opted out?
        - Response: The forecasted sales are the load forecast. There is a portion of the customers who don't pay into the energy efficiency surcharge programs, so the "opt-out sales" show the portion of CenterPoint customers that would be ineligible as they do not contribute to the energy efficiency charge.
- Slide 45: EE Overview: Market Characterization

    - Question: On slide 45, which talks about market characterization, it's pointing out that 67% of folks are incomed qualified. Does that impact adoption rates if a significant portion of those are renter customers versus a homeowner?
        - Response: First, it is important to state that the percents on this screen are not additive, so the slide suggests that roughly half of multi-family homes are income qualified. Willingness and ability to participate in these programs would be affected by if the customer is a renter or owner and that is something we attempt to capture in the market research.
- Slide 50: EE Overview: Types of Potential
    - Questions: What are the parameters for cost-effectiveness?
        - Response: In Indiana, the Utility Cost Test is defined in terms of what is included from an energy efficiency or demand response perspective. The primary benefits are generally the avoided cost of energy, capacity and transmission & distribution.
- Slide 52: EE Overview: Model Outputs
    - Question: What would be the source for net-to-gross ratios?
        - Response: For EE, the net-to-gross ratios will be the latest evaluated net-to-gross ratios that are available to us, and we will use those as a proxy going forward.
- Slide 55: DR Overview: Methodology
    - Question: Will the levelized cost for Market Potential Study measures include avoided T&D [Transmission & Distribution] benefits?
        - Response: In the IRP model, which does not capture the T&D benefit, the avoided cost for T&D is taken out of the cost.
    - Questions: Will MISO-provided DR offerings be factored into the potential estimates?
        - Response: For the aggregation amount that is listed, that aggregator would be the MISO participant. The Aggregation DR will be included in the IRP modeling but is not a function of the market potential study.
    - Question: Does achievable potential account for opt-out customers?
        - Response: They have been excluded from the potential.
- Slide 56: DR Overview: Program Level Concepts
    - Question: For the battery storage program, without large enough penetration of batteries, it's hard for benefits to outweigh the costs. Could we look at a battery storage equipment incentive?
        - Response: Generally, we have found that an incentive substantial enough to drive significant adoption will hurt cost-effectiveness. With that being said, we can follow up on if a sensitivity analysis would be worthwhile.
    - Question: What is the compensation rate for when the battery is dispatched?
        - Response: The report will detail each program and what the incentive structure is.
- Slide 57: DR Overview: Program Level Concepts
    - Question: For the TOU [Time-of-Use] and CPP [Critical Peak Pricing] Rate Pilot Program, is there a specific on-peak to off-peak ratio for the rates that is being considered at this point?

        - Response: It is 4 to 1.
- General Questions
    - Question: For EVs, are customers bringing their own device for the charger? Would customers have to use specific technology to participate?
        - Response: [We are assuming that the customer would be supplying their own charger, and CenterPoint would provide an incentive to join the program, as well as an annual participation incentive. A managed charging program would require some sort of network connection, which could include Wi-Fi, cellular, or a wired connection. A specific technology would not be required, as control could happen through the charger or telematics through the EVs].
    - Question: Some DR measures like batteries and water heaters can be used for other grid services (ancillary services, resilience) – how are these benefits being considered in developing levelized costs and/or accounted for in the IRP? Is it possible to treat these like T&D benefits and reduce from the cost side?
        - Response: When performing cost-effectiveness screening the benefits include the avoided energy, capacity, and T&D. Resilience and ancillary services have not been a benefit of DR captured in the IRP analysis.
    - Question: Has CenterPoint identified a marginal line loss rate which will be used to convert EE savings to the generator?
        - Response: We have a peak demand loss factor, which is higher than the energy loss factor which is used as a proxy for the line loss factor. We will be using 8.4% for the current IRP and Market Potential Study.
    - Question: Regarding the MPS discussion, is it the intent of the potential study to primarily model business-as-usual or explore a fuller scope of savings opportunities beyond existing pilots and programs?
        - Response: From a DR standpoint, it's definitely not business-as-usual. We've included EV growth and demand response for residential and non-residential, and same for battery storage. We're also looking at smart thermostat DR products on the commercial side. We are looking at near- and long-term emerging technologies.

Michael Russo (Forecast Consultant, ITRON) – Presented updates to the demand forecast development process, including impacts from electric vehicle and behind-the-meter solar photovoltaic adoption.

- Slide 63: Forecasting Methodology
    - Question: Does the energy price assumption vary by scenario?
        - Response: No, the energy price assumption will not vary by scenario in the load forecasting. [In the IRP analysis, energy prices will vary by scenario.]
    - Question: Does CenterPoint peak at the same time as the MISO system?
        - Response: In the first stakeholder meeting, the timing of CenterPoint's peak was shared. Please visit centerpointenergy.com/irp to reference those slide decks.
- Slide 67: Scenario Development: Load Forecast

    - Question: Why would you assume a low regulatory scenario would lead to moderate inflation and increased economic growth? Why is there a pessimistic outlook with near-term financial stress and reduced economic growth with the high regulatory case?
        - Response: These are the outlooks and definitions provided by S&P Global. The outlooks were placed in the low and high regulatory scenarios in order to increase or decrease load. If the S&P forecast with high economic growth were utilized in the high regulatory scenario, it would offset the effects from the energy efficiency forecast, thus creating a load forecast that does not significantly deviate from the reference case.
    - Question: Are you considering the possible removal of the Energy Star program?
        - Response: Energy Star has been changing for a number of years. All of our EE programs do not rely on energy star ratings; it is all based off of energy efficiency performance metrics of the equipment. The removal of Energy Star ratings would not affect the modeling.
    - Questions: Are you finding SEER [Seasonal Energy Efficiency Ratio] ratings to being good proxies for Energy Star?
        - Response: Yes. We can attribute significantly higher energy savings to equipment with higher SEER ratings.
    - Question: When looking between high regulatory and alternative high regulatory, can you potentially do the same with low regulatory (an alternative low regulatory with low load)?
        - Response: If we only change one variable (load) in this alternative scenario, it may be better evaluated as a sensitivity analysis.
- Slide 69: Residential Economic Concepts
    - Question: What population are you talking about in the figure?
        - Response: There are a few slides from 1st IRP Stakeholder meeting presentation explaining the change from Evansville to Indiana state population. The state-level population is much more correlated to the number of CenterPoint residential customers than the number of Evansville households.
- Slide 73: Electric Vehicle (EV) Forecasts
    - Question: Is the alternative high electrification case just for the alternative high regulation case and the reference case will be applied to all other scenarios? Would you consider changing the forecast to match the considerations taken in the EE/DR methodologies, such as income?
        - Response: Yes, the reference case will be used for all scenarios except the alternative high regulation scenario, which uses the alternative high electrification forecast. We will discuss this internally, although if we decrease the EV adoption forecast significantly, then our scenarios will lose their differentiation.
- Slide 76: Large Load Sensitivity
    - Question: What considerations about load growth went into the large load sensitivity? Where did the different scenario levels (100, 300, 1,000MW) come from?

        - Response: Those are indicative of the types of speculative load consistent with what CenterPoint has received.
    - Question: Can you provide more information on the determination of that load factor for the large load sensitivity?
        - Response: A 90% load factor is a very common assumption for large load customers.
- General Questions
    - Question: Is there a final report on the load forecast that can be shared with the OUCC [Indiana Office of Utility Consumer Counselor] from Itron?
        - Response: The full report will be available as an attachment to the IRP. We will share the modeling files and scenario-based forecasts ahead of filing the IRP.
    - Question: If federal standards changed for energy efficiency, do you expect them to have a big impact on the load forecast?
        - Response: The impact of these changes would depend on what changes and by how much.

Brian Despard (Sr. Project Manager, Resource Planning and Market Assessments, 1898 & Co.) – Outlined the methodology for capturing uncertainty in model inputs via stochastic modeling.

- Slide 85: CO_2 Methodology
    - Question: Are you going to include Scope 3 emissions?
        - Response: CenterPoint has limited control over Scope 3 emissions as it is related to emissions of energy use by the end-user. [Additionally, electricity generation emissions are not classified as Scope 3.]
- General Questions
    - Question: Why are you only looking at natural gas and coal scenarios?
        - Response: We are looking at uncertainties of coal, natural gas, carbon prices, load, and capital costs.
    - Question: Since you are considering nuclear, do you want to run a stochastic process for uranium?
        - Response: The problem with that is that there are limited forecasts for uranium costs and uncertainty around uranium is difficult to define. We can follow up if this is something we should incorporate.
    - Question: Are you shaping your natural gas prices? What are the sources for the data?
        - Response: We are shaping our natural gas prices on a monthly basis. There is more information on the data sources in 1st IRP Stakeholder meeting presentation.

Brian Despard – Shared the scenario inputs for natural gas, coal, and CO_2 price forecasts.

- No questions.

Drew Burczyk – Discussed the four steps in the portfolio development process including critical decision points, existing and alternative resource implementation, and modeling framework.

- Slide 95: Portfolio Development Methodology Overview
  - Question: In your methodology, are you making near-term decisions in step 2 and long-term decisions in step 3?
    - Response: Yes, we are making both near-term and long-term decisions. The IRP by nature sets the 20-year direction of resources and portfolios, but there are near-term decisions that have to be made during this IRP cycle.
- Slide 97: Step 2: Key Near-Term IRP Decisions
  - Question: Is there a timeline associated with the conversion of FB Culley 3?
    - Response: In our analysis, we are modeling different options for FB Culley 3. The timing options are all compliant with Clean Air Act 111 and include: a conversion to natural gas by 2030, retirement by 2032, or co-fire by 2030 with a retirement by 2039.
  - Question: Is there an option for full retirement for FB Culley 3 and replacement with renewables?
    - Response: Yes. There is a 2032 retirement option, and there are renewable resource options available that will be studied to fill the portfolio capacity need.
  - Question: On the low regulatory scenario, is the only option that is going to be evaluated is continuing FB Culley 3 on coal?
    - Response: It is an additional option to the ones listed above [on slide 97]. It cannot be included in the reference case evaluation due to CAA 111 compliance.
  - Question: Is "suspending" coal operations synonymous with retirement?
    - Response: Yes. Our language is consistent with MISO's language around the retirement of coal plants considering the intention to re-use the interconnection.
- Slide 99: Step 4: Modeling Framework and Diverse Portfolios
  - Question: What if I don't like the final 10 portfolios?
    - Response: If you have ideas for portfolios, please send your ideas to the IRP email: irp@centerpointenergy.com.
  - Question: Have you taken into consideration potential transmission issues (e.g., the difficulties of building new pipelines) related to increased supply & demand of natural gas under the "Low Regulatory" scenario?
    - Response: We are including gas pipeline upgrades cost. There is also analysis on the electric transmission that will be included in the final IRP.
- General Questions
  - Question: Is there a concern with long lead times for new natural gas resources and FB Culley 2?
    - Response: Yes, timing will certainly be considered. In those key decisions, we do need to make sure that the units we are proposing are feasible with the deadline of the MISO interconnection re-use.
  - Question: Related to the question of supply chain constraints for gas turbines, will you evaluate any risks related to gas supply due to factors like increased

demand (without increased production), the export market, pipeline capacity, storage constraints, or risks related to firm supply?
    - Response: This volatility will be simulated via the stochastic analysis.

Drew Burczyk – Presented the capacity expansion modeling overview and preliminary results from the draft reference case.

- Slide 104: Capacity Expansion Model Set Up
    - Question: Have you determined a limit that will be placed on market reliance?
        - Response: The limit on capacity purchases will be higher in the near term and will decrease over time. This allows the model more flexibility by not forcing it to meet all capacity need with new resources in the near-term. For energy purchases, we are limiting those to 15% of peak load. We plan to perform stochastic modeling on energy purchases.
    - Question: Is there a market capacity constraint by statute?
        - Response: Yes, CenterPoint needs 85% of their capacity covered before entering the MISO PRA (Planning Resource Auction) to meet the statute.
- Slide 106: Draft Working Model
    - Question: Is the capacity accreditation the same for PPA solar and utility owned solar?
        - Response: Yes.
- General Questions
    - Question: The base load is increasing. Is this consistent with historical trends? All scenarios have growth in demand.
        - Response: Historically the load has decreased primarily due to CenterPoint EE programs. The base load forecast does not include the impacts of EE since it is a selectable, additive option. Also, the federal codes and standards over the past ten years have resulted in savings significantly higher than what is projected.

General Q&A Section

- General Comment
    - Comment: CenterPoint has previously stated that they plan to be coal free by 2027. I would strongly encourage CenterPoint to consider a portfolio that is coal free by 2030 and look at what an aggressive buildout in renewables and battery storage would look like for customers.

Stakeholder Feedback and/or Data Requests

Clean Grid Alliance (CGA) Comments on CEI South's 2nd IRP Stakeholder Meeting on 5/14/2025
CGA Comments Received: May 29, 2025
CEI South Response Sent: 6/19/2025

Final Scenarios

- **Low Regulatory Scenario (slide 22)**. I disagree with the logic that less regulation will lead to lower prices for gas, as increased demand for the resource (due to IRA, EPA rollbacks) could have the opposite effect of actually driving up prices, especially if the export market increases.
  Thank you for your feedback.

  Under the Low Regulatory Scenario (Stakeholder Meeting #2, slide 22), export market increases are not part of this potential future state. Within this scenario the logic which drives gas prices lower is greater access to supply because regulations restricting drilling are removed.

  Further, this scenario doesn't adequately account for risks related to gas turbine supply chain constraints, availability of firm supply, and gas pipeline capacity. I encourage CenterPoint to model an Alternate Low Regulatory scenario where commodity prices increase related to those factors.

  CEI South will be evaluating the performance of each portfolio through a series of scenarios, sensitivities, and stochastics. In particular, the stochastics will include natural gas price volatility that simulates events like supply constraints.

Supply-side Resource Inputs

- **Capital cost projections for renewables (slides 27-31)**. I have gotten feedback from CGA's members, many of whom are clean energy developers, that these appear high for renewable resources. Can you explain in more detail how these costs are developed? If they are coming from RFP responses, is CenterPoint using high, low, or an average of the bids? Also, were these bids for BTAs, PPAs, or both?

  CEI South is utilizing all-source RFP bids to set the reference, high, and low pricing. Going forward, we apply NREL's future price curves. This approach is outlined on slides 28-31 of the second public stakeholder meeting (Stakeholder Meeting #2). The reference case uses the average RFP pricing as the starting point, the low curve starts with the lowest RFP bid point, and the high curve starts at the high RFP bid point.

Depending on the resource, we received bids for both BTA and PPAs. Please see slides from the first IRP stakeholder meeting for more information on bids that we received. Stakeholder Meeting #1 slides available here: Integrated Resource Plan (IRP).

- **Tech assessment for gas-fired resources (slides 33-34)**. Can you explain why a tech assessment rather than RFP response was used to forecast capital and other costs for gas CCs and CTs? My view is that using the RFP approach to inform costs for one set of resources but not for another could lead to inconsistencies. Again, feedback from CGA members is that both capital and fixed O&M costs for gas resources appear low.

  No gas purchase bids were received. We are required to include a wide variety of resources within the IRP analysis. CEI South is using the best available information, consistent with our prior approach.

- **Storage hybrids**. Just a comment - it appears from the slides that only solar + storage hybrids are being evaluated, but I would encourage CenterPoint to explore storage paired with wind and gas units by allowing the model to select any combination of storage and generating resource.

  CEI South is planning to model both solar + storage and wind + storage within the IRP. This is in addition to modeling each resource independently. We are not planning to model a gas + storage hybrid. Typically, batteries are added to other resources as hybrids to support the resource's capacity accreditation. With gas + storage, there is not this same benefit; therefore, costs increase without a significant additional benefit from analyzing the resources independently.

Demand Forecast

- **Electrification (slide 67)**. During the meeting, it was stated that no limitations were placed on the electrification potential in order to develop scenarios that "push the boundaries". However, recent federal policy changes and rollbacks to electrification incentives are likely to seriously undermine the forecast. As was done with the revision to the EV forecast, I recommend CenterPoint revise its electrification forecast, under both the High and Low Regulatory Scenarios, by limiting the anticipated rate of adoption.

  CEI South's scenarios are meant to represent plausible boundaries. It is plausible that the next administration will double down on electrification in a high regulatory scenario.

- **Large Load Sensitivity (slide 76)**. During the meeting I asked how the load forecast for large customers was derived, and was informed it was based largely on speculative requests. The range adds from 100-1000 MW to the Reference Case, which I suppose

accounts for speculation. However, I think it is very apparent by now that certain large load inquiries, such as from data centers, may be both duplicative (in that the customer is "shopping around") and speculative. Furthermore, the data center industry is facing similar challenges as the electric sector: supply chain constraints and permitting delays due to local opposition, as well as from global market tends/forces creating uncertainty over how much load will materialize. Furthermore, the new Indiana law, P.L. 217, provides for an expedited process by which utilities can seek approval for projects meant to serve large customers that may materialize between IRP submissions, making an inflated forecast unnecessary for purposes of obtaining project approvals. Thus, I recommend:

- Including only that load which is in "active" development (e.g., has/plans to sign a contract with CenterPoint), and/or

  CEI South acknowledges there has been an increase in speculative large load; however, CEI South does not currently have any additional large loads under contract. Until we have more certainty, speculative load will not be included in the reference case. To assess the possible impact of large load, we are running a large load sensitivity that is not specific to any one industry. We will continue to monitor and adjust as needed.

- Providing more information to stakeholders and the IURC regarding those inquiries (e.g., number of requests, capacity requested, whether contracts/PPAs have been signed to bring that load online).

  CEI South provided more information in our last tech-to-tech meeting for those that signed an NDA. You are welcome to participate on behalf of Clean Grid Alliance with a signed NDA. Email irp@centerpointenergy.com to request an NDA.

To: Strategy & Resource Planning Team, CenterPoint Energy Indiana (Vectren South)

From: Citizens Action Coalition of Indiana
Environmental Law and Policy Center
Solar United Neighbors
Vote Solar

Date: August 15, 2025

Subject: Deploying Distributed Capacity Procurement (DCP) in the 2025 IRP — and Preparing for Companion Virtual Power Plants

Executive Summary

MISO's most recent auction laid bare Indiana's seasonal imbalance: capacity for the summer of planning year 2025-26 cleared at $666.50 per MW-day, while winter cleared at $33.20; the capacity-weighted annual price is $217 per MW-day. This dramatic pricing reflects the implementation of MISO's new Reliability-Based Demand Curve (RBDC), which provides more accurate seasonal pricing signals and creates investment incentives for the resources needed during peak demand periods.

To hedge against these extremes and capitalize on the clear economic opportunity, we recommend that CenterPoint analyze two complementary DER portfolios in its 2026 IRP:

- Distributed Capacity Procurement (DCP) — the focus of this memo because it drops into the IRP with minimal new data requirements, and
- Virtual Power Plants (VPPs) — a companion scenario that captures the emerging bulk-system value of behind-the-meter resources.

Why Lead with Distributed Capacity Procurement

A DCP confines itself to front-of-meter assets and therefore avoids the modeling complications inherent in retail pricing, incentives, and customer adoption curves. Rather than rely on new central-station builds that face interconnection delays and supply chain constraints, the utility identifies constrained feeders and invites developers (or its own unregulated affiliate) to supply distribution-connected solar-plus-storage projects.

This approach offers several compelling advantages for CenterPoint's 2026 IRP:

- Immediate Implementation: Because the program's costs, hourly output, and MISO accredited values map directly onto existing IRP inputs, it can be evaluated as soon as feeder deferral values are quantified.

- Supply Chain Resilience: Smaller, distributed projects face fewer supply chain bottlenecks than utility-scale developments and can be deployed more rapidly to meet near-term capacity needs while still being cost-competitive with larger resources.
- Local Economic Benefits: DCP supports local contractors and creates economic development opportunities across CenterPoint's seven-county service territory in southwestern Indiana.

How a DCP Works in Practice

Under a DCP, the utility runs competitive solicitations for distribution-connected "hybrid" projects at customer sites—ideally hybrid solar+storage systems pairing roughly 5 MW-AC of single-axis-tracked solar with a 5 MW / 20 MWh battery and interconnecting at feeders already near their thermal limits. These systems are front-of-the-meter (FTM), utility-controlled assets. Ownership models can be determined in program design.

NREL's 2024 Annual Technology Baseline (Moderate/Moderate 2025) puts overnight capital costs at $1,744 per kW-AC for utility-scale PV and $1,950 per kW for four-hour battery storage. Applying the 30% Investment Tax Credit as modified this year by HR 1 lowers the total cost of a paired 5 MW-AC solar + 5 MW/20 MWh battery block to approximately $12.9 million.

While we use ATB as a transparent technology-cost benchmark, we acknowledge that Indiana's recent utility-scale solar (and solar-plus-storage) experience is trending higher than ATB forecasts. In large part, utility-scale projects have faced significant siting and RTO interconnection queue constraints in recent years. By contrast, C&I solar+storage pricing has been more stable: these projects are sited on customer premises, interconnect at distribution voltages, and are not exposed to the same siting and RTO-level interconnection constraints that have disrupted utility-scale development in recent years.

As for capacity / resource adequacy value, under MISO's forthcoming Direct Loss of Load (DLOL) accreditation—planned for implementation in PY 2028–2029—MISO is already publishing indicative, class-level UCAP percentages by season. Using the April 2025 update and MISO's recommended "Even Loss" storage dispatch (to be implemented in the PY 2026–2027 LOLE study), solar accredits at ~45% (summer), ~28% (spring/fall), and ~19% (winter) of ICAP, while a 4-hour battery accredits at ~61% (summer), ~88% (fall), ~85% (winter), and ~90% (spring). In hybrids, accreditation reflects component contributions but resulting ZRCs remain limited by available firm transmission service/deliverability.

After accounting for modest energy market revenue (approximately $0.40 million per year based on current MISO energy prices) plus a conservative five-percent distribution-deferral benefit, the levelized cost would be expected to be competitive in resource modeling. This represents:

- Strong competitiveness with new combustion turbine capacity, once fuel and carbon risk are properly priced

- Immediate availability without the 5-7 year development timeline typical of central-station projects

Integration with EnCompass Modeling

To streamline optimization, the IRP should aggregate roughly ten feeder-level hybrids into a single 50 MW "DCP Block." Each block then enters EnCompass with:

- Capital Cost: ATB-derived post-ITC capital cost of $258/kW-AC (reflecting $12.9M ÷ 50 MW)
- Distribution Deferral Credit: Conservative five-percent reduction in total system cost
- Transmission Deferral Credit: Based on Attachment O planning studies and avoided transmission upgrades
- Energy Market Revenue: The energy value would be captured through any interaction CenterPoint has with the proxy MISO market in EnCompass.
- Hourly Generation Profile: EnCompass can model a paired solar and battery resource and optimize the battery operations so that it would only need an hourly profile for the solar and then EnCompass could handle the battery dispatch.

The model can select zero, one, or multiple 50 MW blocks, providing sufficiently large increments to affect reserve margin and production cost results without cluttering the expansion plan with dozens of tiny assets.

Why VPPs Remain Essential — and How They Fit Beside DCP

While DCP tackles known feeder constraints with front-of-meter solutions, Virtual Power Plants harness behind-the-meter, customer provided PV, batteries, EV chargers, and flexible loads to supply bulk-system capacity and flexibility.[1] The Department of Energy's 2025 Pathways to Commercial Liftoff: Virtual Power Plants report projects 80–160 GW of VPP capacity—10-20% of U.S. peak demand—could be online by 2030 if utilities adopt proven program designs.[2]

Recent policy developments have accelerated VPP adoption:

- Federal Leadership: The 2025 DOE Liftoff Report confirms that utilities integrating VPPs gain 40-60% lower costs compared to traditional peaker plants, stronger grid resilience, and new revenue streams through FERC Order 2222
- State Mandates: Colorado's SB24-218 mandates that utilities integrate VPPs into long-term planning, setting a precedent other states are likely to follow
- Market Integration: FERC Order 2222 enables aggregated DERs to participate in wholesale markets, creating new revenue opportunities for customers and utilities

[1] Note: the model we are proposing for both the VPP and the DCP model the resources as utility controlled assets, not assuming that the aggregated resources, not assuming market participation under FERC Order 2222.
[2] DOE Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update (January 2025)

- Solar United Neighbors' Model Tariff for Distributed Power Plants (2024) provides a turnkey framework Indiana could adopt, with core principles including universal eligibility, technology-agnostic design, streamlined enrollment, and fair compensation for participants.[3]

Implementation Roadmap

Modeling VPPs rigorously requires customer-adoption curves and incentive analysis that extend beyond the data needed for DCP. For this reason, we recommend CenterPoint:

- Model DCP first (this IRP) to lock in feeder-level capacity and deferral benefits with well-understood inputs; and
- Retain "placeholder" VPP scenarios (e.g., 50 MW, 150 MW build cases) using DOE and SUN default assumptions, signaling to the Indiana Utility Regulatory Commission that a fuller VPP analysis will accompany the next IRP.
- Begin developing BTM VPP programs in the interim outside of the resource planning process, similar to a process required under Virginia's HB 2346 passed earlier this year.[4] We recommend working from the SUN model tariff to develop a utility directed program similar to the Connected Solutions in the northeast. The SUN Model Tariff provides a great starting point for VPP program implementation and the ability to scale programs quickly and cost-effectively.

Strategic Context for CenterPoint's Energy Transition

DCP and VPP programs directly support addressing key challenges:

- Interconnection Queue Congestion: MISO's interconnection queue remains congested, with delays in bringing new generating resources online representing a growing concern. DCP provides an alternative pathway that bypasses transmission-level interconnection studies.
- Load Growth Pressures: Peak electricity demand is projected to grow, driven by energy-intensive data centers, domestic manufacturing, and electrification. DCP and VPP resources can help meet this growth without extensive new transmission infrastructure.
- Cost Management: Utility investments in transmission and distribution infrastructure grew significantly between 2022 and 2023, with capital costs expected to keep rising—putting upward pressure on electricity rates. DER solutions can help defer these investments while maintaining reliability.
- The DCP as proposed does not depend on aggregated DER participation in wholesale markets (it is utility-controlled DER), but FERC Order 2222 will require utilities to allow

[3] The SUN Distributed Power Plant Model Tariff is available at: https://solarunitedneighbors.org/wp-content/uploads/2024/07/SUN_Model-DPP-Tariff_v1-June-2024.pdf
[4] HB 2346 available at: https://lis.virginia.gov/bill-details/20251/HB2346

Distributed Energy Aggregated Resources to participate in aggregated energy & capacity markets beginning in 2030. (FERC’s two orders pertinent to this are in Docket ER22-1640, Oct 2023 and Jan 2025).

Conclusion

Modeled in 50-megawatt blocks whose capital charges are offset by transparent distribution- and transmission-deferral credits, a DCP lets CenterPoint secure firm, clean capacity at roughly half today's summer price while postponing millions in feeder and network upgrades—all without wrestling with retail-rate or adoption uncertainty.

A companion VPP scenario, grounded in DOE's 2025 Liftoff analysis, ensures the IRP also tests the broader customer-side opportunity that will become increasingly valuable as Indiana's grid evolves. Together, these resources position CenterPoint to meet its decarbonization goals while managing costs and maintaining the reliability that southwestern Indiana customers expect.

Our coalition is ready to supply detailed inputs and technical support to help CenterPoint evaluate both resources and build a flexible, least-cost DER roadmap for Indiana's energy future. The economic case is clear, the technology is proven, and the regulatory pathway is established—making 2026 the ideal time to integrate distributed resources into CenterPoint's strategic planning.

CEI South Response in BLUE font

Request Received: 8/15/2025
CEI South Response Sent: 8/29/2025

Subject: Deploying Distributed Capacity Procurement (DCP) in the 2025 IRP — and Preparing for Companion Virtual Power Plants

CEI South Response:

CEI South thanks Citizens Action Coalition of Indiana, Environmental Law and Policy Center, Solar United Neighbors, and Vote Solar for the recommendation to analyze two DER resource portfolios, Distributed Capacity Procurement (DCP) and Virtual Power Plants (VPPs) in CEI South's 2025 IRP. We appreciate the additional research you provided for our review and consideration.

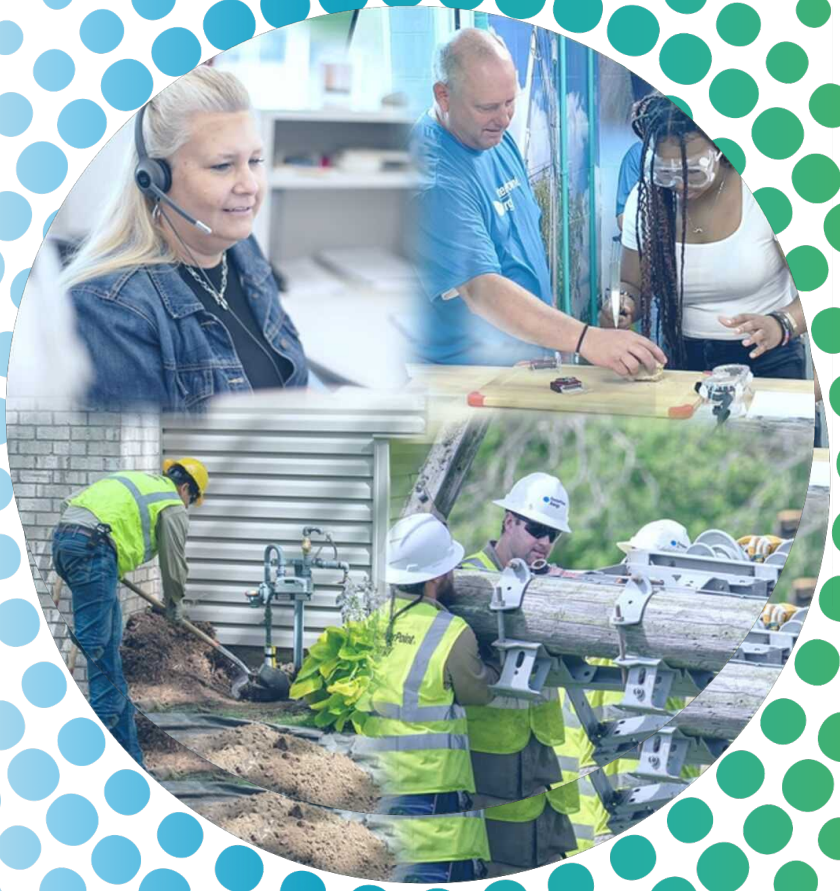
As shared in CEI South's January response to CAC's December 2024 DER Resource request, CEI South's current IRP process includes the consideration of multiple Demand Response (DR) programs that align with the intent of both the DCP and VPP - including assessing EV chargers, battery storage, and grid-enabled water heaters and thermostats. Time of Use and Critical Peak Price rates are also included in the DR evaluation, and similarly to DCP, the rates provide an incentive to the customer that can result in improving grid reliability. Additionally, CEI South is conducting a $500/kw distributed generation (DG) solar incentive sensitivity in the 2025 IRP.

CEI South will continue to monitor developments in these areas. Updates on the DSM Market Potential Study and subsequent IRP inputs, as well as the DG solar sensitivity will be shared in the upcoming 9/11/2025 CEI South public IRP stakeholder meeting.

CenterPoint Energy

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 3



September 11, 2025

Stakeholder Meeting Facilitator: 1898 & Co.

WHO: 1898 & Co. is the business, technology and security consultancy part of Burns & McDonnell

WHAT: The Resource Planning & Market Assessments group has been working on Integrated Resource Plans for over 20 years

HOW: Our team will help facilitate stakeholder meetings – we look forward to working with and hearing from you all

Agenda

Time	Topic	Speaker
9:00	Sign-in & Refreshments	
9:30	Facilitators and Meeting Protocols & Participation	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
9:35	Welcome & Safety Share	Shane Bradford, Vice President, Indiana Electric, CenterPoint Energy
9:45	Stakeholder Feedback & IRP Process Recap	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
10:00	Revisions to Scenarios	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
10:30	BREAK	
10:40	DSM Market Potential Study Initial Results	Jeffrey Huber, Principal, Energy Efficiency, GDS Associates
11:20	Portfolio Development Methodology and Draft Scenario Optimization Results	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
11:50	LUNCH	
12:40	Draft Deterministic Portfolio Results	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:10	Portfolios Discussion	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:30	BREAK	
1:40	Probabilistic Modeling Update	Brian Despard, Senior Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:00	Early Sensitivity Results	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:20	Stakeholder Questions & Feedback	Moderated by Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
3:00	Adjourn	

Modeling Outputs & Preliminary Results

The modeling outputs presented in this meeting are not final and do not represent CEI South's final plans at this time.

CEI South has not selected a preferred portfolio.

Meeting Protocols

- Please focus questions, comments, and feedback to the IRP process and today's agenda topics
- CenterPoint Energy Indiana (CEI) South does not authorize the use of cameras, video/audio recording devices, or AI transcription during the meeting
- Following the meeting, feedback (concepts, inputs, methodology, etc.) and questions may be sent to IRP@CenterPointEnergy.com
- CEI South will be recording the meeting to accurately capture notes and questions. The public meetings are not transcribed or recordings posted; however, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp

Meeting Participation

Time is allotted for questions following each presentation – please hold questions until the designated question period

In-person attendees – please raise your hand to be recognized

Virtual attendees will be in listen-only mode – to participate:

- Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
- Enter questions into the “Q&A” feature in Teams

Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

There will be a list compiled for items to be addressed later. Questions that are not able to be answered in this meeting will be answered later.

Welcome and Safety Share

Shane Bradford

Vice President, Indiana Electric

Safety Share



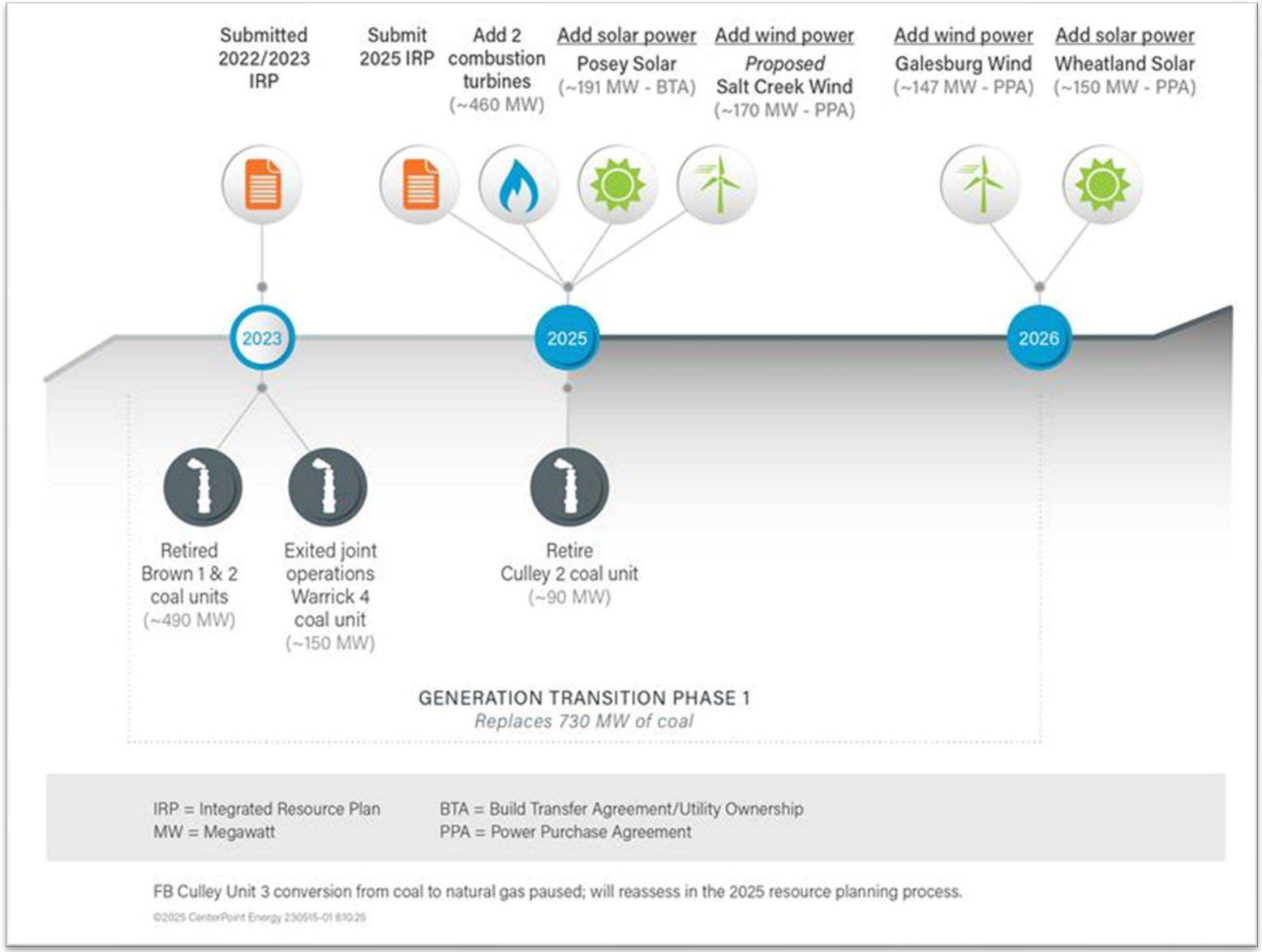
Why Call 811?

Every digging project requires a call to 811.

Hitting an underground utility line while digging can:

- cause serious personal injuries
- harm the environment
- disrupt service to an entire neighborhood and
- potentially incur fines and repair costs

Generation Transition Timeline:



Stakeholder Feedback & IRP Process Recap

Matt Rice

Director, Regulatory and Rates

Summary of Stakeholder Feedback From Meeting #2

Topic	Stakeholder Comments	CEI South Updates/Responses
Generation Timeline	Regarding Salt Creek Wind, is this project going to service CenterPoint customers or just provide power to the MISO grid as accredited power? If it's going to be service to CenterPoint customers, what kind of transmission loss are you expecting since the power is coming from Iowa?	Please see Witness Swanson's public testimony in Cause No. 46218[1]
Objectives & Draft Measures	Will the electric energy burden separate electrically heated homes from gas heated homes, or will those be combined in the aggregate?	We'll look at both the customers with electrically heated homes and the customers with gas heated homes. However, either view will show the same relative difference among portfolios.
Scenarios	Suggest adding an option where load stays at base. In this scenario, generation capital costs could still be high.	CEI South conducted a lower load sensitivity analysis to evaluate how lower the load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Scenarios	When looking between high regulatory and alternative high regulatory, can you potentially do the same with low regulatory (an alternative low regulatory with low load)?	

[1] *https://iurc.portal.in.gov/docketed-case-details/?id=43b79da2-5219-f011-998a-001dd8084fd9*

Summary of Stakeholder Feedback From Meeting #2

Topic	Stakeholder Comments	CEI South Updates/Responses
Supply-Side Resource	Can CEIS incorporate real coal price offers made to CenterPoint. The uncertainty variable is not the mining cost as much as the demand.	Due to the confidential and competitive nature of CEIS's contractual coal price this was discussed during the 8/20/2025 Tech to Tech meeting
Supply-Side Resource	How many bids did CEIS receive for storage?	There were 17 standalone storage bids. The RFP results were shared during the 3/19/2025 Stakeholder meeting. The presentation is available here: centerpointenergy.com/irp.
Supply-Side Resource	Is CEIS accounting for all costs and benefits, including considerations such as health costs? Will these other benefits be incorporated into the IRP?	Health costs are captured within EPA regulations that are included in the applicable scenarios.
Supply-Side Resource	Has CEIS considered the water pressure nuclear option, such as the Westinghouse AP1000?	The general nuclear option included in the Tech Assessment is representative of a variety of future nuclear options. If you have information regarding technology performance or costs that you would like to see in the model, please email **irp@centerpointenergy.com**

Summary of Stakeholder Feedback From Meeting #2

Topic	Stakeholder Comments	CEI South Updates/Responses
MPS	For the battery storage program, without large enough penetration of batteries, it's hard for benefits to outweigh the costs. Could we look at a battery storage equipment incentive?	We performed cost-effectiveness screening using a range of incentives and adoption rates. In all scenarios the Utility Cost Test ratio was less than 1, which is not cost-effective. Results are included in today's (9/11/2025) Stakeholder meeting.
MPS	For EVs, are customers bringing their own device for the charger? Would customers have to use specific technology to participate?	We are assuming that the customer would supply their own charger, and CenterPoint would provide an incentive to join the program, as well as an annual participation incentive. A managed charging program would require some sort of network connection, which could include Wi-Fi, cellular, or a wired connection. A specific technology would not be required, as control could happen through the charger or telematics through the EVs
MPS	Some DR measures like batteries and water heaters can be used for other grid services (ancillary services, resilience) – how are these benefits being considered in developing levelized costs and/or accounted for in the IRP? Is it possible to treat these like T&D benefits and reduce from the cost side?	When performing cost-effectiveness screening, the benefits include the avoided energy, capacity, and T&D. Resilience and ancillary services have not been a benefit of Demand Response captured in the IRP analysis.

Summary of Stakeholder Feedback From Meeting #2

Topic	Stakeholder Comments	CEI South Updates/Responses
Model Inputs	Is CEIS going to include Scope 3 emissions	Scope 3 emissions are outside the scope of the IRP as it's related to emissions of the end-user and separate from electricity generation
Model Inputs	Since CEIS is considering nuclear, does CEIS want to run a stochastic process for uranium?	We are currently using publicly available data sources for uranium pricing forecasts. Uranium pricing is not expected to be a major differentiator in the portfolio risk assessment when compared with other cost drivers. Given this, we do not anticipate that running a stochastic process for uranium will materially change the outcomes of the analysis.
Model Inputs	Is CEIS planning to use the MISO published 2025/2026 indicative DLOL results for the solar and wind accreditation assumptions	We have revised the accreditation values to interpolate between the first season of DLOL and 2035. Providing a smoother shift in accreditation. Revised Solar and Wind capacity accreditation forecasts are included in this presentation's Appendix.
Model Inputs	Recommendation to analyze two DER resource portfolios, Distributed Capacity Procurement (DCP) and Virtual Power Plants (VPPs) in CEI South's 2025 IRP	CEI South's evaluated demand response programs that align with the intent of both DCP and VPP programs as well as a DG Solar incentive during the IRP process. Updates on the evaluations are included in today's (9/11/2025) Stakeholder meeting.

2025 Stakeholder Process

Proposed 2025 CEI South Stakeholder and Tech to Tech Meetings – *Dates and agendas are subject to change*

Meeting 1
March 19

- IRP Process, Objectives, & Draft Metrics
- All-Source RFP Results
- MISO Update
- Environmental Compliance Update
- Draft Sales and Demand Forecast (Reference Case)
- Commodity Inputs
- Large Load Sensitivity Discussion
- Resource Options
- Scenario Development

Tech to Tech
April 28

Meeting 2
May 14

- Follow Up Information From 1st IRP Stakeholder Meeting
- Final Scorecard and Scenarios
- DSM Market Potential Study Update
- Draft Supply-Side Resource Inputs
- Final Load Forecast and Draft Scenario Forecasts
- Probabilistic Modeling Approach and Assumptions
- Portfolio Development Methodology
- Draft Reference Case Modeling Update

Tech to Tech
August 20

Meeting 3
September 11

- Follow Up Information From 2nd IRP Stakeholder Meeting
- Revisions to Scenarios
- DSM Market Potential Study – Initial Results
- Portfolio Development Methodology and Draft Scenario Optimization Results Draft Deterministic Portfolio Results
- Portfolios Discussion
- Scenario and Probabilistic Modeling Update
- Early Sensitivity Results

Tech to Tech
October 14

Meeting 4
October 23

- Follow Up Information from 3rd IRP Stakeholder Meeting
- Preferred Portfolio
- Risk Analysis Modeling and Portfolios
- Risk Analysis Scorecard

Target Submission Date: December 5, 2025

Stakeholder Engagement is Critical to the IRP Process
CEI South is committed to meaningful information sharing and dialogue

Target Data Release Schedule

Draft Load Forecast	Draft Base Case Model	Updated Base Case + Scenario Models	Probabilistic + Sensitivity Analysis Models
3/20/2025 (1)	5/5/2025 (2)	8/20/2025 (3)	10/14/2025 (4)

- *Released data and Tech to Tech meeting attendance will be available to the technical stakeholders with a completed Non-Disclosure Agreement (NDA).*
- *Send NDA requests to IRP@Centerpointenergy.com*

Objectives & Draft Metrics

Objective	Measure	Metrics
Affordability: *Consider portfolios' impact on the retail electric utility service providers ability to provide affordable power across residential, commercial, and industrial customer classes*	➢ 20-year Net Present Value Revenue Requirement ("NPVRR")	➢ $
	➢ 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions	➢ $
	➢ **5th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions**	➢ $
	➢ **Electric energy burden**	➢ **% HH income**
Environmental Sustainability: *Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation*	➢ CO_2 Intensity	➢ Tons CO_2/kwh
	➢ CO_2 Equivalent Emissions	➢ Tons CO_2e
	➢ **SOx and NOx Emissions**	➢ **Tons**
Reliability: *Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all time and withstand sudden disturbances*	➢ **Unserved energy across 200 dispatch iterations under varying market conditions**	➢ MWh
Resiliency: *Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions*	➢ Spinning Reserve	➢ Portfolio MW's That Offer Spinning Reserve
	➢ Fast Start Capability	➢ Portfolio MW's That Offer Fast Start
Stability: *Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters*	➢ **Transmission reliability analysis**	➢ Dynamic VAR Support (MVAR) ➢ Short Circuit Ratio
Risk/Other:	➢ Energy Market Purchase and sales	➢ % (average, near/long term)
	➢ ~~**IRA tax credit exposure**~~	➢ $

Blue text indicates a new measure for this IRP cycle

Red text indicates a revision following prior Stakeholder meeting

MWh = Megawatt hour MVAR = Megavolt-Ampere Reactive

Q&A

Revisions to Scenarios

Matt Rice

Director, Regulatory and Rates

Reference Case Assumptions

- As per Rule 170 IAC 4-7-4, the reference case should reflect the most likely future scenario
- As the legislative landscape evolves, the reference case has been adjusted so that it continues to reflect the most likely future scenario

Original Assumptions

Continuation of Clean Air Act 111(b)&(d)

- Coal plants must retire by 2032 or convert/co-fire by 2030
- Combined Cycles limited to a 40% capacity factor

Continuation of IRA Renewable Tax Credits

- ITC and PTC available through end of 2032

Updated Assumptions

Modification of Clean Air Act 111(b)&(d)

- Coal plants may run through entire study period
  - Add ACE costs to proxy the efficiency target for coal
- No generation limits on Combined Cycles

Modification of IRA Renewable Tax Credits

- Assuming generic solar and wind qualify for ITC/PTC through end of 2029
- Assuming generic nuclear and storage qualify for phased down ITC/PTC through end of 2035

Alternate Reference Case

Based on Stakeholder feedback, we have added an additional Scenario to modeling that reflects a significantly higher load forecast, the Alternate Reference Case.

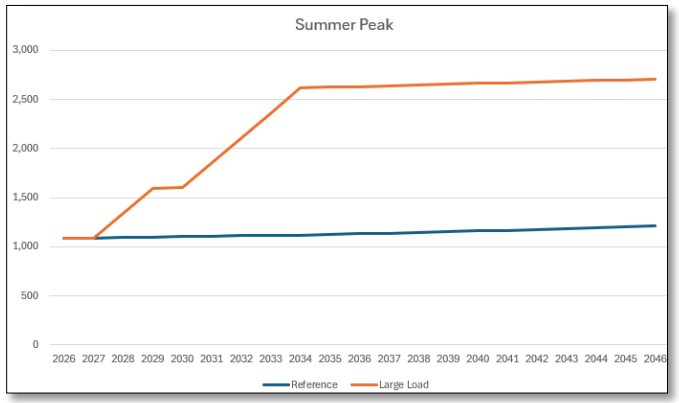
Reference Case vs Alt Reference Case

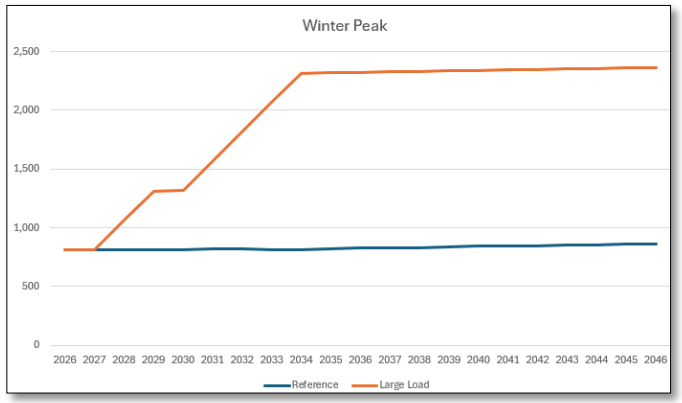
Same

- Policy
  - "ACE Proxy" on existing coal
  - OBBBA modified IRA
  - No additional CO_2 tax
- Commodity Prices
  - Base natural gas and coal prices
- Capital Cost
  - Base generation and EE costs

Different

- Load
  - Potential large load forecast





Reference Case Scenario

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Reference Case	~~Clean Air Act 111 (b & d)~~ **ACE Proxy**	**Modified** IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base

- As per Rule 170 IAC 4-7-4, the base case [reference case] is to be the most likely future scenario. As such, it is designed to be an extension of the status quo
- In the Reference Case Scenario, the Clean Air Act 111(b & d) is rolled back and does not include existing gas resources or a CO_2 Tax. An "ACE Proxy" is included as an environmental efficiency standard for existing coal unit(s)
- **Policy** – IRA modified with changes from the OBBBA
- **Load (-)** – Peak demand growth of 0.5% per year in the Summer and 0.3% per year for Winter for electricity (Does not include impact of CEI South EE program savings).
- **Commodity Prices (-)** – Consensus forecasts for gas, coal, and MISO capacity
- **Generation Capital Costs (-)** – Informed by the All-Source RFP and the Technology Assessment
- **EE Costs (-)** – Based on Updated Market Potential Study

Alternate Reference Case Scenario

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Alternate Reference Case	~~Clean Air Act 111 (b & d)~~ **ACE Proxy**	**Modified** IRA	No additional CO_2 regulation	~~Base~~ **Much Higher**	Base	Base	Base	Base

- As per Rule 170 IAC 4-7-4, the base case [reference case] is to be the most likely future scenario. As such, it is designed to be an extension of the status quo
- The Alt Reference Case Scenario includes the same policy in the Reference Case scenario
  - the Clean Air Act 111(b & d) is rolled back and does not include existing gas resources or a CO_2 Tax. An "ACE Proxy" is included as an environmental efficiency standard for existing coal unit(s)
- **Policy** – IRA modified with changes from the OBBBA
- **Load (↑)** – addition of potential of growing large load drives significant expediated electricity demand growth
- **Commodity Prices (-)** – Consensus forecasts for gas, coal, and MISO capacity
- **Generation Capital Costs (-)** – Informed by the All-Source RFP and the Technology Assessment
- **EE Costs (-)** – Based on Updated Market Potential Study

Scenario Summary

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	~~Clean Air Act 111 (b & d)~~ **ACE Proxy**	**Modified** IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base
Alternate Reference Case	~~Clean Air Act 111 (b & d)~~ **ACE Proxy**	**Modified** IRA	No additional CO_2 regulation	~~Base~~ **Much Higher**	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	No additional CO_2 regulation	Higher	Higher	Higher	Higher	Base
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

Q&A

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 3

On break – we will return at 10:10 CDT

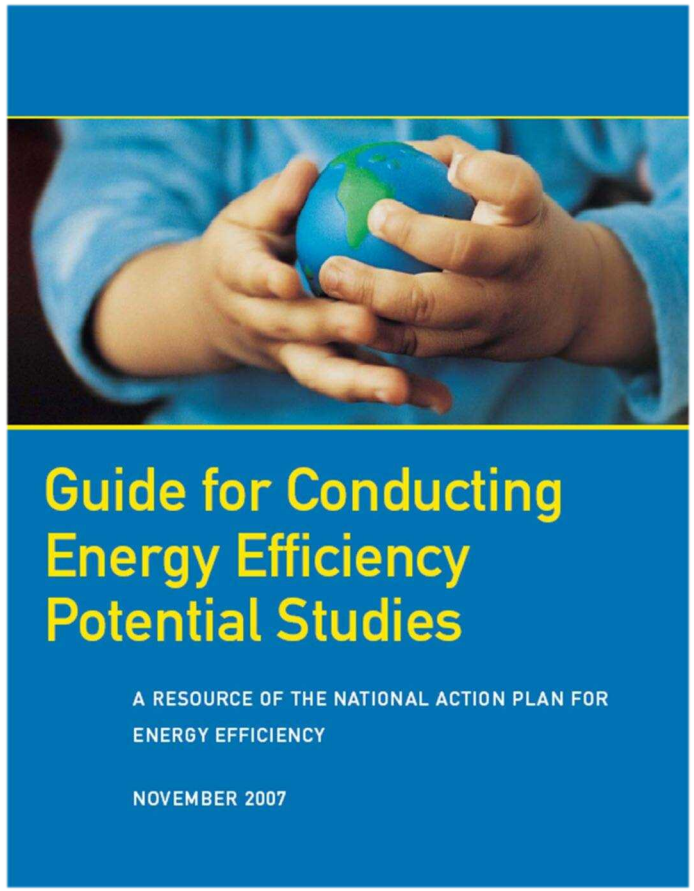
DSM Market Potential Study Initial Results

Jeffrey Huber
Principal, Energy Efficiency, GDS Associates

TOPIC OVERVIEW

- Market Potential Study Recap
  - What is a Market Potential Study (MPS)?
  - MPS & IRP Process
- Energy Efficiency (EE) Market Potential Study Overview
  - Market Research
  - Study Results
  - IRP Inputs
- Demand Response (DR) Market Potential Study Overview
  - Methodology & Modeling
  - Study Results
  - IRP Inputs
- Q&A

WHAT IS A MARKET POTENTIAL STUDY?



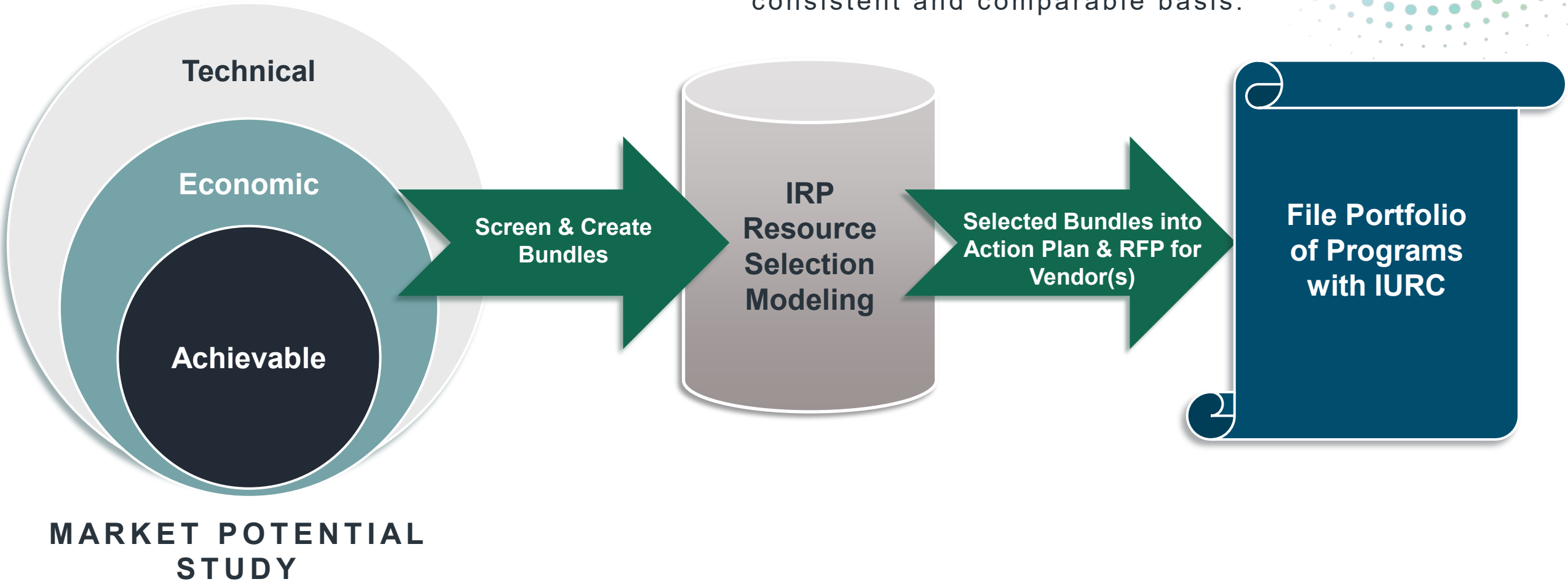
Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies.

-National Action Plan for Energy Efficiency

THE MPS & IRP

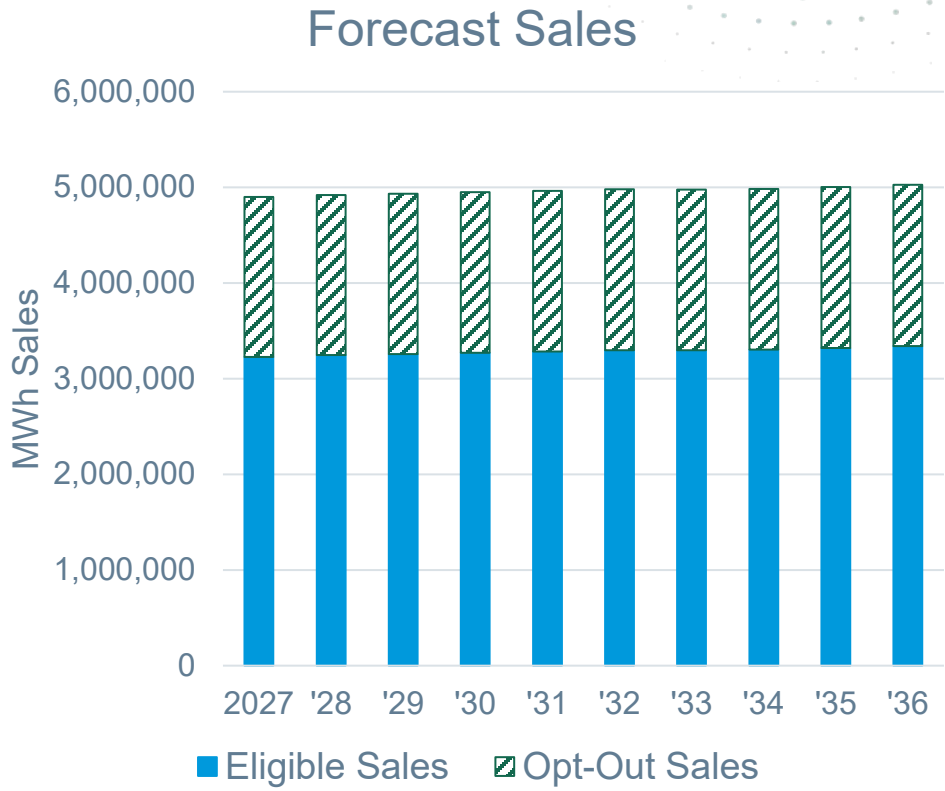
IURC Rules – 170 IAC 4-7-8-c-4

"Analysis showing Supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis."



EE OVERVIEW: MARKET CHARACTERIZATION

- LOAD FORECAST
  - Review of Sales and Customer Counts
    - Residential (single family/multifamily ; market rate/income qualified)
    - Commercial (by building type)
    - Industrial (by industry type)
  - Review Eligible Sales
    - 48% of all C&I sales are from customers who have opted-out of EE programs
    - Percentage of sales from other “atypical” facilities with limited traditional EE opportunities
  - Estimating Consumption by End-Use



C&I = Commercial & Industrial

EE OVERVIEW: TYPES OF POTENTIAL OVERVIEW

TECHNICAL POTENTIAL

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

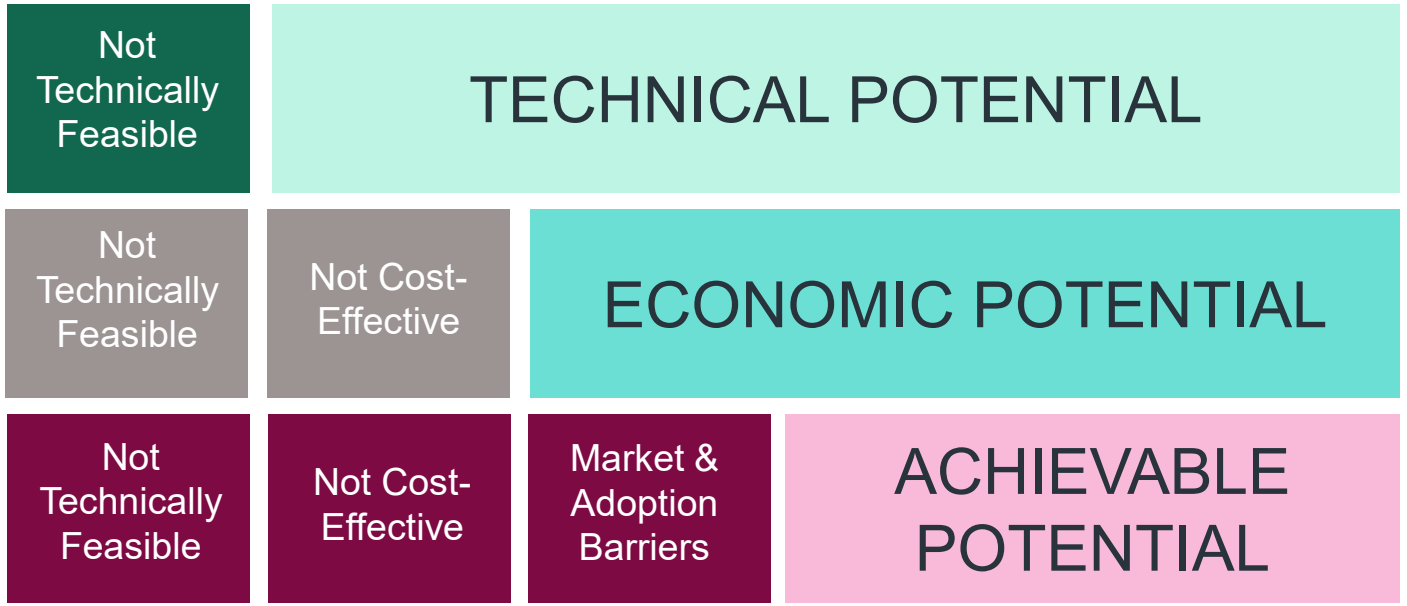
ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the **Utility Cost Test**. Only cost-effective measures are included.

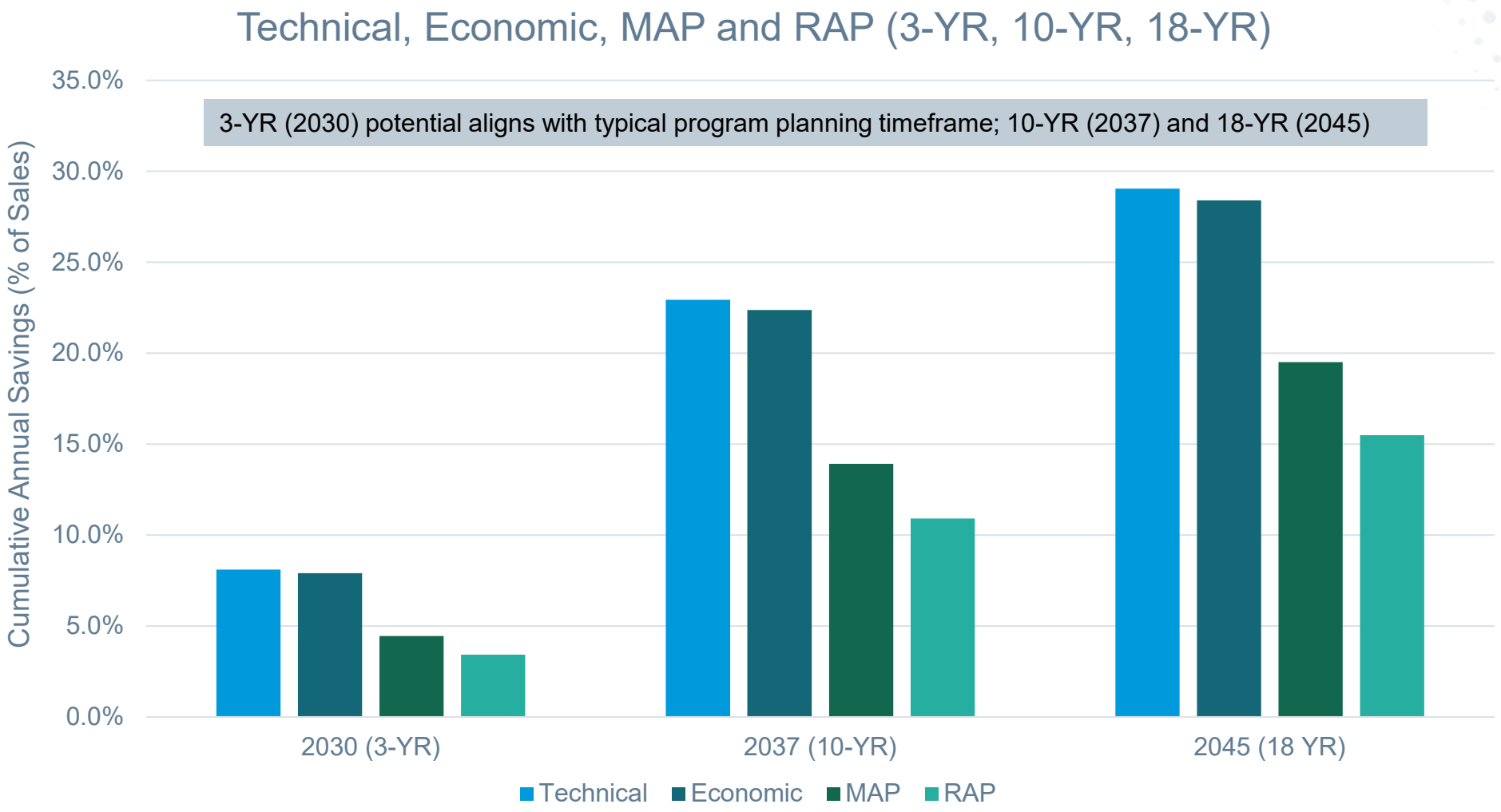
ACHIEVABLE POTENTIAL

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

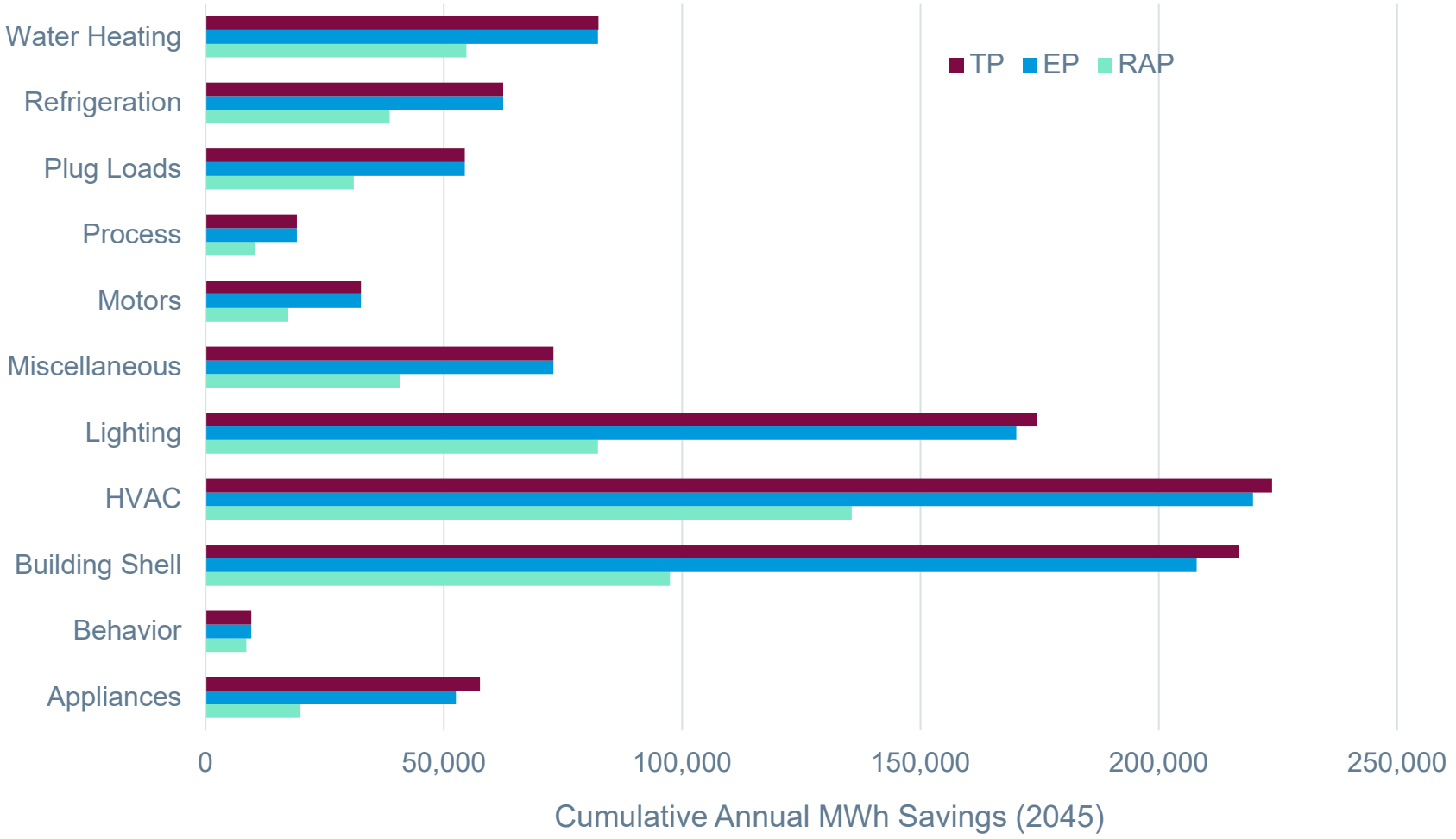


OVERALL POTENTIAL – All SECTORS



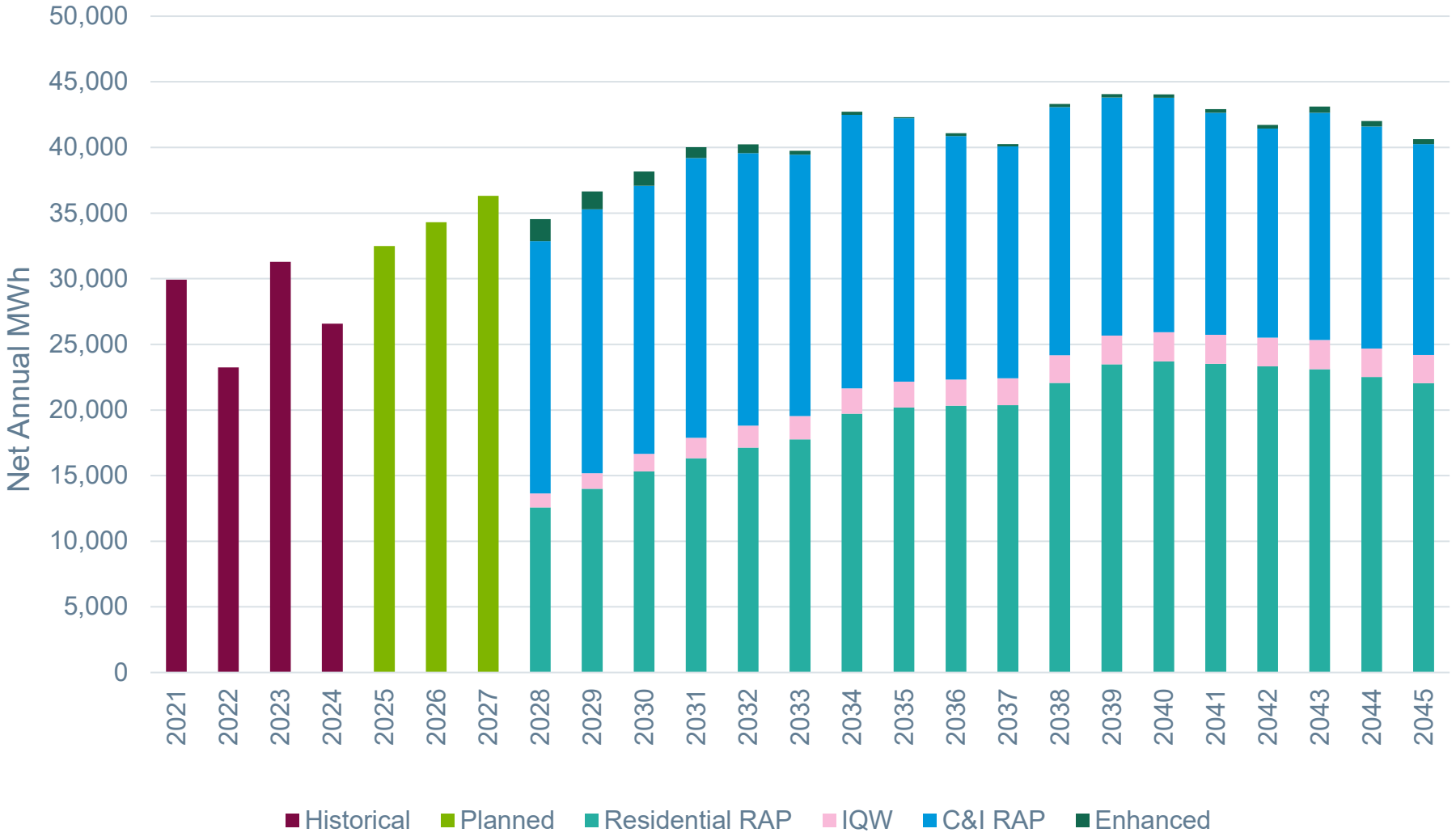
MAP = Maximum Achievable Potential *RAP = Realistic Achievable Potential*

OVERALL TP/EP/RAP BY END USE – All SECTORS



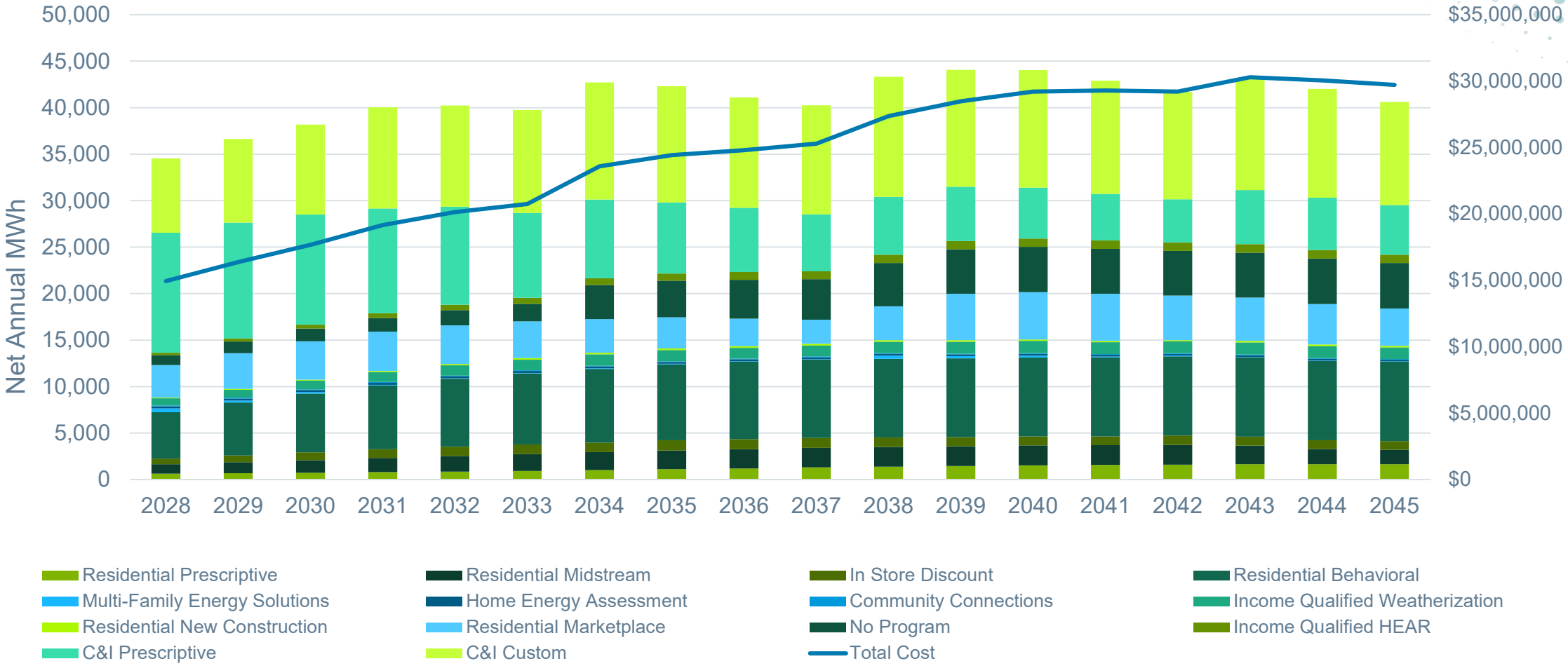
- HVAC, Building Shell and Lighting are the leading overall end-uses
- Lighting is nearly all in the C&I sector
- Building Shell is largely in the residential sector
- Behavior provides low cumulative annual savings but remains a key element of annual savings (1st-yr kWh)
- Water Heating, Refrigeration, Plug Loads, and Miscellaneous (mostly C&I) have significant potential

Incremental Annual "Achievable" vs Historical and Planned



- Savings are shown as "net"
- Incremental savings from Enhanced RAP shown in dark green shade at top of bars
- Enhanced C&I was developed with coordination with OSB
- Enhanced RAP used for C&I sector only
- Some historical years shown for comparison

Program-Level Incremental Annual "Achievable" (savings and total program costs)

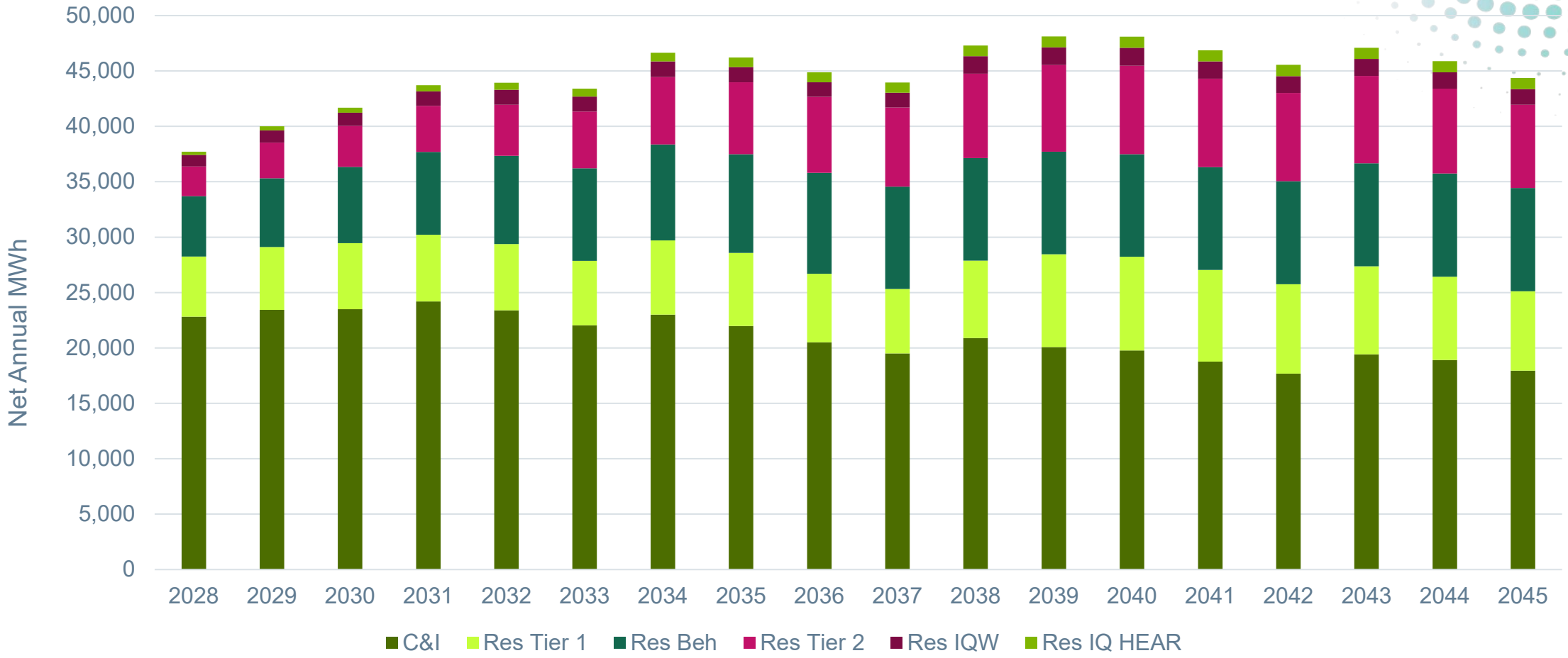


DSM IN THE IRP: EXPECTED INPUT STRUCTURE

- DSM Inputs are:
  - Sector based (residential, income-qualified, and nonresidential)
    - Residential and nonresidential will be selectable resources; income-qualified will be a “going-in” resource
  - Three time-vintages (2028-2030, 2031-2033, and 2034-2045)
  - Based on RAP and/or “Enhanced” RAP (commercial sector)
  - Based on net savings
  - Costs reflect utility incentive and non-incentive costs (less NPV T&D benefits)
  - Include hourly profiles for each bundle

RAP = Realistic Achievable Potential *NPV = Net Present Value* *T&D = Transmission & Distribution*

ANNUAL SAVINGS BY BUNDLE



*Savings are at generator (account for line losses)

DR OVERVIEW: OVERVIEW

- Goal of the DR MPS is to develop IRP inputs, but will also share some common assumptions with IRP where possible
  - Peak load forecast by season and rate class
  - Electric vehicle adoption forecast
  - Behind-the-meter solar penetration forecast
- DR MPS will also consider results of the EE MPS
  - Use consistent end-use saturation estimates
  - Consider select EE technology adoption estimates/efficiency trends and EE rebates
- Prioritizes current demand response offerings and rate structures

DR OVERVIEW: STARTING POINT

- Historical DR Program Offerings
  - DLC Central AC (Switch and Thermostat)
  - DLC Water Heating (Switch)
- Programs Under Consideration (by 2028)
  - Time of Use (TOU) with Critical Peak Pricing (CPP) Rate
  - DR Aggregation* *(Potential impacts previously analyzed by CenterPoint outside of MPS)*
- Additional Programs for MPS
  - DLC Water Heating (Grid-Enabled)
  - DLC Electric Vehicle (EV)
  - Battery Storage

DR OVERVIEW: METHODOLOGY

- Programs are screened for cost-effectiveness using the Utility Cost Test (UCT)
  - UCT = ratio of Net Present Value (NPV) benefits to NPV cost per program over 20-year lifespan
  - NPV benefits include avoided generation capacity (based on a combined Cyle natural gas plan) and avoided transmission and distribution capacity
  - DR offerings with a UCT ratio less than 1.0 may still be presented as resource options in the IRP model
- MPS will contain two DR potential scenarios:
  - RAP (Realistic Achievable Potential): projections of future DR potential at typical incentive rates and marketing levels
  - MAP (Maximum Achievable Potential): more “aggressive” projection of future DR potential, achieved by offering more generous incentives and/or top-performing jurisdiction benchmarking

DR RESULTS

Sector	DR Program	UCT Result	MW Savings			
			Spring	Summer	Fall	Winter
Residential	DLC AC Switch	Fail	0.0	0.1	0.0	0.0
	DLC Thermostat (Smart Cycle)	Pass	2.6	12.7	2.3	0.0
	DLC Thermostat (BYOT)	Pass	3.7	17.8	3.2	0.0
	DLC Water Heater Switch	Fail	0.0	0.1	0.0	0.0
	DLC Grid-Enabled Water Heater	Fail	2.4	3.9	2.4	5.7
	DLC Electric Vehicle	Fail	0.7	1.2	0.7	1.2
	TOU + CPP Rate	Pass	3.5	5.7	3.6	2.4
	Battery Storage	Fail	0.4	0.7	0.4	0.7
C&I	DLC Thermostat (BYOT)	Pass	0.7	3.6	0.6	0.0
	DLC Grid-Enabled Water Heater	Pass	2.4	2.6	2.4	2.6
	DLC Electric Vehicle	Fail	0.0	0.0	0.0	0.0
	TOU + CPP Rate	Pass	1.9	2.1	1.9	1.3
	Battery Storage	Fail	0.3	0.4	0.3	0.4
Subtotal of Programs Above 1.0 UCT Ratio			**14.9**	**44.5**	**14.1**	**6.3**
Subtotal of Demand Response from MPS/IRP			**18.8**	**50.8**	**18.0**	**14.2**
CNP DR Aggregator Totals			19.2	25.0	22.0	18.8
Total of All Demand Response			**37.8**	**75.8**	**37.0**	**33.2**

DR IRP Inputs

- All programs/sectors were bundled individually for the IRP inputs
- New DR programs provided year-round savings.
  - Existing Summer Cycler program (AC Switch & WH Switch) only provided savings in summer.
  - DLC Thermostat program provides savings spring through fall.
  - Summer peak savings generally more significant than the other seasons.

Q&A

Portfolio Development Methodology and Draft Scenario Optimization Results

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

Portfolio Development Methodology Overview

1) Begin with Existing Portfolio

- Establish the current resource mix as the foundation of the analysis

2) Define Critical IRP Decision Points

- Identify key planning questions and decision points to be addressed in the IRP

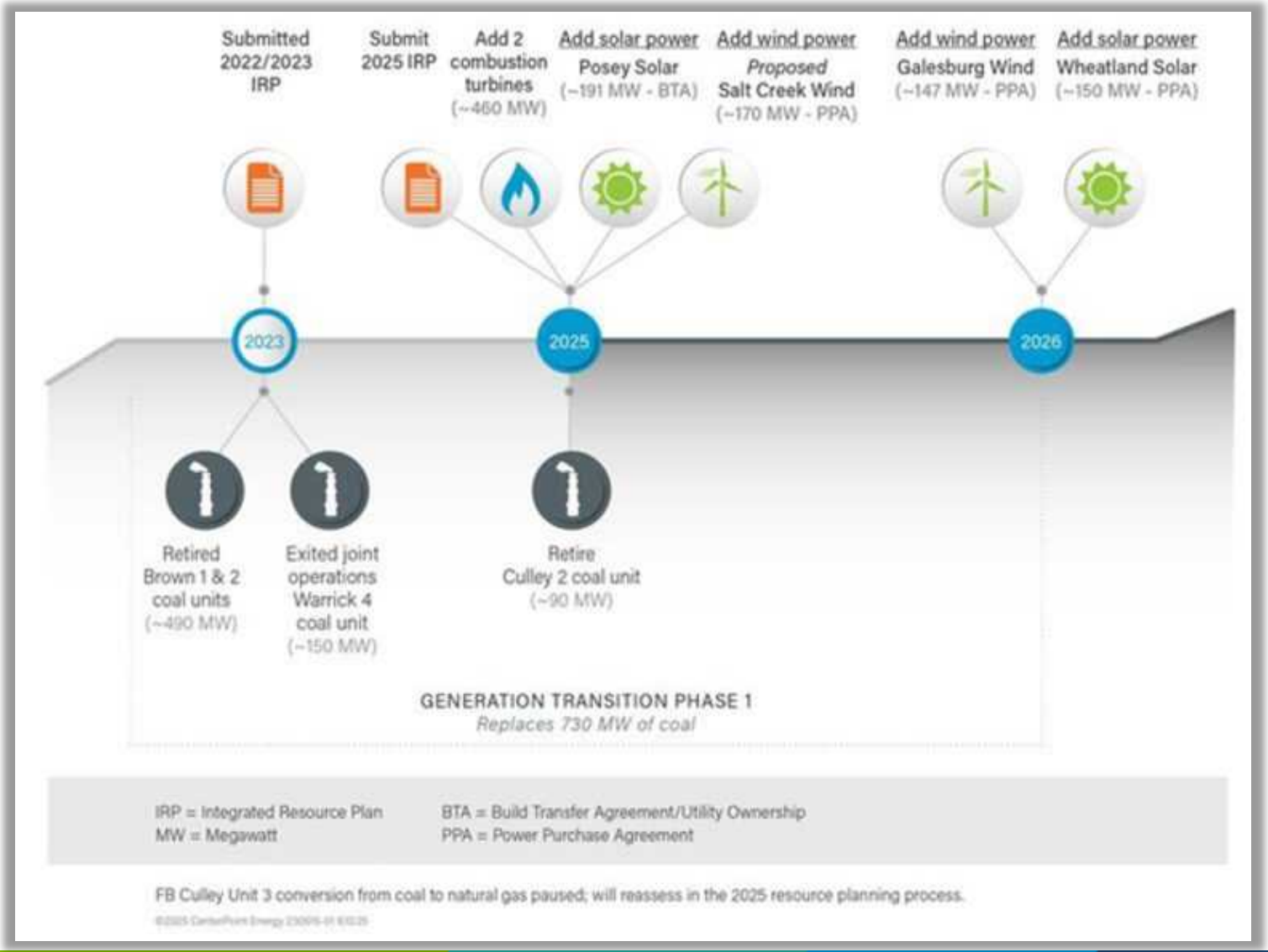
3) Identify Alternative Resources

- Explore new and emerging resource alternatives to supplement the existing resources

4) Develop a Modeling Framework to Evaluate Options

- Analyze trade-offs of resource selections
- Create diverse portfolios to assess resource and portfolio trade-offs against the 5 pillars

Portfolio Development Methodology
Step 1 Update: Generation Transition Timeline



Portfolio Development Methodology
Step 2: Key Near-Term IRP Decisions

- CEI South plans to suspend F.B. Culley 2 operations in December 2025
- Approximately 3-year timeline to reuse the existing interconnection
- Due to site area and condition of the unit, the resources being studied are:
  - Battery Storage
  - Aeroderivative
  - Reciprocating Engines

F.B. Culley 2

Demand Side Management

- Finalize DSM inputs with new MPS
- Determine what levels and programs are frequently selected under optimization simulations.
- Additional programs and optionality being studied in this IRP

- For the Reference Case Scenario, F.B. Culley 3 has the following paths:
  - Convert to natural gas on either 1/1/2030 or 1/1/2035
  - Co-Fire on gas and coal through 2038 and then retire 12/31/2038
  - Retire on 12/31/2032 or 12/31/2034
  - Continue on coal with ACE like efficiency upgrades by 2029

F.B. Culley 3

Portfolio Development Methodology
Step 2: Key Near-Term IRP Decisions

- Optimized Scenario simulations selected F.B. Culley 2 Battery.
- Deterministic F.B. Culley 2 pathways showed Battery having lowest NPVRR.
- Additional portfolio testing selected Battery pathway over Aeroderivative, Reciprocating engine, and no replacement options.
- FBC2 Battery included in draft portfolios.

F.B. Culley 2

Demand Side Management

- Optimization and deterministic runs had strong consistency in the DR and EE programs selected.
- Included consistent base level of DR and EE in all 12 draft portfolios.
- Additional stress testing to be done.

- F.B. Culley 3 option selection is a larger capacity block strongly tied to other resource selections.
- F.B. Culley 3 retirement pathways are selected most commonly in optimization in combination with the selection of ABB 5+6 conversion to a CCGT (ABB 7)
- Still examining different options in draft portfolios.

F.B. Culley 3

Portfolio Development Methodology
Step 3: Resource Alternatives



Simple Cycle Natural Gas



Combined Cycle Natural Gas



Peaking Natural Gas



Nuclear



Existing Unit Conversions



Wind



Solar



Storage



Hydroelectric



DSM / Innovative Rates

Storage Resource Options

Current Options:

- 50 MW 4-hour Storage
- 100 MW 4-hour Storage
- 100 MW 8-hour Storage
- 100 MW 10-hour Non-Lithium-Ion Storage

New Option:

- **100 MW 100-hour Non-Lithium-Ion Storage**
  - Added following stakeholder feedback
  - Representative of Iron-Air technology

Metric	100-hour Non-Lithium-Ion Storage
Installed Capacity (MW)	100
Duration (hours)	100
Assumed Operational Life (years)	15
Round Trip Efficiency (%)	34%

Portfolio Development Methodology
Step 4: Portfolio Development

- Portfolios are constructed to test alternative resource mixes and evaluate tradeoffs of various resource selections/decisions
- Portfolios are initially developed as:
  - **Scenario driven portfolios**: portfolios that align with different plausible futures
  - **Decision-driven portfolios**: develop targeted portfolios that evaluate different key decision pathways or include unique resource types
- Initial results are reviewed to identify trends and tradeoffs
- Additional portfolios are then developed to broaden the range of resource mixes and evaluate their performance

Preliminary Project Selections - Scenarios

Year	Reference Case	Alt High Reg	High Reg	Low Reg	Alt Reference Case
Load Level	Base	↑↑	↓	↑	↑↑↑
2025	+1 AB Brown 5 & 6 Gas Turbine (464 MW) +1 Posey Solar (191 MW) +1 Salt Creek Wind(170 MW)				
2026	+1 Wheatland Solar (150 MW) +1 Galesburg Wind (147 MW) + EE & DR 61 MW*				
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+2 200 MW Wind (400 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)
2031			+1 200 MW Wind (200 MW)		
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV + Storage (150 MW) +2 100 MW Solar PV (200 MW) +2 200 MW Wind (400 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW) +1 200 MW Wind (200 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	+1 2x1 J Class Fired CCGT (1474 MW)
2040				+1 100 MW 4 Hour Storage (100 MW)	
2043			+1 Non IRA Solar PV + Storage (150 MW)		
2044	+1 Non IRA Solar PV + Storage (150 MW)				
2045		+1 Non IRA Wind (200 MW)			+1 FB Culley:3 thru 2045 (270 MW) +1 J Class SCGT (437 MW) +1 Non IRA Wind + Storage (300 MW)

*Full list of the EE & DR programs is included in the Appendix.

Q&A

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 3

On break – we will return at 12:30 CDT

Draft Deterministic Portfolio Results

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

Deterministic Modeling Approach

- Stress test of one critical decision at a time, including F.B. Culley 2 and 3 alternative options
- Review the results for how the model responds:
  - Influence of the selection of other resources
  - Portfolio NPV impacts
- Results are used to inform final portfolio selections

Deterministic Runs – F.B. Culley 2

	Aeroderivative	No Replacement	Reciprocating Engine	Storage
2028	+1 FBC2 Aero (114 MW)	1 FB Culley:2 Interconnect Expires	+1 FBC2 Recip Engines (92.0 MW)	+1 FBC2 Storage (90 MW)
2029				
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)
2031				
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 100 MW 4 Hour Storage (100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2033				
2034				
2035				
2038				
2041				
2042				
2043				
2044	+1 Aeroderivative (57 MW)		+1 Aeroderivative (57 MW)	
2045				

- F.B. Culley 2 resource online by 12/31/2028 to comply with MISO interconnect re-use policy
- Storage portfolio is lower cost
  - Utilizing the interconnection for F.B. Culley 2 for storage is lower cost than all alternatives, including allowing the interconnection rights to expire
- Storage selected no matter what F.B. Culley 3 or A.B. Brown decision occurs

Deterministic Runs – F.B. Culley 3

	Retire 2032	*Retire 2035*	Co-Fire 2030	Convert 2030	*Convert 2035*	*Coal Thru 2045*
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2029						
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)		+1 FB Culley:3 Co-Fire 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Unfired CCGT 2030 (750 MW)	1 ABB5/6 Continue
2031						
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	+1 100 MW 4 Hour Storage (100 MW)				+2 100 MW 4 Hour Storage (200 MW) +1 200 MW Wind (200 MW)
2033						
2034						
2035		-1 FB Culley:3 Retire 2035 (-270 MW) +1 AB Brown7: Fired CCGT 2035 (912 MW)			+1 FB Culley:3 NG 2035 (270 MW)	
2038			-1 FB Culley:3 Retire (270 MW)			
2041						
2042						+1 Aeroderivative (57 MW)
2043			+1 Aeroderivative (57 MW)			
2044						
2045						+1 FB Culley:3 thru 2045 (270 MW)

- Model generally favors F.B. Culley 3 retirement, but decision is heavily influenced by the path chosen at A.B. Brown 5 & 6
- *Green highlighted* F.B. Culley 3 options are not compliant with the environmental policy in the High Reg and Alt High Reg scenarios

Initial DSM Program Selection

- The EE/DR programs selected in at least 95% of the optimizations, and consistently showed benefits to the portfolio, were then locked in for initial portfolio testing.
- Additional stress testing of DSM program selection is planned as we continue fine-tuning portfolios. There's still opportunity for additional programs to be selected in the model moving forward.

Start Year	Demand Program	Program Description	Initial Selection Rate
2028	DR_CI BYOT (4 MW)	Commercial & Industrial Bring Your Own Thermostat	76%
2028	DR_CI TOU CPP (2 MW)	Commercial & Industrial Time of Use	90%
2028	**DR_Res TOU CPP (6 MW)**	**Residential Time of Use**	**95%**
2028	DR_Res EV (0.1 MW)	Residential Electric Vehicle Management	0%
2028	DR_Res Battery (0.1 MW)	Residential Battery Storage	0%
2028	CI_EV (<0.01 MW)	Commercial & Industrial Electric Vehicle Management	0%
2028	CI_Battery (0.01 MW)	Commercial & Industrial Battery Storage	0%
2028	DR_CI WH Grid (3 MW)	Commercial & Industrial Grid-Enabled Water Heater	19%
2028	DR_Res BYOT (19 MW)	Residential Bring Your Own Thermostat	5%
2028	DR_Res_Smart Cycle	Residential Smart Cycle	0%
2028	DR_Res WH Grid	Residential Grid Enabled Water Heater	0%
2028	**DR_Res AC Switch**	**Residential AC Switch**	**All In**
2028	**DR_Res WH Switch**	**Residential Water Heater Switch**	**All In**
2028, 2031, 2034	**EE_CI_ERAP_V1, V2, V3**	**Commercial & Industrial Enhanced Realistic Achievable Potential**	**90 – 100%**
2028, 2031, 2034	**EE_Res_Tier 1_HER_V1, V2, V3**	**Residential Tier 1 & Home Efficiency Rebates**	**95 – 100%**
2028, 2031, 2034	EE_Res_Tier2_V1 , V2 , V3	Residential Tier 2	5%
2028, 2031, 2034	**EE_IQ_HEAR_V1, V2, V3**	**Income Qualified Home Electrification and Appliance Rebates**	**All In**
2028, 2031, 2034	**EE_IQW_V1 , V2 , V3**	**Income Qualified Weatherization**	**All In**

Bolded programs are those that are locked in the initial portfolios.

Q&A

Portfolios Discussion

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

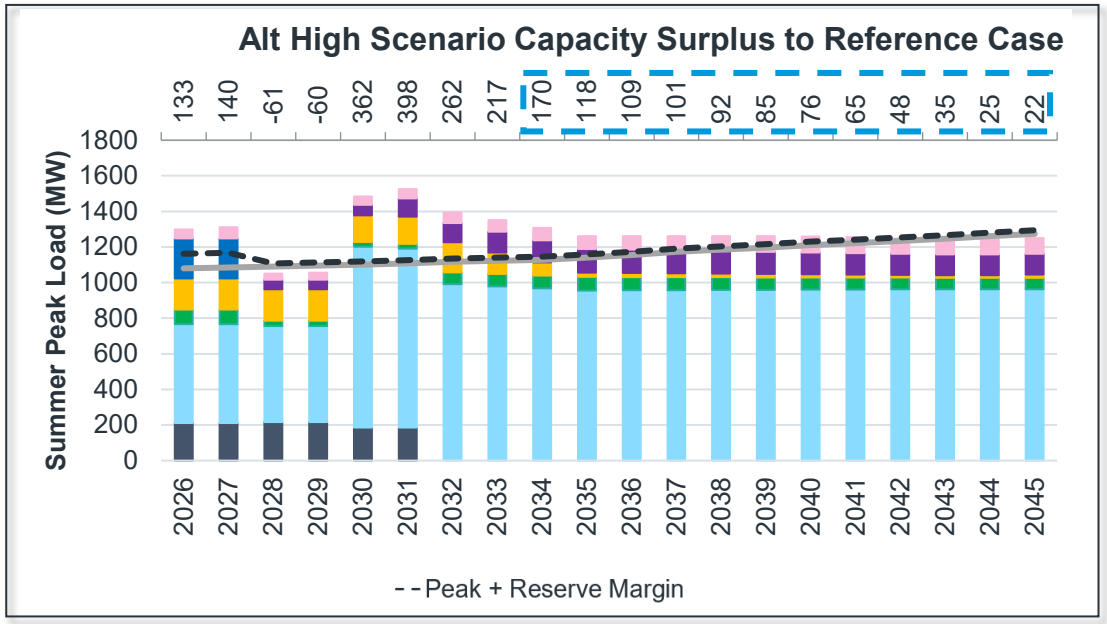
Portfolio Development Methodology
Step 4: Portfolio Development

- Portfolios are constructed to test alternative resource mixes and evaluate tradeoffs of various resource selections/decisions
- Portfolios are initially developed as:
  - **Scenario driven portfolios**: portfolios that align with different plausible futures
  - **Decision-driven portfolios**: develop targeted portfolios that evaluate different key decision pathways or include unique resource types
- Initial results are reviewed to identify trends and tradeoffs
- Additional portfolios are then developed to broaden the range of resource mixes and evaluate their performance. These portfolios each evaluate how a key decisions or decisions affect net present value and other scorecard metrics.

Modification of Scenario Portfolios to Align with Reference Case Load

Load Level	Alt High Reg ↑↑
2025	+1 AB Brown 5 & 6 Gas Turbine (464 MW) +1 Posey Solar (191 MW) +1 Salt Creek (170 MW)
2026	+1 Wheatland Solar (150 MW) +1 Galesburg Wind (147 MW)
2028	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)
2031	
2032	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV + Storage (150 MW) +2 100 MW Solar PV (200 MW) +2 200 MW Wind (400 MW)
2040	
2043	
2044	
2045	+1 Non IRA Wind (200 MW)

Scenario portfolios were adjusted to meet reference case load to avoid overbuilding/underbuilding and have a fair NPV comparison.



Modified Alt High Reg ↑↑
+1 AB Brown 5 & 6 Gas Turbine (464 MW) +1 Posey Solar (191 MW) +1 Salt Creek (170 MW)
+1 Wheatland Solar (150 MW) +1 Galesburg Wind (147 MW)
+1 FBC2 Storage (90 MW)
+1 AB Brown7: Fired CCGT 2030 (912 MW)
+1 Solar PV + Storage (150 MW)
-1 FB Culley:3 Retire 2032 (-270 MW) +**1** 100 MW Solar PV (**100 MW**) +**1** 200 MW Wind (**200 MW**)
~~+1 Non IRA Wind (200 MW)~~

Draft Portfolios

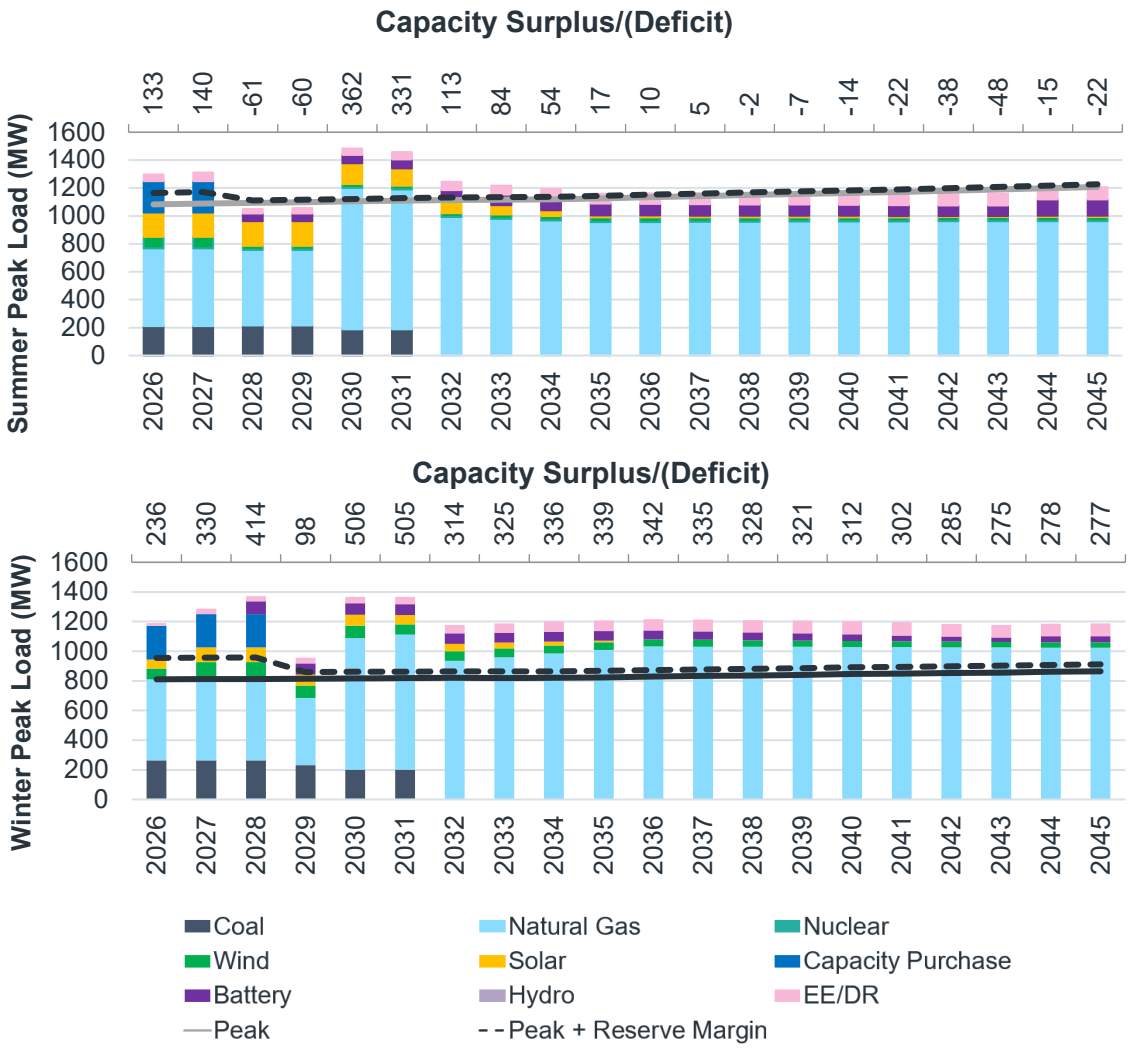
Year	Portfolio1: Reference Case Portfolio	Portfolio2: FBC3 NG Flexibility on NG 2035	Portfolio3: FBC3 on Coal without ABB7	Portfolio4: FBC3 on Coal to SMR	Portfolio5: FBC3 to Simple Cycle Gas Turbine	Portfolio6: Renewable Heavy Portfolio	Portfolio7: FBC3 Gas Conversion with Renewables	Portfolio8: Low Reg Approach	Portfolio9: High Reg Approach	Portfolio10: Alt High Reg Approach	Portfolio11: FBC3 Co-Fire 2030	Portfolio12: Delayed Reference Case
2025	+1 AB Brown 5 & 6 Gas Turbine (464 MW) ; +1 Posey Solar (191 MW) ; +1 Future Wind 1 Project (Salt Creek, 170 MW)											
2026	+1 Wheatland Solar (150 MW) ; +1 Galesburg Wind (147 MW)											
2028	+1 FBC2 Storage (90 MW)											
2029									+1 100 MW 4 Hour Storage (100 MW)			
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)	1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (912 MW)	1 ABB5/6 Continue	1 ABB5/6 Continue	+1 FB Culley:3 NG 2030 (270 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+2 200 MW Wind (400 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 FB Culley:3 Co-Fire 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (912 MW)	
2031					+1 100 MW 4 Hour Storage (100 MW)	+1 100 MW 4 Hour Storage (100 MW)				+1 Non IRA Solar PV + Storage (150 MW)		
2032	-1 FB Culley:3 Retire 2032 (-270 MW)		+1 100 MW 4 Hour Storage (100 MW)			-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW)	+1 100 MW 4 Hour Storage (100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW) +1 Non IRA Wind (200 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind (200 MW) +1 Non IRA Solar (100 MW)		
2033			+1 100 MW 4 Hour Storage (100 MW)				+1 100 MW 4 Hour Storage (100 MW)					
2034												+1 AB Brown7: Fired CCGT 2034 (912 MW)
2035		+1 FB Culley:3 NG 2035 (270 MW)		-1 FB Culley:3 Retire 2035 (-270 MW) +1 Nuclear - SMR (100 MW)	-1 FB Culley:3 Retire 2035 (-270 MW) +1 J Class SCGT (437 MW)							-1 FB Culley:3 Retire 2035 (-270 MW)
2038						+1 Non IRA Wind (200 MW)					-1 FB Culley:3 Retire (270 MW)	
2039							+1 Non IRA Solar PV (100 MW)					
2040			+1 50 MW 4 Hour Storage (50 MW)				+1 Non IRA Wind (200 MW)	+1 100 MW 4 Hour Storage (100 MW)				
2041			+1 Non IRA Wind (200 MW)			+1 Non IRA Wind (200 MW)						
2043						+1 50 MW 4 Hour Storage (50 MW) +1 Non IRA Wind (200 MW)	+1 50 MW 4 Hour Storage (50 MW) +1 Non IRA Wind (200 MW)		+1 100 MW 4 Hour Storage (100 MW) +1 Non IRA Wind (200 MW)			
2044	+1 Non IRA Solar PV + Storage (150 MW)										+1 Non IRA Wind (200 MW)	+1 Non IRA Solar PV + Storage (150 MW)
2045			+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Wind (200 MW)		+1 Non IRA Wind (200 MW)	+1 Non IRA Wind (200 MW)	+2 Non IRA Wind (400 MW)					
Average Portfolio NPV ($000)	$4,099,174	$4,296,258	$4,326,738	$4,986,020	$4,565,149	$4,680,591	$4,731,170	$4,135,718	$4,466,083	$4,255,968	$4,286,442	$4,127,707
% Delta to Min	0.0%	4.8%	5.6%	21.6%	11.4%	14.2%	15.4%	0.9%	9.0%	3.8%	4.6%	0.7%

1- Reference Case

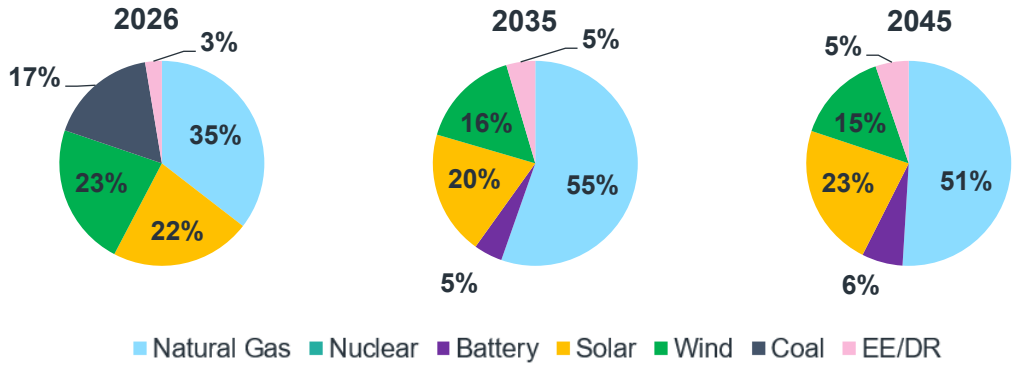
Model Selections:

FB Culley 3 Retire on 12/31/31
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Fired CCGT 01/01/30
1x Non-IRA Solar + Storage

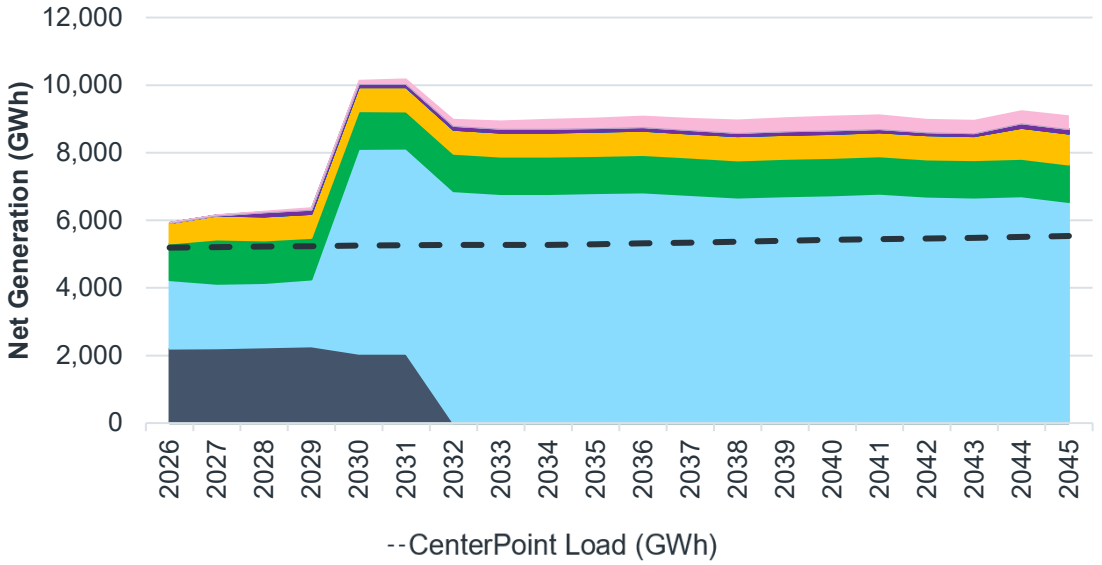
Balance of Load and Resources



Installed Capacity (MW)



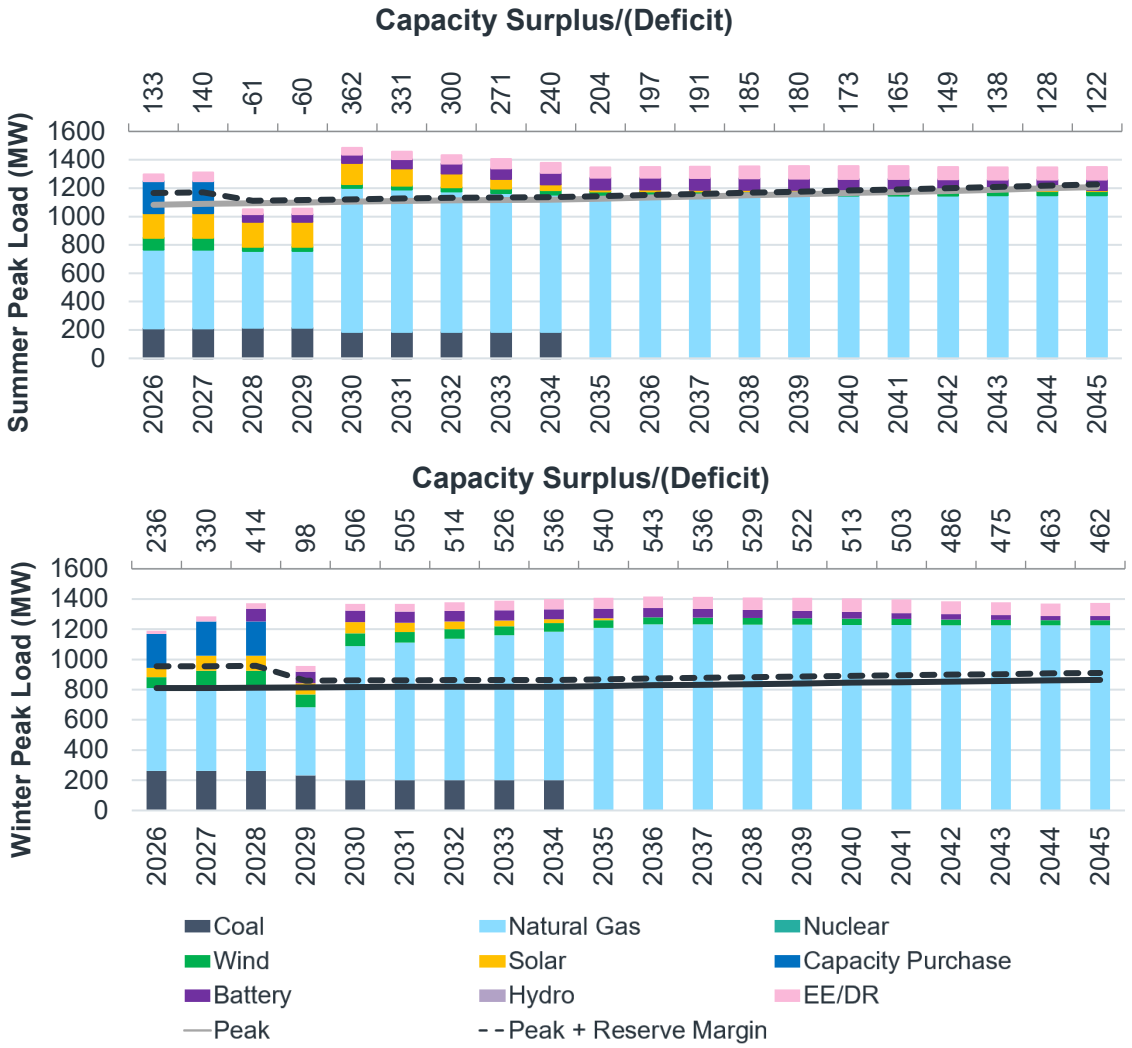
Generation (MWh)



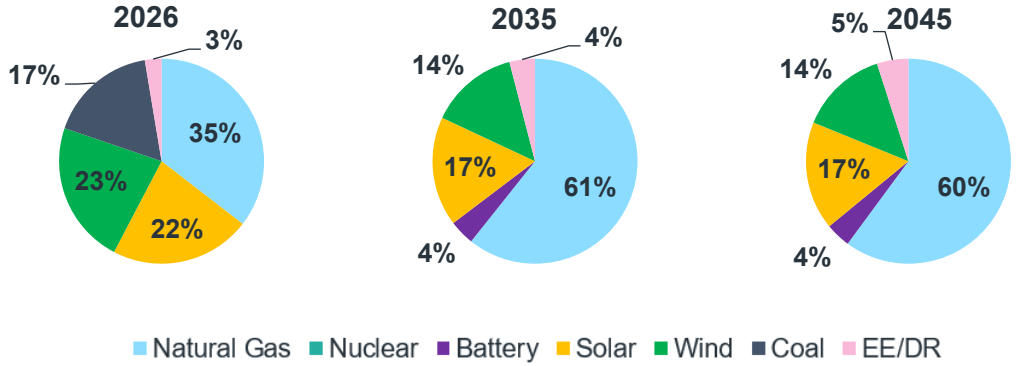
2 - FBC3 Flexibility on NG 2035

Model Selections:
FB Culley 3 Conversion on 01/01/35
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Fired CCGT 01/01/30

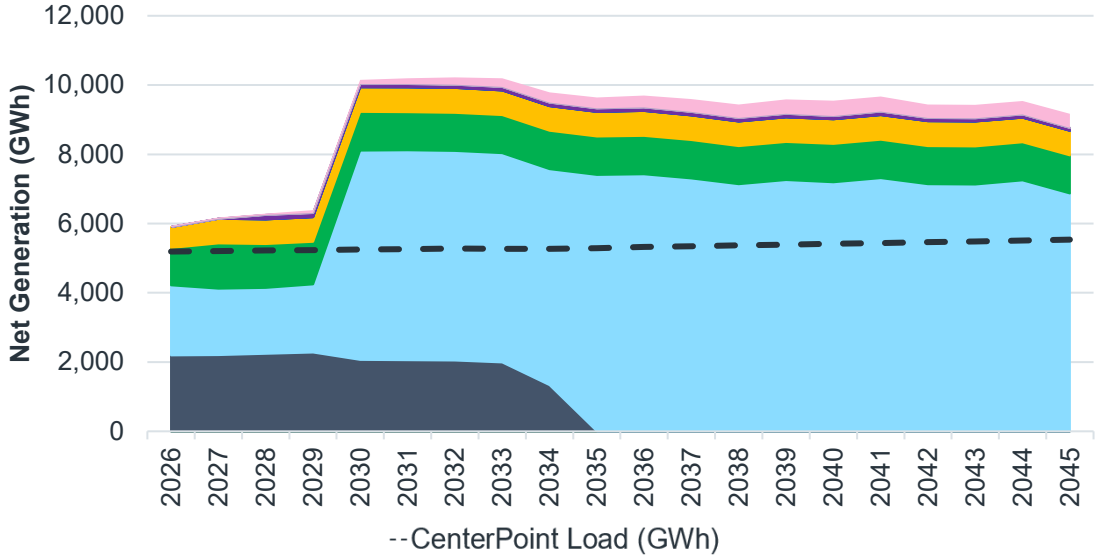
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)

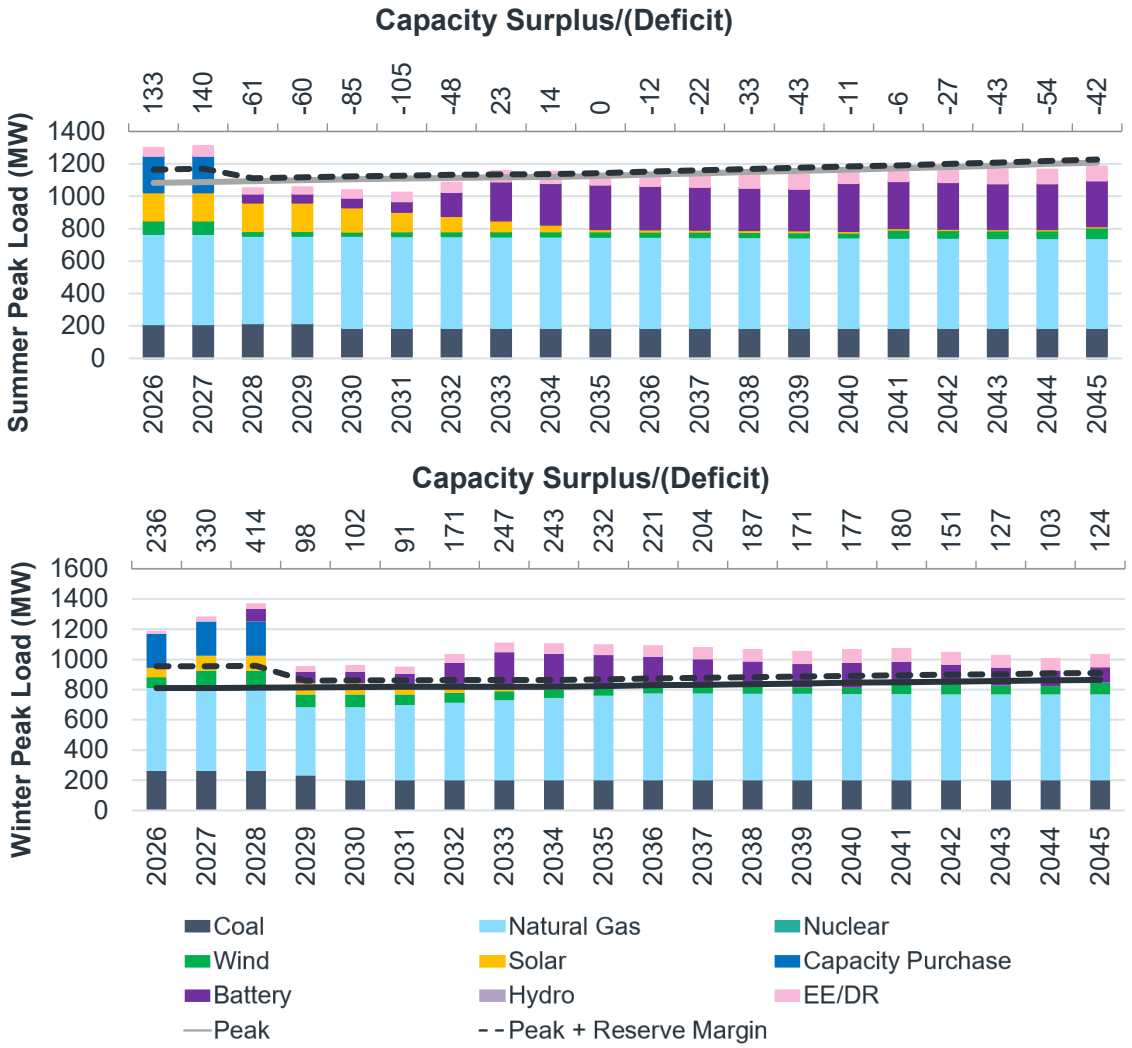


3 – FBC3 on Coal without ABB7

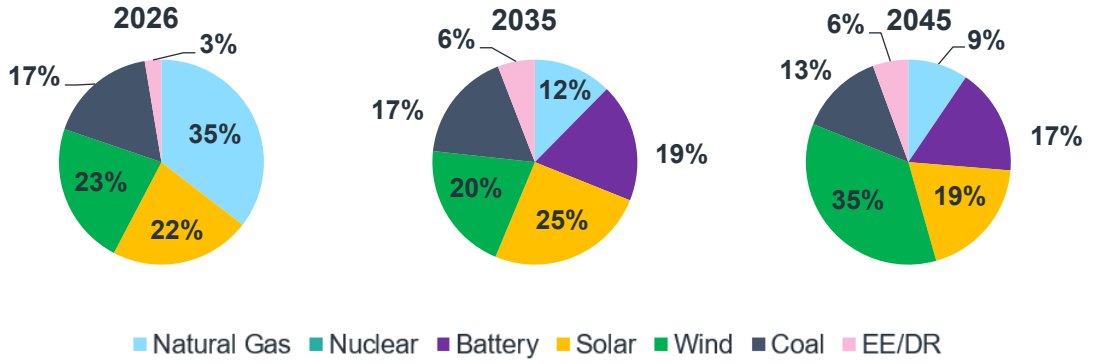
Model Selections:

FB Culley 3 BAU through 12/31/45
FB Culley 2 Start Storage 01/01/28
AB Brown BAU
2x 100 MW 4 Hour Storage
1x 50 MW 4 Hour Storage
2x Non-IRA Wind

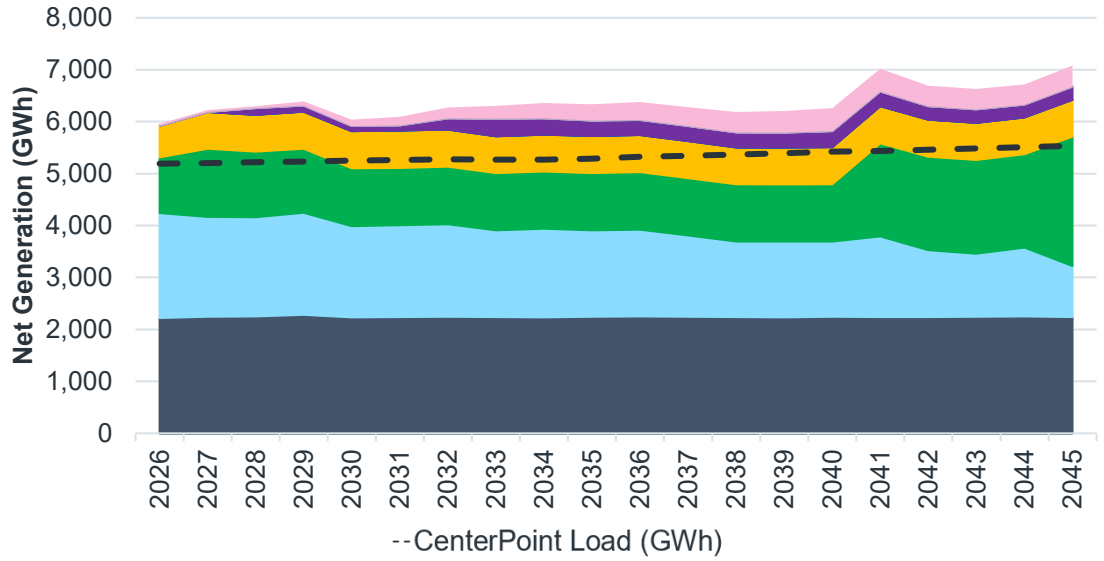
Balance of Load and Resources



Installed Capacity (MW)



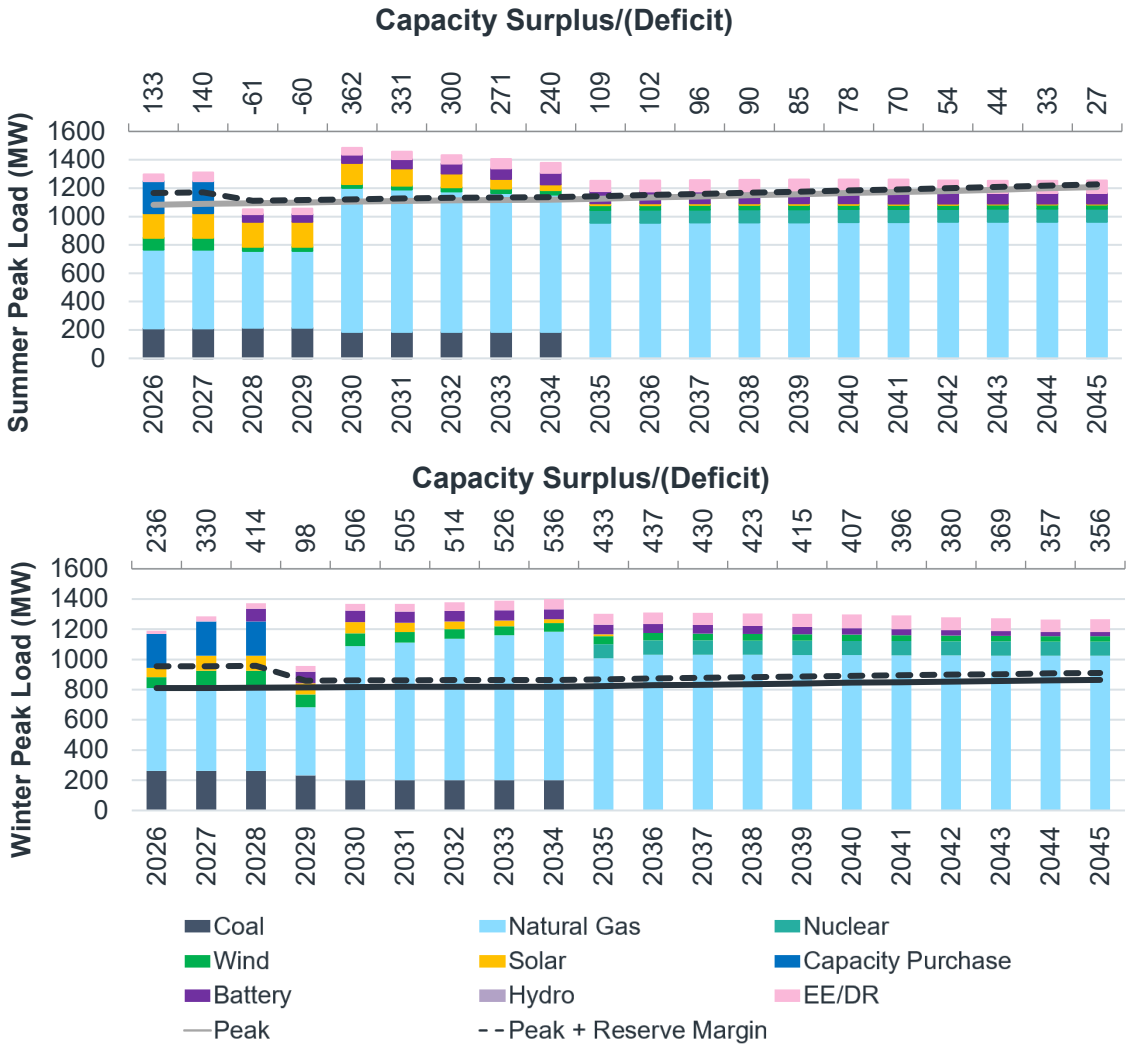
Generation (MWh)



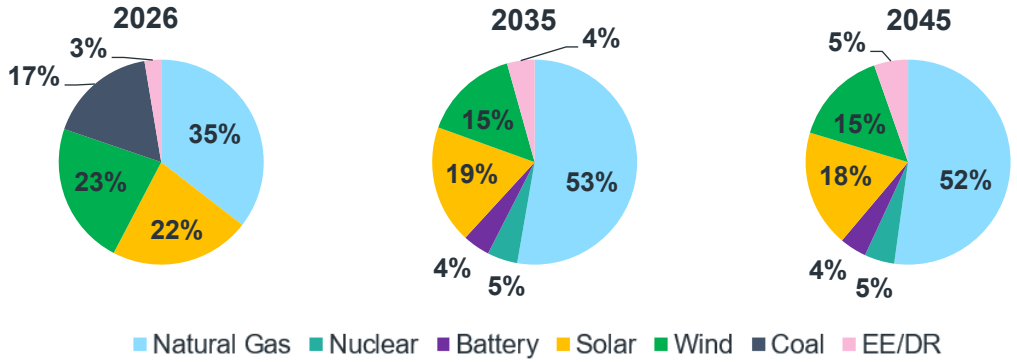
4 - FBC3 on Coal to SMR

Model Selections:
FB Culley 3 Retire on 12/31/34
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Fired CCGT 01/01/30
1x Nuclear – SMR

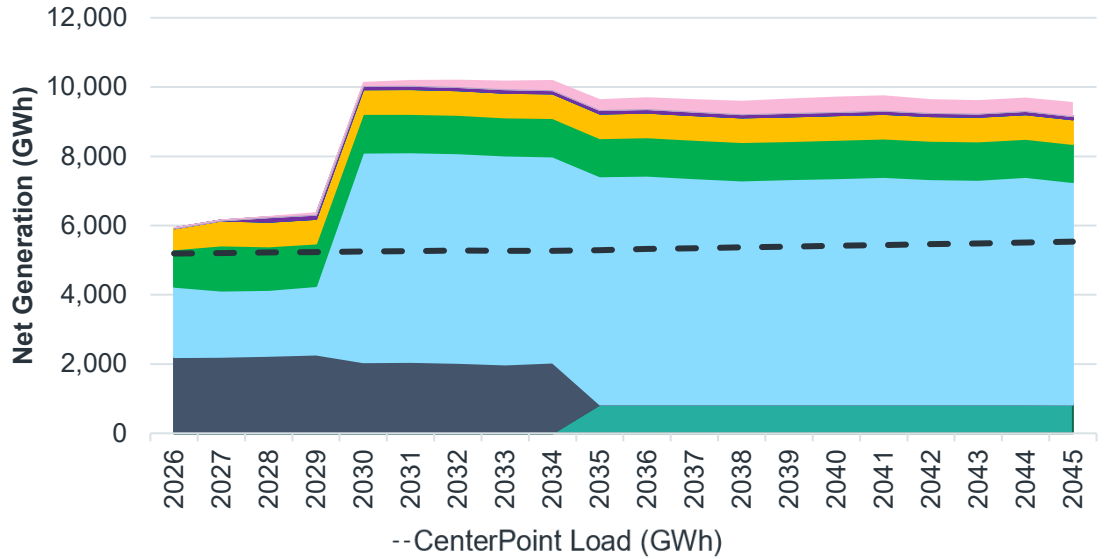
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)



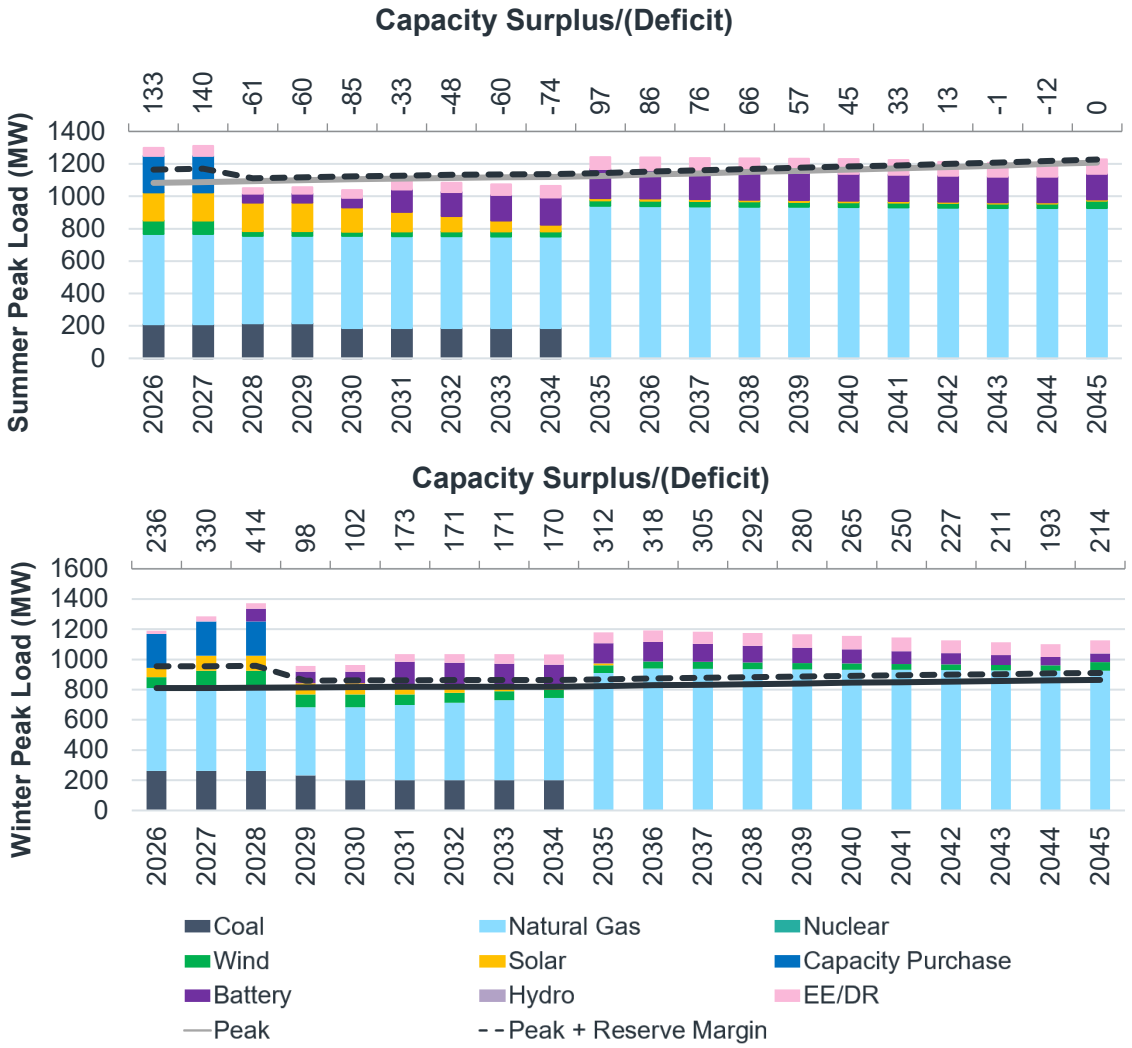
5 - FBC3 Simple Cycle Gas Turbine

Model Selections:

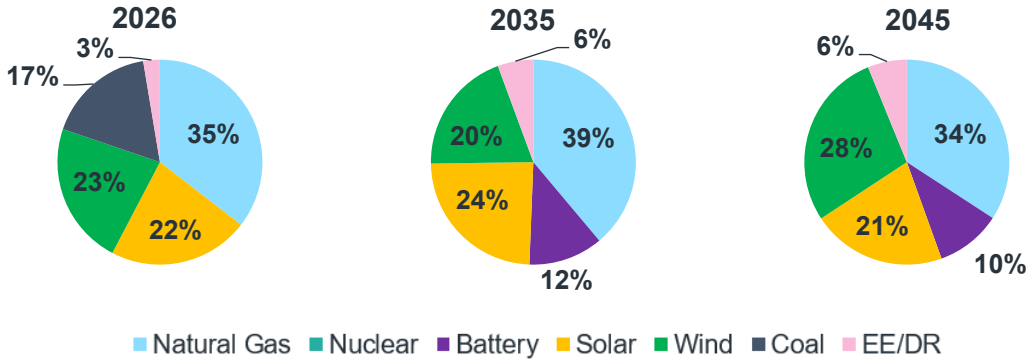
FB Culley 3 Retire on 12/31/34
FB Culley 2 Start Storage 01/01/28
AB Brown BAU
1x 100 MW 4 Hour Storage
1x J Class SCGT
1x Non-IRA Wind

CenterPoint Energy

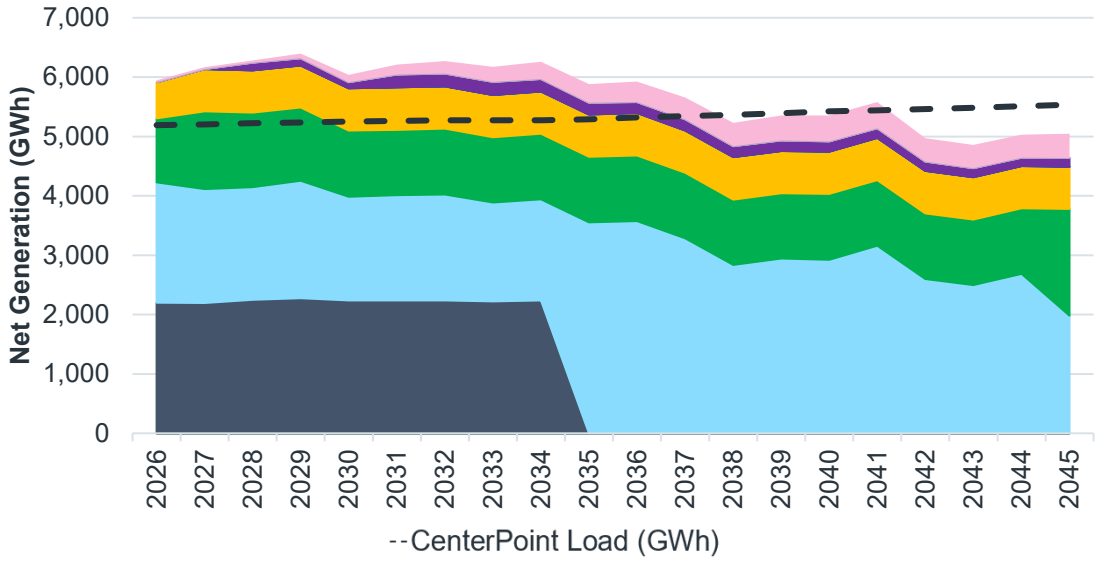
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)



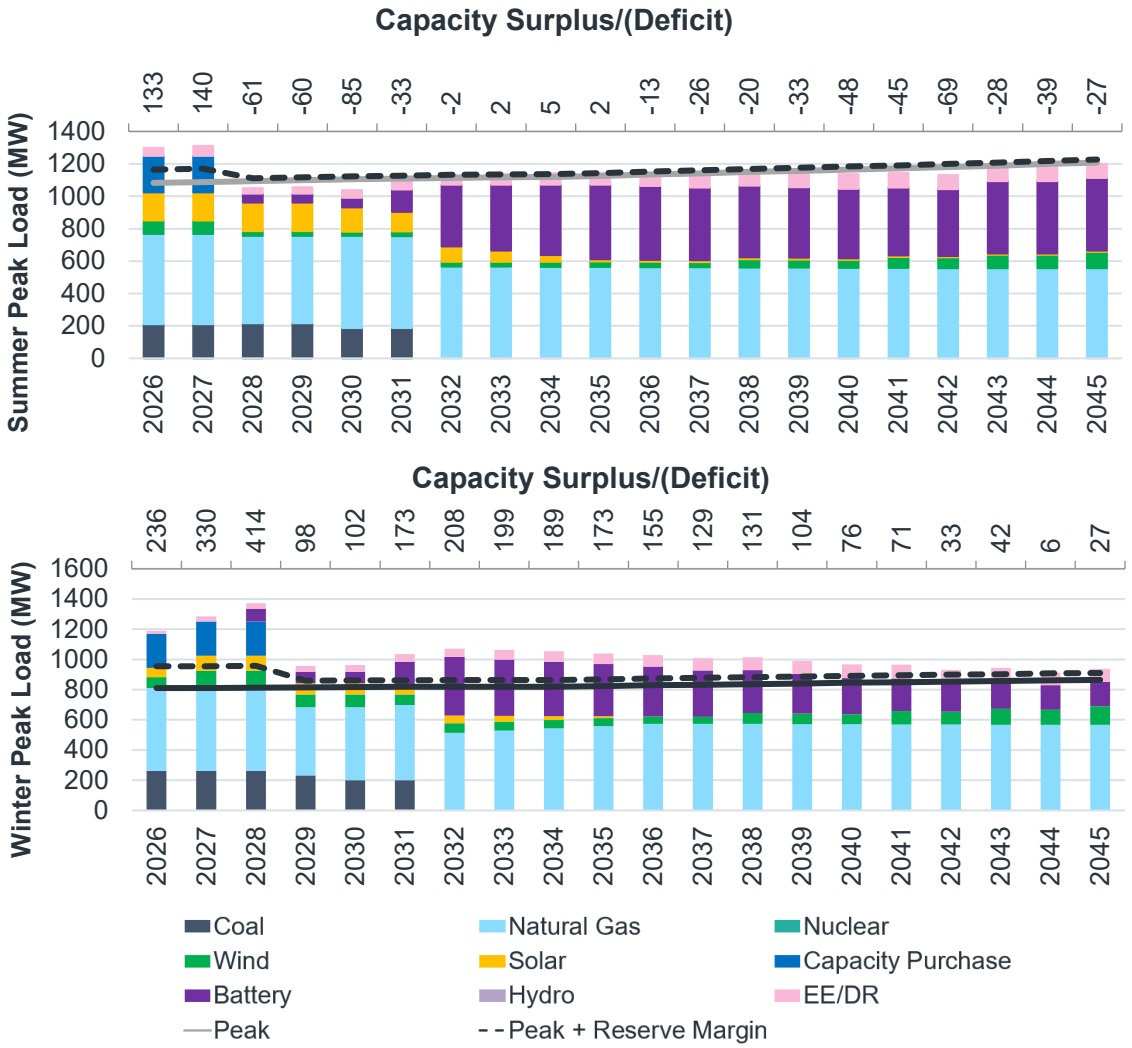
6 - Renewable Heavy Portfolio

Model Selections:

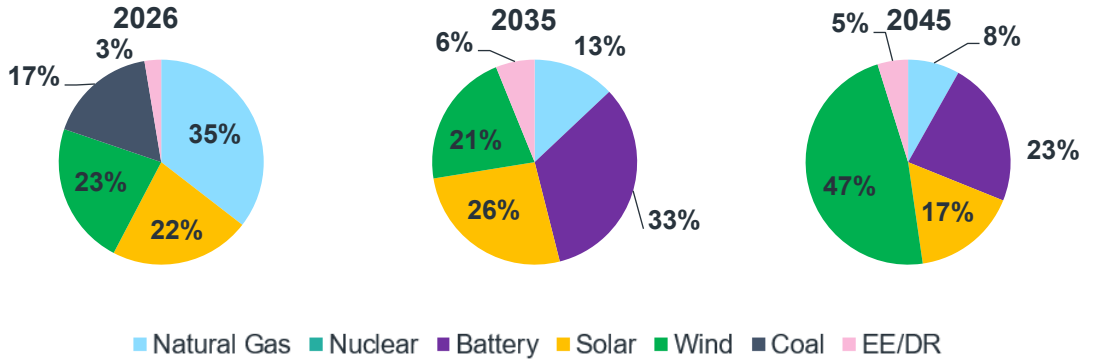
FB Culley 3 Retire on 12/31/31
FB Culley 2 Start Storage 01/01/28
AB Brown BAU
4x 100 MW 4 Hour Storage
4x Non-IRA Wind
1x 50 MW 4 Hour Storage

CenterPoint Energy

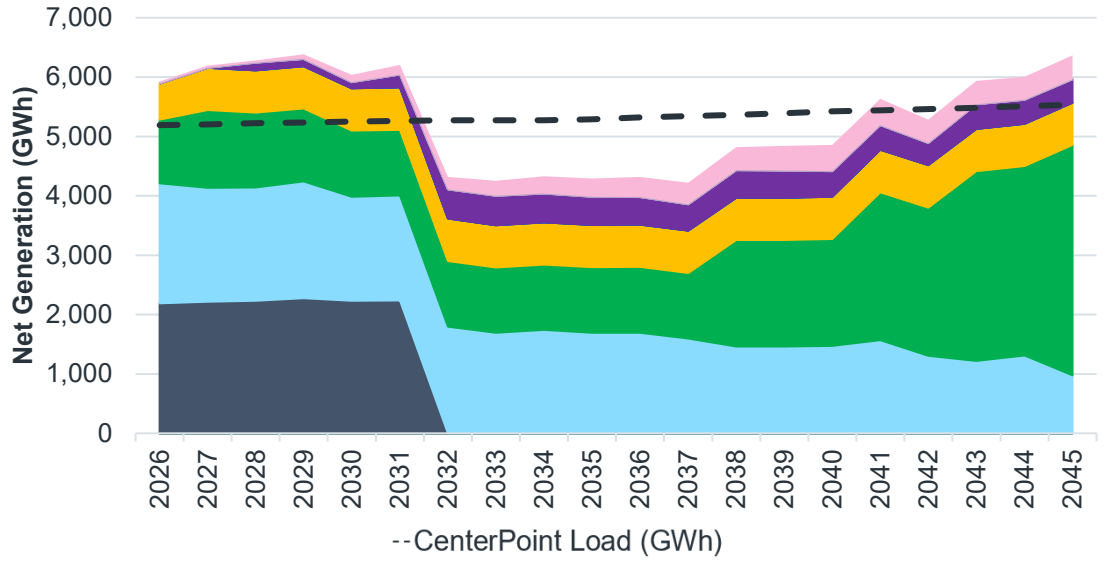
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)



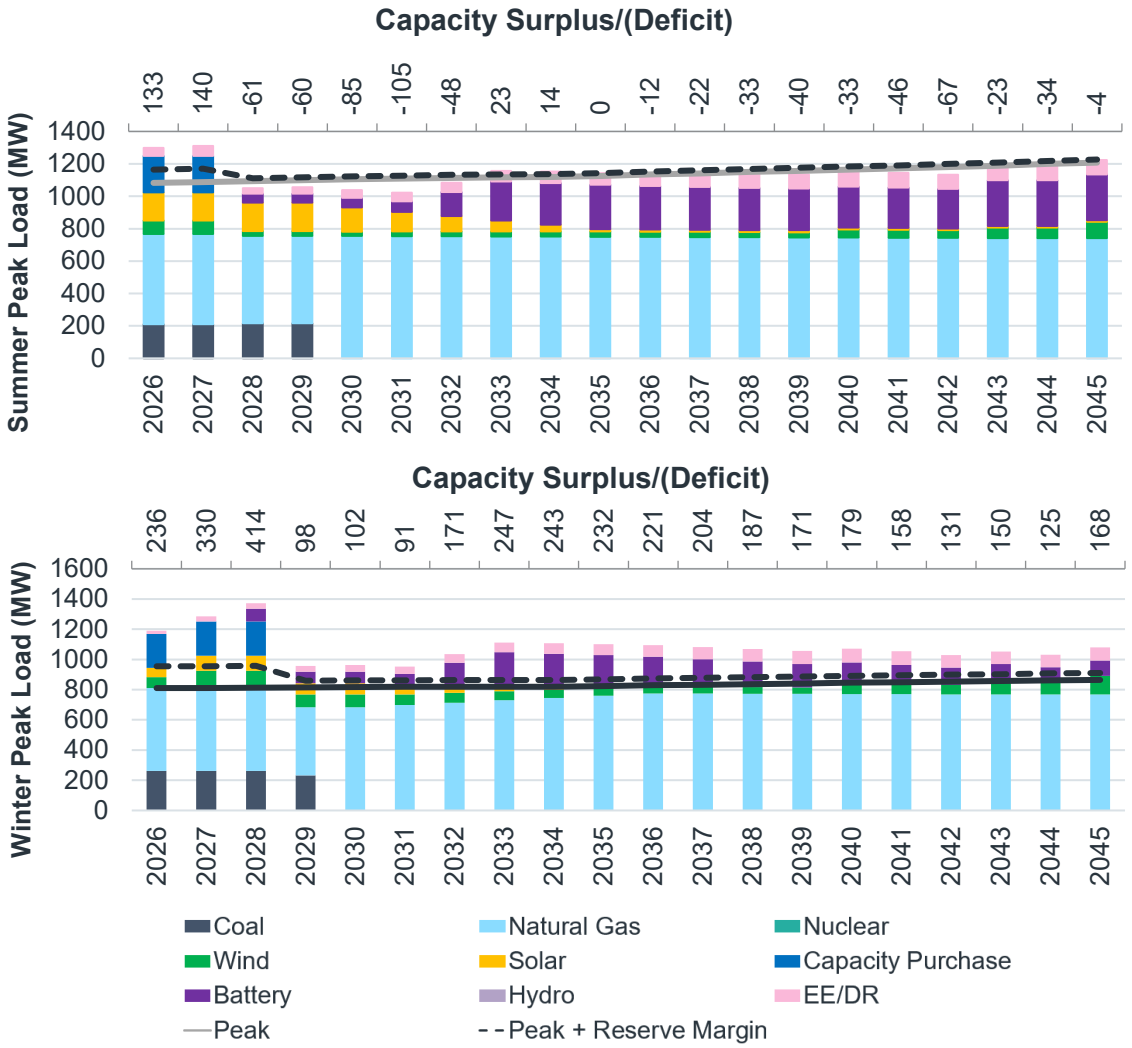
7 - FBC3 Gas Conversion with Renewables

Model Selections:

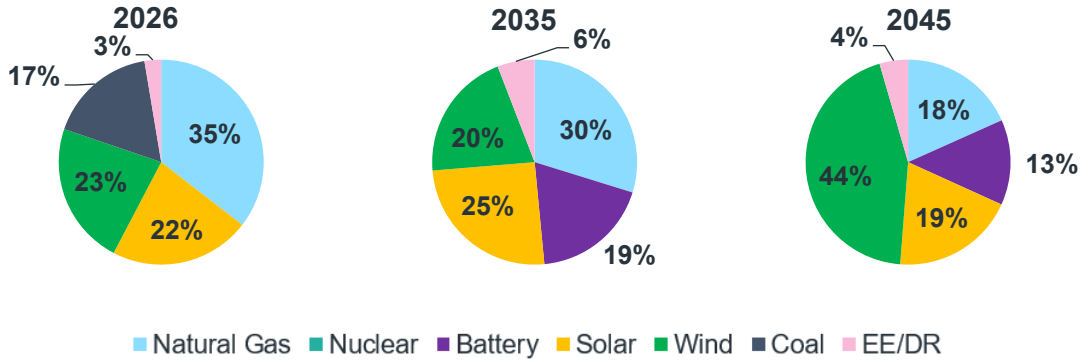
FB Culley 3 Conversion in 01/01/30
FB Culley 2 Start Storage 01/01/28
AB Brown BAU
1x Non-IRA Solar
2x 100 MW 4 Hour Storage
4x Non-IRA Wind
1x 50 MW 4 Hour Storage

CenterPoint Energy

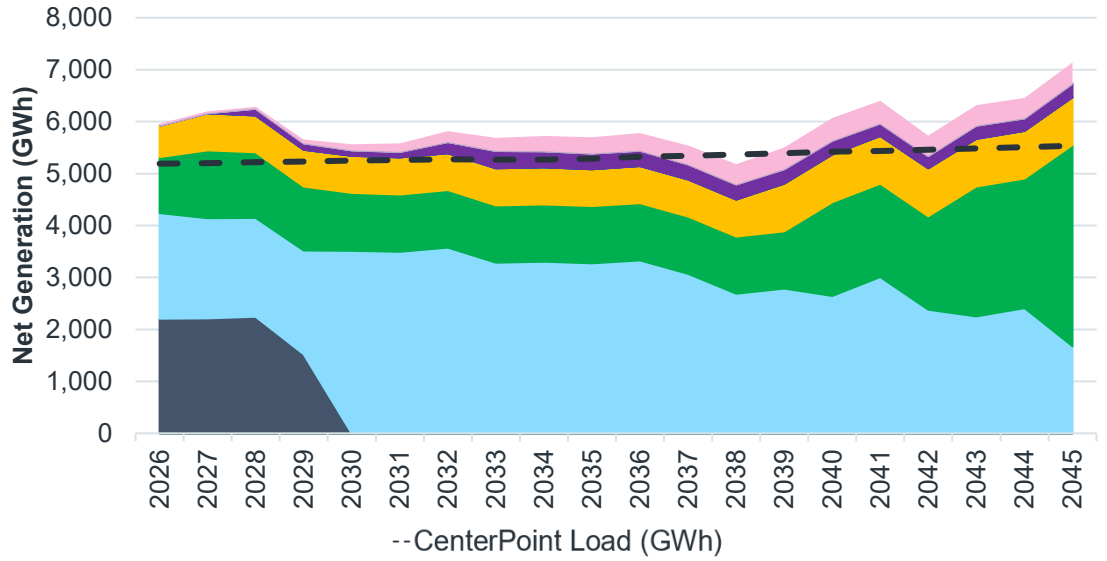
Balance of Load and Resources



Installed Capacity (MW)



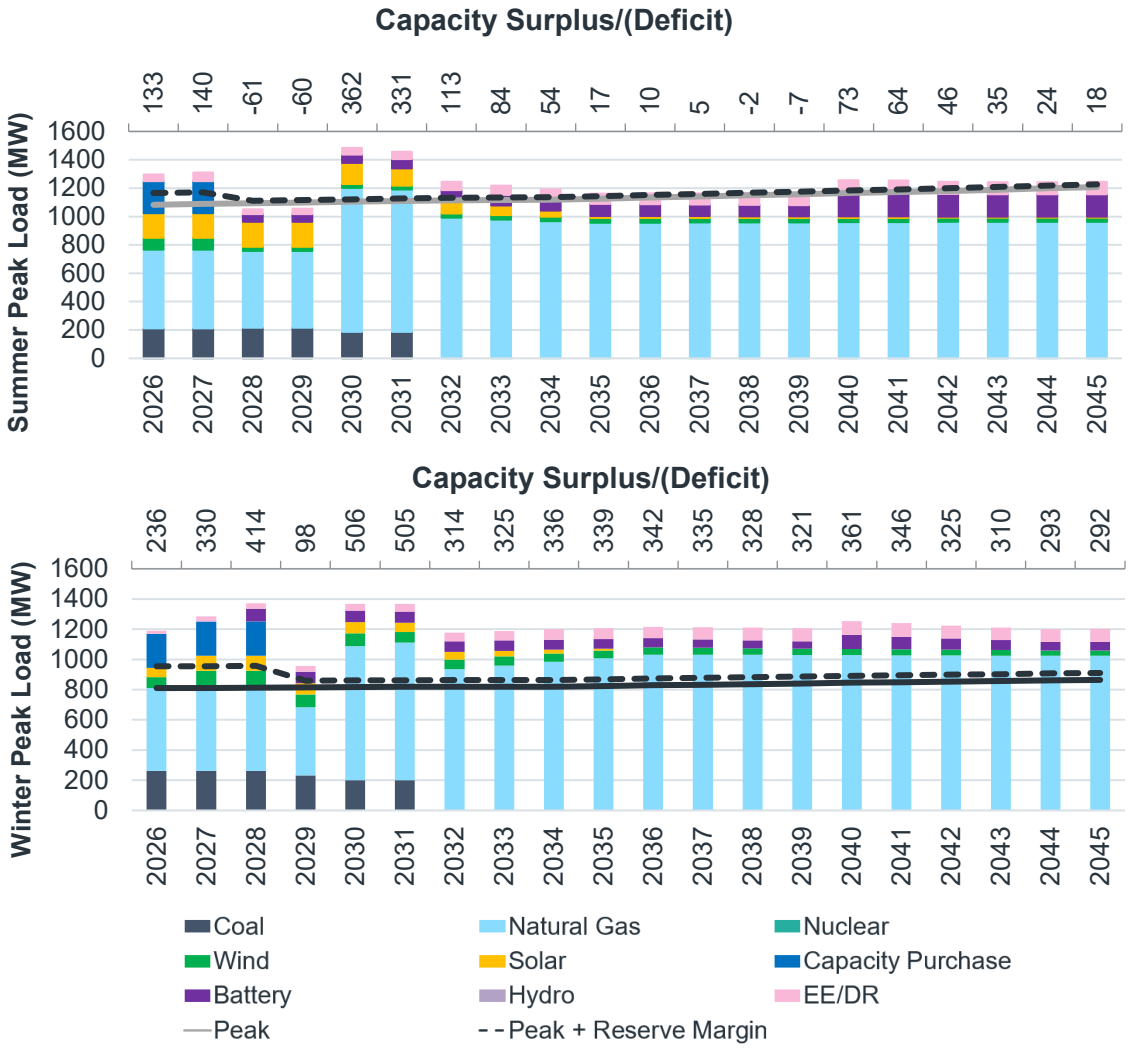
Generation (MWh)



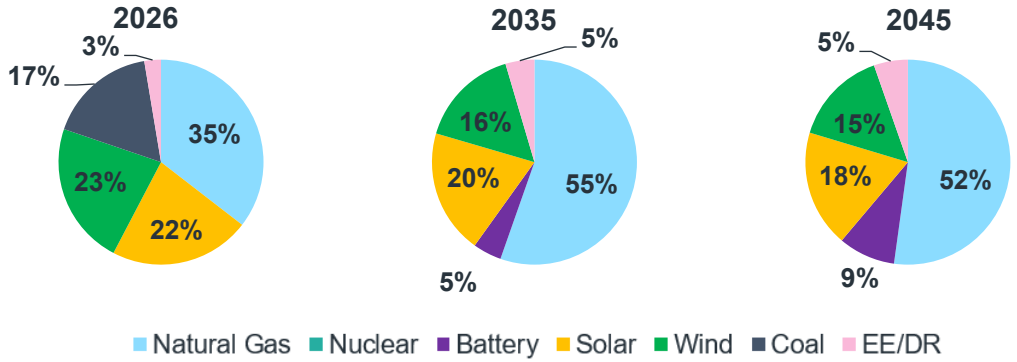
8 - Low Reg Approach

Model Selections:
FB Culley 3 Retire on 12/31/31
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Unfired CCGT 01/01/30
1x 100 MW Storage

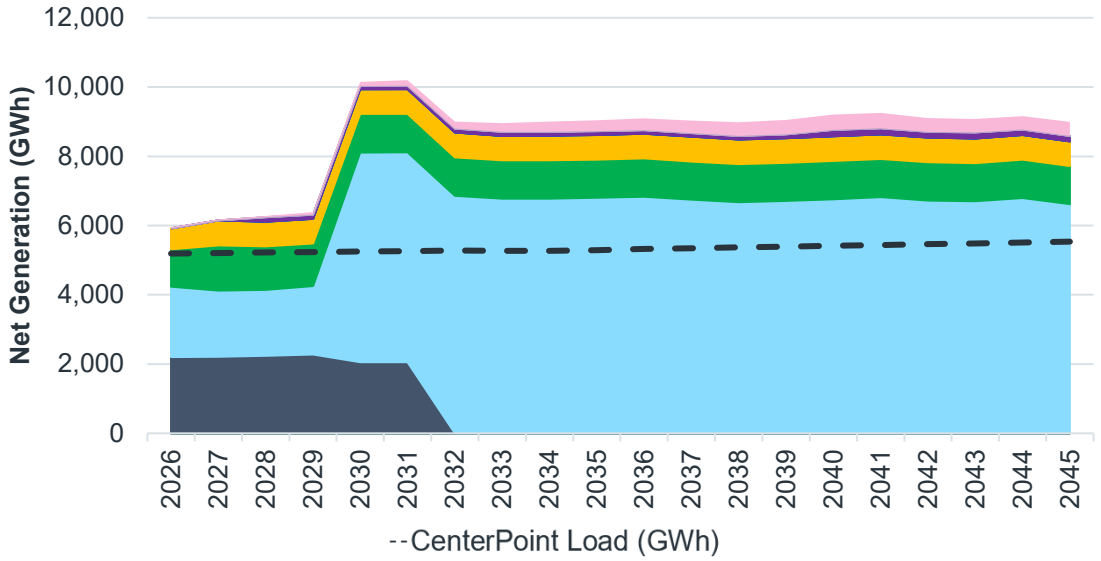
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)

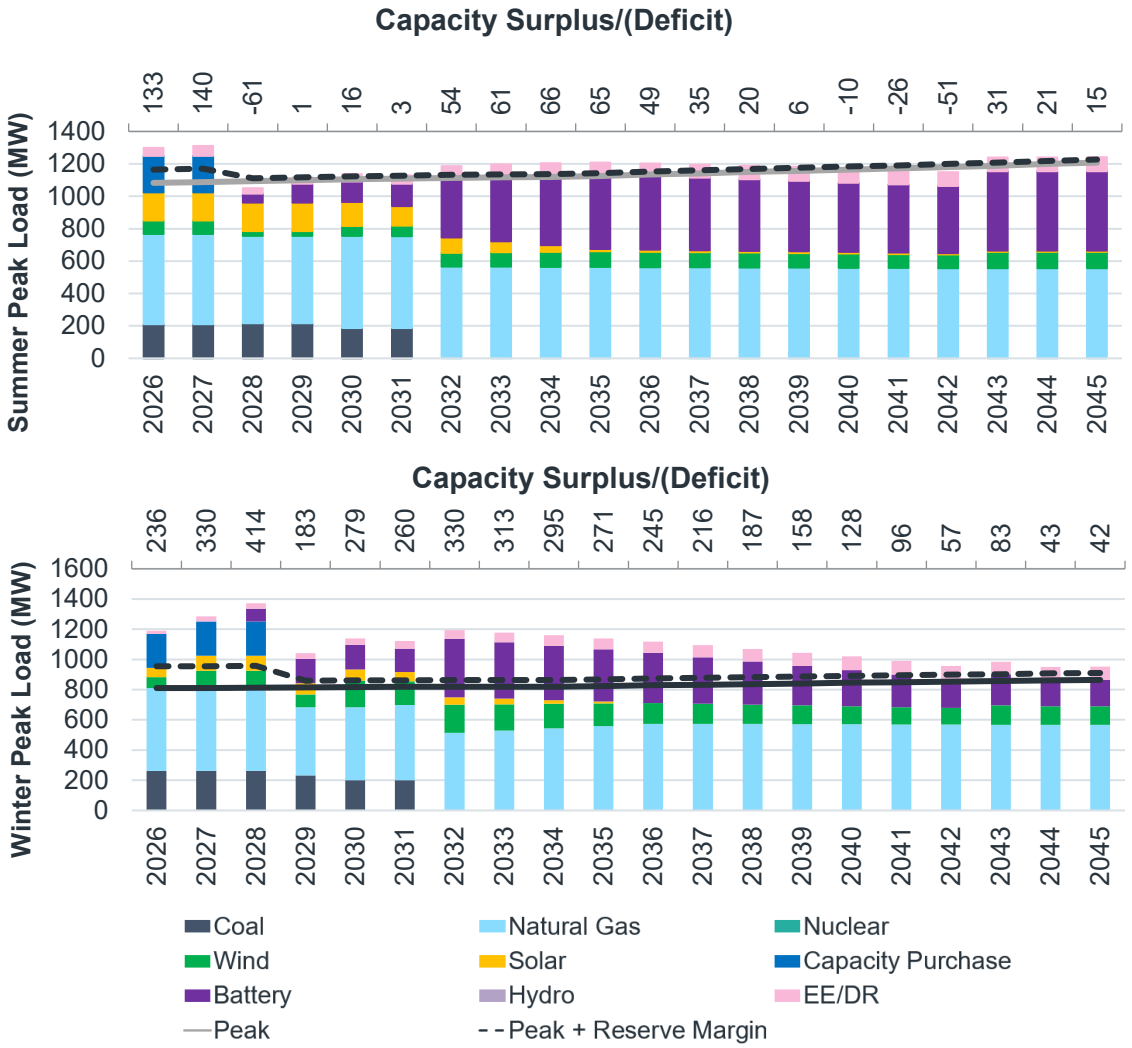


9 - High Reg Approach

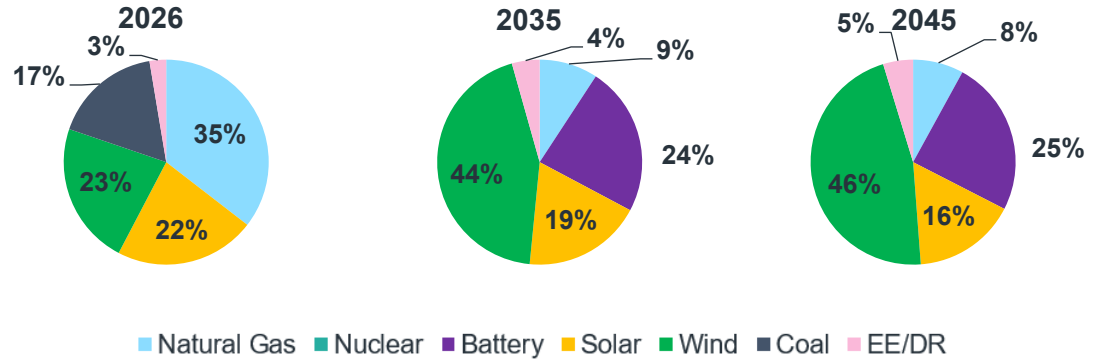
Model Selections:

FB Culley 3 Retire on 12/31/31
FB Culley 2 Start Storage 01/01/28
AB Brown BAU
5x 100 MW 4 Hour Storage
2x Non-IRA Wind
2x 200 MW Wind

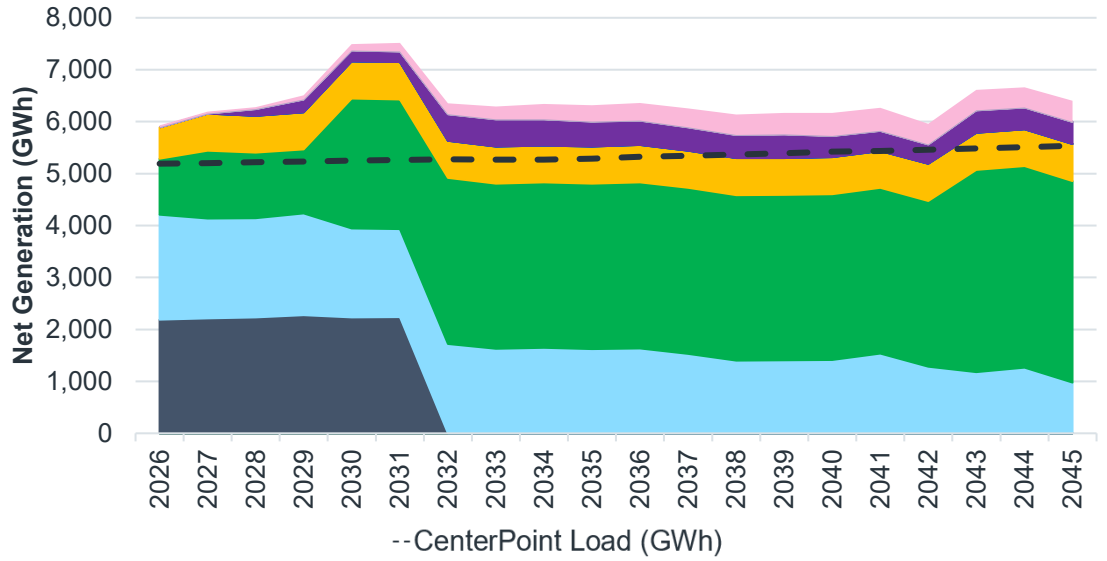
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)

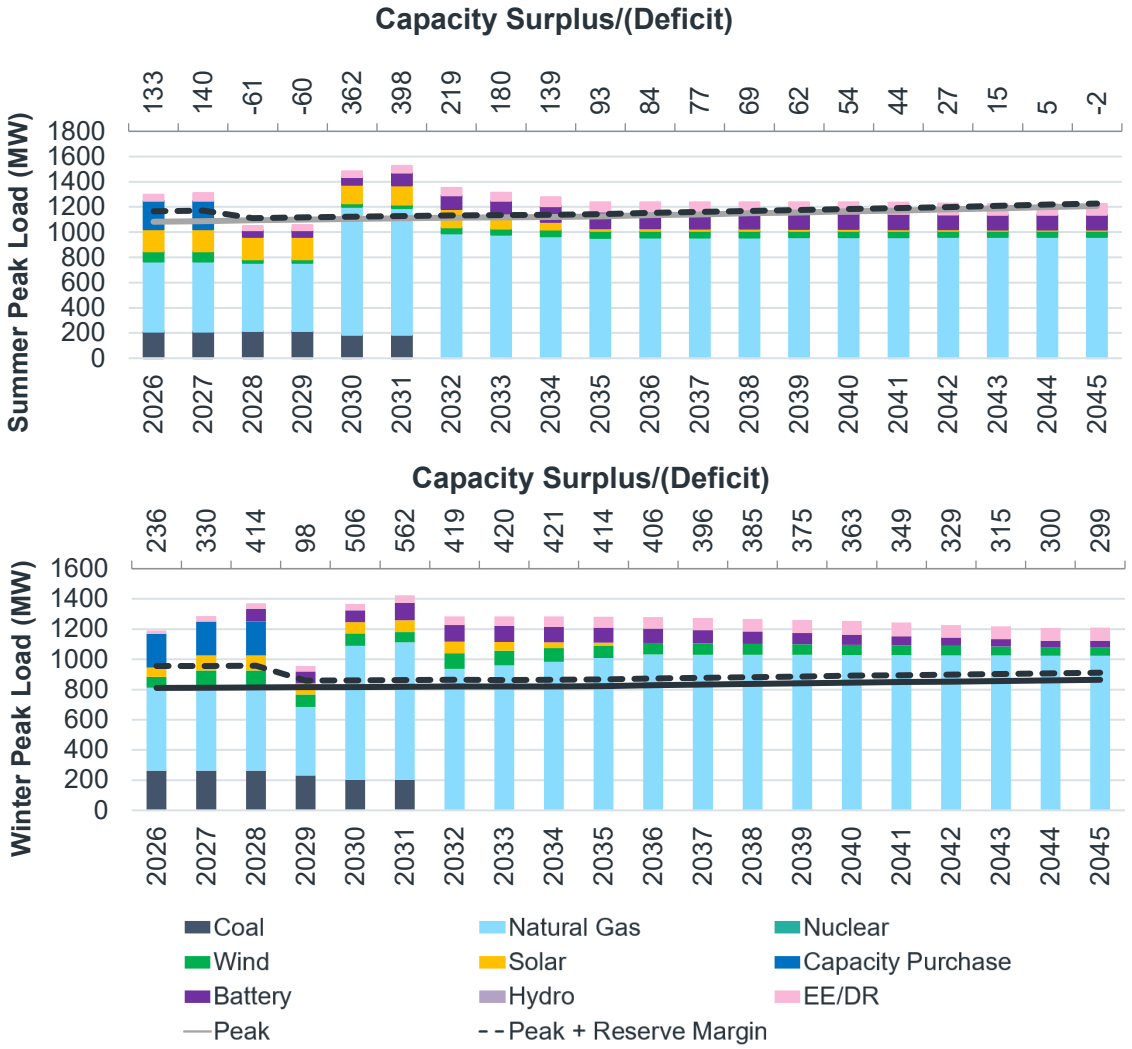


10 - Alt High Reg Approach

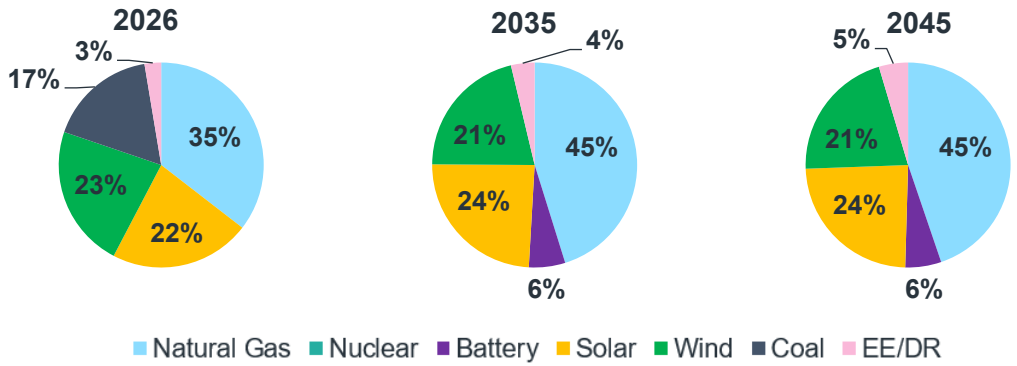
Model Selections:

FB Culley 3 Retire on 12/31/31
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Fired CCGT 01/01/30
1x Non-IRA Solar + Storage
1x Non-IRA Solar
1x Non-IRA Wind

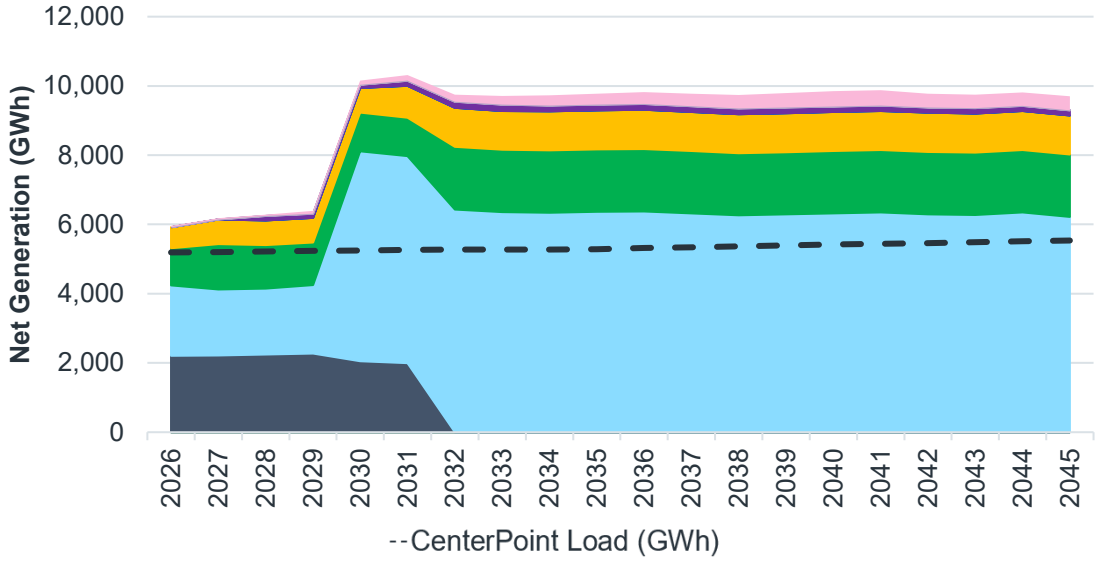
Balance of Load and Resources



Installed Capacity (MW)



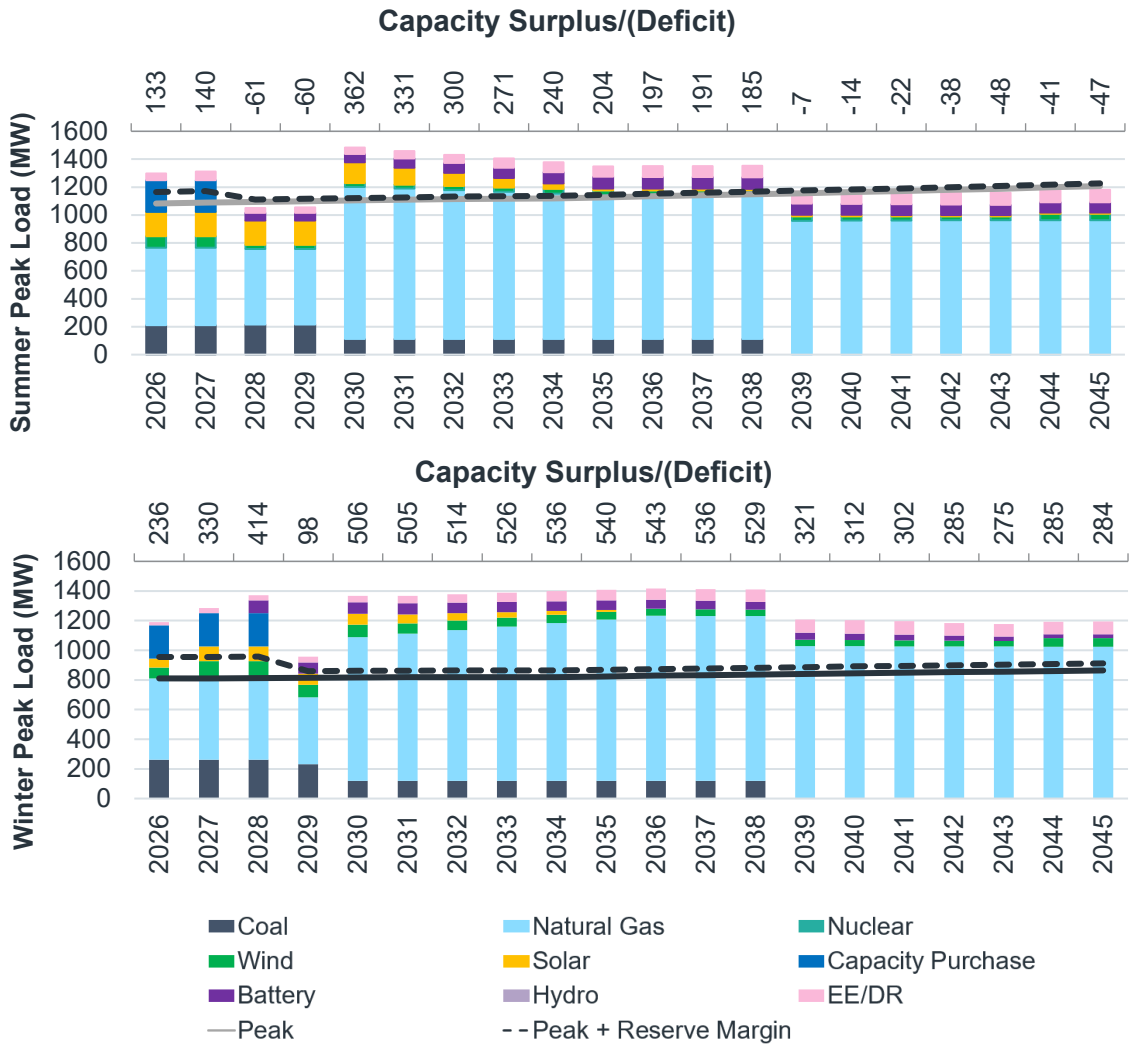
Generation (MWh)



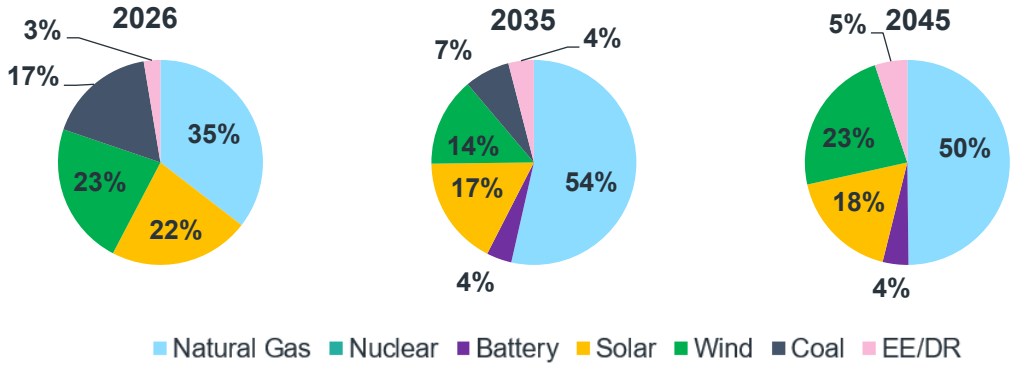
11 - FBC3 Co-Fire 2030

Model Selections:
FB Culley 3 Co-Fire on 01/01/30
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Fired CCGT 01/01/30
1x Non-IRA Wind

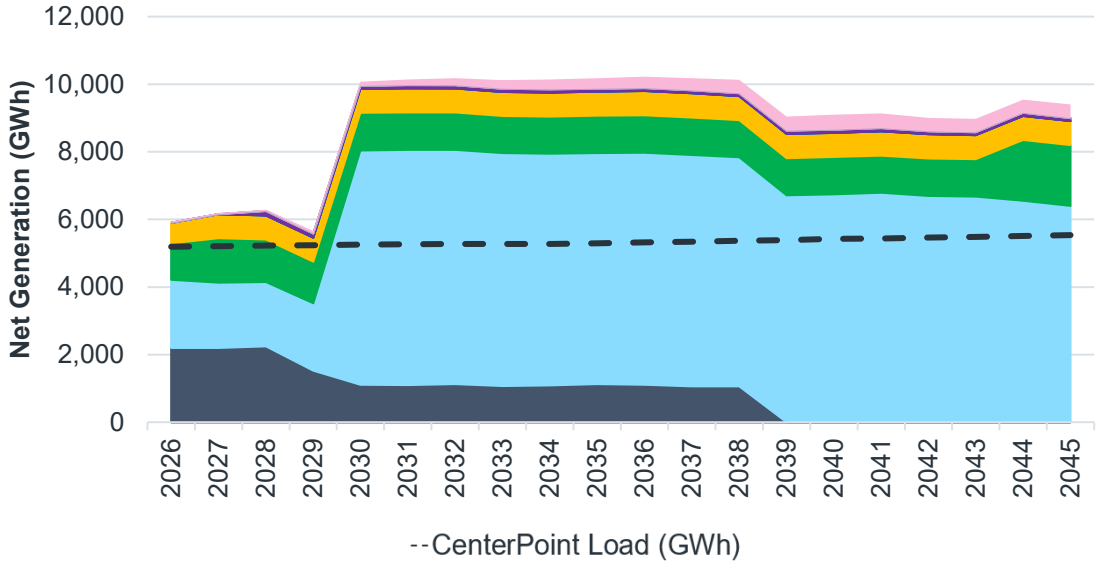
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)

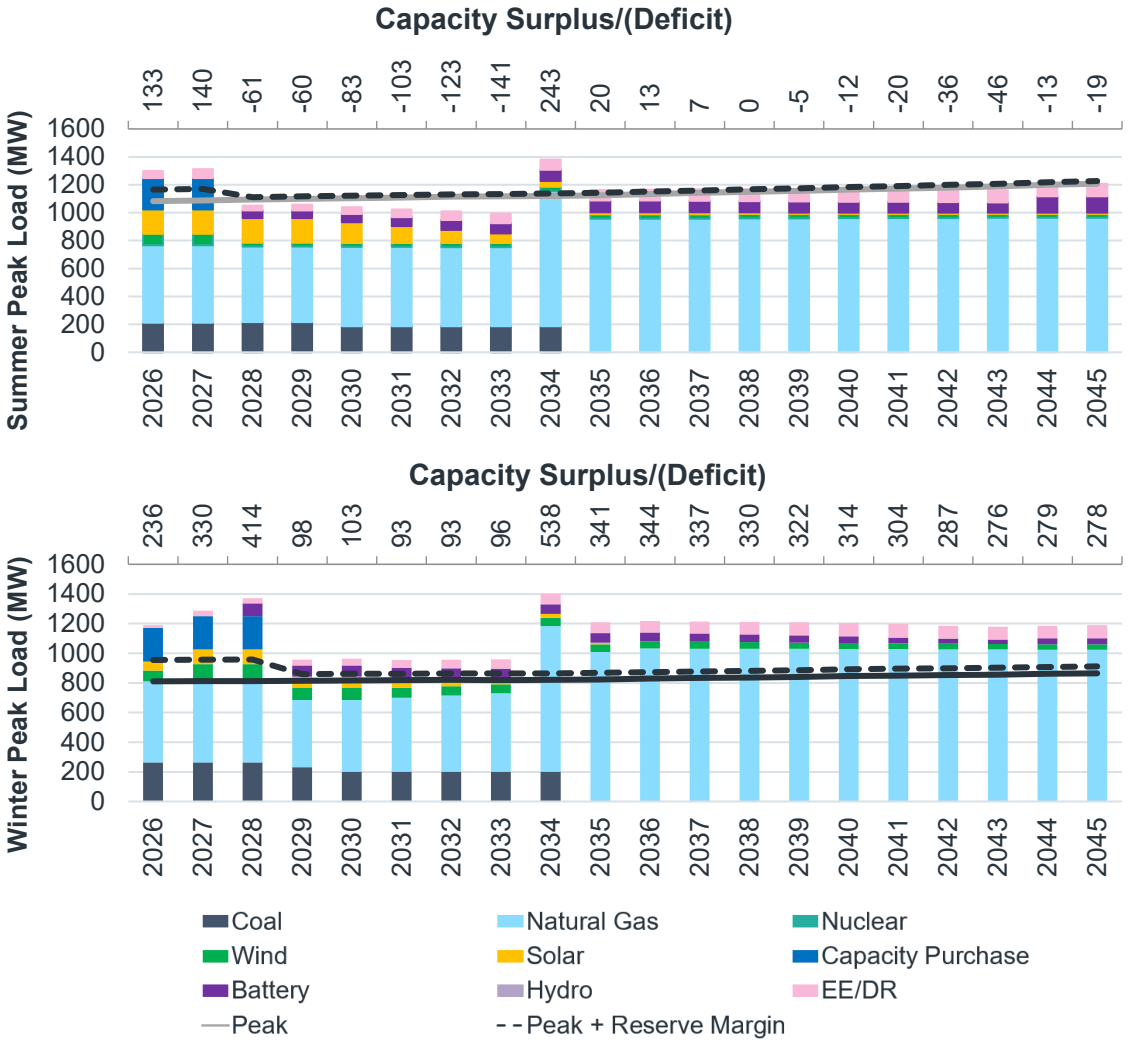


12 – Delayed Reference Case

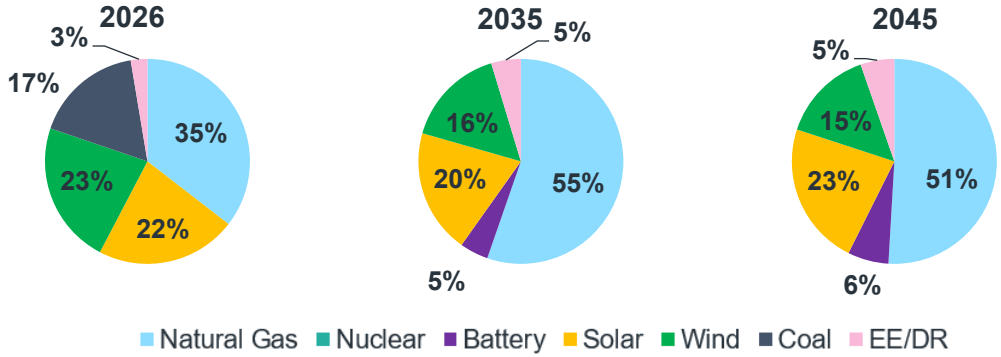
Model Selections:

FB Culley 3 Retire on 12/31/34
FB Culley 2 Start Storage 01/01/28
AB Brown 5&6: Start Fired CCGT 01/01/34
1x Non-IRA Solar + Storage

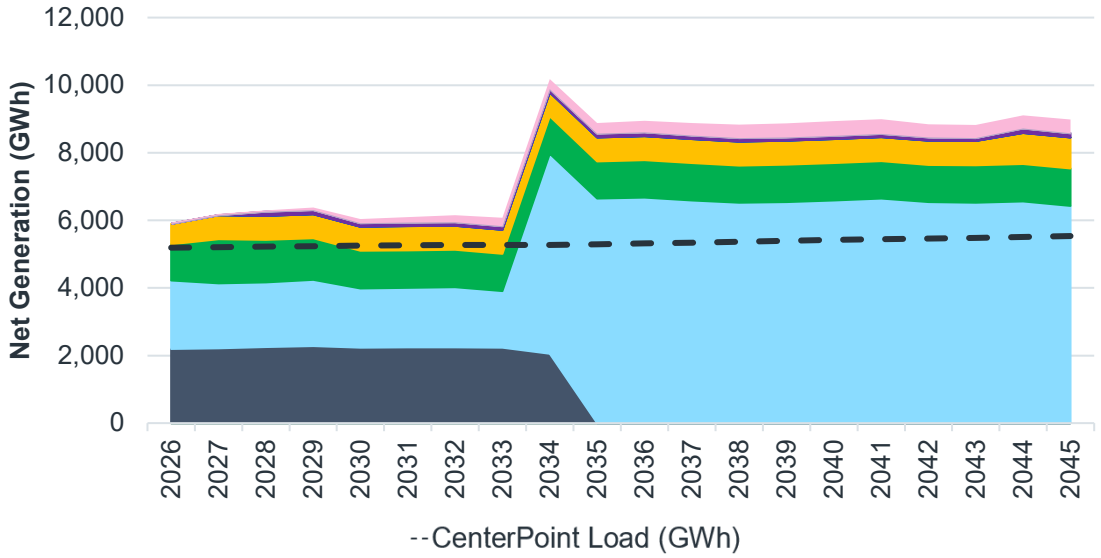
Balance of Load and Resources



Installed Capacity (MW)



Generation (MWh)



Q&A

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 3

On break – we will return at 1:25 CDT

Probabilistic Modeling Update

Brian Despard
Senior Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Approach Overview

Objective: Utilize stochastic analysis around key IRP inputs to measure uncertainty around power supply portfolio costs.

Two Purposes:

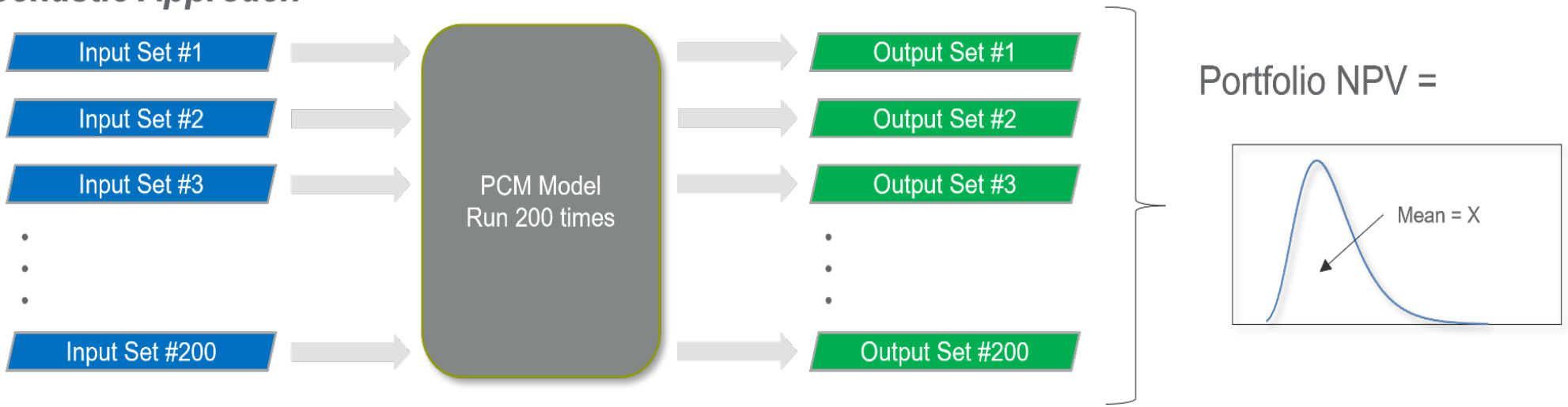
1. Evaluate results of stochastic inputs analysis to inform on what inputs to use for various scenarios; and
2. Stochastically develop 200 “families” of correlated inputs to run through production cost modeling – result will be probability distribution around power supply costs

Production Cost Modeling
Stochastics Process Overview

Typical Deterministic Approach



Stochastic Approach



PCM = Production Cost Model *NPV = Net Present Value*

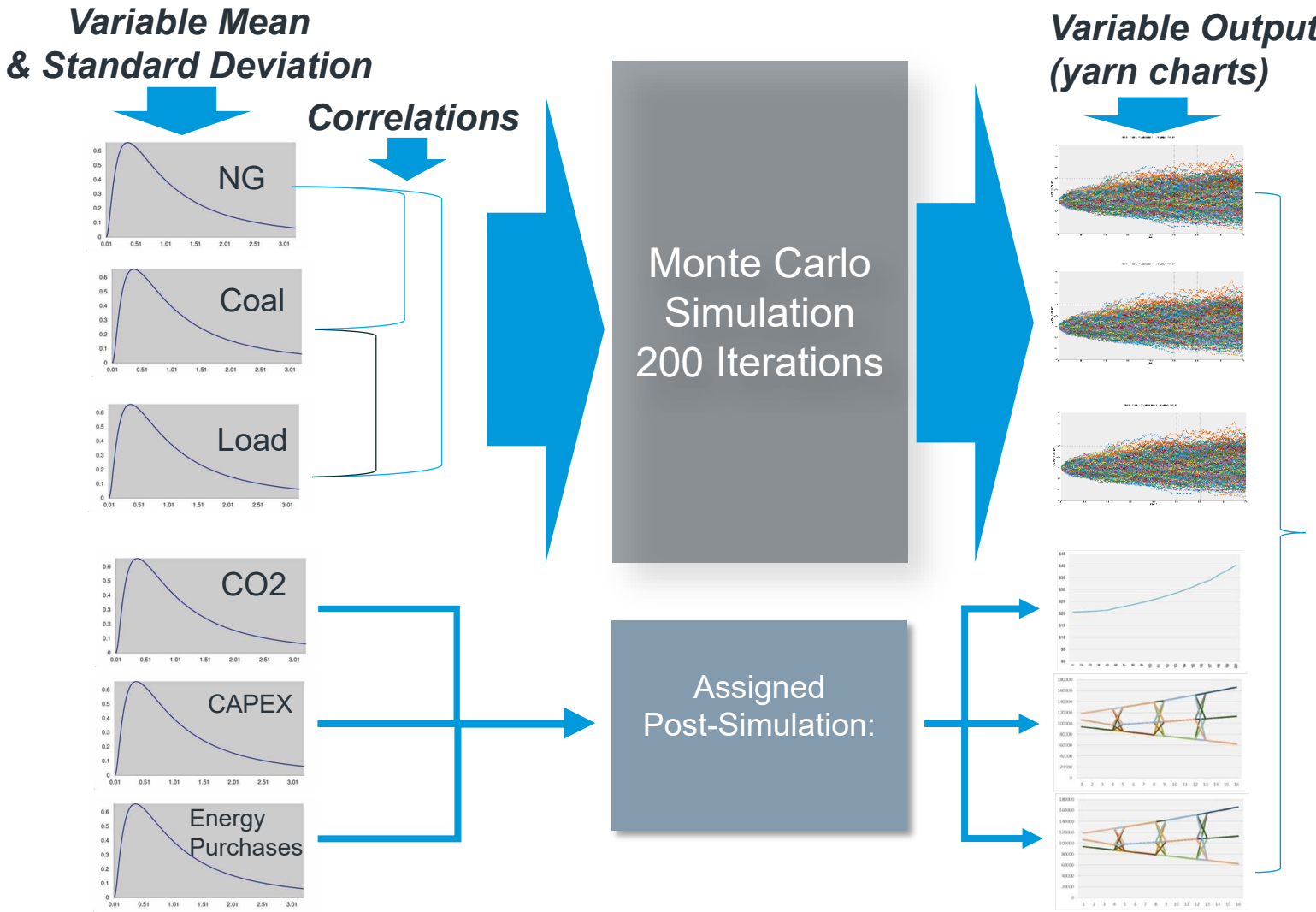
Uncertainty Variables

- Natural Gas Prices
- Coal Prices
- Peak Demand
- CO_2 Costs
- Capital Costs
- Energy Purchase & Sales

Stochastics Process Overview

1. Develop uncertainty variable parameters by month – expected value, volatility, correlations
2. Input variables into Monte Carlo simulation model
3. Run simulations with uncertainty variables being the output
4. Evaluate output implied distributions for each variable
5. Identify 200 sets of uncertainty variable “families”

Stochastics Process Overview (Cont.)



200 families of inputs where each iteration (family) reflects variable levels and paths that are tied together by correlations

Graphic and charts for illustrative purposes only

Stochastically Developed Uncertainty

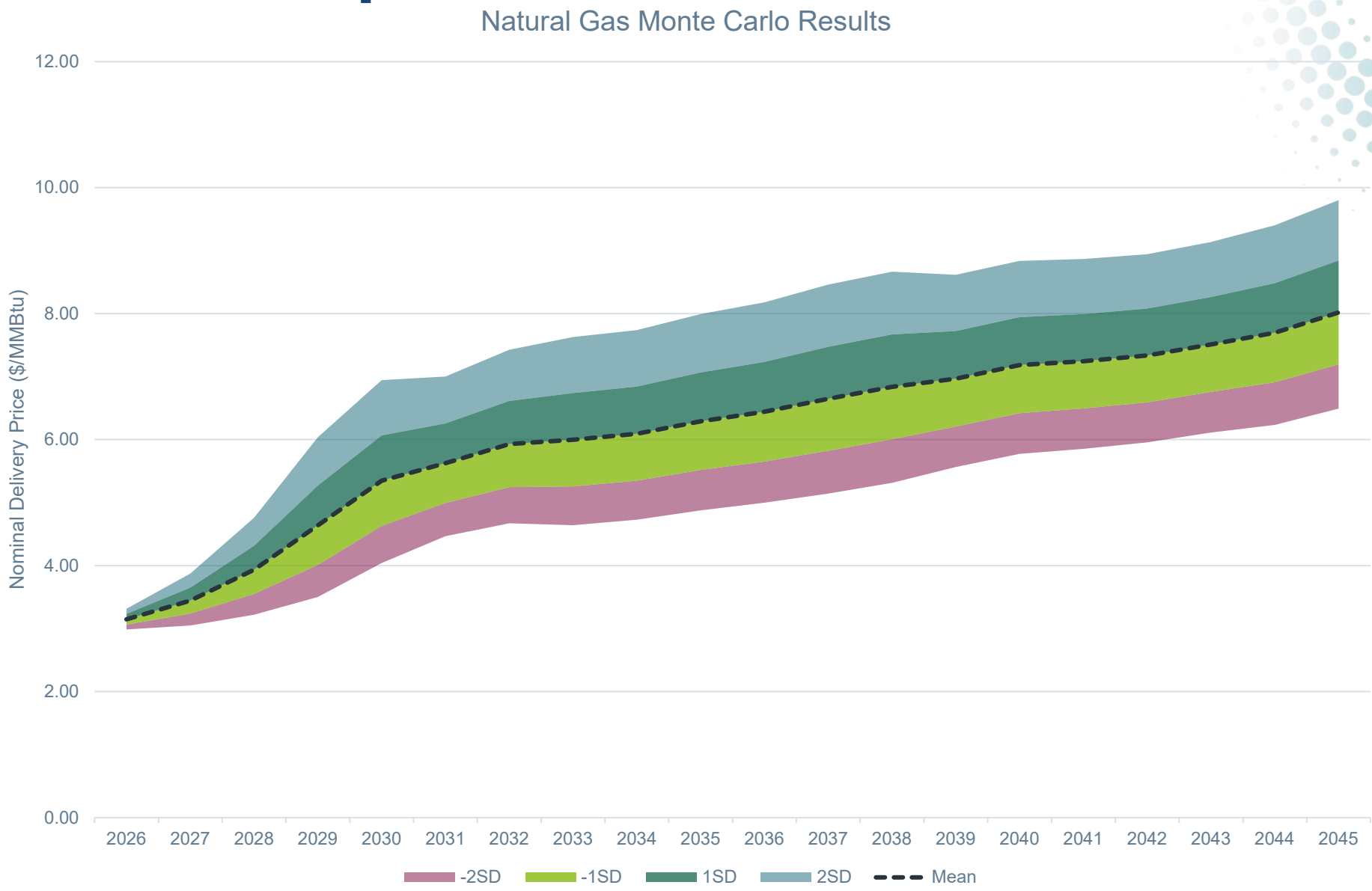
Expected Values (mean values): Reference case forecasts for each variable

Volatilities (standard deviations):

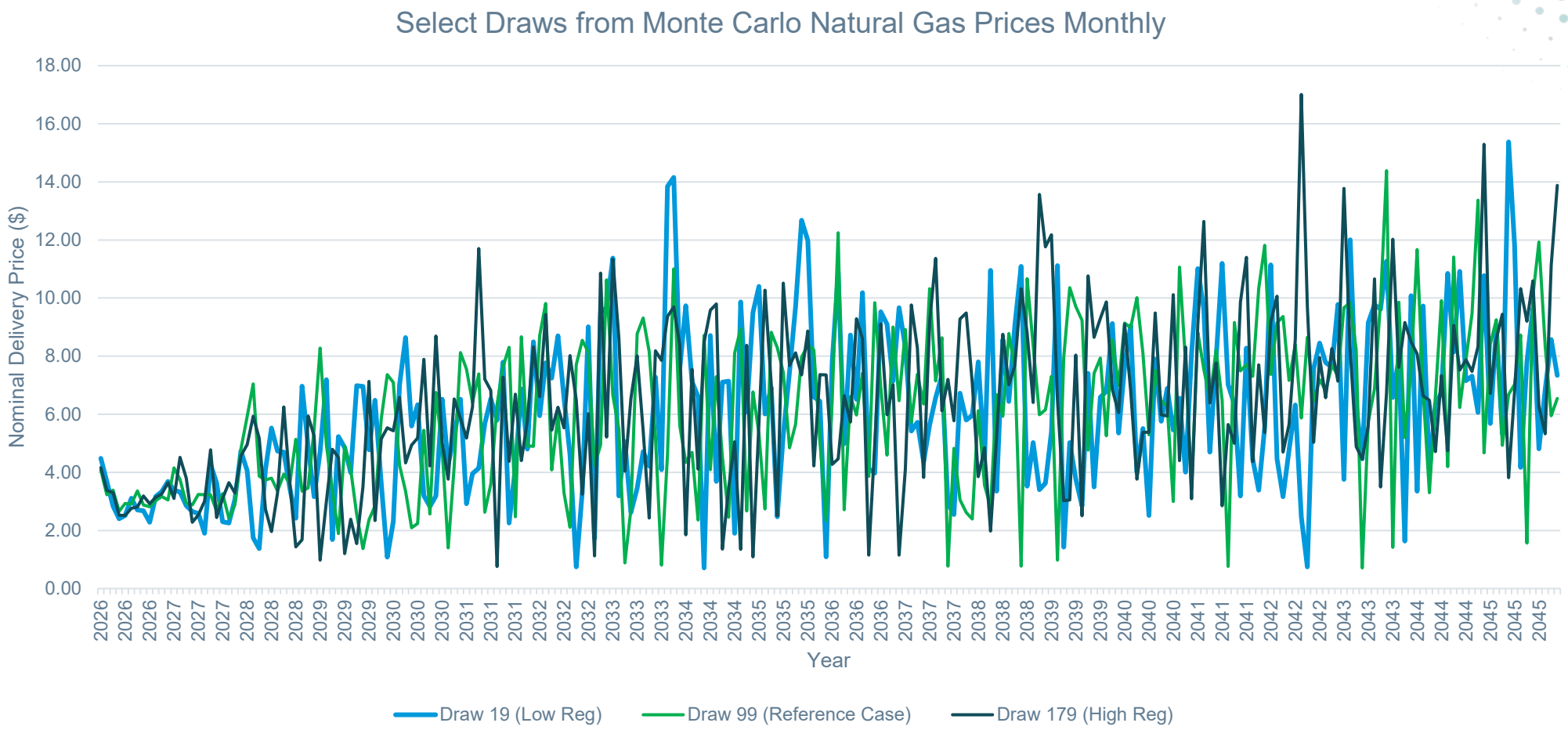
- **Natural gas pricing**: From base/high/low ABB forecast
- **Coal pricing**: From EIA's 2025 Annual Energy Outlook
- **Demand**: From various Itron demand scenarios

For **CO2 Costs, Capital Costs,** & **Energy Purchases**, the variations are assigned post-simulation. The stochastic process for **CO2 Costs and Capital Costs** are explained in detail on the next slides.

Natural Gas Example



Natural Gas Example (Continued)



CO_2 Methodology

- A CO_2 tax will be implemented only for the high regulatory scenario
- For the risk analysis, the following process is used to create variation in the CO_2 forecast
  - Assigned 200 EnCompass draws based on:
    - First 150 draws use Reference Case forecast ($0/Ton)
    - Last 50 draws implement a carbon tax

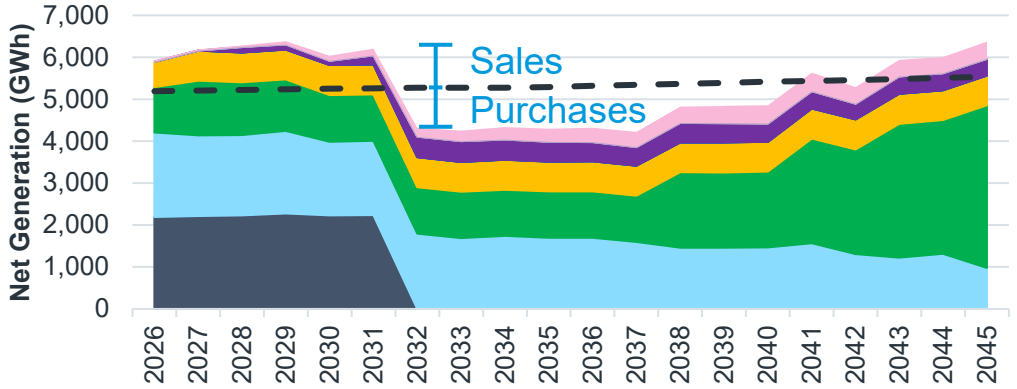
Capital Cost Methodology

- For the risk analysis, the following process is used to create variation in the capital cost forecast
  - Assigned 200 EnCompass draws based on:
    - First 50 draws use the Low forecast
    - Next 100 draws use the Reference Case forecast
    - Last 50 draws use the High forecast
  - Every 4 years, draws randomly reshuffles and the above assignments are made
  - The Low, Reference, and High forecasts align with the capital cost curves discussed in Stakeholder Meeting 2.

Energy Purchases/Sales Stochastics

- In the production cost model, the purchasing or selling of energy with the MISO market lowers portfolio costs, for the benefit of customers.
- Initial modeling approach allowed for a constraint of 660 MW energy sales and purchases limit, informed by transmission transfer capability.

Portfolio 6 Generation with 660 MW Energy Purchases & Sales Limit



- Through the risk analysis the limit of energy purchases or sales allowed on an hourly basis is tested. Across the 200 draws:
  - 1/3 assigned a 165 MW energy purchases & sales limit
  - 1/3 assigned a 330 MW energy purchases & sales limit
  - 1/3 assigned a 660 MW energy purchases & sales limit

Uncertainty Variable Parameters Expected Correlations

Variable	Demand	NG Price	Coal Price	CO_2 Cost	Dev CAPEX
Demand		Slightly Positive	Zero	Zero	Zero
NG Price	Slightly Positive		Slightly Positive	Negative	Positive
Coal Price	Zero	Slightly Positive		Negative	Zero
CO_2 Cost	Zero	Negative	Negative		Positive
Dev CAPEX	Zero	Positive	Zero	Positive	

Q&A

Early Sensitivity Results

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

Sensitivity Modeling

- **Sensitivity:** a single variable that drives results
  - Sensitivities may be used to change only one variable at a time to understand the impact of that single risk factor
- Early sensitivity analysis:
  - Alternate low regulatory sensitivity – *based on stakeholder input, using the low regulatory scenario but with a lower load forecast*
  - Large load addition – *varies only the load forecast*
  - Distributed solar incentive – *varies the adoption rate of rooftop solar (results in lower load forecast) to examine tradeoff of additional distributed solar incentive on total portfolio cost*
  - Energy sales sensitivity – *varies the energy sales limit between CEI South and MISO*

Alternate Low Reg Sensitivity

- Based on stakeholder feedback, we explored a low regulatory worldview with lower load growth
- Since only a single variable is altered, this alternate low regulatory case was explored as a sensitivity tied to the low regulatory scenario

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower
Alternate Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	**Lower**	Lower	Lower	Higher	Lower

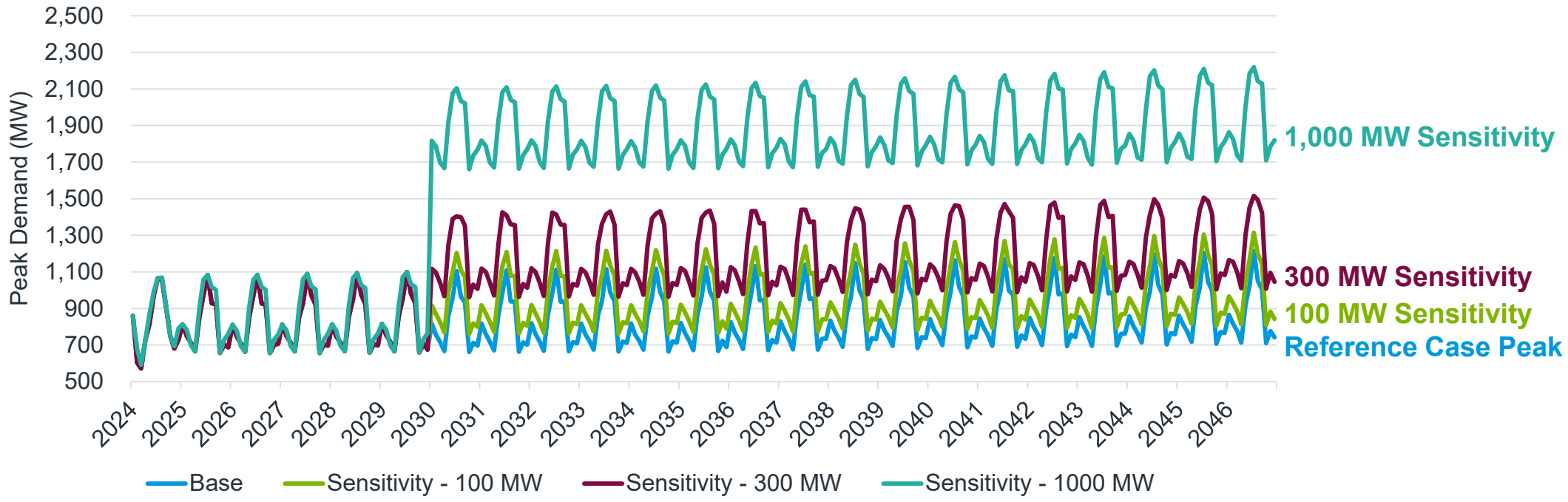
Alternate Low Reg Sensitivity

Year	Low Reg Scenario	Alternate Low Reg Sensitivity
2025	+1 AB Brown 5 & 6 Gas Turbine (464 MW) +1 Posey Solar (191 MW) +1 Salt Creek (170 MW)	+1 AB Brown 5 & 6 Gas Turbine (464 MW) +1 Posey Solar (191 MW) +1 Salt Creek (170 MW)
2026	+1 Wheatland Solar (150 MW) +1 Galesburg Wind (147 MW)	+1 Wheatland Solar (150 MW) +1 Galesburg Wind (147 MW)
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)
2031		
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2040	+1 100 MW 4 Hour Storage (100 MW)	
2043		
2044		
2045		

- The alternate low reg sensitivity simulation produced a similar portfolio to the low reg scenario
- The resource mix resulting from the alternate low reg is broadly captured by the low reg and reference case portfolios
- A distinct alternate low reg portfolio would be redundant

Large Load Sensitivity

- Analysis of 3 load sizes (100 MW, 300 MW, 1000 MW) representative of any new large load user in CEI South territory
  - New growth, expansion and retention of current customers
  - Not limited to data center customers



Large Load Sensitivity
Reference Case Portfolio Performance

Year	Reference Portfolio	100 MW Load Addition	300 MW Load Addition	1,000 MW Load Addition
2025	+1 AB Brown 5 & 6 Gas Turbine (464 MW) +1 Posey Solar (191 MW) +1 Salt Creek (170 MW)			
2026	+1 Wheatland Solar (150 MW) +1 Galesburg Wind (147 MW)			
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+2 100 MW Solar PV (200 MW) +1 FBC2 Storage (90 MW)
2029				+2 100 MW Solar PV (200 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 AB Brown7: Fired CCGT 2030 (912 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 AB Brown7: Fired CCGT 2030 (912 MW)
2031				+2 100 MW 4 Hour Storage (200 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)		
2033		+1 100 MW 4 Hour Storage (100 MW)		+1 100 MW 4 Hour Storage (100 MW)
2038				+1 1x1 J Class Unfired CCGT (568 MW)
2040	+1 100 MW 4 Hour Storage (100 MW)			
2043				
2044				
2045		+1 Non IRA Wind (Battery) (100 MW) +1 Non IRA Wind (Hybrid) (200 MW)	+1 FB Culley:3 thru 2045 (270 MW) +1 J Class SCGT (385 MW)	+1 FB Culley:3 thru 2045 (270 MW) +1 J Class SCGT (385 MW)

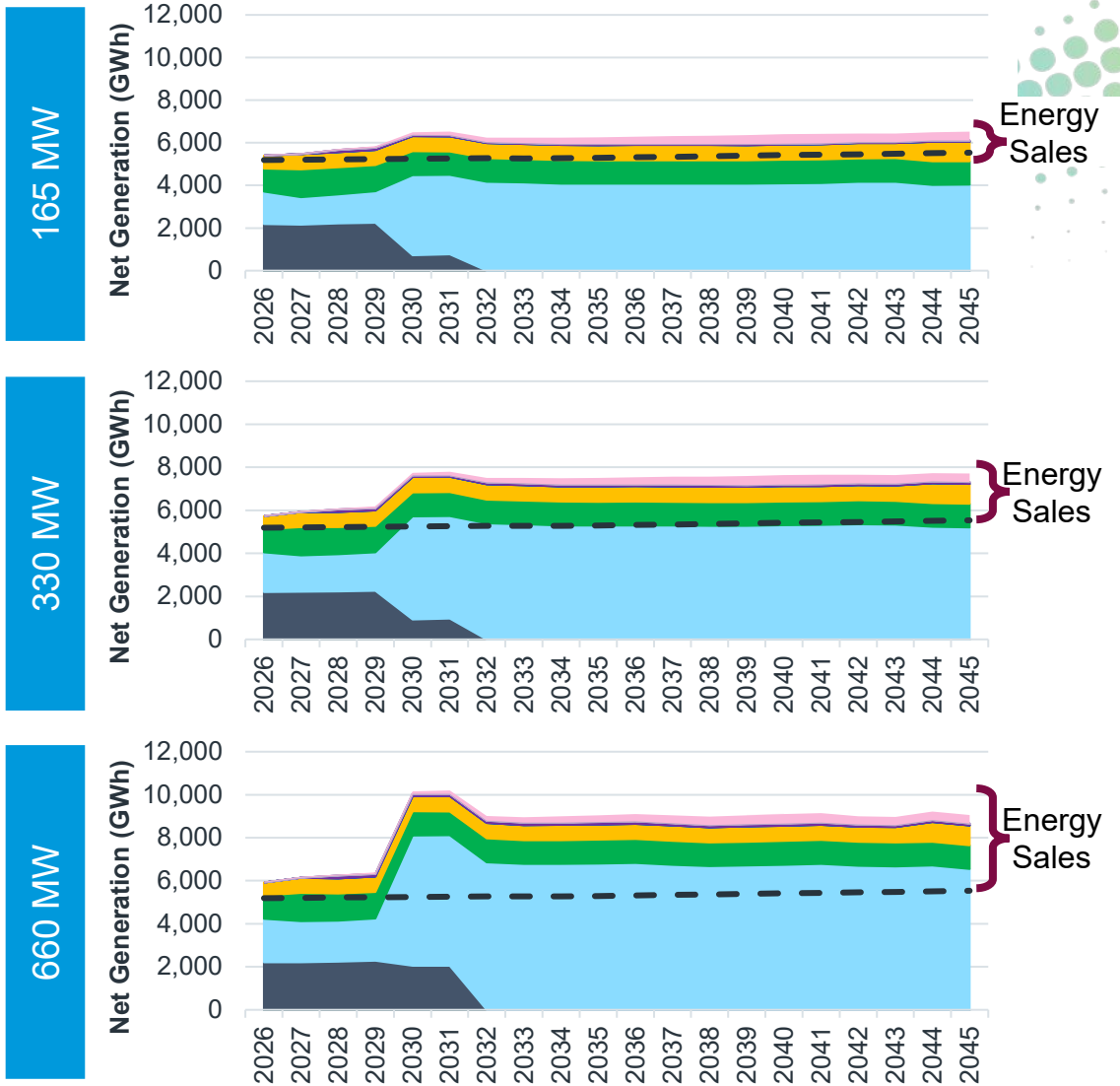
Distributed Generation (DG) Solar Incentive

- First stakeholder meeting covered the methodology for forecasting adoption and load impacts of a $500 per kW incentive for DG solar resources starting in 2026
- Itron generated a DG Solar Incentive load forecast
- Incentive estimated to have an NPV of ~$54MM
- Optimization run produced the same portfolio buildout as the reference case, but had a 1.5% increase in total portfolio cost
  - Additional Distributed Generation Solar resources do not eliminate the need for CEI South to build other resources

Year	Incremental Capacity MW Incentive	DG Solar Incentive Costs
2026	4.8	$2,420,500
2027	5.0	$2,476,500
2028	5.2	$2,610,500
2029	5.5	$2,757,000
2030	5.7	$2,868,500
2031	6.0	$3,014,000
2032	6.2	$3,093,000
2033	6.4	$3,204,500
2034	6.7	$3,339,500
2035	6.9	$3,440,000
2036	7.0	$3,496,000
2037	7.3	$3,630,500
2038	7.5	$3,731,500
2039	7.6	$3,799,000
2040	7.8	$3,899,500
2041	8.0	$3,989,000
2042	8.2	$4,078,500
2043	8.3	$4,168,500
2044	8.4	$4,191,000
2045	8.6	$4,303,000
Net Present Value of Incentive Costs		**$54,176,622**

Energy Sales Sensitivity

- Varying the energy sales quantifies the risk related to allowing high amounts of market interaction
- Running various scenario runs through different sales limits
- Analyzing the impact on NPV for lower MISO market energy sales above CEI South own energy needs



Q&A

Stakeholder Questions and Feedback

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

Q&A

- In-person attendees – please raise your hand to be recognized
- Virtual attendees will be in listen-only mode – to participate:
  - Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
  - Enter questions into the “Q&A” feature in Teams

- Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

Appendix

Planned New Resources

The listed projects are planned resources coming online in 2026 and were included in all the preliminary portfolios.

Year	Supply Side	Demand Side
2026	Wheatland Solar (150 MW) Galesburg Wind (147 MW)	DR: Industrial (25 MW) DR: Residential Direct Load Control AC Switch (1 MW) DR: Residential Bring Your Own Thermostat (13 MW) DR: Residential Smart Cycle (14 MW) DR: Residential Water Heat Switch (0.4 MW) EE: Income Qualified Home Electrification and Appliance Rebates (0.1 MW) EE: Commercial & Industrial Enhanced Realistic Achievable Potential (4 MW) EE: Residential Tier 1 & Home Efficiency Rebates (3 MW)

Narrative - High Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher

- In the High Regulatory Scenario, the Clean Air Act 111(b & d) is enforced as well as expanded to include existing gas resources and a CO_2 Tax is added
- **Load (↓)** – additional regulation drives lower demand growth for electricity
- **Commodity Prices (↑)** – additional environmental regulations increase costs for producing NG and coal, thus driving prices up
- **Generation Capital Costs (↓)** – continuation of the IRA, technology advancements, and lower demand for new generation results in lower capital costs
- **EE Costs (↑)** – lower load leads to less opportunity for cost-effective energy efficiency. In addition, a high regulatory environment leads to more codes and standards for equipment; This in turn results in higher incentives for more efficient equipment

Narrative – Alternate High Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	No additional CO_2 regulation	Higher	Higher	Higher	Higher	Base

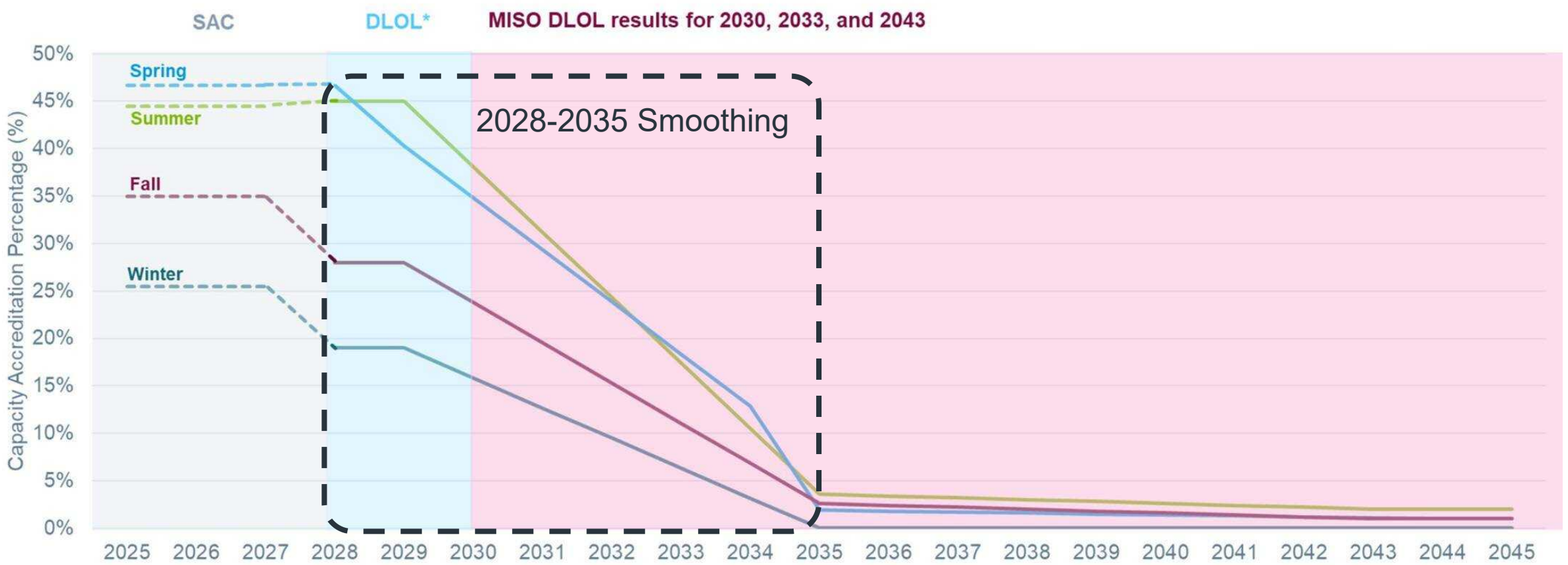
- The Alternate High Regulatory Scenario includes the same policy in the high regulatory scenario
  - The Clean Air Act 111(b & d) is enforced as well as expanded to include existing gas resources
- **Load (↑)** – additional regulation surrounding electrification of buildings and transportation drives significant electricity demand growth
- **Commodity Prices (↑)** – strict environmental regulations increase costs for producing natural gas and coal, while electrification-driven demand increases fuel consumption, driving prices up
- **Generation Capital Costs (↑)** – Demand for additional generation to match load growth as well as stringent regulation leads to increasing capital costs of generation technology
- **EE Costs (-)** – higher load creates greater opportunity for utility sponsored EE, balanced by federal/state incentives for adoption of cost-effective energy efficiency incentives which increases cost for utility sponsored EE

Narrative - Low Regulatory

Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation Capital Costs	EE Costs
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

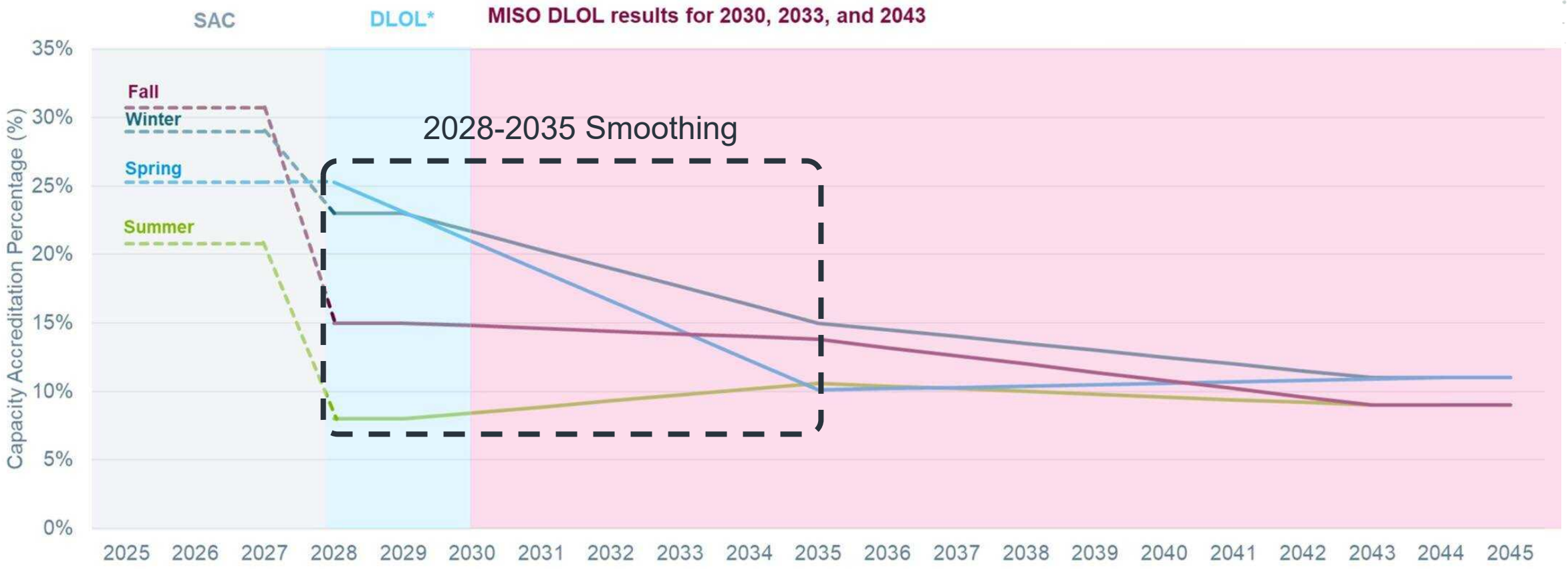
- Under the Low Regulatory Scenario, several environmental policies are eventually revised, including CAA 111. No new carbon emission regulations are created
- **Load (↑)** – reduced regulation encourages expansion of industrial/other large load users
- **Commodity Prices (↓)** – lower regulatory encourages the use of fossil fuels, increasing supply and lowering prices
- **Generation Capital Costs (↑)** – reduced incentives for renewables and increased pressure from tariffs drive costs up for new generation. Additional load growth also leads to an increase in demand, and higher costs
- **EE Costs (↓)** – higher load leads to greater opportunity for cost-effective energy efficiency and thus decreasing incentive costs

Updated Solar Capacity Accreditation Forecast



*DLOL values for 2028 – 2029 utilize MISO published 2025/2026 PY DLOL values

Updated Wind Capacity Accreditation Forecast



*DLOL values for 2028 – 2029 utilize MISO published 2025/2026 PY DLOL values

CenterPoint 2025 IRP
3rd Stakeholder Meeting Minutes Q&A
September 11, 2025, 9:30 am – 2:30 pm CDT

Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Introduced the meeting facilitator and covered meeting protocols and participation.

Shane Bradford (Vice President, Indiana Electric, CenterPoint Energy) – Shared the safety message for the meeting and the updated generation timeline.

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Provided an overview of the IRP process and summarized stakeholder feedback.

Matt Rice – Discussed the revisions to the scenarios including the comparison of Reference Case and Alternate Reference Case scenarios.

- Slide 20: Reference Case Assumptions
    - Question: When you say 40% capacity, is that operating at 40% capacity or at 100% capacity operating at 40% of the time?
        - Response: The latter.
    - Question: Can you briefly talk about what 111(d) was meant for?
        - Response: It is applicable to existing coal plants, and it was requiring either a 90% carbon capture and sequestration (CCS) by 2032 or retirement of the unit. In the preliminary modeling, it was driving retirements early in the model. The current administration has moved to either rescind 111(d) in full or at least rescind the 90% CCS rule. We have removed this from the reference case and applied an ACE Proxy cost, which targets efficiency for coal units is based on assumptions from the first Trump administrations' 111(d) rule.
- Slide 21: Alternate Reference Case
    - Question: In reference to the large load scenario, are you taking into account that gas turbines are expensive and difficult to obtain, especially considering the renewable projects that are being cancelled? Also, are you considering the feasibility of meeting load with an older coal plant that has had outages before?
        - Response: Yes, we are considering feasibility of generation and transmission to serve this load. For example, the load forecast increases to the current transmission limit for CEI South and then, after anticipated deployment of MISO Tranche 2, the load increases again. Our model also includes operational parameters of generation performance, such as scheduled and forced outages.

Jeffery Huber (Principal, Energy Efficiency, GDS Associates) – Presented a recap of the Market Potential Studies and discussed the energy efficiency and demand response modeling updates.

- Slide 32: EE Overview: Types of Potential Overview
    - Question: Can you differentiate the parameters of what factors are considered technical potential versus economic potential? What is the time frame?
        - Response: The only limitation on technical potential is what is technically feasible and the amount of load that the technology can save. For

example, heat pump water heaters cannot be installed everywhere due to size restrictions, so there is a limit on deployment. Economic potential then takes that technical potential and uses the Utility Cost Test (UCT) to filter out technologies that are not cost-effective. There is generally a small delta between the technical potential and economic potential for this study.

  - Question: Has CenterPoint considered the use of any other cost-effectiveness tests other than the Utility-Cost Test for determining "Economic Potential"?
    - Response: The Utility-Cost Test is the primary screening test that is used in Indiana, which is why it is used for this analysis.
  - Question: How do you consider the “health cost” in this study?
    - Response: There are other tests, such as the total resource cost test and societal test, which have opportunities to incorporate some of these externalities. However, in Indiana, the test that is utilized by the Commission is the Utility Cost Test, which is why it is the primary test for our market potential study.
- Slide 34: Overall TP/EP/RAP by End Use – All Sectors
  - Question: For items such as the lighting, the HVAC, and the building shell, I am assuming you are looking at the installation of equipment instead of making the building shell more efficient. Are factors such as more efficient installation and construction technique and design that increase the efficiency of the building shell being considered?
    - Response: HVAC and lighting are generally equipment, but the building shell category includes items such as improvements to windows, air and duct sealing, and insulation.
- Slide 38: Annual Savings by Bundle
  - Question: Can you explain the purpose of bundling the Residential programs? Is the methodology behind the bundles just economies of scale?
    - Response: From prior experience, there was concern that Residential as a single bundle would be at risk of not getting selected, and that is not a preferred outcome. By bundling into Tiers, there’s a higher chance that lower cost residential savings will get selected by the model. No, it is not economies of scale due to some measures (e.g., HVAC, building shell) in each bundle having varying cost; it’s more about the mix of measures.
- Slide 42: DR Results
  - Question: For residential DR EV and battery storage, given that potential savings is very small and driven by low adoption of EV and storage, is there a way to look at the analysis and find what adoption rate would be necessary for it to be cost effective? What would the penetration rate need to look like for the EV programs to be cost effective? What is the delta between where the levels currently are and where they need to be?
    - Response: Correct, the potential savings are driven by the forecasted adoption of EV’s and solar. We did run a sensitivity where we increased incentives at various levels to increase the participation rate. We also looked at decreasing the incentive in order to lower the cost. In both

cases, we could not find any incentive level that would make these programs cost-effective.
    - Question: Absent of incentives, what does deployment have to be for the EV and battery storage programs to be cost-effective?
        - Answer: I don't have that number currently, but of the customers that have rooftop solar, only 8% have batteries. The deployment would have to be significantly higher than current levels.
    - Question: Do we know what percentage of participation there is in Commercial & Industrial customers as compared to residential customers? On slide 43, it says that the residential savings in the Spring are 2.6 MW, but C&I savings are 0.7 MW. Why does the C&I program not have a larger impact?
        - Response: The C&I thermostat program is somewhat limited to smaller businesses that have a traditional smart thermostat installed. Larger customers typically have a different configuration that does not connect to a smart thermostat. Those MW savings would be captured in the DR Aggregation.
- General Questions
    - Question: For DR, are you considering a carrot and stick approach to the Commercial & Industrial customers, such as raising rates during peak hours to disincentivize C&I customers during peak hours and then lowering rates during off-peak?
        - Response: There is a time-of-use rate included in the market potential study. There are other alternatives of that described approach included in the DR Aggregation.
    - Question: Was there any acknowledgement that some of the renters in the area aren't in control of whether to participate in these programs? Are there any new programs or outreach in place to reach out to the owners of rental units? Do these programs require landlord approval to get the installation done?
        - Response: We do break out the potential between single family and multiple family households with varying assumptions for adoption rates. We do offer programs such as the Income Qualified Weatherization program where if a customer does not have a smart thermostat, there is one installed at the time of the assessment for no cost to the customer. In the plan that was approved for 2025-2027, CEI South did roll out a multi-family direct install program to specifically target that segment and install equipment to help electric and gas savings. These programs do require approval from the property owner.
    - Question: What line loss assumptions are you using?
        - Response: It's the peak line loss from the latest study, and it starts at 8.4% and is grossed up to 9 or 10%. This is used as a proxy for the marginal losses.
    - Question: Does this 20-year plan represent a percentage increase in participation both on the residential and industrial side? Have you factored in how increasing incentives would increase participation?
        - Response: Yes, the starting point is informed by what percentage of customers are currently signed up for programs. Then, the percentages

are increased over time. Also, we have a maximum achievable potential, which is the maximum participation case as well as a realistic achievable potential.

- Question: You mentioned that you bundled the EE and DR programs strategically so that programs wouldn't be completely ignored by the model. I would like to point out that the model does not have morality and programs that could make a significant impact in the lives of customers should not be discounted just because the model did not select it.
  - Response: The programs included in the income qualified bundle generally come with an incentive level that would cover up to 100% of the measure cost. We recognize that this program is advantageous and therefore it is treated as a hardcoded, forced in resource rather than a selectable resource.

Drew Burczyk – Shared the portfolio development methodology and steps and draft scenario optimization results.

- Slide 48: Portfolio Development Methodology, Step 2: Key Near-Term IRP Decisions
  - Question: What specific "other resource options" are considered when it is stated that "F.B. Culley 3 option selection is a larger capacity block strongly tied to other resource selections."?
    - Response: The FB Culley 3 decision is largely tied to the pathway at AB Brown 5 and 6 conversion to a CCGT. In the modeling, there are instances when having the AB Brown conversion and FB Culley 3 online, CEI South is long on capacity and energy. While the decisions are not explicitly linked, they are both larger resources that influence each other.
- Slide 50: Portfolio Development Methodology, Step 3: Resource Alternatives
  - Question: Are you looking at hybrid systems (like solar plus storage)?
    - Response: Yes, we are considering both solar plus storage as well as wind plus storage hybrid resources.
- Slide 51: Storage Resource Options
  - Question: You mentioned that the energy goes back to the grid, which would mean that the energy is not stored at CenterPoint. If a battery is charging from solar during the day, you're not necessarily storing it for eight hours since you're using it over that entire period of time. Is that part of how this works?
    - Response: The hours that are listed for battery duration is representative of the number of continuous hours that a battery can discharge at maximum output. The battery can store the power for longer. So, the battery can charge during low prices and then wait to discharge and sell energy back to the grid when it is economical to do so.
  - Question: Looking at all the generation sources, is there acknowledgement that if CenterPoint's own resources are not getting dispatched it might end up costing the customers more if CenterPoint's resources aren't running as much?
    - Response: Yes, the dispatch of different units is a fundamental piece of the IRP modeling. We are looking at how each of the different resources is valued on both the energy and capacity basis.

- Slide 53: Preliminary Project Selections - Scenarios
    - Question: Under high regulatory scenario, for the solar and wind projects, are any of the projects that have gone away are in the table on this slide?
        - Response: The previous projects that Shane was talking about earlier today are not included in this table. The solar and wind projects that are seen in this table are generic resources that CEI South does not have a contract in place for.
- General Questions
    - Question: Given that FB Culley 3 has experienced an 8-month outage, are there any modeling efforts that take into consideration reducing the impact to customers if another prolonged outage occurs at FB Culley 3?
        - Response: In the model, there are costs for maintenance to help prevent outages. Also, the reliability of each unit is accounted for in its accreditation.

Drew Burczyk – Discussed the deterministic modeling approach, portfolios, and draft results.

- General Questions
    - Question: Can you remind me of what the existing AB Brown units are? What is AB Brown 7?
        - Response: AB Brown 7 is the conversion of the existing AB Brown 5 and 6 simple cycle gas units into a Combined Cycle Gas Turbine.

Drew Burczyk – Shared the portfolio development methodology including results from the draft portfolios.

- Slide 64: Modification of Scenario Portfolios to Align with Reference Case Load
    - Question: Why are manual modifications necessary? If you wanted to compare based on the same load, wouldn't you just run with the same load and let the model pick?
        - Response: The scaling of the alternate scenario buildouts is so those portfolios can meet the reference case need. The removal of resources for higher load scenarios or addition of resources for lower load scenarios attempts to allow the portfolios to compete on an even playing field. Otherwise, some portfolios could be advantaged/disadvantaged when going through the risk analysis process.
    - Question: Is the load forecast for the scenario runs different than the reference case load forecast? Why would you not run each scenario with the same load forecast rather than running the model with different load forecasts and making manual adjustments?
        - Response: Yes. Slide 53 shows an arrow representing the load level for each scenario as compared to the reference case load. We ran the scenarios with their different load forecasts because the different load level influences the decisions that are made during capacity expansion.
    - Question: If load is varying, can you compare the net present value of the given portfolio?
        - Response: Correct. We used the scenarios with different load levels to generate a portfolio for each scenario, made manual adjustments to scale

up or down the buildout, and then locked in that portfolio and ran it through the reference case load.

- Question: Why is the capacity surplus highlighted? How did you come to the decision to take away solar and wind?
  - Response: The highlighted capacity surplus is a visual aid to show how the portfolio is long on capacity and thus drives the need for the portfolio to be scaled down to be closer to the capacity need for the reference case. When selecting which resources to remove, we tried to preserve the direction of the scenario buildout and removed resources that had multiple units and ability to be scaled up/down.
- Question: Why wouldn't it make sense to re-run the capacity expansion simulation instead of just the production cost simulation?
  - Response: We could look into running the alternate high scenario with the reference case forecast and see if the optimization produces anything different.

[Based on portfolio development concerns, related to adjusting portfolios raised in the meeting, CEI South does not plan to make manual adjustments to scenario-based portfolios. Rather, these portfolios will be run in the stochastic modeling as developed, whether rooted in higher or lower load than the reference case.]

- Slide 65: Draft Portfolios
  - Question: If each portfolio has its own set of variables and those change with time, there are an infinite number of possible forecasts for all of the variables (e.g., coal costs may go up or down and some of the O&M costs could go up while others go down). With all of that uncertainty, you're just using a baseline forecast, how is any of that variability being considered?
    - Response: As we get into the risk analysis, we will run each of these portfolios through 200 different families of inputs. Each family of input will be different to represent 200 different futures, but each portfolio will be simulated with the same 200 families of inputs. [The 200 different futures represent the full probabilistic range.]
- Slide 69: Portfolio 4
  - Question: The in-service date for an SMR in 2035 seems very early. Can you speak to the decision to allow for the early in-service date?
    - Response: These are not final portfolios and are still being developed. The 2035 in-service date is what we have determined as the earliest possible date that nuclear can come online in the model, and it happens to align with the timing of the FB Culley 3 retirement in that portfolio.
- General Questions
  - Question: Can you provide the documents that make it clear what changes are being made to these portfolios?
    - Response: Yes, we can provide documentation surrounding what changes were made. [Documentation posted to IRP File Share site for technical stakeholders]

- Question: In your modeling, are you considering a swing with the high regulatory approach? In the last 20 years, there have been a lot of swings in regulations.
  - Response: Yes, there are three draft portfolios that take inspiration from the portfolios generated by the scenario that corresponds to the portfolio name. For instance, portfolio 10 was developed under the Alternate High Regulatory scenario, which has an expanded Clean Air Act and different assumptions for IRA tax credits. All portfolios will be stress-tested under the different scenarios with different regulatory assumptions.
- Question: Comparing Portfolio 6 & 10 and their installed capacity of solar, it seems there needs to be less concern for regulatory requirements. Why are the numbers so low for a renewable heavy portfolio?
  - Response: For portfolio 6, the renewable heavy portfolio, the solar installed capacity as a percentage of the resource mix is decreasing over time because other resources (wind and storage) are coming online.

Brian Despard (Sr. Project Manager, Resource Planning and Market Assessments, 1898 & Co.) – Presented updates to the methodology for capturing uncertainty in model inputs via stochastic modeling.

- Slide 83: Uncertainty Variables
  - Question: For the uncertainty variable, why wouldn't regulatory environment be on the uncertainty variable list? What is the relationship between the uncertainty variable and the 200 families of inputs?
    - Response: The overall approach is based on the overall statistical variability of the variables and not based on a single qualitative measure (like policy) that causes uncertainty. We use statistical measures for each variable, such as mean and standard deviation, along with their correlations and let the variables randomly change within those parameters. The 200 draws of these variables, such as coal prices, gas prices, technology costs, and so on then make up the family of inputs. [Additionally, CEI South is varying the regulatory environment, as it relates to CO_2.]
  - Question: If each variable influences other variables, isn't there an infinite number of possibilities?
    - Response: Technically, yes. However, there are two different types of uncertainty that we are capturing in two different ways. The first is scenario uncertainty, where we identify future worldviews which can help inform the portfolios. Then there is risk analysis, which is primarily looking at uncertainty of the reference case. The 200 families of inputs then show how much the production cost of the portfolios change as these variables change.
- General Questions:
  - Question: Is it safe to assume you won't be applying stochastics to the large load portfolio(s)?
    - Response: Yes.

Drew Burczyk – Presented the sensitivity inputs and early model outputs.

- Slide 100: Distributed Generation (DG) Solar Incentive
  - Question: How many total megawatts of solar are included in this incentive and what percentage of CenterPoint's total capacity need? How much is the $54MM going to buy against the total capacity needs?
    - Response: For each of the portfolios, there is a different resource mix and therefore a different capacity gap to solve for, so the capacity need is different across each of the 12 portfolios. For the first pass of this sensitivity, the overall resource mix did not change, meaning that CEI South would have to build the same resources to serve its' load and also pay the DG Solar incentives. [Over 20 years, the DG solar incentive is applied to 137 MW of rooftop solar.]

General Q&A Section

- General Questions
  - Question: Can you explain MISO DLOL accreditation and the 2035 smoothing?
    - Response: MISO is moving to the direct loss of load (DLOL) methodology of accrediting resources. We used MISO provided information to inform an accreditation curve for each resource over time. Based on stakeholder feedback, we extended the decline from the initial DLOL inputs from 2028 to 2035 to avoid the sharp drop off of solar and wind accreditation in 2028.
  - Question: Why is MISO able to set the rules for the accreditation of resources? How does this relate to the price per kilowatt hour of electricity?
    - Response: Because CEI South is a member of the MISO market, CEI must meet the planning requirements set by MISO, which includes using their resource accreditation values. By being a MISO member, CenterPoint is able to lean on market energy and capacity supply as needed and not build as many resources.
  - Questions: Would you consider a study with FB Culley 3 retiring in 2030?
    - Response: [Thank you for your feedback]
  - Questions: Why does smoothing end in 2035?
    - Response: Stakeholders suggested the 2035 smoothing and this process was reasonable, so it was incorporated.
  - Questions: How do the issues at Salt Creek in Iowa affect the project?
    - Response: All problems have been solved. There has no impact to the project timeline or to CenterPoint.
  - Questions: Can CenterPoint itemize their bills to customers?
    - Response: Please see the CenterPoint website, where is shows an explanation of the bills. [https://www.centerpointenergy.com/en-us/residential/customer-service/resource-hub/understanding-your-bill?sa=in]
  - Question: Can CenterPoint explain the extra fees that are increasing bills?

        - Response: We're happy to speak to anyone interested in an explanation of their bills. [Please see the website above for and explanation of recent bill format changes.]
    - Question: At some point, will CenterPoint make its rate impact model (for the scorecard metric) available for review?
        - Response: Yes. We will be able to share that with technical stakeholders who have an NDA signed.
    - Comment: I [stakeholder] have made a portfolio to share.
        - [Stakeholder provided comments posted to Integrated Resource Plan (IRP) website]
    - Comment: [Stakeholder request for inclusion of renewable energy sources in IRP]
        - Response: [Stakeholder provided comments posted to Integrated Resource Plan (IRP) website]

Stakeholder Feedback and/or Data Request

From: IRP
To:
Subject: Re: [External Email] CGA feedback re: IRP stakeholder meeting #2
Date: Thursday, October 2, 2025 6:54:00 PM
Attachments: image001.png
image002.png

Emily –
Good evening. Apologies for the delayed response. I've added our responses below in blue text. Please let me know if you have any additional questions.

Leslie

Leslie Hamby
Manager, Integrated Resource Planning and Generation Analysis
CenterPoint Energy | Regulatory Legal

From: Emily Piontek <
Sent: Thursday, September 11, 2025 4:30 PM
To: IRP <IRP@centerpointenergy.com>
Subject: Re: [External Email] Re: [External Email] CGA feedback re: IRP stakeholder meeting #2

Good afternoon — I have just a few follow-up questions from these responses + today's public meeting:

To my query about resource build limits (questions 5 and 6), CEI South responded that those constraints will be relaxed in the next round of capacity expansion modeling.

- **Will those results be presented at the next Tech-to-Tech meeting?**
  CEI South Response: Yes, 1898 can share the updated results with relaxed constraints at the next tech-to-tech meeting on October 15.

To my query under question #7, the CEI South team responded on the likelihood of "expansion of resource options" under the Alt Reference Case scenario.

- **Can you clarify whether you mean the *build limits* or *technology types* will be expanded upon?** During today's public meeting, Drew mentioned that 100-hour LDES (iron-air) has been included as an option (thank you!), so I'm wondering if this is the resource type the model would be allowed to select under the next round of modeling or

whether there are new resource types and/or higher build limits that will be considered under the Alt Reference Case.

CEI South Response: For the Alt Reference Case, 1898 has increased the build limits, and we have expanded our technology types to include an additional large Combined Cycle Gas Turbine option (G/H Class). These results can be shared at the next tech-to-tech meeting.

Thanks in advance!

Sierra Club Informal Discovery Request
CenterPoint Energy Indiana South 2025 IRP
Sierra Club Data Request Set No. 1
CEIS Response: October 6, 2025
CEIS Revised: October 8, 2025

Sierra Club respectfully asks that CenterPoint Indiana South provide complete responses to these data requests:

1.1 Has CEIS evaluated whether Culley unit 3 will require additional investments to comply with final, proposed, or possible future environmental regulations if it continues to operate on coal, including, but not limited to: existing consent decrees, new source review provisions, coal combustion residuals, effluent limitation guidelines, national ambient air quality standards, cooling water intake standards, a cross-state air pollution rule, the mercury and air toxics standards, regional haze, and carbon dioxide emission limits?

a. If so, please provide a summary that briefly describes the additional investments, including the purpose, and capital and annual O&M costs of such investments.
CEI SOUTH REPONSE: Yes, CEIS has evaluated potential additional investments that could reasonably be expected to be incurred should FB Culley Unit 3 continue operating with coal as the fuel source. CEIS has considered an efficiency standard ("ACE proxy") as a reasonably possible future regulation for coal-fired power plants and those costs are factored into the relevant scenarios.

b. If so, please specify which of those costs that would be incurred even if the unit were to retire or convert to gas before 2030, i.e., unavoidable costs.
CEI SOUTH REPONSE: Investments to comply with cooling water intake standards are the same for both coal and natural gas firing of the unit, so continuing the use of coal does not change the investment that would be required. The timing for these costs is anticipated to occur in the 2026-2028 timeline. The cost of disposing coal combustion residuals has been factored into scenarios that include FB Culley Unit 3 continuing to operate as a coal-fired unit.

1.2 Please provide the forced outage rates for existing generating units over the last five years.
CEI SOUTH REPONSE: The requested data is given in the following table.

Year	ABB3	ABB4	FBC3
2020	4.7	16.16	1.77
2021	0.5	4.33	1.43
2022	2.92	1.29	62.15*
2023	0.17	1.74	22.49*
2024	5.87	0	5.27

**FBC3 2022 and 2023 forced outage rates largely due to boiler feed pump failure*

1.3 Regarding the option to convert Culley unit 3 to operate on gas.

a. What is CEIS estimate of the capital cost to convert Culley unit 3 to operate on gas. **CEI SOUTH REPONSE:**

The response to 1.3.a and supporting documentation posted to the data sharing site fall under CEIS's IRP NDA and are considered CONFIDENTIAL.

b. How does the unit's heat rate change when converting to operate on gas? Provide the heat rate when operating on coal and on gas.
CEI SOUTH REPONSE: Based on historical operating date, the heat rate of FB Culley 3 is 11,657 Btu/kWh at minimum capacity of 135 MW and 10,561 Btu/kWh at its maximum capacity of 270 MW.
The heat rate when converting to gas is not expected to change. The EnCompass modeling software interprets these inputs as the average heat rate at the block load level. The heat rate and maximum/minimum capacity remain the same on both coal and natural gas in the modeling, as they are based on historical FB Culley 3 data. The largest impact on the operation and performance of the unit in the model is driven by the change in fuel costs which impact unit dispatch.

c. How does the conversion impact ramping rate, start up cost and timing? Please provide this information for the unit when operating on coal and gas.
CEI SOUTH REPONSE: In the IRP modeling, the ramp rate and startup costs and timing remain the same on both coal and natural gas as they are based on historical FB Culley 3 data. The requested data is given in the following table.

Parameter	Unit	Value
Ramp Up Rate	MW/min	2
Ramp Down Rate	MW/min	2
Cold Startup Cost	$	30,725
Minimum Downtime	hours	24
Minimum Uptime	hours	24

d. Does the conversion impact VOM, FOM or planned capital investments? If yes, please provide this information for the unit when operating on coal and gas. **CEI SOUTH REPONSE:**

The documentation posted to the data sharing site falls under CEIS's IRP NDA and is considered CONFIDENTIAL.

e. Does CEIS expect the units utilization (capacity factor) to change when operating on gas vs coal? If yes, please provide the expected capacity factors when operating on both fuels.
CEI SOUTH REPONSE: Yes, CEI South expects that the conversion of FB Culley 3 from firing on coal to natural gas will likely impact the operation and dispatch of the unit, typically operating less frequently under a Natural Gas conversion scenario after conversion. For example, in initial modeling results of Portfolio 2 (which has the AB Brown SCGT to CCGT conversion and the FB Culley 3 Natural Gas conversion in 2035), the capacity factor of FB Culley 3 on coal in the early years of the study period is higher (typically in the 80-90% range) than when FB Culley 3 is converted to gas (typically in the 20-30% range) in the second half of the study period under reference case scenario assumptions.

f. Does CEIS's expect its environmental compliance requirements or costs will change if the unit is converted to operate on gas relative to operating on coal? Please outline all expected environmental compliance costs and regulations CEIS expects will apply to unit 3 operating on coal and then operating on gas.
CEI SOUTH REPONSE: Yes, the requested data is given in the following table.

Requirement	On coal/year	On Gas/year
Ash disposal	$2.4M	$0.00
H2SO4 control	$200k	$0.00
Mercury control	$50k	$0.00
SO2 control	$3.3M	$0.00
NOx control	$1.2M	TBD

From: IRP
To: IRP; Liwei Lu
Subject: RE: [External Email] load forecast
Date: Monday, October 13, 2025 2:44:30 PM
Attachments: image001.png
image002.png

Good afternoon Liwei.

The reference, low, and high load forecast used for the 2025 IRP is now available on the IRP File Sharing site – the document is titled “Monthly & Annual Load Summary”. As a reminder, anything marked as confidential on the file share site can only be shared with those that have signed the CEI South IRP NDA and/or agreement to be bound.

CenterPoint IRP File Sharing

Please let me know if you have any follow up questions.

Leslie

Leslie Hamby
Manager, Integrated Resource Planning and Generation Analysis
CenterPoint Energy | Regulatory Legal

From: Liwei Lu
Sent: Monday, October 6, 2025 10:07 AM
To: IRP <IRP@centerpointenergy.com>
Subject: [External Email] load forecast

Hi Leslie,

Good morning! Hope this email finds you well.

This is Liwei Lu from the State Utility Forecasting Group. I wonder if you have a load forecast used for this IRP process. Is it possible to share with us?

Thank you so much!
Liwei

JIM DANIELS' 20 YEAR PLAN FOR CENTERPOINT– EVANSVILLE, IN

1. Set EDG rate to 90% of retail.

2. Begin installing solar and wind systems at all of Centerpoint properties. Budget $30 million per year.

3. Increase conservation measures. More audits to discover savings and provide incentives for low income citizens to save energy.

4. Offer real incentives for non-profits and businesses and government entities to install renewable energy, and help them use excess capacity to funnel to area s where solar is not practical. Eliminate Peak demand chrges.

5. Offer discounted rates for all new construction and major remodeliong efforts that result in the lowering of significant energy use.

6. Phase out Centerpoint regulatory staff, attorneys, lobbyists, and consultants as the increase in clean renewable energy comes online as they will not be needed.

###

CITY OF EVANSVILLE
Evansville Climate Collaborative (ECC)
One NW MLK Jr. Blvd; Civic Center Complex; Evansville, Indiana 47708
Ph: 812-435-6145 Fax: 812-435-6155 Email: climate@evansville.in.gov

September 11, 2025

To whom it may concern:

I am writing to represent the Evansville Climate Collaborative, a City of Evansville agency leading collective action to promote a more sustainable, healthy, and resilient community. I am here to advocate for the inclusion of significant clean, renewable energy sources in CenterPoint's next integrated resource plan.

Our agency is tasked with implementing Evansville's Climate Action Plan (CAP), which outlines actionable strategies to improve our air quality and our resilience to climate impacts. The plan recommends 50 priority actions across 5 sectors – energy, transportation, waste, land, and resilience. When implemented, these actions will make our buildings more efficient, our vehicles cleaner, our waste useful, our urban space greener, and our community more resilient.

The plan aims to reduce our greenhouse gas emissions by 30% by 2030 and 80% by 2050. Through an inventory of our annual greenhouse gas emissions, we discovered that our community contributed 2.7 million metric tons of gases in 2023. Energy consumption for buildings and facilities is the source of 79% of those emissions because the energy is generated primarily from fossil fuels. The burning of fossil fuels is the primary source of greenhouse gases and other air pollutants that have negatively impacted our region's air quality for decades.

If we are to meet our goals of reducing air emissions, we must focus primarily on improving the energy efficiency of our buildings and on using cleaner energy sources. While the City can advocate for energy efficiency improvements in buildings to help our residents and businesses save energy use and costs, it will make a small impact in reducing emissions compared to changing how that energy is generated. We must collaborate with our utility provider CenterPoint Energy and advocate for the transition to clean, renewable sources for energy generation.

Clean, renewable energy sources should be a priority for our community and our utility, given they achieve the 5 guiding principal pillars of House Enrolled Act 1007– Reliability, Resiliency, Affordability, Stability, and Environmental Sustainability. Emerging climate impacts like extreme temperatures and storms will change our energy demand and test our energy supply. Diversification of energy sources supplying the grid will improve the reliability of our energy and our community's resilience during interruptions caused by weather events. Power generated from newer solar and wind technologies is also more affordable in the long run compared to keeping antiquated fossil fuel power plants safely operational. They can also stabilize energy costs compared to the volatile market fluctuations of fossil fuels. Our residents have been demanding relief from the burden of their energy costs, and this is one way to deliver that relief. And finally, renewable energy sources like solar and wind are abundant and sustainable, whereas fossil fuels are not.

No matter how you frame it, renewable energy sources are a good investment. They will provide the residents of our community with better air quality, improved energy reliability, lower energy costs, and enhanced energy security. They will also ensure our community can be safer and more resilient to the climate impacts we will face.

We urge CenterPoint to prioritize clean, renewable energy sources in their energy mix in the next IRP. We advocate for at least the same commitment to renewable energy sources as promised in the current IRP. We emphasize the urgency of this matter to prepare our community for the impacts we will face. Thank you for considering this request.

With gratitude,

Lauren Lynch

Lauren Lynch, Director

Dear Shane Bradford and Matt Rice,

CenterPoint Energy Indiana is at a crossroads right now. CenterPoint can choose a future reliant on old, polluting, uneconomic coal or they can choose the path of affordability, and clean, renewable energy. This company has the opportunity to do what is right for its customers, our health, and the environment by retiring coal, and investing in affordable, renewable energy projects and contracts. FB Culley is an aging, polluting, coal plant[1] that is costing us not only in our bank accounts, but in our health outcomes every time we breathe air polluted by coal. CenterPoint says they are community partners, yet CenterPoint is attempting to backtrack on coal retirements and abandoning clean energy contracts, all while receiving rate increases that severely burden our communities and neighbors. Over 350 people have contributed to the Sierra Club Indiana Beyond Coal petition asking CenterPoint to move beyond coal and to invest in more affordable, renewable energy. Retiring coal and increasing renewables is popular and what many in the community want.

CenterPoint's customers, and our environment and climate are at a breaking point. If CenterPoint continues to prop up coal at FB Culley, it would be at the expense of customers and southwest Hoosiers. To show a positive commitment to our community, CenterPoint needs to retire coal at FB Culley, as originally planned in your previous Integrated Resource Plan, and invest in clean, renewable energy. Wind and solar are now cheaper than aging coal plants and gas. The average levelized cost of energy for coal is $118/MWh while utility-scale solar is $61/MWh[2]. Wind and solar do not require fuel to run, unlike coal plants, and renewable energy outputs result in energy generated without pollution. It's an obvious win-win. Considering CenterPoint is a billion dollar company[3], we believe that you have the responsibility to move beyond coal, invest in wind, solar, and battery storage, while not continuing to burden customers with extreme costs for return rates. The solution is simple, move beyond coal, and strive towards renewable energy. Don't backtrack on your 2027 coal retirement. Not only is our future at risk, but so is our present, and coal is not the answer.

Signed,
Sierra Club Indiana Beyond Coal Campaign Supporters, Members, and CenterPoint Customers

[1] Sierra Club Comments on CenterPoint Energy Indiana South's 2022/2023 Integrated Resource Plan, https://www.in.gov/iurc/files/Sierra-Club-Comments-on-CenterPoint-Indiana-2023-IRP.pdf
[2] The Climate Reality Project, https://www.climaterealityproject.org/blog/how-do-renewables-lower-cost-electricity
[3] CenterPoint Energy Gross Profit 2010-2025, https://macrotrends.net/stocks/charts/CNP/centerpoint-energy/gross-profit

CenterPoint Energy

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 4



October 23, 2025

Stakeholder Meeting Facilitator: 1898 & Co.

WHO: 1898 & Co. is the business, technology, and security consultancy part of Burns & McDonnell

WHAT: The Resource Planning & Market Assessments group has been working on Integrated Resource Plans for over 20 years

HOW: Our team will help facilitate stakeholder meetings – we look forward to working with and hearing from you all

Agenda

Time	Topic	Speaker
9:00	Sign-in & Refreshments	
9:30	Facilitators and Meeting Protocols & Participation	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
9:40	Safety Share & Welcome	Shane Bradford, Vice President, Indiana Electric, CenterPoint Energy
9:50	Follow Up Information From Stakeholder Meeting #3	Leslie Hamby, Manager IRP & Generation Analysis, CenterPoint Energy
10:00	Preferred Portfolio	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
10:40	Break	
10:50	Risk Analysis Modeling and Portfolios	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
11:00	Portfolio Characteristics and Considerations	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
11:30	Lunch	
12:30	Risk Analysis Scorecard	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
12:45	Alternate Reference Case	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:00	Sensitivity Results	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:30	Summary	Matt Rice, Director Regulatory & Rates, CenterPoint Energy
1:40	Stakeholder Questions & Feedback	Moderated by Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:30	Adjourn	

Meeting Protocols

- Please focus questions, comments, and feedback to the IRP process and today's agenda topics
- CenterPoint Energy Indiana (CEI) South does not authorize the use of cameras, video/audio recording devices, or AI transcription during the meeting
- Following the meeting, feedback (concepts, inputs, methodology, etc.) and questions may be sent to IRP@CenterPointEnergy.com
- CEI South will be recording the meeting to accurately capture notes and questions. The public meetings are not transcribed or recordings posted; however, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp

Meeting Participation

Time is allotted for questions following each presentation – please hold questions until the designated question period

For those in the room, please keep side conversations to a minimum. The ceiling mics are sensitive, and additional noise may make it hard for those online to hear

In-person attendees – please raise your hand to be recognized

Virtual attendees will be in listen-only mode – to participate:

- Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
- Enter questions into the “Q&A” feature in Teams

Identifying yourself by name prior to speaking to help us keep track of feedback and follow up actions

There will be a list compiled for items to be addressed later. Questions that are not able to be answered in this meeting will be answered later

Welcome and Safety Share

Shane Bradford

Vice President, Indiana Electric

Safety Share - Halloween

Drivers should be aware that around Halloween, there will likely be more pedestrians on the roads and in unexpected places.

Safety Tips for Drivers

- **#1:** Be alert for trick-or-treaters and other pedestrians.
- **#2:** Slow down and scan the road. Remember: Slower speeds save lives.
- **#3:** Watch for young trick-or-treaters in unexpected places. Children may be unaware of traffic and dart into the street unexpectedly.
- **#4:** If you see a drunk driver, contact law enforcement.

Safety Tips for Pedestrians

- **#5:** Before festivities begin, create a “buddy system” to get each other home safely and prevent walking alone.
- **#6:** Follow the rules of the road and obey signs and signals.
- **#7:** If possible, cross streets at crosswalks or intersections. Look for cars in all directions, including those turning left or right.



Source: https://www.nhtsa.gov/halloween-safety-tips

Image: https://pixabay.com/

Stakeholder Feedback & IRP Process Recap

Leslie Hamby

Manager IRP & Generation Analysis

Summary of Stakeholder Feedback From Meeting #3

Topic	Stakeholder Comments	CEI South Updates/Responses
Modeling:	Scenario Portfolios – Explain why manual modifications applied to scenario portfolios to align with the Reference Case load	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling:	Scenario Portfolios – Request to re-run the capacity expansion simulation instead of the production cost simulation	
Modeling:	Scenario Portfolios – Request to share documentation illustrating manual modifications made to the scenario portfolios	
Modeling:	Build Limits – Request for CEI South to consider running scenarios with relaxed limits	CEI South ran a simulation and chose to relax limits to allow more resources to be selected within the capacity expansion model.
Modeling:	Consider a study with FB Culley 3 retiring in 2030	Given the unprecedented amount of uncertainty at this time and future transmission upgrades that will help with system reliability and resilience, it would not be prudent to consider retirement prior to 2032, as is being considered within this IRP.

Summary of Stakeholder Feedback From Meeting #3

Topic	Stakeholder Comments	CEI South Updates/Responses
Affordability Measure	Request for energy burden calculation	CEI South will make the energy burden workpaper available to technical stakeholders with a signed NDA.
Rates	Request to provide guidance on bill itemization	Please see the CenterPoint website, where is shows an explanation of the bills. https://www.centerpointenergy.com/en-us/residential/customer-service/resource-hub/understanding-your-bill?sa=in

2025 Stakeholder Process

Proposed 2025 CEI South Stakeholder and Tech to Tech Meetings – *Dates and agendas are subject to change*

Meeting 1
March 19

- IRP Process, Objectives, & Draft Metrics
- All-Source RFP Results
- MISO Update
- Environmental Compliance Update
- Draft Sales and Demand Forecast (Reference Case)
- Commodity Inputs
- Large Load Sensitivity Discussion
- Resource Options
- Scenario Development

Tech to Tech
April 28

Meeting 2
May 14

- Follow Up Information From 1st IRP Stakeholder Meeting
- Final Scorecard and Scenarios
- DSM Market Potential Study Update
- Draft Supply-Side Resource Inputs
- Final Load Forecast and Draft Scenario Forecasts
- Probabilistic Modeling Approach and Assumptions
- Portfolio Development Methodology
- Draft Reference Case Modeling Update

Tech to Tech
August 20

Meeting 3
September 11

- Follow Up Information From 2nd IRP Stakeholder Meeting
- Revisions to Scenarios
- DSM Market Potential Study – Initial Results
- Portfolio Development Methodology and Draft Scenario Optimization Results Draft Deterministic Portfolio Results
- Portfolios Discussion
- Scenario and Probabilistic Modeling Update
- Early Sensitivity Results

Tech to Tech
October 15

Meeting 4
October 23

- Follow Up Information from 3rd IRP Stakeholder Meeting
- Preferred Portfolio
- Risk Analysis Modeling and Portfolios
- Portfolio Characteristics and Considerations
- Risk Analysis Scorecard
- Alternate Reference Case
- Sensitivity Results

Target Submission Date: December 5, 2025

Stakeholder Engagement is Critical to the IRP Process
CEI South is committed to meaningful information sharing and dialogue

Target Data Release Schedule

Draft Load Forecast	Draft Base Case Model	Updated Base Case + Scenario Models	Probabilistic + Sensitivity Analysis Models
3/20/2025 1	5/5/2025 2	8/20/2025 3	10/15/2025 4

- *Released data and Tech to Tech meeting attendance will be available to the technical stakeholders with a completed Non-Disclosure Agreement (NDA).*
- *Send NDA requests to IRP@Centerpointenergy.com*

Final Objectives & Metrics

Objective	Measure	Metrics
Affordability: *Consider portfolios' impact on the retail electric utility service providers' ability to provide affordable power across residential, commercial, and industrial customer classes*	➢ 20-year Net Present Value Revenue Requirement ("NPVRR")	➢ $
	➢ 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions	➢ $
	➢ **5th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions**	➢ $
	➢ **Incremental Electric energy burden (2030 – 2035)**	➢ **% HH income**
Environmental Sustainability: *Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation*	➢ CO_2 Intensity	➢ Tons CO_2/kwh
	➢ CO_2 Equivalent Emissions	➢ Tons CO_2e
	➢ **SOx and NOx Emissions**	➢ **Tons**
Reliability: *Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all times and withstand sudden disturbances* **Resiliency:** *Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions* **Stability:** *Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters*	➢ **Unserved energy across 200 dispatch iterations under varying market conditions**	➢ MWh
	➢ Spinning Reserve	➢ Portfolio MW's That Offer Spinning Reserve
	➢ Fast Start Capability	➢ Portfolio MW's That Offer Fast Start
	➢ **Transmission reliability analysis**	➢ **Dynamic VAR Support (MVAR)** ➢ **Short Circuit Ratio**
Risk/Other:	➢ Energy market purchase and sales	➢ % (average, near/long term)
	➢ **Capacity sales and purchases**	➢ **$**

Blue text indicates a new measure for this IRP cycle

MWh = Megawatt hour MVAR = Megavolt-Ampere Reactive

Q&A

Preferred Portfolio

Matt Rice

Director, Regulatory and Rates

How did we get here?

CEI South has navigated considerable uncertainty during our generation transition. While the projected mix of resources has evolved, CEI South has remained focused on providing reliable, affordable, sustainable, stable, and resilient power for its customers.

2020

- IRP recommends closing or exiting all coal except F.B. Culley 3, replacing with a diverse mix of renewables and natural gas resources

2021

- CEI South files for 626 MWs of solar resources

2022

- CEI South files for 130 MWs of solar resources
- CEI South refiles for 150 MWs of solar due to cost increases

2023

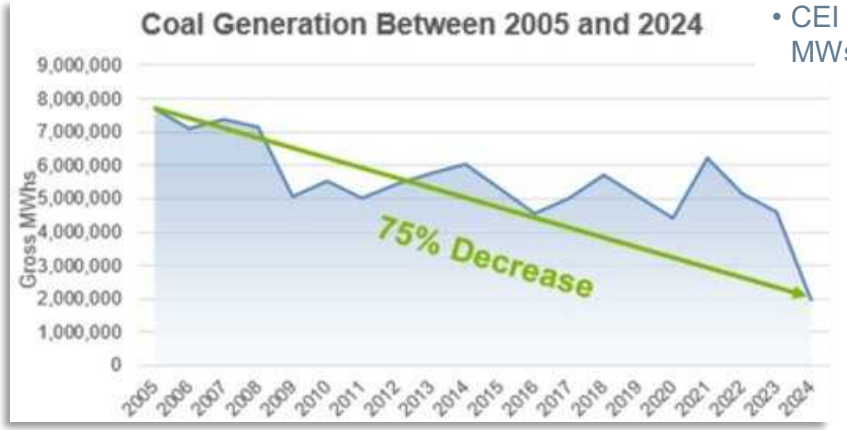
- CEI South files for 200 MWs of wind
- CEI South refiles for 285 MWs of solar due to cost increases
- IRP recommends converting F.B. Culley 3 to natural gas, replacing with wind and solar resources
- CEI South files first base rate case in 14 years (80% of revenue increase was for Posey Solar and A.B. Brown 5 & 6)

2024

- 130 MWs of solar canceled due to increased project cost
- FERC approves MISO's accreditation methodology - dramatically lowering capacity credit for solar resources
- CEI South files for 317 MWs of wind resources to replace canceled and at-risk renewables projects

2025

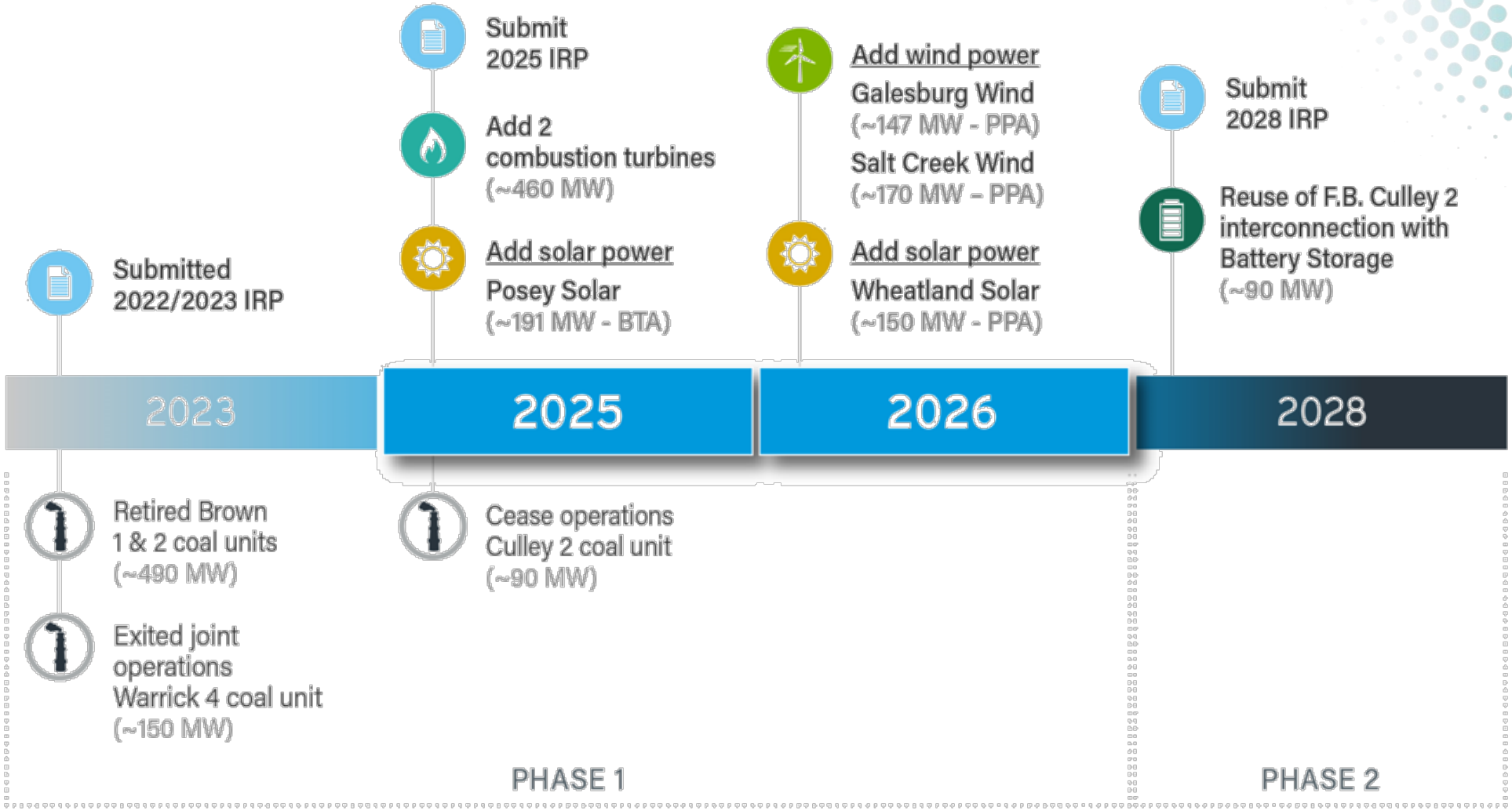
- Given uncertainty and affordability concerns, CEI South re-evaluates conversion of F.B. Culley 3 to natural gas in 2025 IRP
- 190 MW Posey Solar and 460 MW combustion gas turbines come on-line
- Executive orders from Federal and State government to avoid coal retirements
- Repeal of IRA tax incentives for wind and solar resources increases cost
- Repeal of EPA Greenhouse Gas (111) rule proposed
- 200 MW wind project and 285 MWs of solar projects canceled due to cost increases



Key Risk Considerations

	CHANGE	RISK
MISO Direct Loss of Load ("DLOL")	Major changes to capacity accreditation construct lowers the amount of installed capacity that counts towards reliability	Could over or under build resources needed to reliably and affordably serve customers
EPA Greenhouse Gas Regulations	Proposed repeal of rule 111 of the Clean Air Act is still in early stages	If finalized as proposed may not stand up to litigation or future administrations
Cost of Resources	Costs associated with all types of resources have increased dramatically due to supply chain issues or, in some cases, increased demand in the near term	Unaffordable customer bills in the near and long term
Policy Change	Executive Orders from Federal and State government focused on preserving coal plants; and less friendly towards renewable resources	May be required to continue running coal units targeted for retirement
Large Load Additions	Unprecedented load growth	Being able to safely and timely meet demand while isolating stranded asset risk away from existing retail customers
Regulatory Risk	New IURC Commissioners in 2026; more enhanced state/federal focus on affordability	Increased risk asset costs will not be fully depreciated

Generation Timeline[1]



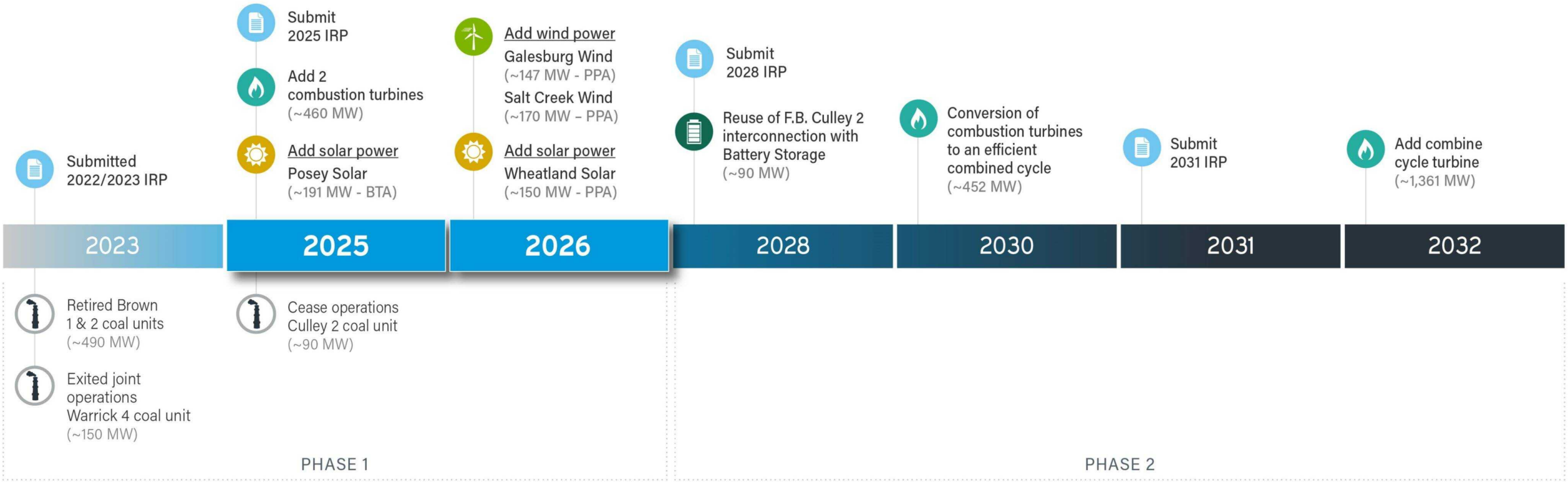
[1] *Beyond 2028, CNP will reassess generation resource selections in the next IRP*

The Preferred Portfolio[1] provides near term rate stability, while preserving flexibility to adapt to uncertainty

- Based on factors outside of CEI South's control (MISO accreditation, renewable cost increases, and repeal of tax incentives) conversion of F.B. Culley 3 with renewables/storage is no longer affordable relative to alternatives (14-17% higher)
  - The future of F.B. Culley 3 will be evaluated in a subsequent IRP
- Least cost option to replace F.B. Culley 3 in near and long term is conversion of new A.B. Brown combustion turbines (CTs) to combined cycle, along with separate battery storage projects in the near and long term
  - Preferred Portfolio provides near-term rate stability for customer **affordability** by delaying this large capital investment, while F.B. Culley 2 battery storage enables avoidance of certain required capacity purchases
  - Preferred Portfolio is within 3% of the lowest cost option in the long term
  - F.B. Culley 2 battery storage (interconnection may be utilized by 2028) cost estimate to be validated through RFP
- **Maximizes flexibility** to navigate unprecedented uncertainty; **minimizes risk**
- Provides **affordable**, **reliable** energy with a well-balanced mix of **sustainable** energy resources and continued focus on demand side resources
- **Maintains jobs and tax base** in Warrick County
- Produces **reliability** and **stability** benefits with on-system base load resources, particularly on both sides (east and west) of our system
- System **resilience** will continue to be prioritized in the evaluation of F.B. Culley 3
- Provides **flexibility** to serve a large load addition, should an **economic development** project materialize (See Alternate Preferred Portfolio)

[1] *CEI South chose portfolio 12 as the preferred portfolio. Beyond 2028, CNP will reassess generation resource selections in the next IRP.*

Alternate *Generation Timeline*



The Alternate Preferred Portfolio provides necessary flexibility to quickly pivot, keeping Southern Indiana competitive for economic development and growth

- Preserves **maximum future flexibility**, keeping Southern Indiana **competitive for economic development** and **growth**
  - Speed to market is important for prospective customers, regardless of industry
  - **Adds tax base and jobs** in our community, which helps all customers thrive
  - Aligns with Federal and State goals
- Conversion of new A.B. Brown CTs to a CCGT and F.B. Culley 2 battery storage become the most **affordable** options in the near term to support ramp
- Utilizes F.B. Culley 3 until replacement / conversion to natural gas is decided
- Adds efficient on-system base load generation for **reliability, stability** and **resilience**

Due Diligence:

- CEI South continues to have on-going conversations with prospective customers - No contract has been signed
- CEI South will continue with further studies
- Build out is dependent on prospective customer preferences
- Any new contract will address cost allocations and include protections for existing and future customers
  - Contribution to fixed costs could lower existing customer bills
  - CEI South will work to minimize risk to existing customer base (e.g., stranded assets and subsidization)

CT = Combustion Turbine *CCGT = Combined Cycle Gas Turbine*

Short Term Action Plan (Next Three Years)

Continue to implement generation transition

1

- Galesburg Wind: 147 MW – PPA (*Approved by IURC)*
- Salt Creek Wind: 170 MW – PPA (*Pending IURC approval)*
- Wheatland Solar: 150 MW – PPA *(Approved by IURC)*

Conduct an RFP for storage at F.B. Culley 2 and begin negotiations

2

- If affordable, submit a Certificate of Public Convenience and Necessity (CPCN) for 90 MW battery storage

File for DSM Plan, consistent with results of the Preferred Portfolio

3

Continue to work through due diligence for possible large load addition

4

Q&A

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 4

On break – we will return at 10:26 CDT

Risk Analysis Modeling and Portfolios

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

Scenario-Driven Portfolios
Updated Approach

Allow the model to construct an optimized portfolio for each scenario, then lock in those model outputs and run through reference case assumptions

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	No additional CO_2 regulation	Higher	Higher	Higher	Higher	Base
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

Scenario-Driven Portfolios
Updated Approach

Year	Optimized Reference Case *(Portfolio 1)*	Optimized Low Reg *(Portfolio 8)*	Optimized High Reg *(Portfolio 9)*	Optimized Alt High Reg *(Portfolio 10)*
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)			
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)		
2040	+1 50 MW 4 Hour Storage (50 MW)			
2042		+1 50 MW 4 Hour Storage (50 MW)		
2043	+1 50 MW 4 Hour Storage (50 MW)			
2045		+1 Non IRA Solar PV + Storage (100 + 50 MW)		

Updates to F.B. Culley 2 Selections

- As we continued to build out the model and refine inputs, we re-ran portfolios around the F.B. Culley 2 (FBC2) optionality.
- With the updates, the FBC2 storage decision flipped to be slightly less economic than allowing the interconnection rights to expire ("FBC2 Do Nothing") under reference case assumptions.
- The model was re-optimized for all scenarios allowing for the selection of FBC2 pathway, no longer forcing FBC2 battery in all scenario and Final Portfolios.

Year	F.B. Culley 2 Aeroderivative	F.B. Culley 2 No Interconnect Re-Use	F.B. Culley 2 Reciprocating Engines	F.B. Culley 2 Storage
2028	+1 FBC2 Aero (86 MW)	1 FBC2 Do Nothing	+1FBC2 Recip Engines (110 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031				
2032	-1 FB Culley:3 Retire 2032 (-270 MW) +1 50 MW 4 Hour Storage (50 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2033		+1 100 MW 4 Hour Storage (100 MW)		+1 50 MW 4 Hour Storage (50 MW)
2034				
2035				
2038				
2039				
2040				
2041	+1 Non IRA Solar PV (100 MW)		+1 50 MW 4 Hour Storage (50 MW)	
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)		
2043				+1 50 MW 4 Hour Storage (50 MW)
2044				
2045	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	
% Delta to Min NPV	8.1%	0.0%	5.3%	1.0%

Updated EE/DR Model Selections

Program Name	Fixed vs Selectable	Selection Frequency	Selection Percent
DR Industrial*	**Fixed**	**19/19**	**100%**
DR_CI Battery	Selectable	0/19	0%
DR_CI BYOT	**Selectable**	**19/19**	**100%**
DR_CI EV	Selectable	0/19	0%
DR_CI TOU CPP	Selectable	18/19	94%
DR_CI WH Grid	Selectable	9/19	47%
DR_Res AC Switch	**Fixed**	**19/19**	**100%**
DR_Res AC Switch_NT	**Fixed**	**19/19**	**100%**
DR_Res Battery	Selectable	1/19	5%
DR_Res BYOT	Selectable	4/19	21%
DR_Res BYOT_NT	**Fixed**	**19/19**	**100%**
DR_Res EV	Selectable	1/19	5%
DR_Res Smart Cycle	Selectable	1/19	5%
DR_Res Smart Cycle_NT	**Fixed**	**19/19**	**100%**
DR_Res TOU CPP	**Selectable**	**19/19**	**100%**
DR_Res WH Grid	Selectable	1/19	5%
DR_Res WH Switch	**Fixed**	**19/19**	**100%**
DR_Res WH Switch_NT	**Fixed**	**19/19**	**100%**
EE_CI_ERAP_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_IQ HEAR_NT, V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_IQW_V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_Res_Tier 1_HER_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_Res_Tier2_V1, V2, V3	Selectable	2/19 - 3/19	11-16%

- The EE/DR programs selected in at least 95% of the optimizations (**bolded**), consistently showed benefits to the portfolio, and were locked in for final portfolios
- The remaining EE/DR programs are still able to be selected in the portfolio optimizations

**DR Industrial is recognized as the DR Aggregation program*

Final Portfolios

(NPV values are the average from 200 stochastic runs)

Year	Portfolio1_Reference Case Portfolio	Portfolio2_FBC3 NG Flexibility on NG 2035	Portfolio3_FBC3 on Coal without ABB7	Portfolio4_FBC3 on Coal to SMR	Portfolio5_FBC3 to Simple Cycle Gas Turbine	Portfolio6_Renewable Heavy Portfolio	Portfolio7_FBC3 Gas Conversion with Renewables	Portfolio8_Low Reg Approach	Portfolio9_High Reg Approach	Portfolio10_Alt High Reg Approach	Portfolio11_FBC3 Co-Fire 2030	Portfolio12_Delayed Reference Case
2028	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	1 ABB5/6 Continue	+1 FB Culley:3 NG 2030 (270 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)	+1 FB Culley:3 Co-Fire 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	
2032	-1 FB Culley:3 Retire 2032 (-270 MW)		+1 100 MW 4 Hour Storage (100 MW)			-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW)		-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)		
2033	+1 100 MW 4 Hour Storage (100 MW)		+2 100 MW 4 Hour Storage (200 MW)		+1 100 MW 4 Hour Storage (100 MW)	+2 100 MW 4 Hour Storage (200 MW)	+2 100 MW 4 Hour Storage (200 MW) +1 50 MW 4 Hour Storage (50 MW)					
2034										+1 AB Brown7: Fired CCGT 2034 (850 MW)		+1 AB Brown7: Fired CCGT 2034 (850 MW)
2035		+1 FB Culley:3 NG 2035 (270 MW)		-1 FB Culley:3 Retire 2035 (-270 MW) +1 Nuclear - SMR (100 MW)	-1 FB Culley:3 Retire 2035 (-270 MW) +1 J Class SCGT (385 MW)							-1 FB Culley:3 Retire 2035 (-270 MW)
2038								+1 50 MW 4 Hour Storage (50 MW)				
2039											-1 FB Culley:3 Retire (270 MW) +2 50 MW 4 Hour Storage (100 MW)	
2040	+1 50 MW 4 Hour Storage (50 MW)						+1 Non IRA Wind (200 MW)				+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)
2041					+1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind (200 MW)						
2042			+1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW)		+1 Non IRA Wind + Storage (200 + 100 MW)	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)				
2043	+1 50 MW 4 Hour Storage (50 MW)											
2044											+1 50 MW 4 Hour Storage (50 MW)	
2045			+1 FB Culley:3 thru 2045 (270 MW) +2 Non IRA Solar PV (200 MW) +1 Non IRA Wind (200 MW)		+1 Non IRA Wind (200 MW)		+1 100 MW 4 Hour Storage (100 MW) +2 Non IRA Wind (400 MW)	+1 Non IRA Solar PV + Storage (100 + 50 MW)				+1 50 MW 4 Hour Storage (50 MW)

Portfolio NPV ($000)	$3,726,310	$3,717,752	$4,033,713	$4,455,790	$4,306,033	$4,308,725	$4,375,241	$3,764,366	$4,296,985	$4,211,036	$3,854,126	$3,835,823
Delta to Reference ($000)	$0	-$8,558	$307,403	$729,480	$579,723	$582,415	$648,931	$38,056	$570,675	$484,726	$127,816	$109,513
Delta to Reference (%)	0%	0%	8%	20%	16%	16%	17%	1%	15%	13%	3%	3%

Final Portfolios – Demand Side Selections

Demand Resource	Portfolio1_ Reference Case Portfolio	Portfolio2_FBC3 NG Flexibility on NG 2035	Portfolio3_FBC3 on Coal without ABB7	Portfolio4_FBC3 on Coal to SMR	Portfolio5_FBC3 to Simple Cycle Gas Turbine	Portfolio6_ Renewable Heavy Portfolio	Portfolio7_FBC3 Gas Conversion with Renewables	Portfolio8_Low Reg Approach	Portfolio9_High Reg Approach	Portfolio10_Alt High Reg Approach	Portfolio11_ FBC3 Co-Fire 2030	Portfolio12_ Delayed Reference Case
DR Industrial (25 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_CI BYOT (4 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res AC Switch (1 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res AC Switch_NT (1 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res BYOT_NT (13 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res Smart Cycle_NT (14 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res TOU CPP (6 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res WH Switch (0 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_Res WH Switch_NT (0 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_CI_ERAP_NT (4 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_CI_ERAP_V1 (12 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_CI_ERAP_V2 (13 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_CI_ERAP_V3 (39 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQ HEAR_NT (0 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQ HEAR_V1 (0 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQ HEAR_V2 (0 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQ HEAR_V3 (2 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQW_V1 (1 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQW_V2 (1 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_IQW_V3 (6 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_Res_Tier 1_HER_NT (2 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_Res_Tier 1_HER_V1 (9 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_Res_Tier 1_HER_V2 (11 MW)	x	x	x	x	x	x	x	x	x	x	x	x
EE_Res_Tier 1_HER_V3 (31 MW)	x	x	x	x	x	x	x	x	x	x	x	x
DR_CI Battery (0 MW)								x				x
DR_CI TOU CPP (2 MW)	x		x	x	x	x	x	x	x	x	x	x
DR_CI WH Grid (3 MW)	x				x	x	x	x				x
DR_Res Battery (1 MW)							x	x				
DR_Res BYOT (19 MW)					x		x	x				x
DR_Res EV (1 MW)												x
EE_Res_Tier2_V1 (3 MW)						x		x				x
EE_Res_Tier2_V2 (4 MW)						x		x			x	
EE_Res_Tier2_V3 (23 MW)			x	x	x		x					

***Bolded** programs are those that were fixed into all portfolios*
DR Industrial is recognized as the DR Aggregation program

Q&A

Portfolio Characteristics & Considerations

Matt Rice

Director, Regulatory and Rates

1- Reference Case

Benefits

- More affordable long term. Among lowest cost and cost risk
- Relatively environmentally friendly (highly efficient generation with relatively low SOx and NOx emissions)
- Adds tax base and some jobs in Posey County

Challenges

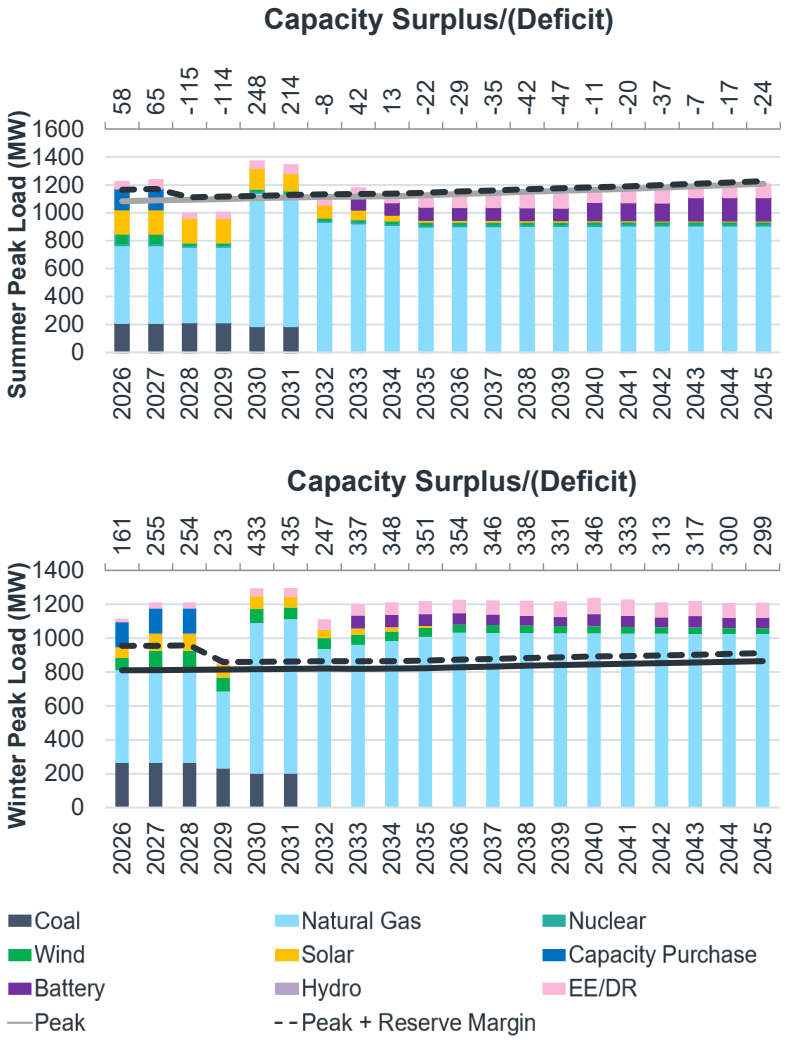
- Less flexible to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - MISO accreditation reform
  - State/Federal coal policies
- Fuel costs
- Limiting economic development opportunities (with loss of FBC3)
- Near-term large capital investment on conversion (ABB7) necessitates a near-term rate increase
- Near-term loss of spinning mass on east side of system
- Loss of jobs and tax base in Warrick County in 2032
- Loss of FBC2 interconnection (90MW) – future cost risk
- Loss of FBC3 interconnection (270MW)– future cost risk
- Energy and capacity sales revenue risk
- Increased demand for HRSGs, near term price risk

Model Selections

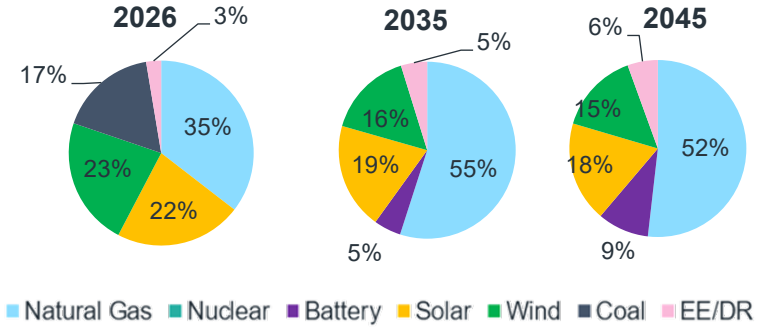
F.B. Culley 2 Do Nothing
A.B. Brown Start CCGT 01/01/2030
F.B. Culley 3 Retire 12/31/2031

1x 100 MW Storage
2x 50 MW Storage

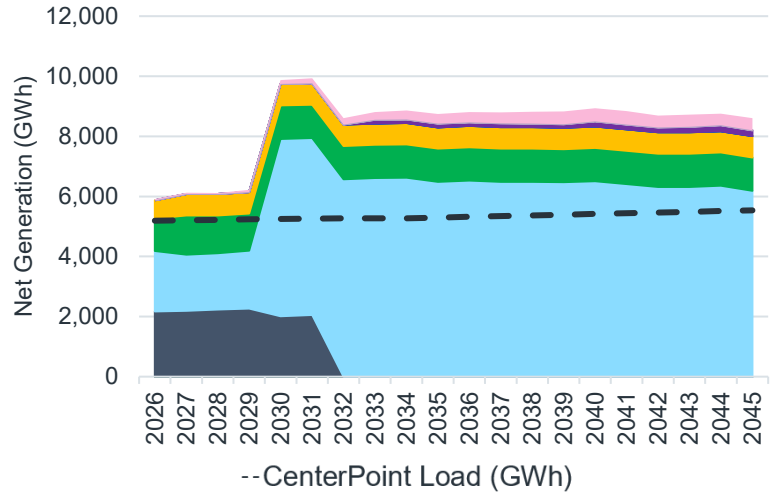
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



2 – FBC3 on NG 2035

Benefits

- More affordable long term. Among lowest cost and cost risk
- Maintains jobs and tax base in Warrick County
- Maintains FBC3 interconnection (270MW)
- Maintains spinning mass both sides of system in the long term
- Provides economic development opportunities with excess near term capacity and energy
- Adds tax base and some jobs in Posey County

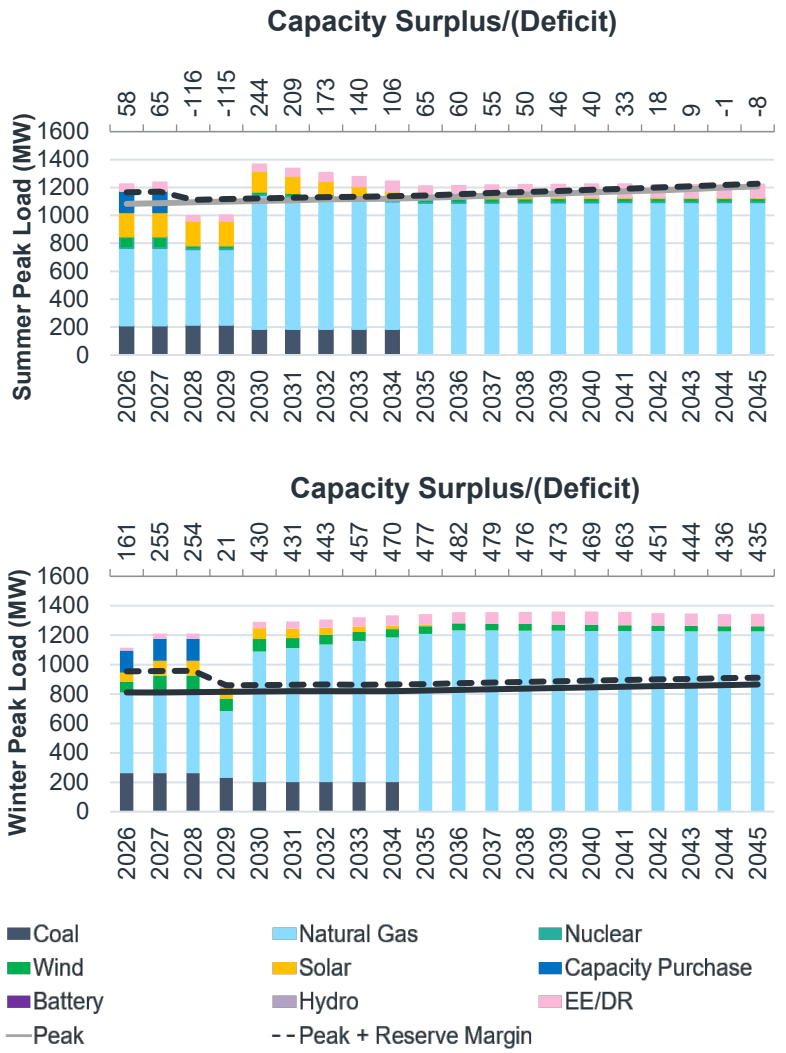
Challenges

- Near-term large capital investment on conversion (ABB7) necessitates a near-term rate increase
- Less flexible to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - MISO accreditation reform
- Fuel costs
- Overbuilds capacity in the near term
- Highest energy and capacity sales revenue risk
- Loss of FBC2 interconnection (90MW) – future cost risk
- Least resource diversity with least fast start resources
- Availability of gas capacity in 2035 is a risk
- Some unserved energy risk
- Increased demand for HRSGs, near term price risk

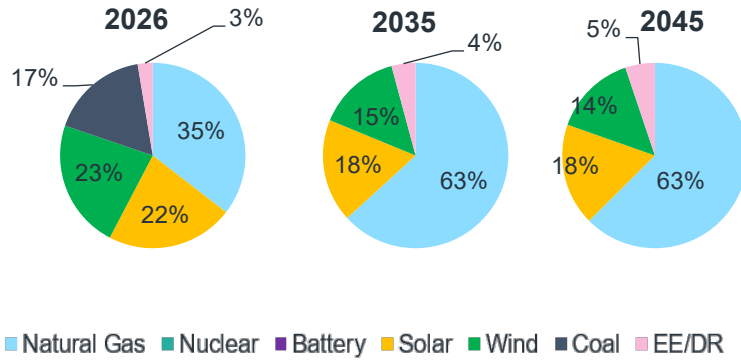
Model Selections

F.B. Culley 2 Do Nothing
A.B. Brown Start CCGT 01/01/2030
F.B. Culley 3 Start NG 01/01/2035

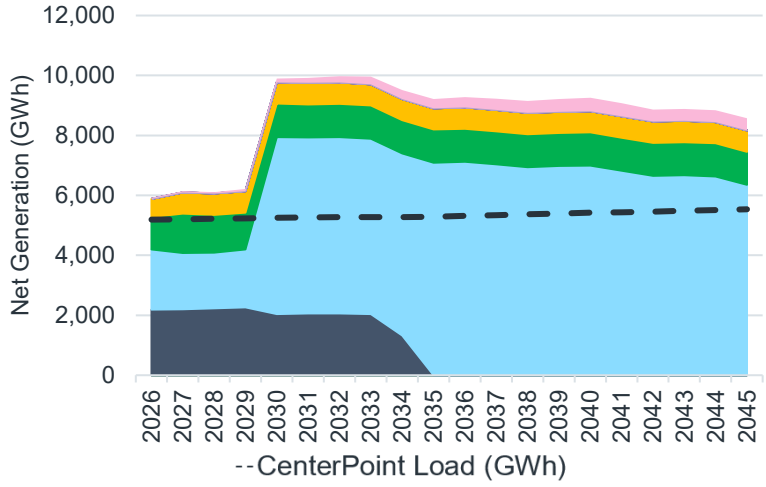
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



3 – FBC3 on Coal without ABB7

Benefits

- Provides rate stability - avoids near-term large capital investment before 2032
- Most diverse (widest variety) generation portfolio in the long-term
- Maintains jobs and tax base in Warrick County
- Maintains FBC3 interconnection (270MW)
- Maintains spinning mass both sides of system in the long term
- Consistent with state and federal near-term objectives to maintain coal

Challenges

- Long-term affordability. Higher cost and cost risk
- Environmental Challenges
  - Highest environmental emissions
  - Highly exposed to future regulatory risk
  - Customers' long term health concerns
- Investor risk (contains coal in the long run)
- Loss of FBC2 interconnection (90MW) – future cost risk

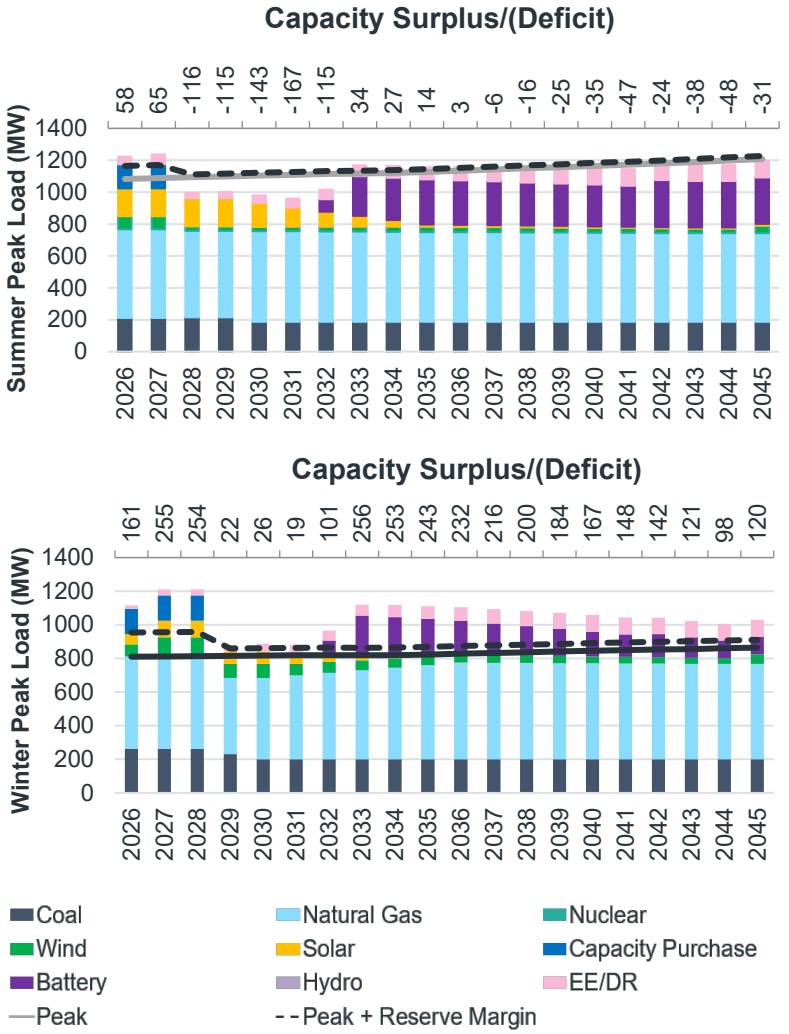
Model Selections

F.B. Culley 2 Do Nothing
A.B. Brown 5/6 Continue
F.B. Culley 3 Continue on Coal

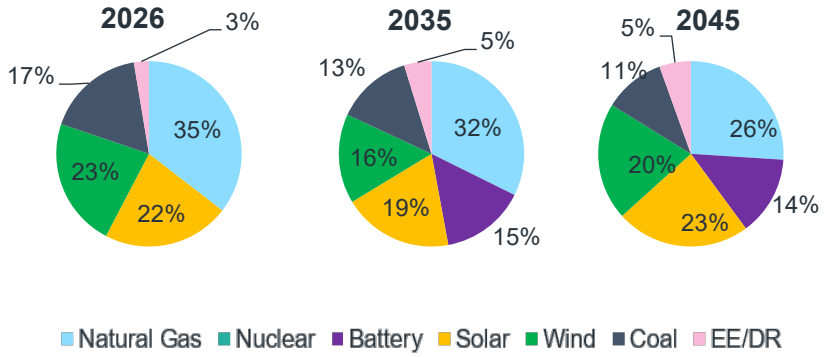
3x 100 MW Storage
1x 50 MW Storage
2x Non IRA Solar PV
1x Non IRA Wind

CenterPoint Energy

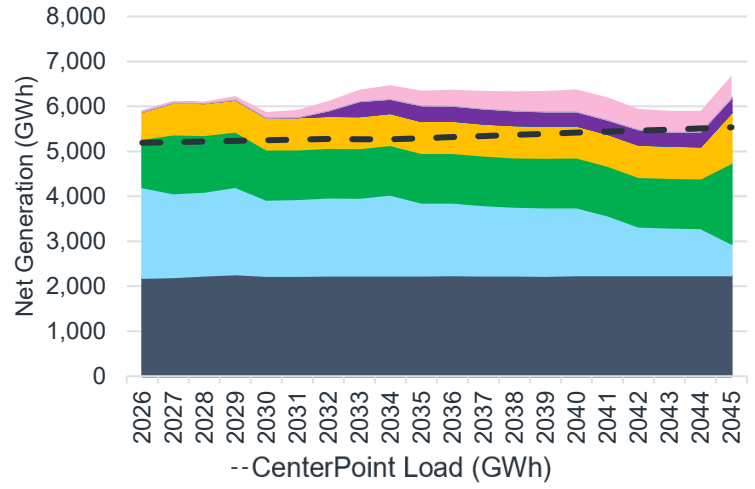
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



4 – FBC3 on Coal to SMR

Benefits

- Meets state and federal desire for nuclear energy
- Adds some jobs and tax base in Posey County. Maintain some jobs from F.B. Culley 3 closure
- Maintains spinning mass both sides of system in the near term
- Maintains 270MW interconnection (FBC3) in near-term

Challenges

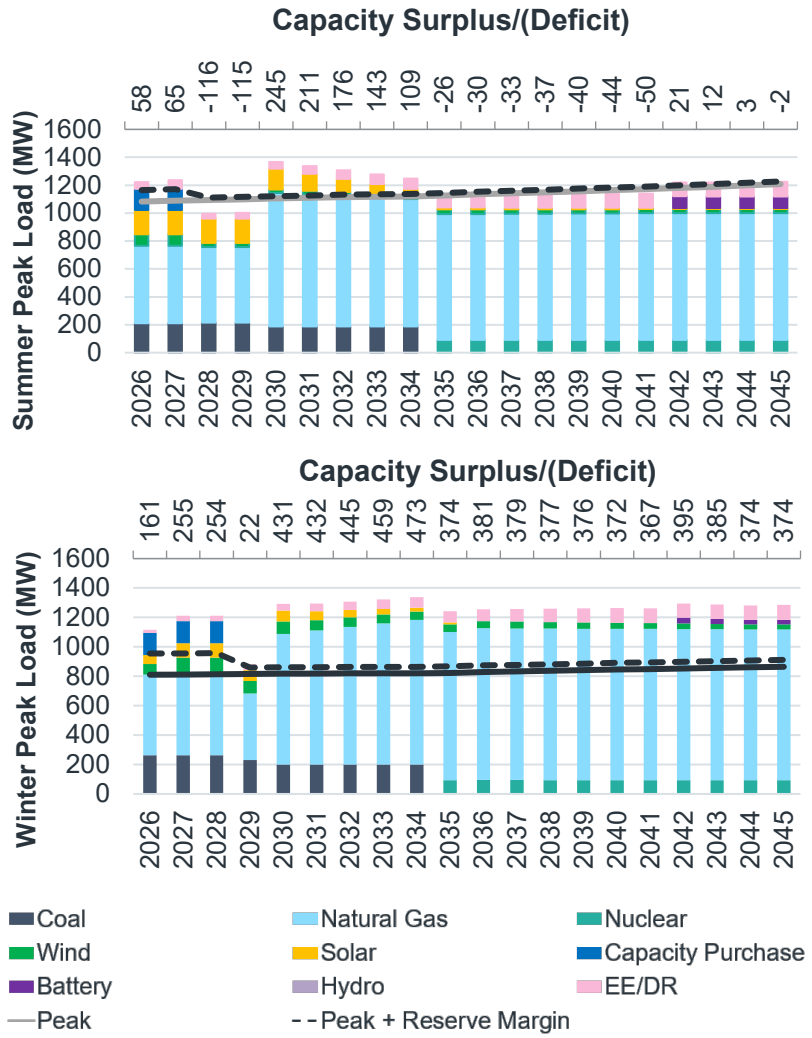
- Highest cost portfolio in the long run
- Long term cost risk – unproven technology
- Less flexible to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - MISO accreditation reform
- Fuel costs
- Large near-term capital investment on conversion (ABB7) necessitates a near-term rate increase
- Loss of jobs and tax base in Warrick County in 2035
- Loss of FBC2 interconnection (90MW) – future cost risk
- Energy and capacity sales revenue risk
- Increased demand for HRSGs, near term price risk

Model Selections

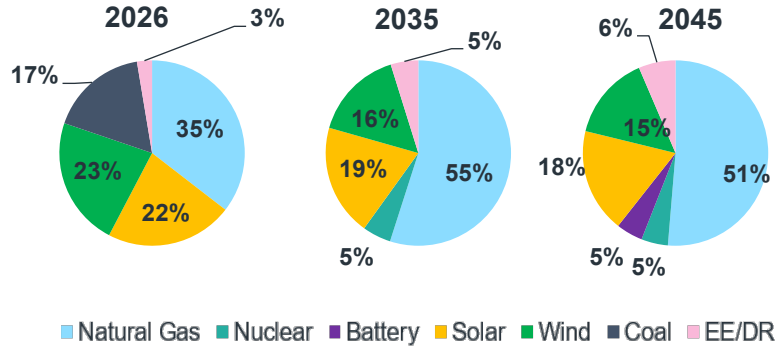
F.B. Culley 2 Do Nothing
A.B. Brown Start CCGT 01/01/2030
F.B. Culley 3 Retire 12/31/2034

1x 100 MW Nuclear - SMR
1x 100 MW Storage

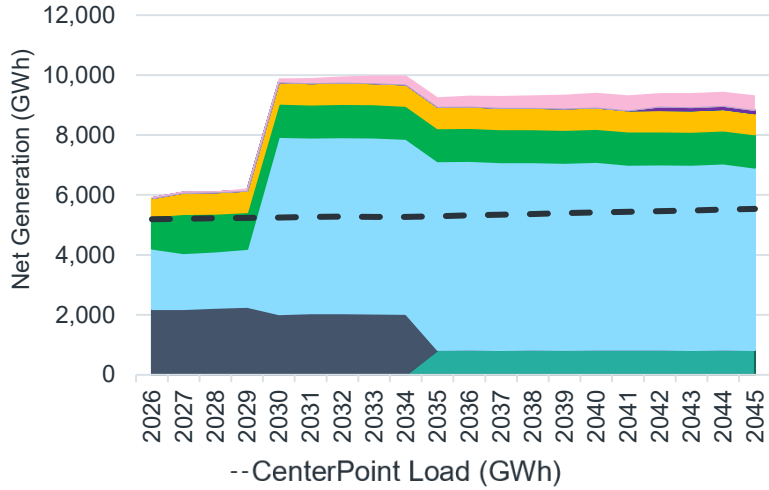
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



5 – FBC3 to Simple Cycle Gas Turbine

Benefits

- Less reliant on energy purchases and sales from the market
- Allows for continued reliance on renewables in the long-run
- Flexible. Allows time to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - MISO accreditation reform
  - State/Federal coal policies
- Limited/minimum near-term capital investment with relatively low near-term energy burden
- Maintains spinning mass both sides of system in the near term
- Maintains 270MW interconnection (FBC3) in near-term

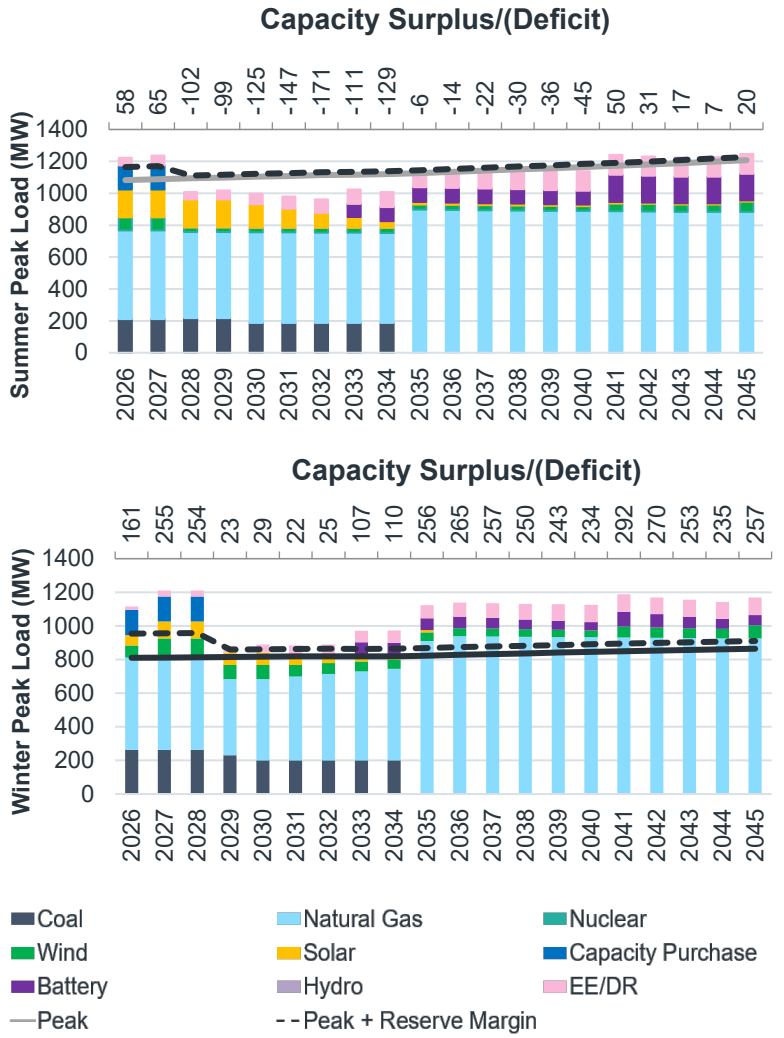
Challenges

- High-cost portfolio in the long run
- High long term cost risk
- Low spinning mass both sides of system by 2035
- Less diverse (multiple gas CTs)
- Relatively high long term energy burden
- Availability of gas capacity in 2035 is a risk
- Potential for gas pipeline regulatory risk (siting dependent)
- Loss of FBC2 interconnection (90MW) – future cost risk
- Fuel costs

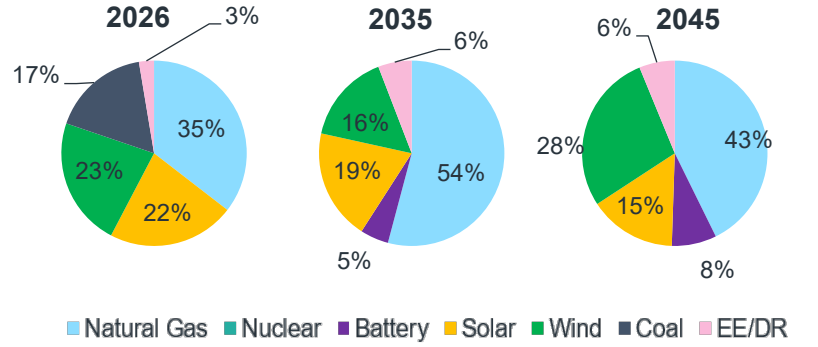
Model Selections

F.B. Culley 2 Do Nothing
A.B. Brown 5/6 Continue
F.B. Culley 3 Retire 12/31/2034
1x 100 MW Storage
1x J Class SCGT
1x Non IRA Wind + Storage
1x Non IRA Wind

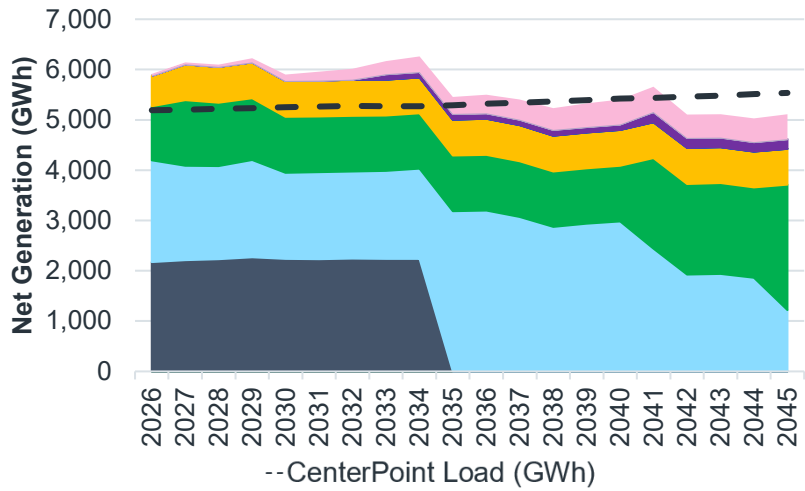
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



6 – Renewable Heavy Portfolio

Benefits

- Limited/minimum near-term capital investment until 2032 with low near-term energy burden due to tax incentives
- Environmentally friendly (CO2 emissions)
- Relatively low energy and capacity sales revenue risk
- Less fuel risk
- Less regulatory compliance risk
- Relatively high fast start capability (batteries)

Challenges

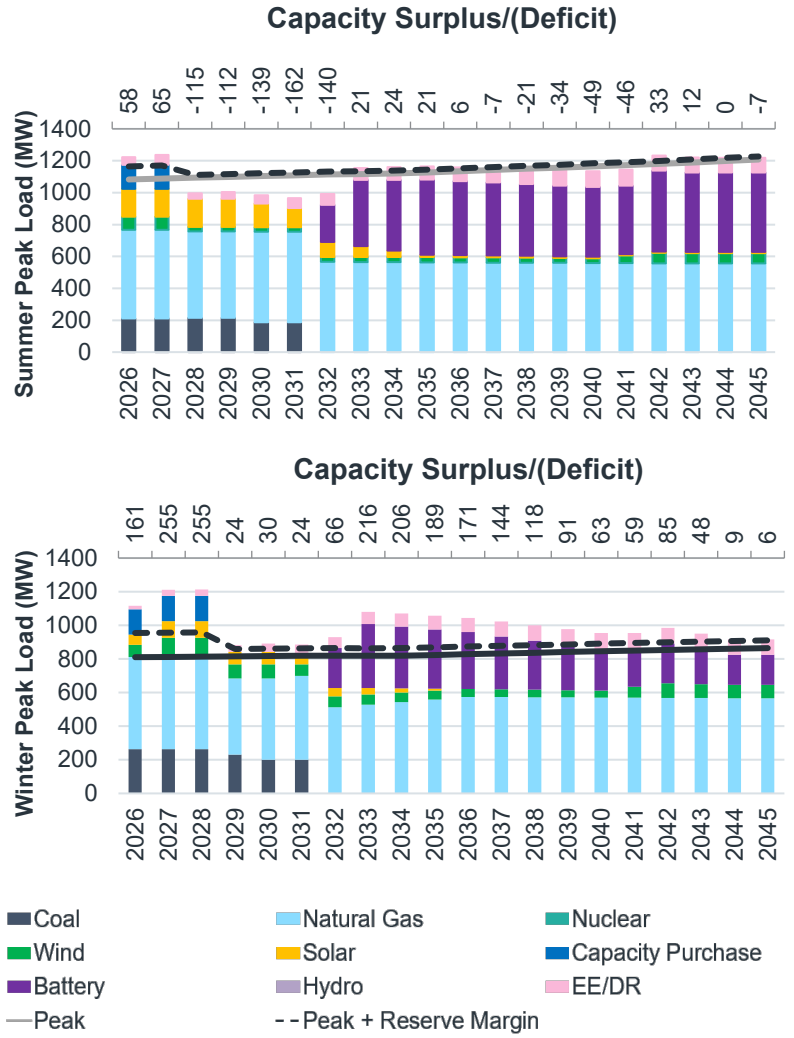
- Much less affordable:
  - High cost and cost risk portfolio in the long run
  - High energy burden in the long run
- Less flexible to adapt to regulatory & market conditions
  - MISO accreditation reform
  - State/ Federal coal policies
- Heavily reliant on energy market purchases
- Loss of spinning mass on East side of system
- More reliant on near term capacity purchases
- Loss of jobs and tax base in Warrick County in 2032
- Execution risk (500 MWs of storage between 2032-2033)
- Includes 300 MWs of additional wind in the long term (likely out of state) – local clearing requirement and congestion risk
- Loss of FBC3 interconnection (270MW)– future cost risk
- Loss of FBC2 interconnection (90MW) – future cost risk
- Limiting economic development opportunities (with loss of FBC3)

Model Selections

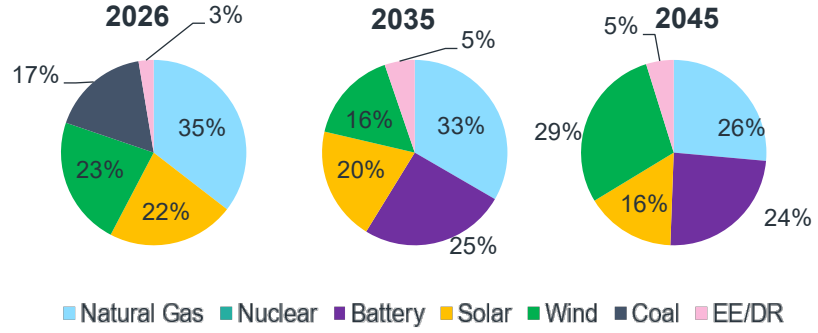
F.B. Culley 2 Do Nothing
A.B. Brown 5/6 Continue
F.B. Culley 3 Retire 12/31/2031

5x 100 MW Storage
1x Non IRA Wind
1x Non IRA Wind + Storage

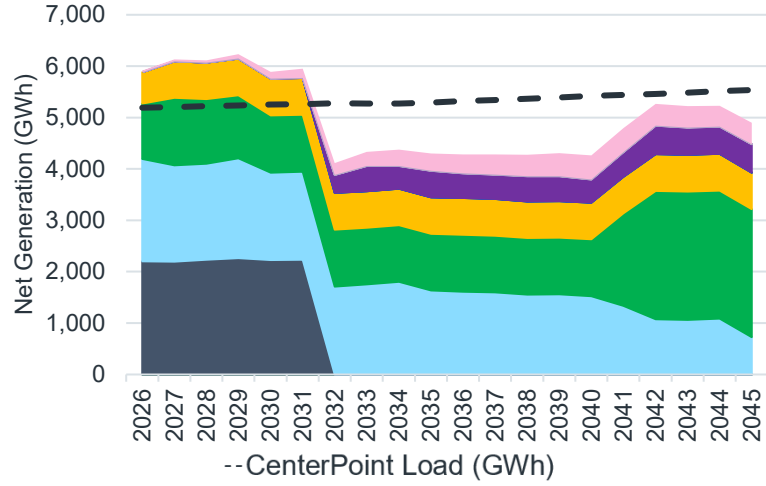
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



7 – FBC3 NG with Renewables

Benefits

- Diverse generation portfolio
- Environmentally friendly (CO2 emissions)
- Maintains jobs and tax base in Warrick County in the long run
- Maintains FBC3 interconnection (270MW) – lowers future cost risk
- Maintains spinning mass on east side of system in the long run
- Less regulatory compliance risk

Challenges

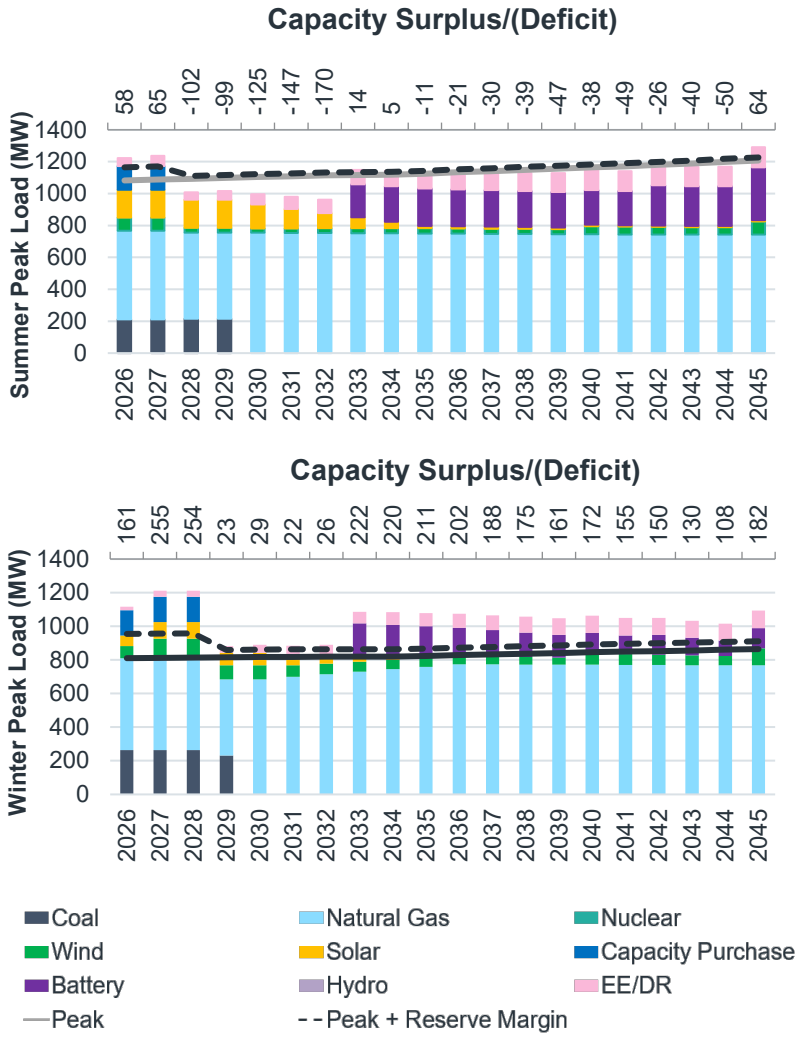
- High-cost portfolio in the long run
- High long term cost risk
- High energy burden in the near and long run
- Less flexible to adapt to regulatory & market conditions
  - MISO accreditation reform
  - State/ Federal coal policies
- Relatively high NOx emissions
- Loss of FBC2 interconnection (90MW) – future cost risk
- Limiting economic development opportunities (with early conversion of FBC3)

Model Selections

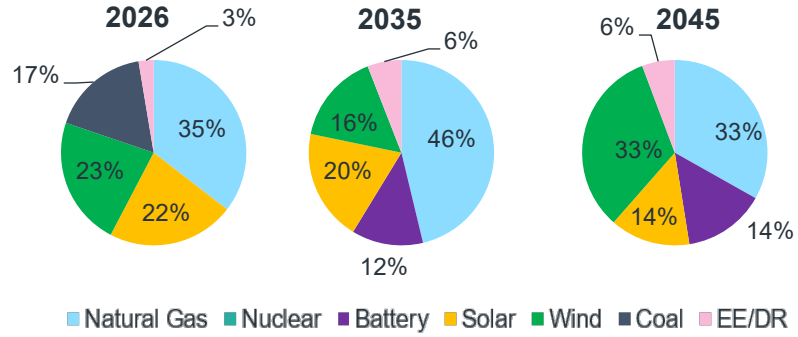
F.B. Culley 2 Do Nothing
A.B. Brown 5/6 Continue
F.B. Culley 3 Start NG 01/01/2030

3x 100 MW Storage
2x 50 MW Storage
3x Non IRA Wind

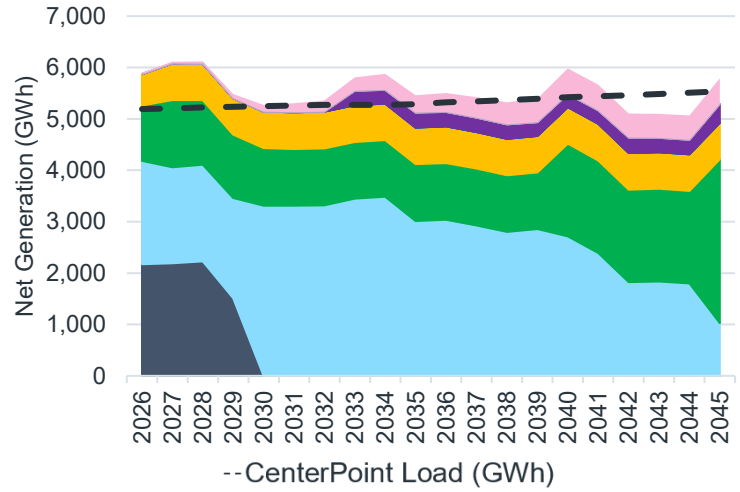
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



8 – Low Reg Approach

Benefits

- Long-term affordability. Among lowest cost and cost risk
- Relatively environmentally friendly (highly efficient generation with relatively low SOx and NOx emissions)
- Adds tax base in Posey and Warrick Counties
- Allows for near term economic development opportunities with early excess capacity
- Maintains FBC2 interconnection (90MW) – avoids future cost risk and provides reliability to the system

Challenges

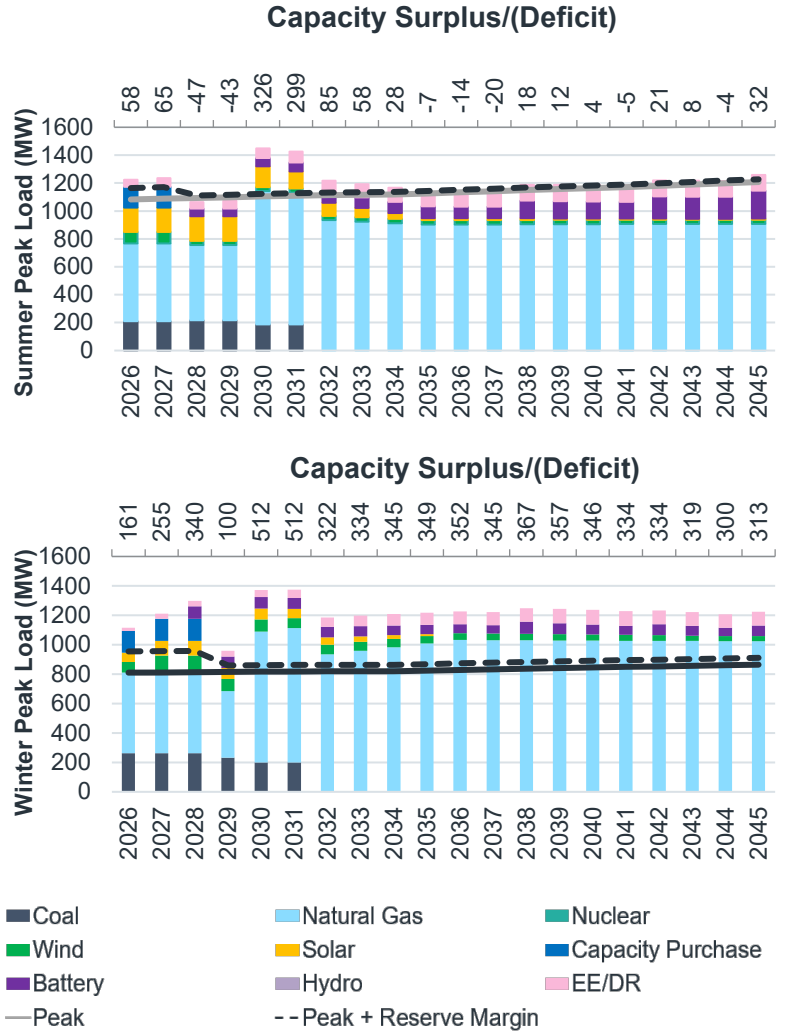
- Less flexible to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - MISO accreditation reform
  - State/Federal coal policies
- Fuel costs
- Limiting long-term economic development opportunities (with loss of FBC3)
- Near-term large capital investment on conversion (ABB7) necessitates a near-term rate increase
- Near-term loss of spinning mass on east side of system
- Loss of jobs in Warrick County in 2032
- Loss of FBC3 interconnection (270MW)– future cost risk
- Energy and capacity sales revenue risk
- Increased demand for HRSGs, near term price risk

Model Selections

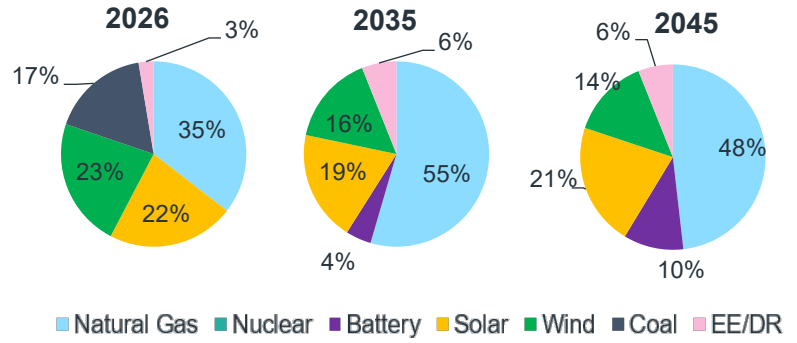
F.B. Culley 2 Storage
A.B. Brown Start CCGT 01/01/2030
F.B. Culley 3 Retire 12/31/2031

2x 50 MW Storage
1x Non IRA Solar + Storage

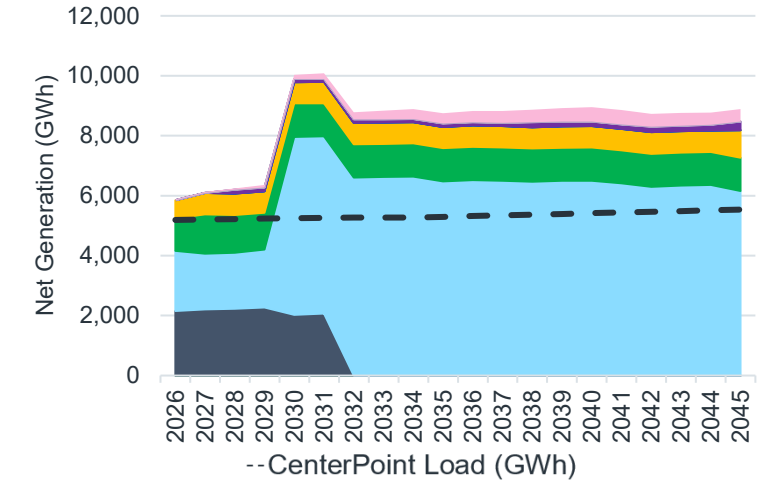
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



9 – High Reg Approach

Benefits

- Environmentally friendly (low CO2 emissions)
- Less reliant on energy and capacity sales
- Low fuel cost risk
- Less regulatory compliance risk
- Relatively high fast start capability (batteries)
- Well positioned for potential change in federal policy

Challenges

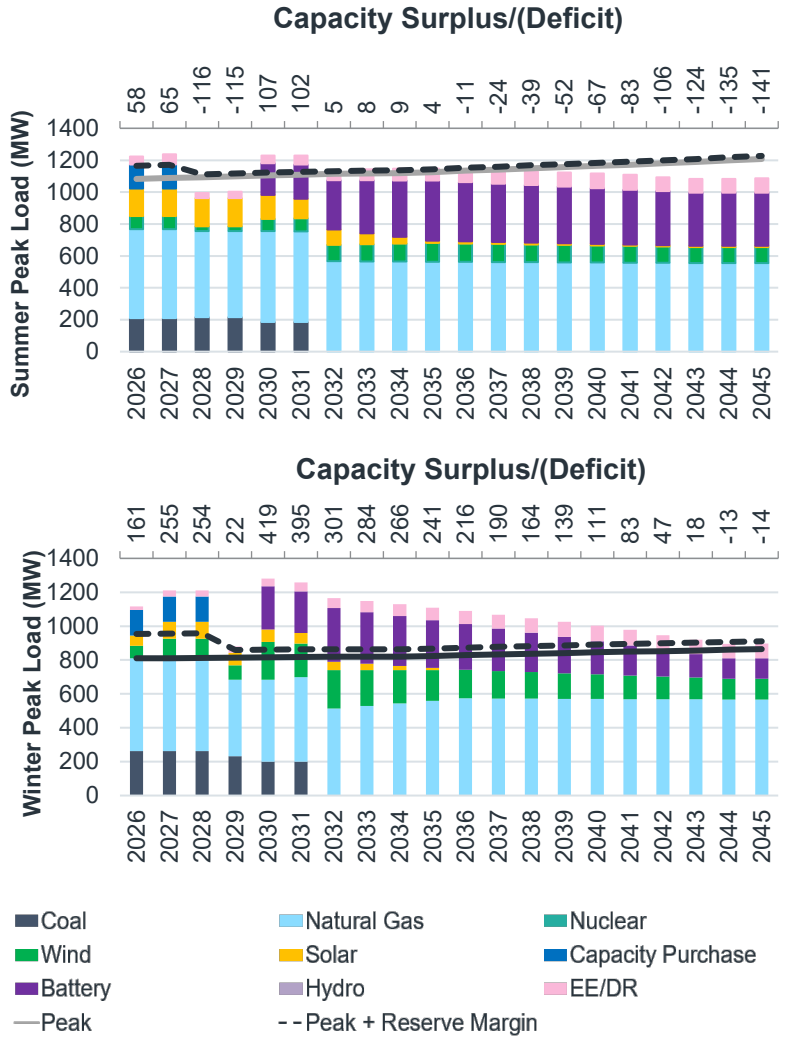
- Much less affordable:
  - High cost and cost risk portfolio in the long run
  - Among the highest energy burden in the near and long run
- Reliant on energy purchases
- Near-term loss of spinning mass on east side of system
- Loss of jobs and tax base in Warrick County
- Execution risk (800 MWs of wind + 400 MW of storage between 2032-2033)
- Includes 800 MWs of additional wind (likely out of state) – local clearing requirement and congestion risk
- Loss of FBC3 interconnection (270MW) – future cost risk
- Loss of FBC2 interconnection (90MW) – future cost risk
- Less flexible to adapt to regulatory & market conditions
  - MISO accreditation reform
  - State/Federal coal policies

Model Selections

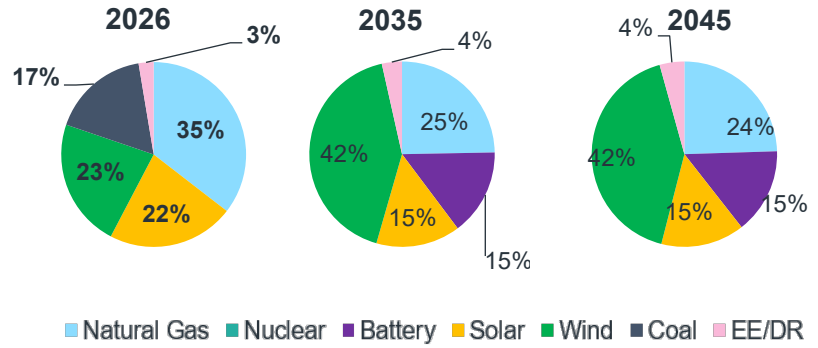
F.B. Culley 2 Do Nothing
A.B. Brown 5/6 Continue
F.B. Culley 3 Retire 12/31/2031

4x Non IRA Wind + Storage

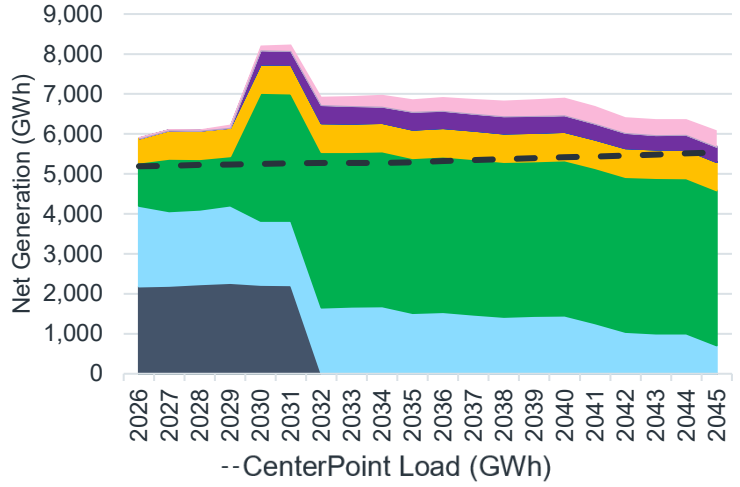
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



10 – Alt High Reg Approach

Benefits

- Flexible. Allows time to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - MISO accreditation reform
- Fuel costs
- Relatively environmentally friendly (highly efficient generation with relatively low CO2 and SOx emissions)
- Diverse generation portfolio
- Adds some jobs and tax base in Posey County in 2035
- Allows for economic development opportunities with excess capacity in the long run

Challenges

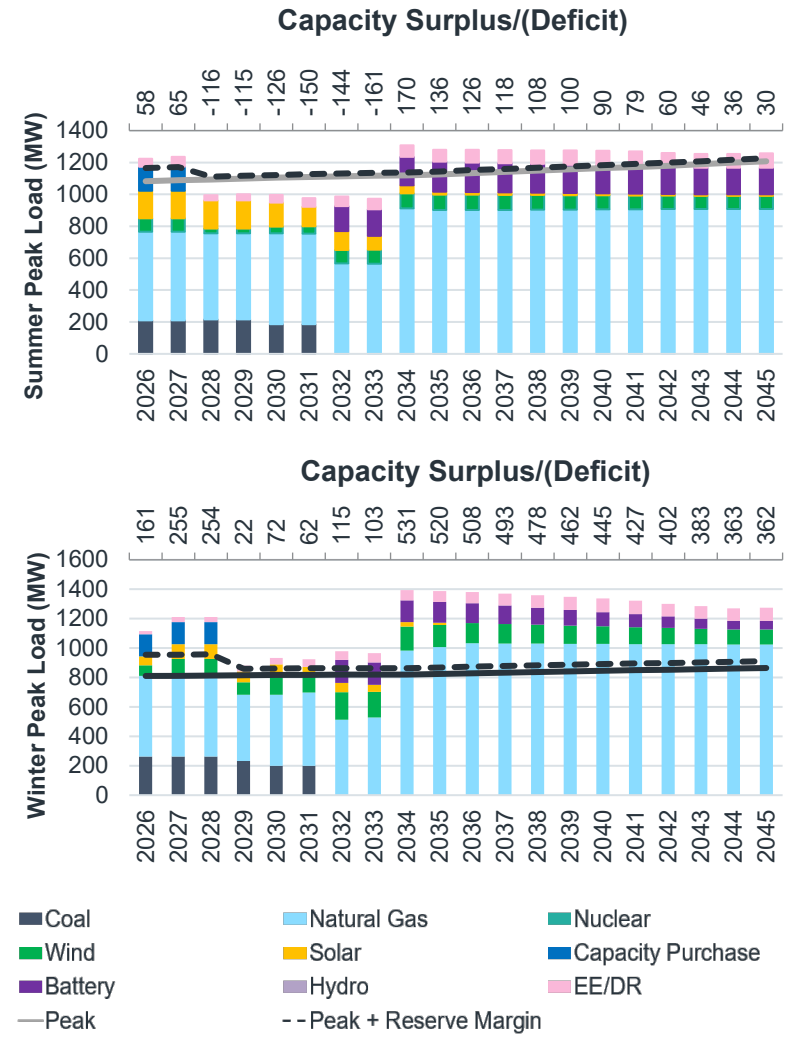
- Much less affordable:
  - High cost and cost risk portfolio in the long run
  - High energy burden in the long run
- Execution risk (wind, solar and battery in the near term)
- Loss of jobs and tax base in Warrick County
- Includes 600 MWs of additional wind (likely out of state) – local clearing requirement and congestion risk
- Near-term loss of spinning mass on east side of system
- More reliant on near term capacity purchases
- Limiting economic development opportunities in near-term (with loss of FBC3)
- Loss of FBC3 interconnection (270MW) – future cost risk
- Loss of FBC2 interconnection (90MW) – future cost risk
- Inconsistent with state and federal near-term objectives to maintain coal

Model Selections

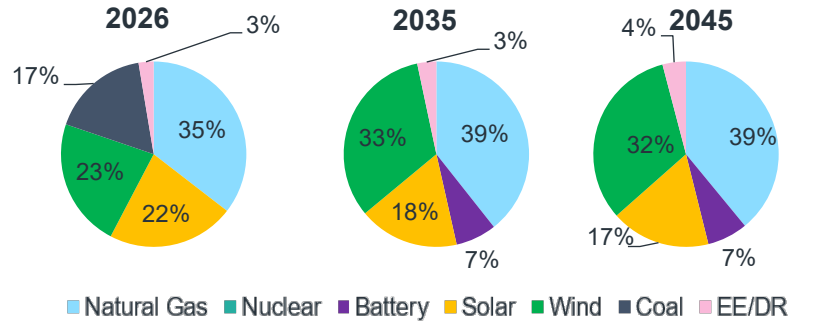
F.B. Culley 2 Do Nothing
A.B. Brown Start CCGT 01/01/2034
F.B. Culley 3 Retire 12/31/2031

1x Non IRA Wind
1x Non IRA Solar
2x Non IRA Wind + Storage

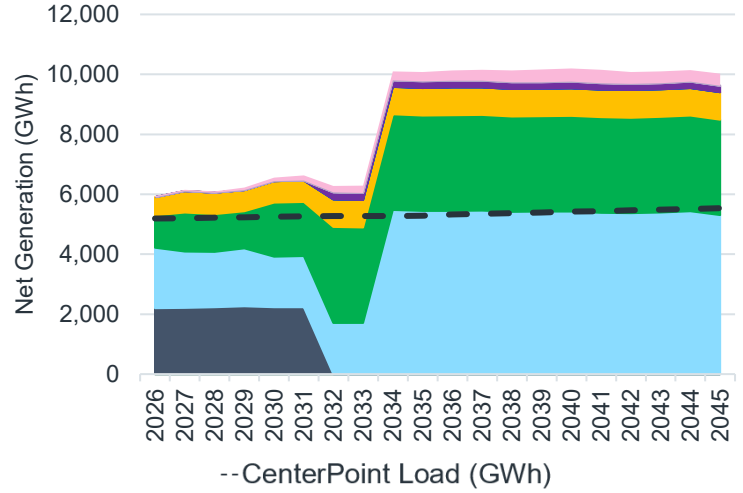
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



11 – FBC3 Co-Fire 2030

Benefits

- Relatively low-cost portfolio in the long run
- Relatively low long-term cost risk
- Allows for economic development opportunities with excess capacity and energy
- Consistent with State and Federal near-term objectives to maintain coal
- Maintains jobs and tax base in Warrick County
- Adds tax base and jobs in Posey County
- Slightly lower emissions
- Maintains FBC3 interconnection (270MW) – lowers future cost risk
- Maintains spinning mass on east side of system in the long term

Challenges

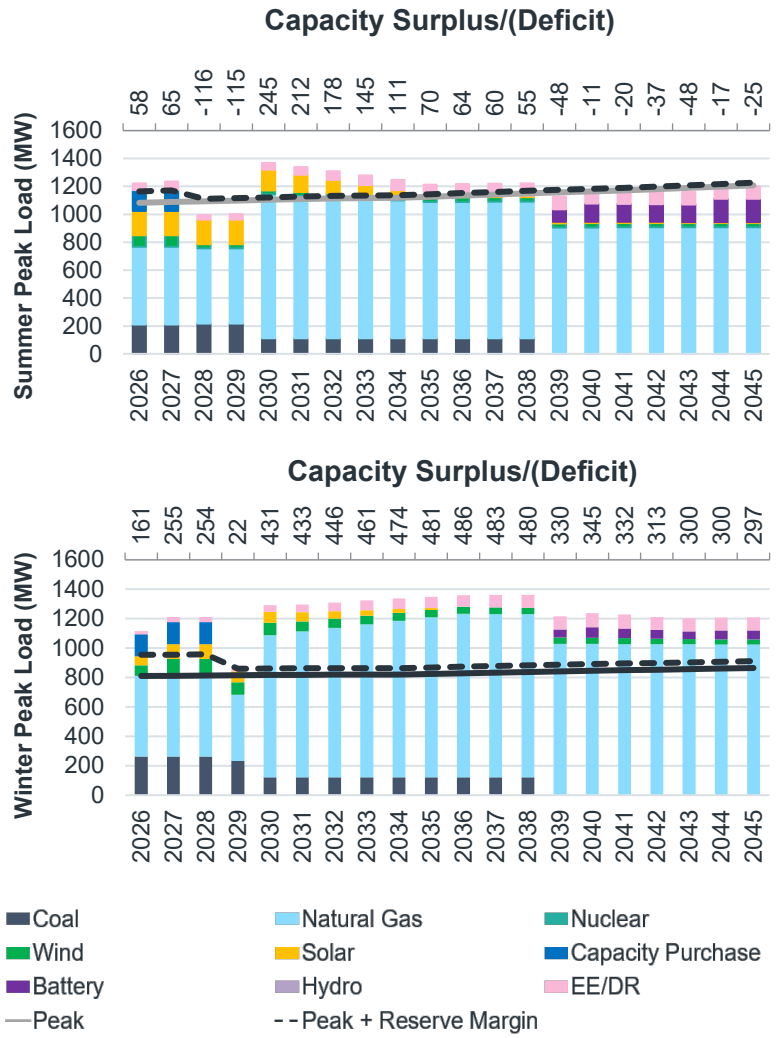
- Less flexible to adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
- Fuel costs
- Near-term large capital investment on conversion (ABB7) necessitates a near-term rate increase
- Investor Risk (continues coal in long term)
- Environmental Challenges
  - Highly exposed to future regulatory risk
  - Customers' long tern health concerns
- Near-term execution risk with 2 significant projects
- Operations risk (hybrid fuel combustion)
- Loss of FBC2 interconnection (90MW) – future cost risk
- Energy and capacity sales revenue risk
- Increased demand for HRSGs, near term price risk

Model Selections

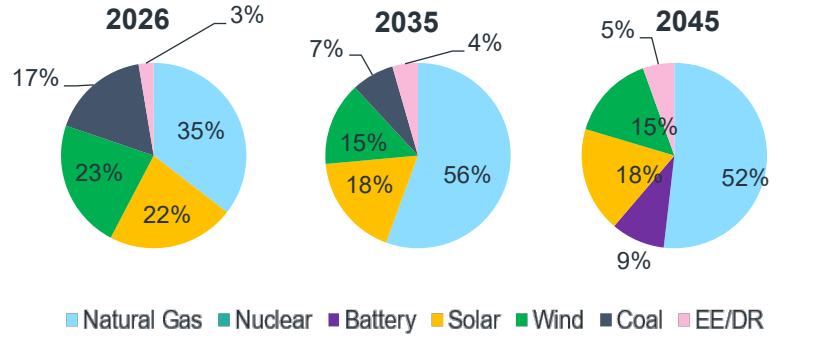
F.B. Culley 2 Do Nothing
A.B. Brown Start CCGT 01/01/2030
F.B. Culley 3 Start Co-Fire 01/01/2030 & Retire 12/31/2038

4x 50 MW Storage

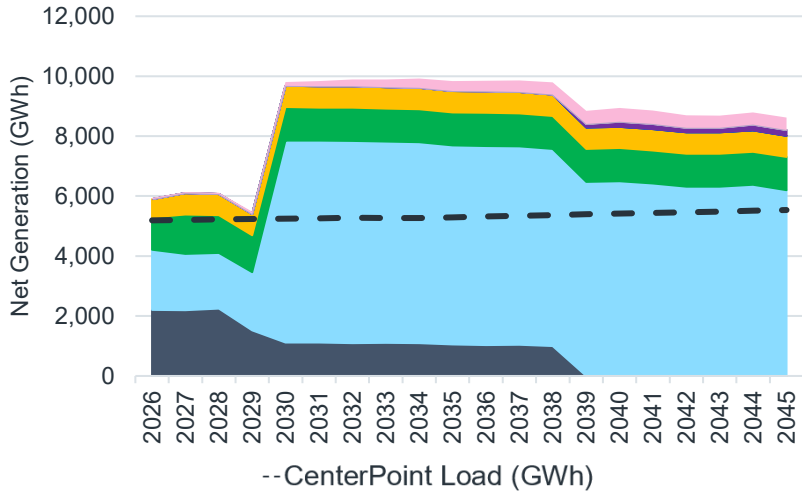
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



12- Delayed Reference[1]

Benefits

- Allows time to reassess in next IRP and adapt to regulatory & market conditions
  - EPA policies – Greenhouse Gas
  - State/Federal coal policies
  - MISO accreditation reform
- Limited near-term capital investment with relatively low energy burden
- Maintains diverse gen portfolio in the near term
- Maintains tax base in Warrick County and jobs through 2035
- Maintains 270MW interconnection (FBC3) in near-term
- Maintains FBC2 interconnection (90MW) – avoids future cost risk and provides reliability to the system
- Maintains spinning mass both sides of system in the near term
- Allows for economic development opportunities
- Adds some jobs and tax base in Posey County in 2034

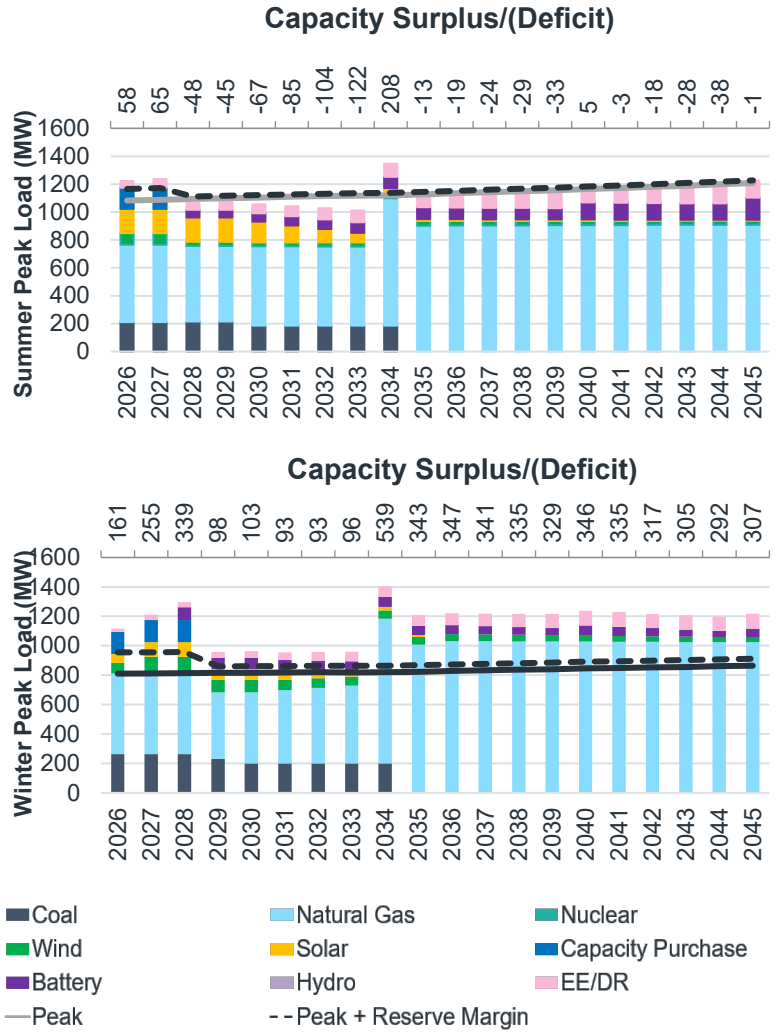
Challenges

- Uncertainty of availability of gas capacity in 2035
- Fuel costs in the long run

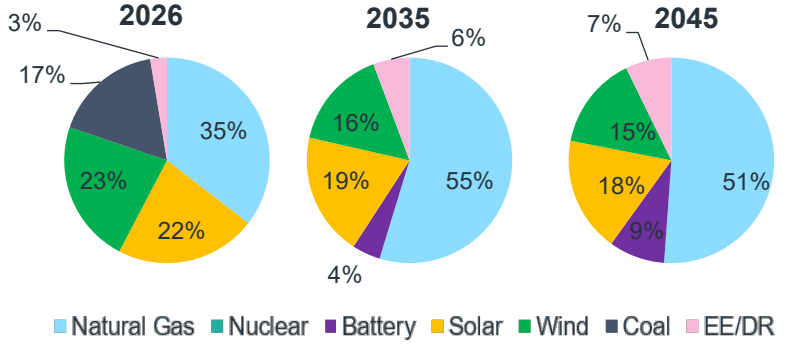
Model Selections

F.B. Culley 2 Storage — *2x 50 MW Storage*
A.B. Brown Start CCGT 01/01/2034
F.B. Culley 3 Retire 12/31/2034

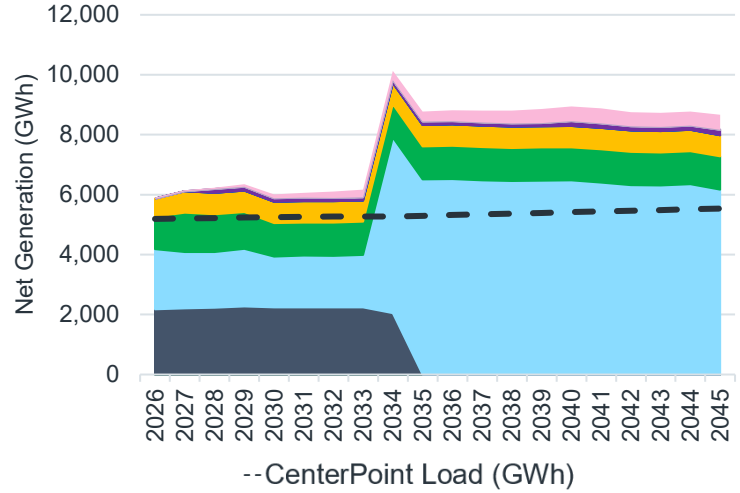
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



[1] *CEI South chose portfolio 12 as the preferred portfolio. Beyond 2028, CNP will reassess generation resource selections in the next IRP.*

Q&A

CenterPoint Energy Indiana South Integrated Resource Plan

Public Stakeholder Meeting 4

Lunch – we will return at 12:15 CDT

Risk Analysis Scorecard

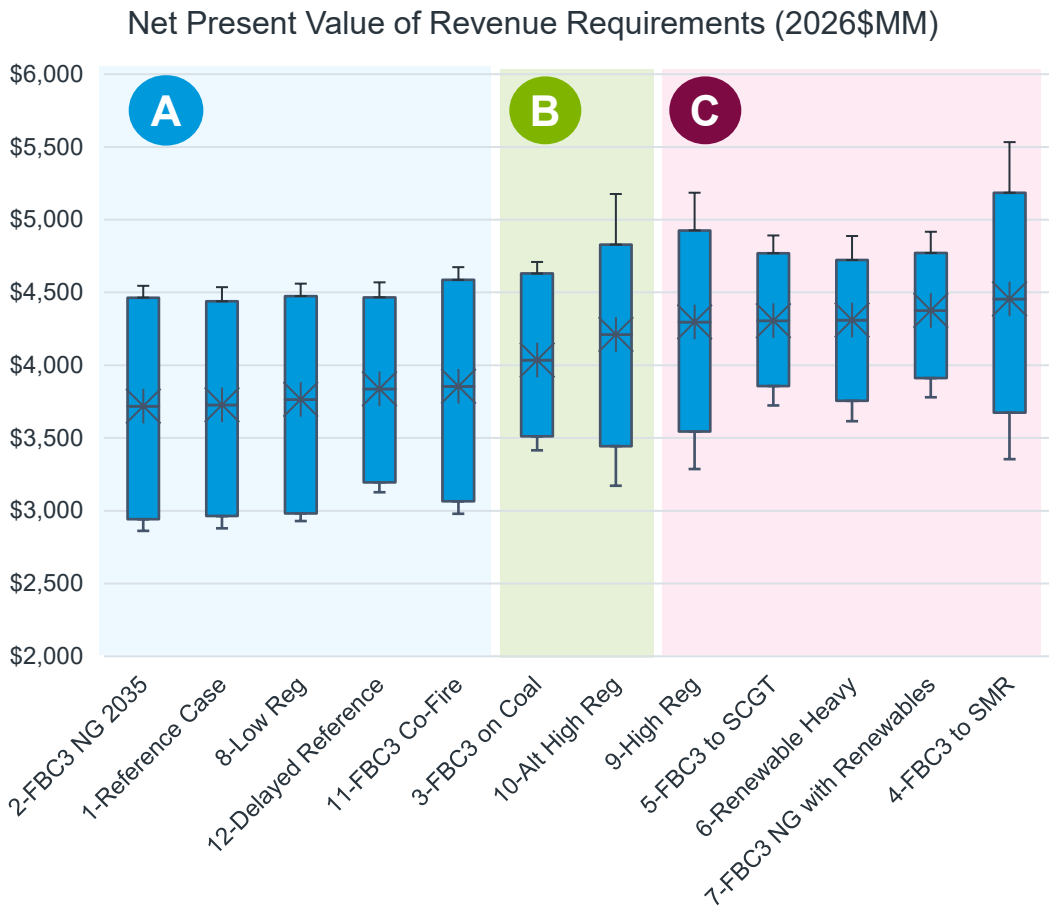
Drew Burczyk
Project Manager, Resource Planning & Market Assessments, 1898 & Co.

Final Scorecard

	Affordability					Environmental Sustainability				Reliability/Resiliency/Stability					Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	Incremental Energy Burden (%) 2030 - 2035	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (1000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Transmission Reliability Analysis MVAR	Transmission Reliability Analysis SCR	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
2-FBC3 NG 2035	$3,718	0%	$2,941	$4,464	0.13% - 0.22%	0.368	48,696	18,017	13,091	119	1,031	253	753	3.5	26%	9%	$217	$6
1-Reference Case	$3,726	0%	$2,963	$4,439	0.11% - 0.25%	0.346	44,302	12,877	10,650	61	842	340	665	3.5	26%	10%	$140	$14
8-Low Reg	$3,764	1%	$2,983	$4,475	0.15% - 0.20%	0.345	44,199	12,908	10,582	49	842	366	665	3.5	26%	10%	$167	$6
12-Delayed Reference	$3,836	3%	$3,195	$4,467	0.16% - 0.26%	0.391	46,535	21,885	14,539	56	701	444	665	3.5	23%	12%	$115	$18
11-FBC3 Co-Fire	$3,854	3%	$3,064	$4,587	0.18% - 0.17%	0.354	46,317	14,397	11,812	61	937	308	753	3.5	26%	10%	$192	$12
3-FBC3 on Coal	$4,034	8%	$3,511	$4,630	0.03% - 0.29%	0.522	53,636	51,793	25,931	43	302	835	626	3.5	15%	19%	$117	$22
10-Alt High Reg	$4,211	13%	$3,444	$4,829	0.17% - 0.48%	0.280	34,415	14,226	10,985	29	660	486	665	3.5	25%	9%	$159	$19
9-High Reg	$4,297	15%	$3,543	$4,926	0.43% - 0.44%	0.234	25,913	13,701	12,322	15	113	935	605	3.5	20%	14%	$128	$23
5-FBC3 to SCGT	$4,306	16%	$3,857	$4,770	0.14% - 0.59%	0.408	41,016	22,763	16,698	73	154	955	665	3.5	14%	21%	$93	$26
6-Renewable Heavy	$4,309	16%	$3,756	$4,723	0.10% - 0.62%	0.329	28,966	14,385	14,597	38	113	985	605	3.5	11%	30%	$95	$22
7-FBC3 NG with Renewables	$4,375	17%	$3,912	$4,771	0.26% - 0.49%	0.357	34,642	8,289	18,780	76	302	802	626	3.5	14%	23%	$106	$24
4-FBC3 to SMR	$4,456	20%	$3,674	$5,185	0.15% - 0.76%	0.342	45,224	18,653	11,950	52	938	273	665	3.5	26%	9%	$171	$13

The color coding represents the relative ranking between the portfolios

Affordability
Net Present Value of Revenue Requirements (NPVRR)



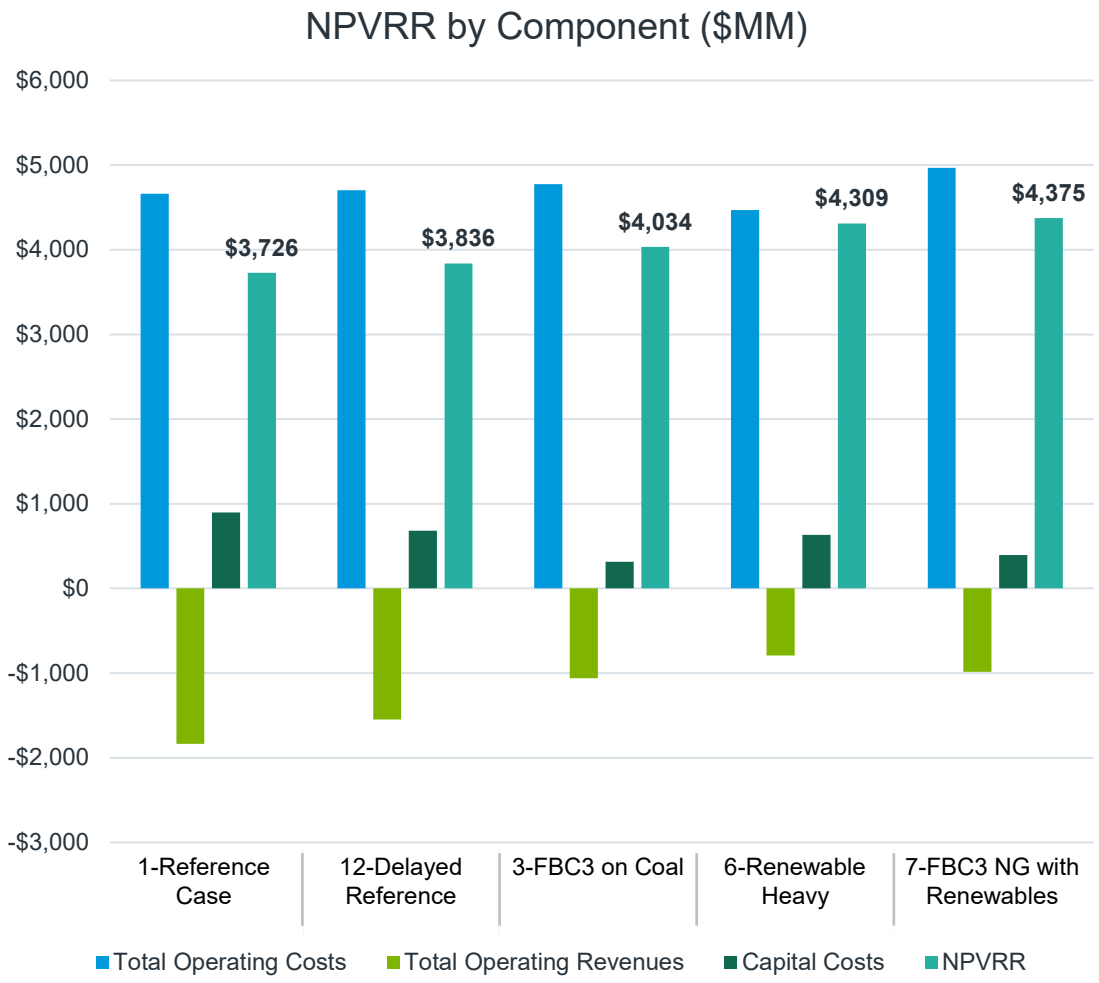
A. Within 5% of lowest average NPVRR

B. Within 15% of lowest average NPVRR

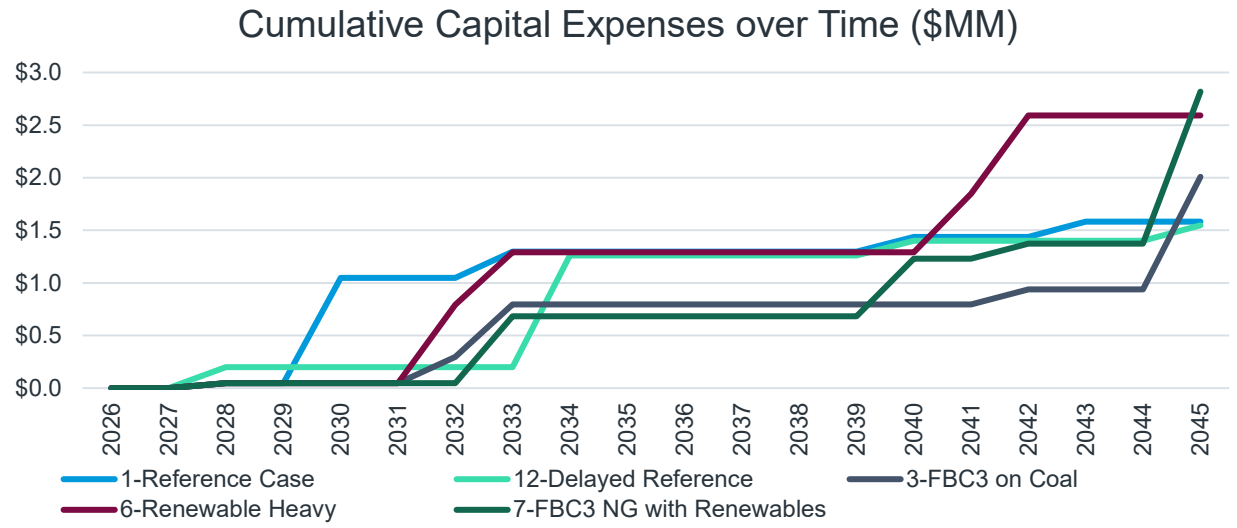
C. Within 20% of lowest average NPVRR

- Portfolios including the A.B. Brown conversion to a CCGT generally have a lower average portfolio NPV
- The distribution of NPVRR outcomes (5th and 95th percentiles) illustrates the range of NPVs derived from 200 stochastic simulations
- Factors such as capital cost, fuel cost, CO_2 tax, and market purchases or sales influence the variability in portfolio NPV results examined through the risk analysis
- While all portfolios are evaluated, portfolios (1, 3, 6, 7, 12) selected from each NPVRR category (A, B, and C) will be presented for data visualization on the following slides.
- The Preferred Portfolio average NPV is within 3% of the least cost portfolio, while relying less on market sales and capacity revenues than other group A portfolios.

Affordability
Revenue Requirements Components

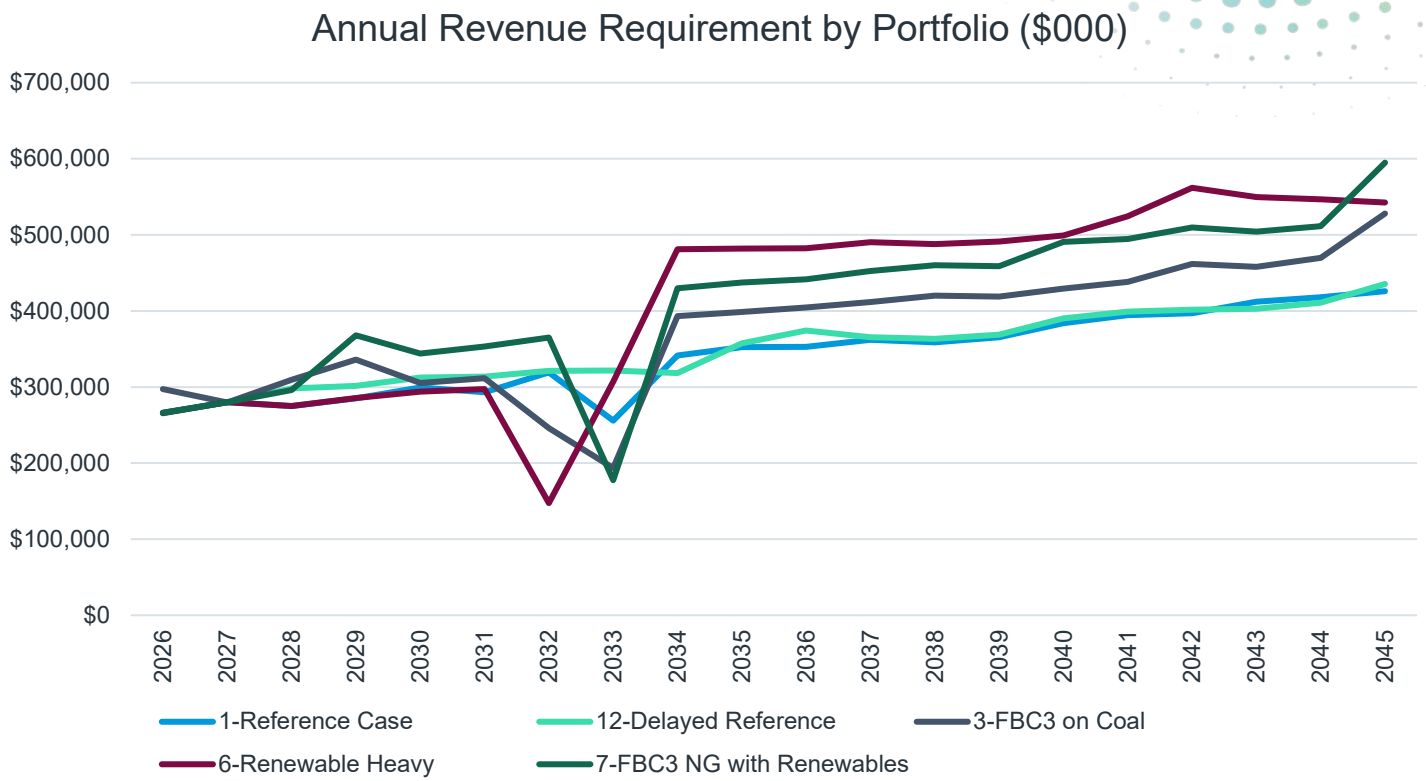


- Timing and magnitude of capital investment vary across portfolios and contribute to the NPVRR ranking of portfolios.
- Operating revenues, associated largely with market energy sales, lower the NPVRR for portfolios with the A.B. Brown conversion to a CCGT.
- Delaying the capital spend in Portfolio 12 leads to an NPV that is ~$200MM less than Reference Case Portfolio



Affordability
Annual Revenue Requirements by Portfolio

- Revenue Requirements are the sum of the total operating and capital costs minus operating revenues
- Dips in 2032 and 2033 are indicative of investment tax credit (ITC) benefits from adding storage resources to the system
- Portfolio 3, which includes FB Culley 3 on coal, has a slightly higher 2026 revenue requirement due to environmental upgrades.



Affordability
Incremental Electric Energy Burden

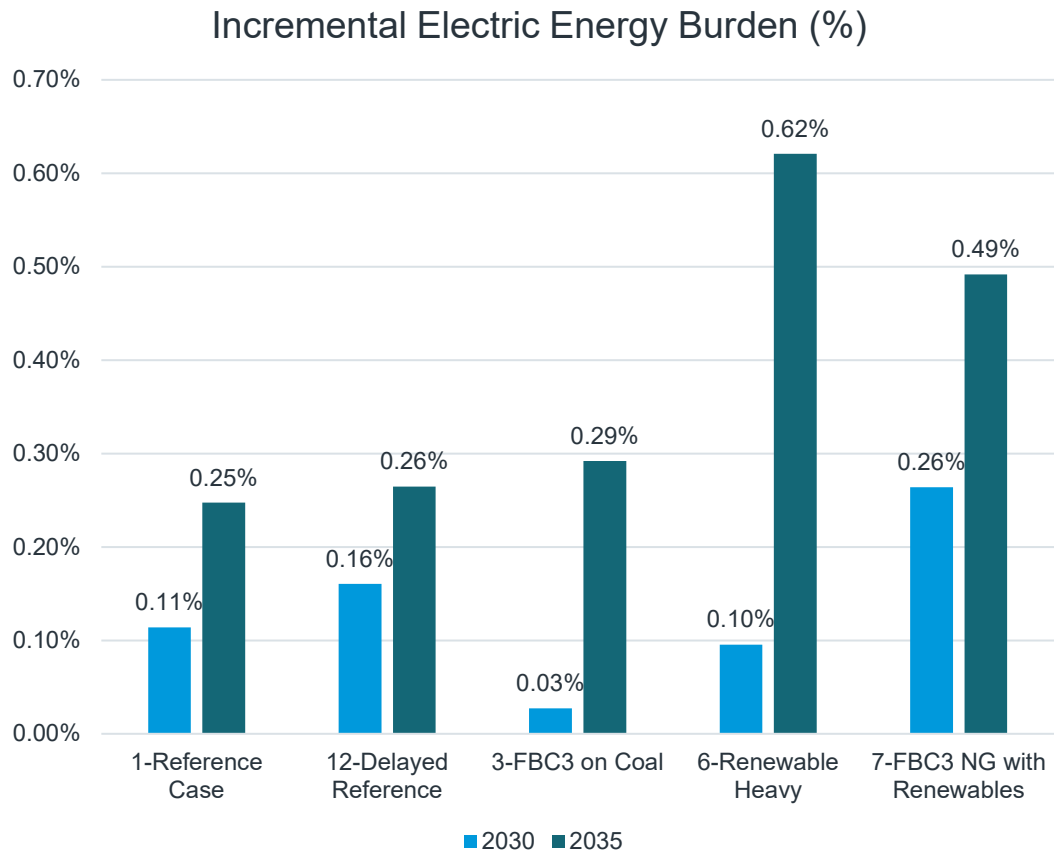
- Electric energy burden measures the affordability of increases in energy prices when compared to median household income of Vanderburgh County

Incremental Electric Energy Burden Approach

$$\frac{\left[\text{Expected annual energy bill for a given year}\right] - \left[\text{Expected annual energy bill for 2026}\right]}{\text{Projected Median Household Income for Vanderburgh County for a given year}}$$

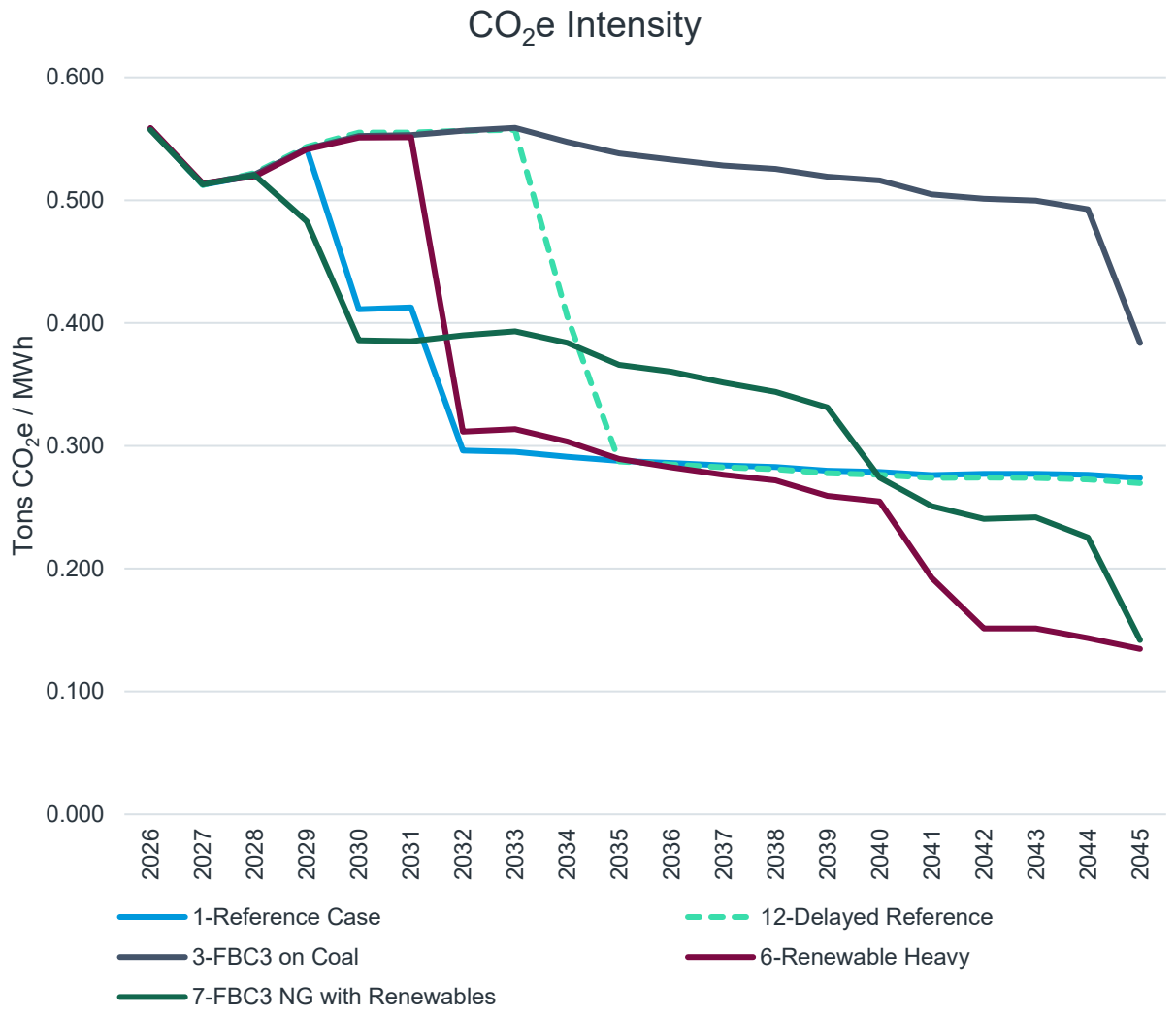
Affordability
Incremental Electric Energy Burden

- Portfolios that convert A.B. Brown 7 to a CCGT frequently have the lowest average increase in electric energy burden over both 5- and 10-year periods
- Postponing the capital expenditure for A.B. Brown 7 in the Preferred Portfolio results in lower near-term capital investment compared to the Reference Case, reducing the risk of short-term cost increases while still balancing long-term affordability
- The inclusion of 2026 environmental investments in Portfolio 3 leads to a higher initial reference point for calculating incremental energy burden compared to other portfolios



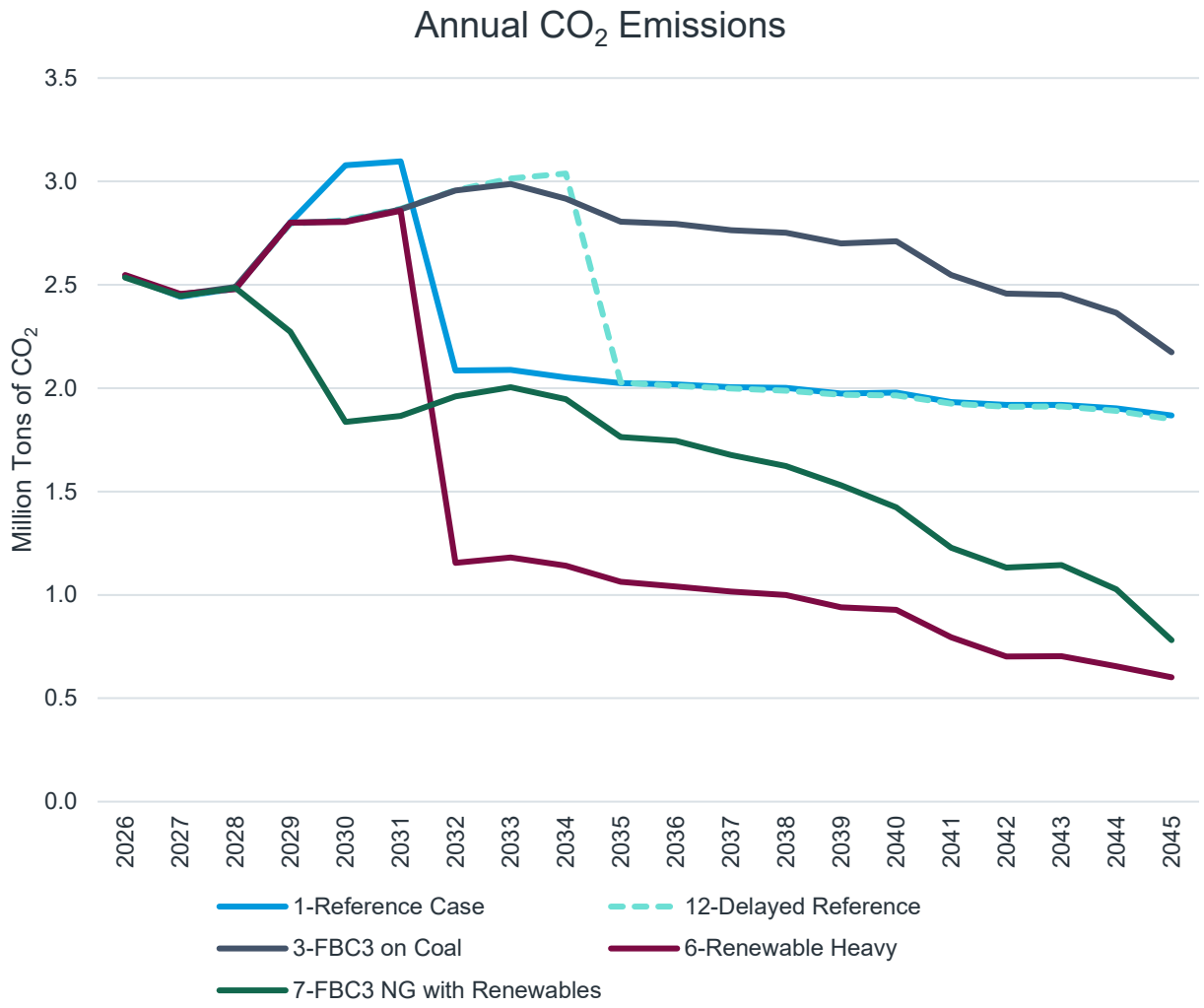
Sustainability
CO_2e Emission Intensity

- CO_2 intensity is a measure of the emissions produced by a portfolio divided by the MWh of the energy produced
- Every portfolio shows a decline in CO_2e intensity over time
- The shutdown or conversion of F.B. Culley 3 in 2030-2035 results in a reduction in emissions intensity for those respective portfolios
- All portfolios, except for Portfolio 3, show a large reduction from 2026 throughout the second half of the study period



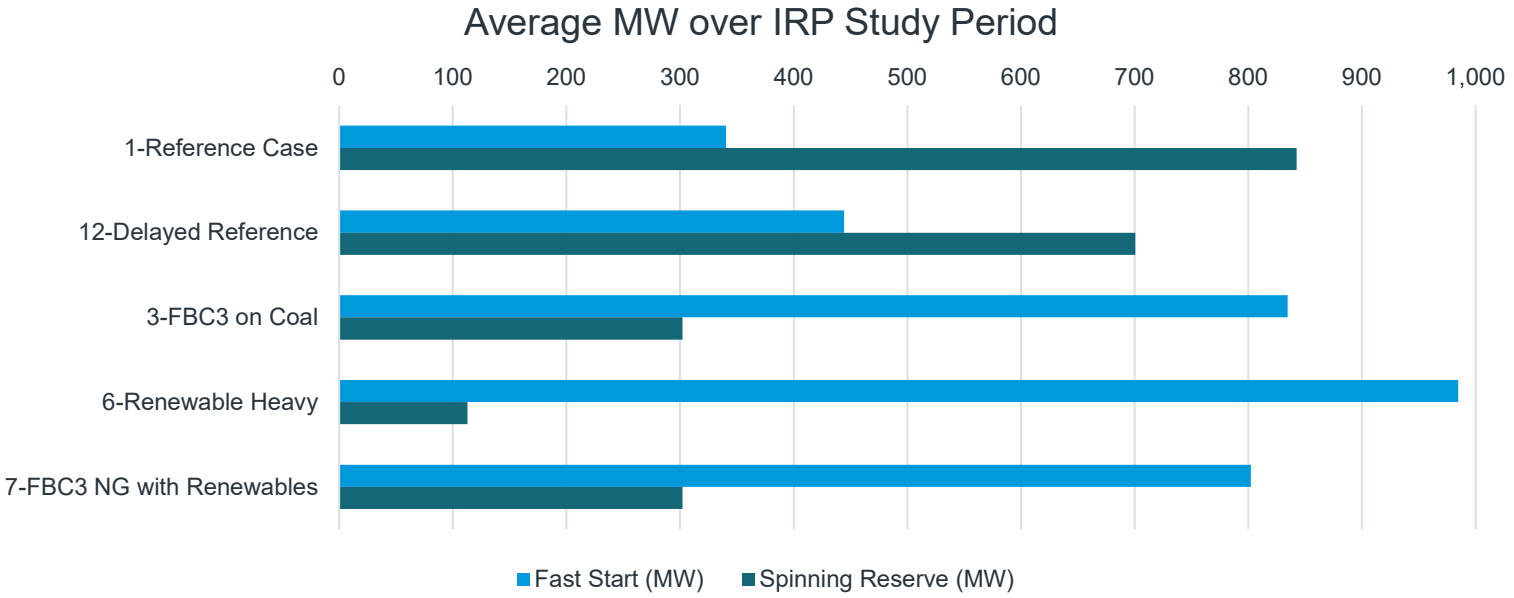
Sustainability
CO_2 Total Emissions

- Total CO_2 emissions over the study period follow a similar trend to CO_2 intensity by portfolio
- Most portfolios experience a decline in annual emissions over the study period
- This decline is largely associated with the timing of the FB Culley 3 conversion or retirement



Reliability & Resiliency
Fast Start , Spinning Reserves, Unserved Energy

- Fast Start resources (such as CTs, Batteries) are units that can reach full output within a few minutes. They give the grid operational flexibility by quickly ramping up when there's an unexpected drop in generation or an increase in demand.
- Spinning Reserve resources (CCs, Coal, Nuclear) are already online and synchronized to the grid. They can rapidly increase output to help stabilize system frequency and replace lost generation during sudden outages.

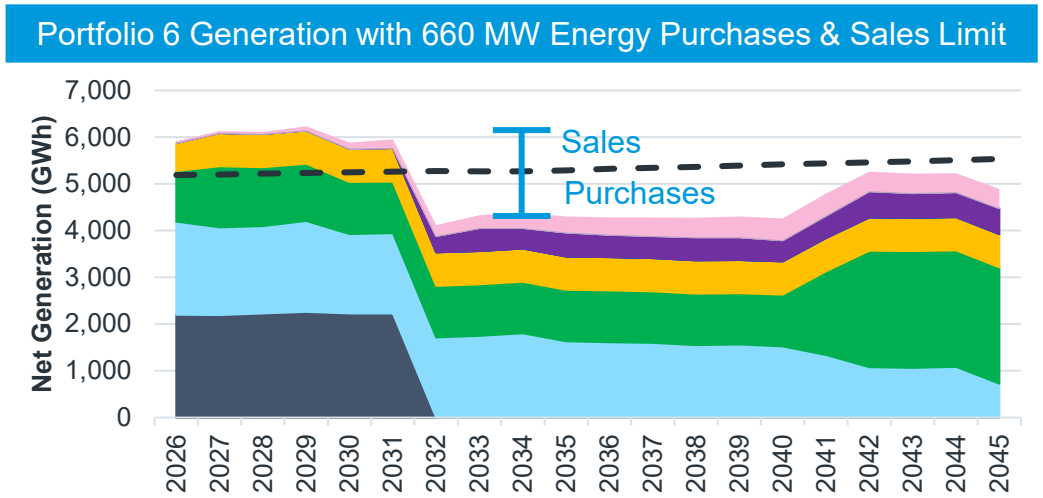


Portfolio	Average Annual Unserved Energy (MWh)
1-Reference Case	3.1
12-Delayed Reference	2.8
3-FBC3 on Coal	2.2
6-Renewable Heavy	1.9
7-FBC3 NG with Renewables	3.8

Stability and additional transmission analysis slides can be found in the Appendix

Risk/Other
Energy Purchases/Sales

- In the production cost model, the purchasing or selling of energy with the MISO market lowers portfolio costs for the benefit of customers
- In the risk analysis, the allowable amount of energy sales varied across the 200 draws to highlight the impact of energy sales on portfolio performance
  - 1/3 of the draws assigned 165 MW energy sales limit
  - 1/3 of the draws assigned 300 MW energy sales limit
  - 1/3 of the draws assigned 660 MW energy sales limit
- In the risk analysis, the limit for energy market purchases was kept at 660 MW for all runs
  - Reducing the market purchases would force portfolios to incur unrealistic unserved energy penalties

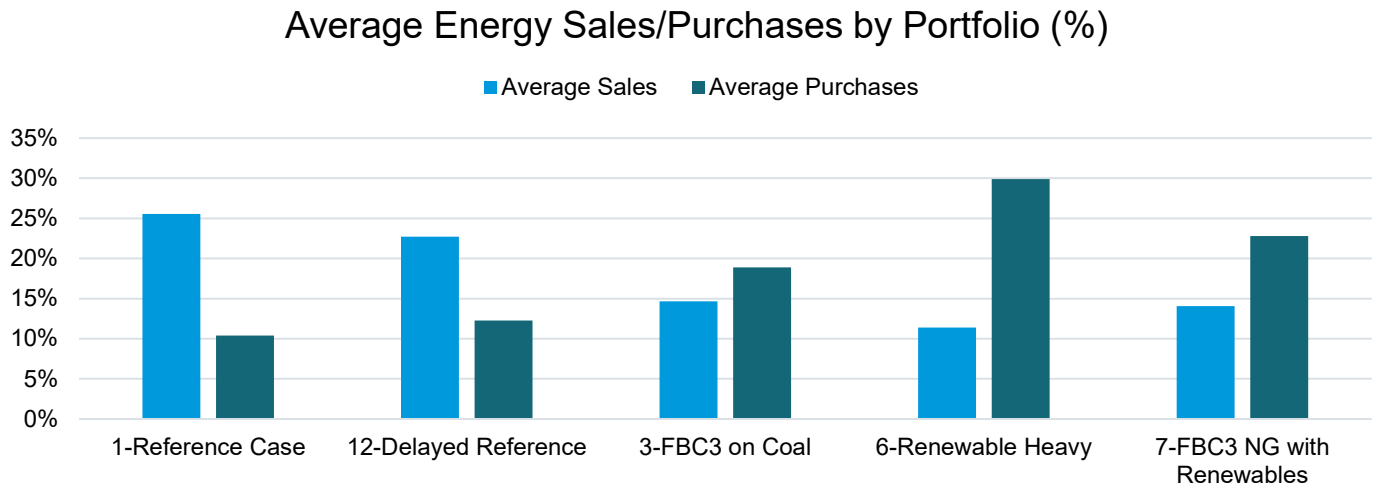


Risk/Other
Energy Purchases/Sales

- The Preferred Portfolio has moderate energy sales, suggesting that it can sell excess energy but does not depend as much on sales profits to maintain its cost-effectiveness across the study period as other portfolios with A.B. Brown 7.
  - Of the portfolios within 5% of the lowest NPVRR, Portfolio 12 shows the lowest reliance on energy sales over the study period.

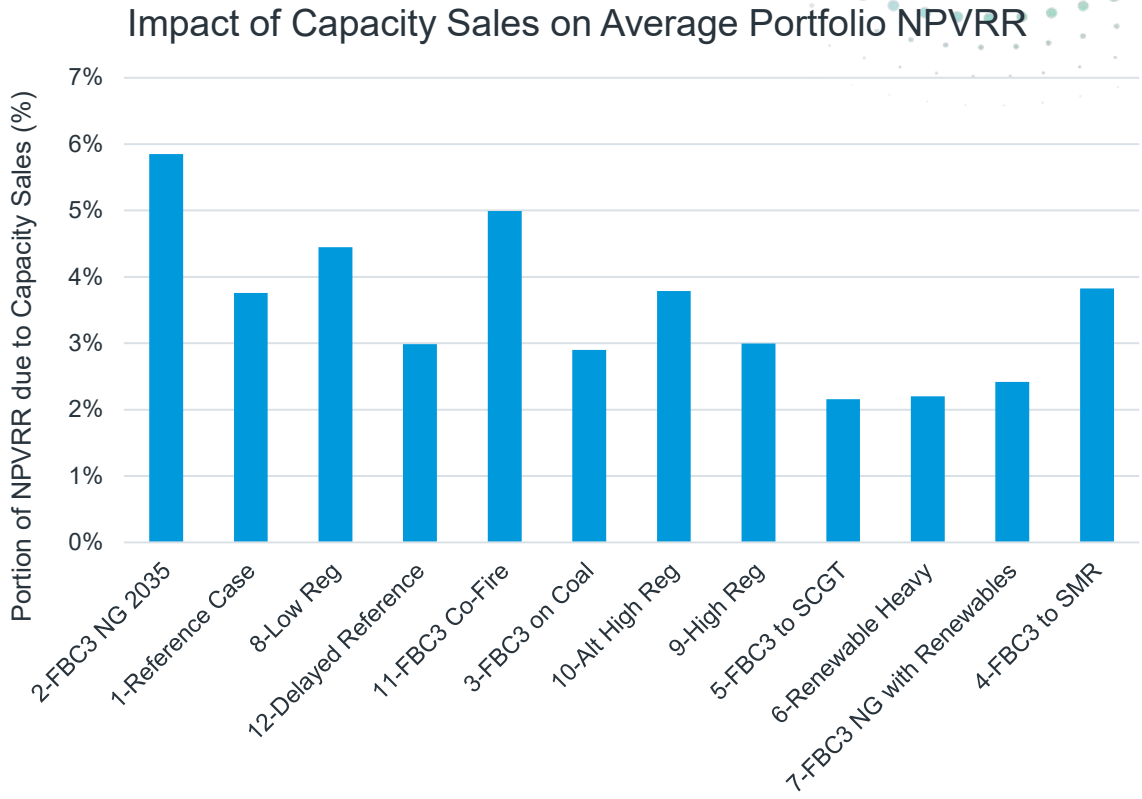
- The Preferred Portfolio shows lower reliance on market purchases, indicating that CEI South can serve its customers' energy needs, while still capable of purchasing energy from the MISO market when economically advantageous to do so.

Portfolio Description	Energy Market Sales (%)			Energy Market Purchases (%)		
	Average	Short Term Max	Long Term Max	Average	Short Term Max	Long Term Max
2-FBC3 NG 2035	26%	32%	31%	9%	16%	9%
1-Reference Case	26%	32%	30%	10%	17%	11%
8-Low Reg	26%	32%	30%	10%	17%	11%
12-Delayed Reference	23%	17%	31%	12%	21%	11%
11-FBC3 Co-Fire	26%	32%	31%	10%	22%	11%
3-FBC3 on Coal	15%	18%	18%	19%	21%	26%
10-Alt High Reg	25%	20%	32%	9%	17%	5%
9-High Reg	20%	26%	23%	14%	17%	16%
5-FBC3 to SCGT	14%	17%	18%	21%	20%	29%
6-Renewable Heavy	11%	16%	13%	30%	37%	40%
7-FBC3 NG with Renewables	14%	17%	19%	23%	26%	30%
4-FBC3 to SMR	26%	32%	31%	9%	16%	8%



Risk/Other
Capacity Purchases/Sales

- The model is designed to allow CEI South to sell surplus system capacity during any season
- Portfolios containing greater surplus capacity experience increased capacity sales, which reduce the portfolio's NPV
  - Portfolio 2 benefited most relative to other portfolios from the allowance of capacity sales, which led to the stochastic average NPVRR being lower than the Reference Case Portfolio
- Capacity sales are made at the consensus IRP seasonal capacity price. There is uncertainty in the future price and demand for capacity sales, which lead to the breakout of this metric in the risk section of the scorecard.



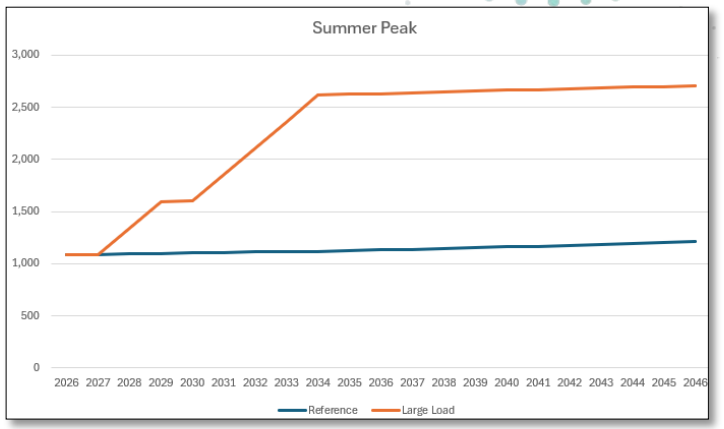
Q&A

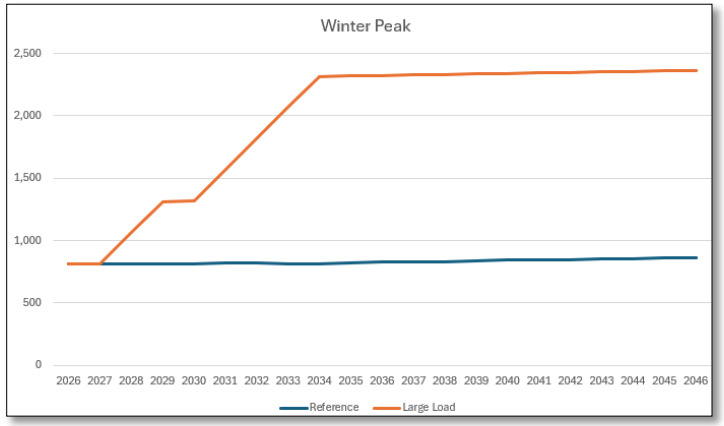
Alternate Reference Case

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

Alternate Reference Case

- The alternate reference case includes all the assumptions of the reference case but contains a different load forecast
- Carries the same portfolio development process but did not perform stochastic risk analysis
- Allows for additional resource buildout and extra capacity purchases in the near-term





Alternate Reference Case Results

In all portfolios, the model selected:

- F.B. Culley 2 storage
- Continue F.B. Culley 3
- Convert A.B. Brown to a CCGT

Year	1: Optimization Run	2: 1x1 J Class in 2032	3: Renewables + CT's	4: FB Culley 3 NG Conversion 2030	5: FB Culley 3 NG Conversion 2035
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031			+1 Non IRA Wind + Storage (200 + 100 MW)		
2032	+1 2x1 J Class Fired CCGT (1361 MW)	+1 1x1 J Class Unfired CCGT (568 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 2x1 J Class Fired CCGT (1361 MW)	+1 2x1 J Class Unfired CCGT (1144 MW)
2033			+5 Non IRA Wind + Storage (1,000 + 500 MW)		+1 2x1 J Class Fired CCGT (1361 MW)
2034		+1 2x1 J Class Unfired CCGT (1144 MW)	+2 Non IRA Wind + Storage (400 + 200 MW)		
2035	+1 J Class SCGT (385 MW)		+1 J Class SCGT (385 MW)	+1 J Class SCGT (385 MW)	+1 FB Culley:3 NG 2035 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)
2036					
2037			+1 50 MW 4 Hour Storage (50 MW)		
2039		+1 50 MW 4 Hour Storage (50 MW)			
2040	+1 50 MW 4 Hour Storage (50 MW)		+1 F Class SCGT (222 MW)	+1 Non IRA Wind (Battery) (100 MW) +1 Non IRA Wind (Hybrid) (200 MW)	
2041					+1 50 MW 4 Hour Storage (50 MW)
2042	+1 100 MW 4 Hour Storage (100 MW)	+1 50 MW 4 Hour Storage (50 MW)			
2043					+1 50 MW 4 Hour Storage (50 MW)
2044		+1 50 MW 4 Hour Storage (50 MW)	+1 Non IRA Wind (200 MW)		
2045	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Solar + Storage (100 + 50 MW) +1 Reciprocating Engine (110 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)
% Delta to Min NPV	0.81%	0.00%	6.58%	1.24%	2.55%

1 – Optimized Alternate Reference Case – Alternate Preferred Portfolio

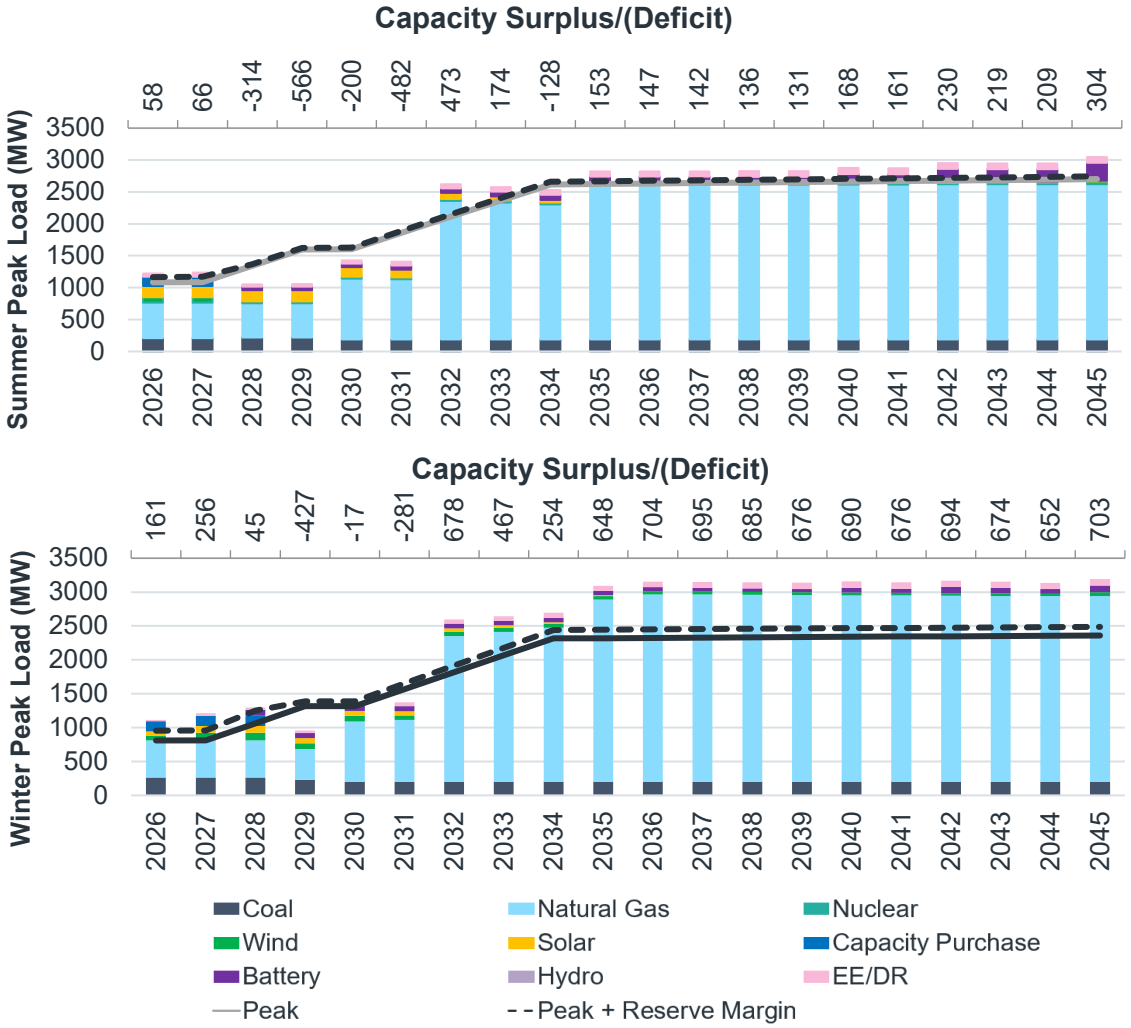
Model Selections

F.B. Culley 2 Storage
A.B. Brown Start CCGT 01/01/2030
F.B. Culley 3 Continue on Coal

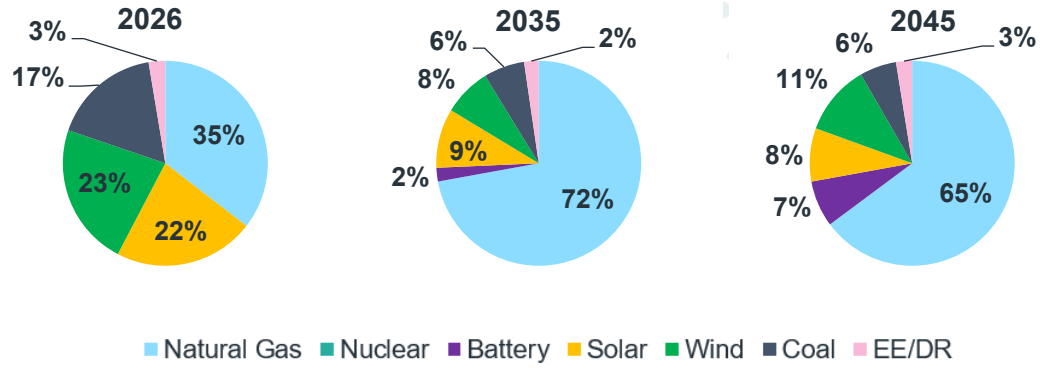
1x 2x1 J Class Fired
1x J Class SCGT
1x 50 MW Storage
1x 100 MW Storage
1x Non IRA Wind + Storage

CenterPoint Energy

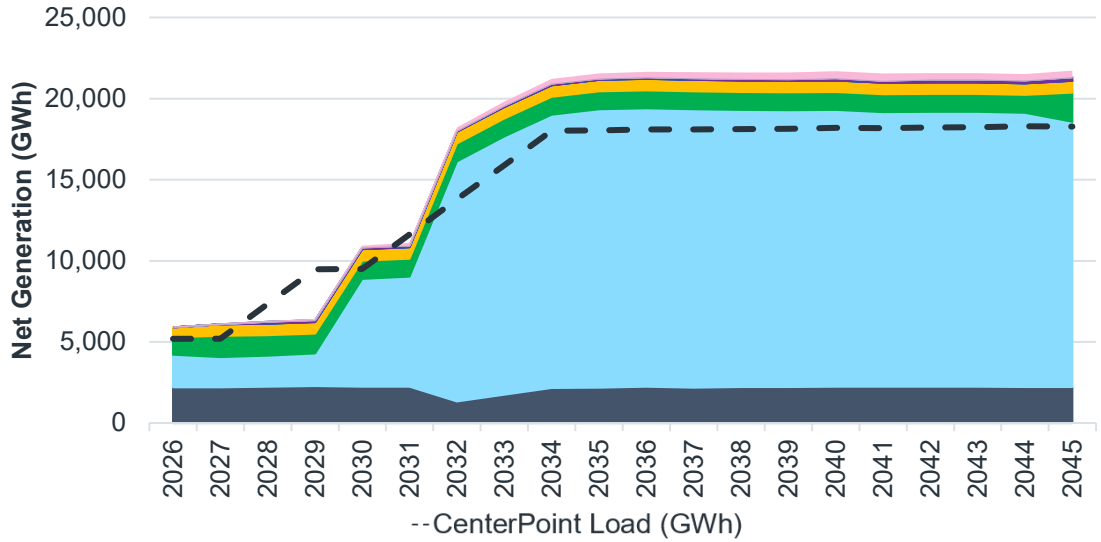
Balance of Load and Resources



Installed Capacity (MW)



Generation (GWh)



Q&A

Sensitivity Results

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

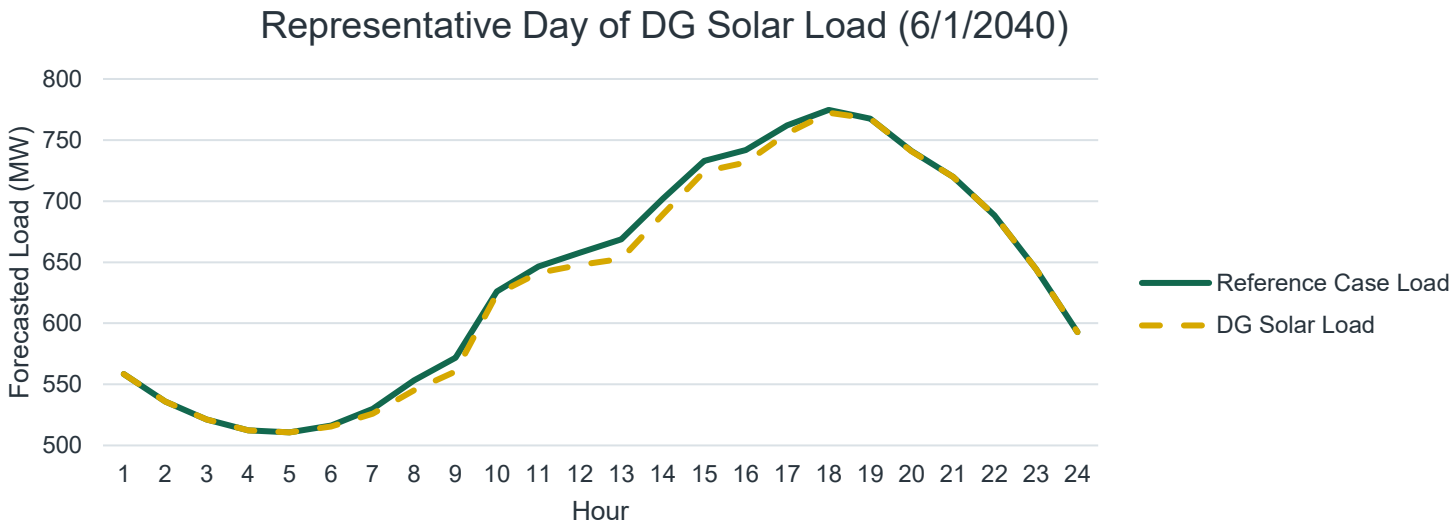
Sensitivity Modeling Summary

- Sensitivities are used to change only one variable at a time to understand the impact of a single risk factor

Sensitivity	Description	Results
Distributed Solar Incentive	Adjusts the adoption rate of rooftop solar (results in lower load forecast) to examine the tradeoff of additional distributed solar incentive on total portfolio cost.	The incentive delays the need for new battery storage projects by one year after 2040. However, the cost for the program outweighs the cost benefit.
Large Load addition	Increases the Reference Case load forecast at three distinct levels.	F.B. Culley 3 is selected in the model to remain online longer for load additions above 300 MW. Additional storage deployment also increases under higher load conditions, due to the need for additional accredited capacity.
A.B. Brown 5/6 Conversion Costs	Increases the estimated capital costs of converting A.B. Brown 5 and 6 units to a Combined Cycle by up to 30%.	Overall portfolio rankings generally remain consistent with the risk analysis scorecard. The Preferred Portfolio (Portfolio 12) becomes closer to the reference case, within approximately 1% of NPVRR.
F.B. Culley 2 Storage	Simulates Portfolio 12 with and without F.B. Culley 2 storage, evaluating the effect of allowing interconnection rights to expire.	The cost difference between the cases is negligible, confirming that the inclusion of F.B. Culley 2 storage in the Preferred Portfolio remains reasonable.
Demand Response Term	Tested the impact on DR selections under a 6-year program duration.	No additional programs were selected when evaluated based on the first 6 years.
Alternate Low Regulatory*	Simulates a low regulatory environment with reduced load growth to its impact on portfolio build out.	The resource mix resulting from the alternate low regulatory simulation is broadly captured by the low reg and reference case portfolios and a portfolio specifically built for an alternate low reg scenario would be redundant.

Distributed Generation (DG) Solar

- DG Solar sensitivity is modeled to reduce system load by 137 MW by 2045 through a$500/kW incentive beginning in 2026
- The reference case model is re-optimized with a lower load forecast and an added cost of $34.6M



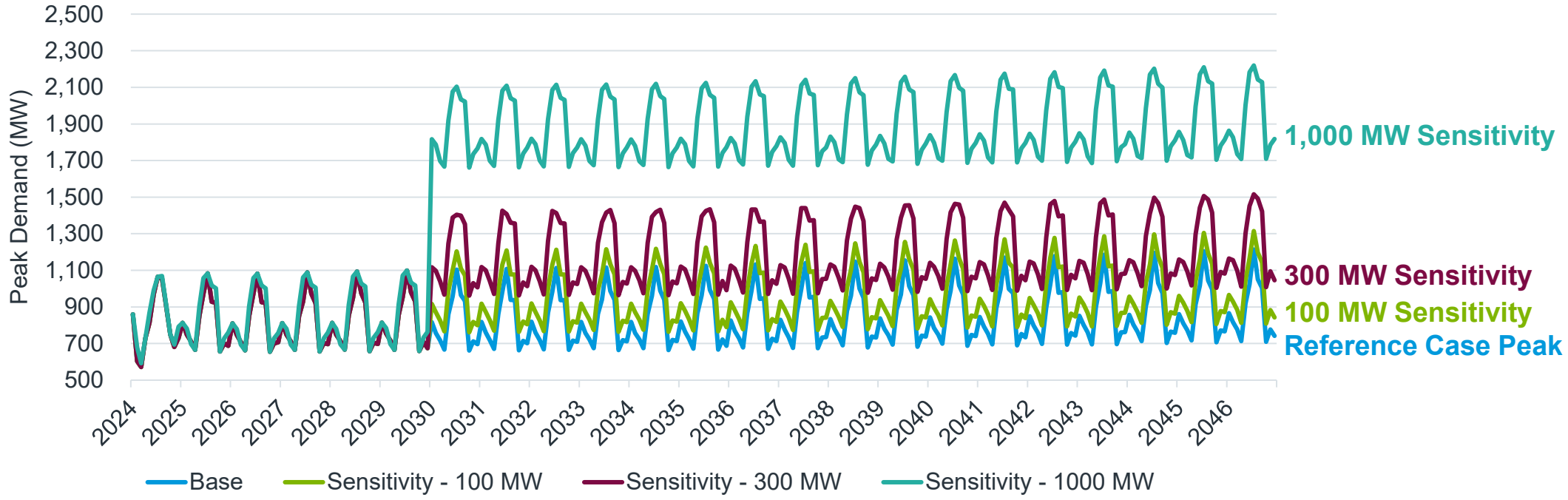
Distributed Generation (DG) Solar

- Despite lower load, the model selects nearly identical portfolios
- Additional behind-the-meter solar resources do not eliminate the need for CEI South to build other resources
  - DG Solar primarily affects energy, while long-term resource needs continue to be driven by capacity
- The value of the incentive is to delay the battery storage projects for one year after 2040

Year	Portfolio1_Reference Case	Distributed Solar Optimization
2028	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2029		
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)	+1 100 MW 4 Hour Storage (100 MW)
2034		
2035		
2038		
2039		
2040	+1 50 MW 4 Hour Storage (50 MW)	
2041		+1 50 MW 4 Hour Storage (50 MW)
2042		
2043	+1 50 MW 4 Hour Storage (50 MW)	
2044		+1 50 MW 4 Hour Storage (50 MW)
2045		
Portfolio NPV ($000)	$3,592,252	$3,605,209
Delta to Reference	-	$12,957
% Delta to Reference	-	0.36%

Large Load Addition

- Analysis of 3 load sizes (100 MW, 300 MW, 1000 MW) representative of any new large load user in CEI South territory
  - New growth, expansion and retention of current customers
  - Not limited to data center customers

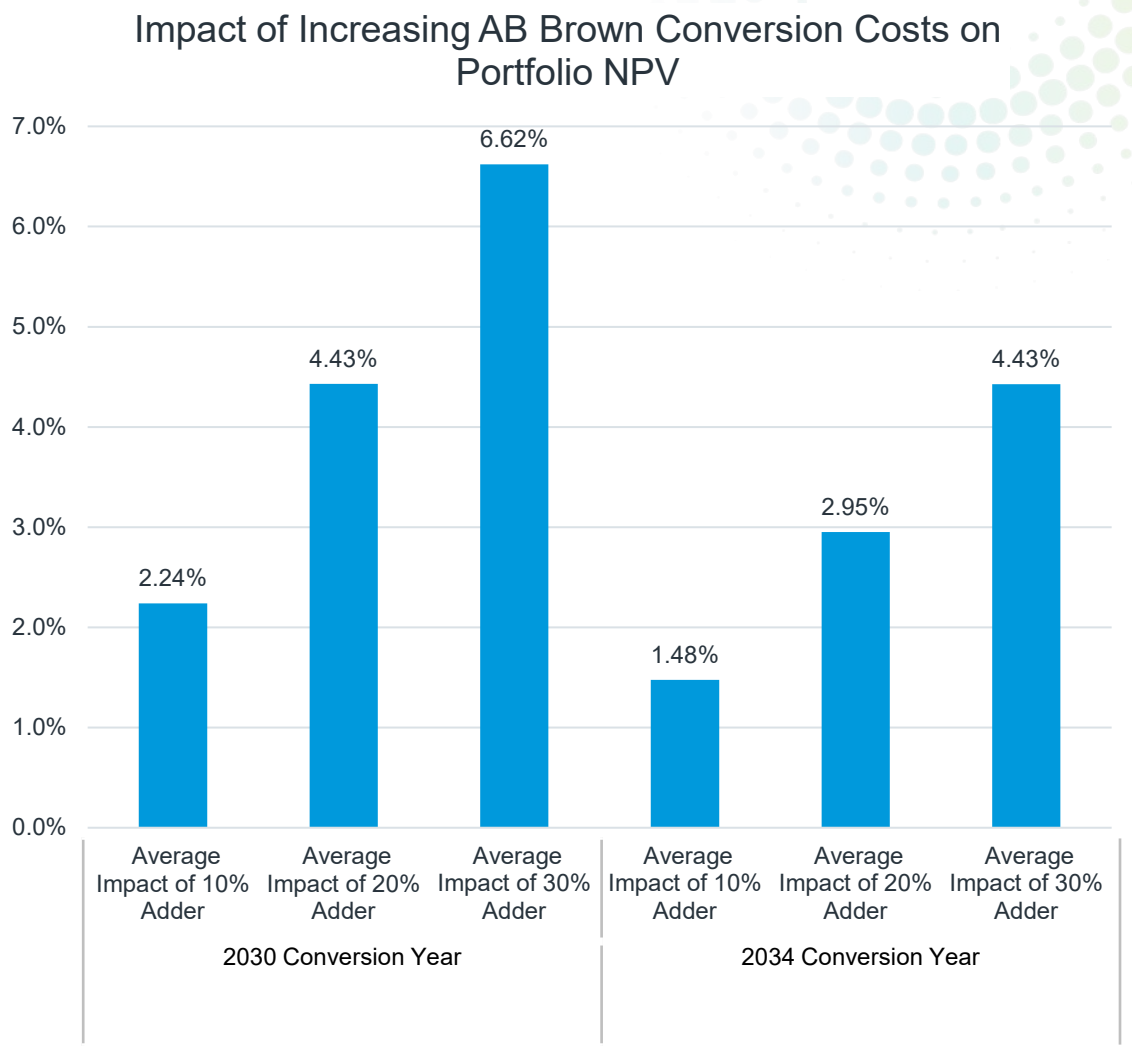


Large Load Sensitivity

Year	Reference Case Portfolio	100 MW Sensitivity	300 MW Sensitivity	1,000 MW Sensitivity
2028	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)
2029				+3 100 MW Solar PV (300 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+4 100 MW 4 Hour Storage (400 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW) +2 Non IRA Wind + Storage (400 + 200 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)		+1 50 MW 4 Hour Storage (50 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)	+2 100 MW 4 Hour Storage (200 MW)	+2 100 MW 4 Hour Storage (200 MW) +1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW)
2034				
2035				+1 Non IRA Wind + Storage (200 + 100 MW)
2038				
2039				+1 F Class SCGT (222 MW)
2040	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)		
2041				
2042			+1 50 MW 4 Hour Storage (50 MW)	
2043	+1 50 MW 4 Hour Storage (50 MW)			
2044		+1 Non IRA Wind + Storage (200 + 100 MW)		+1 Non IRA Wind (200 MW)
2045			+1 FB Culley:3 thru 2045 (270 MW) +1 50 MW 4 Hour Storage (50 MW)	+1 FB Culley:3 thru 2045 (270 MW)
Portfolio NPV ($000)		$4,098,207	$5,004,166	$9,989,943

AB Brown 7 Capital Costs

- The capital costs of converting A.B. Brown 5 and 6 to a 2x1 Combined Cycle Gas Turbine are varied stochastically in the risk analysis
- An additional sensitivity was performed to evaluate the impact of a 10%, 20%, or 30% increase in cost for the A.B. Brown conversion
- The results show that increasing costs have a greater effect on the portfolios with an earlier conversion at A.B. Brown



A.B. Brown 7 Capital Costs

- The portfolios with a 2030 conversion of ABB7 all move in the same direction relative to each other
- The portfolios with a 2034 conversion of ABB7 become closer in cost to those with the ABB7 2030 conversion

	Delta to Min NPV (200 draws)	Delta to Min NPV (with ABB7 10% adder)	Delta to Min NPV (with ABB7 20% adder)	Delta to Min NPV (with ABB7 30% adder)
Portfolios with ABB SCGT to CCGT Conversion in 2030				
1-Reference Case	0.2%	0.2%	0.2%	0.2%
2-FBC3 NG 2035	0.0%	0.0%	0.0%	0.0%
4-FBC3 on SMR	19.9%	19.9%	19.9%	19.9%
8-Low Reg	1.3%	1.3%	1.3%	1.3%
11-FBC3 Co-Fire	3.7%	3.7%	3.7%	3.7%
Portfolios with ABB SCGT to CCGT Conversion in 2034				
10-Alt High Reg	13.3%	12.4%	11.7%	10.9%
12-Delayed Reference	3.2%	2.4%	1.7%	1.1%
Portfolios without ABB7				
3-FBC3 on Coal	8.5%	6.1%	3.9%	1.8%
5-FBC3 to SCGT	15.8%	13.3%	10.9%	8.6%
6-Renewable Heavy	15.9%	13.4%	11.0%	8.7%
7-FBC3 NG with Renewables	17.7%	15.1%	12.7%	10.4%
9-High Reg	15.6%	13.1%	10.7%	8.4%

F.B. Culley 2 Sensitivity: Portfolio 12

- A sensitivity analysis was performed on Portfolio 12 to determine the portfolio cost impact of building a storage resource at the F.B. Culley 2 site versus allowing the interconnect re-use to expire

- The total portfolio NPV is within 1%, indicating there is minor savings associated with allowing the interconnect to expire

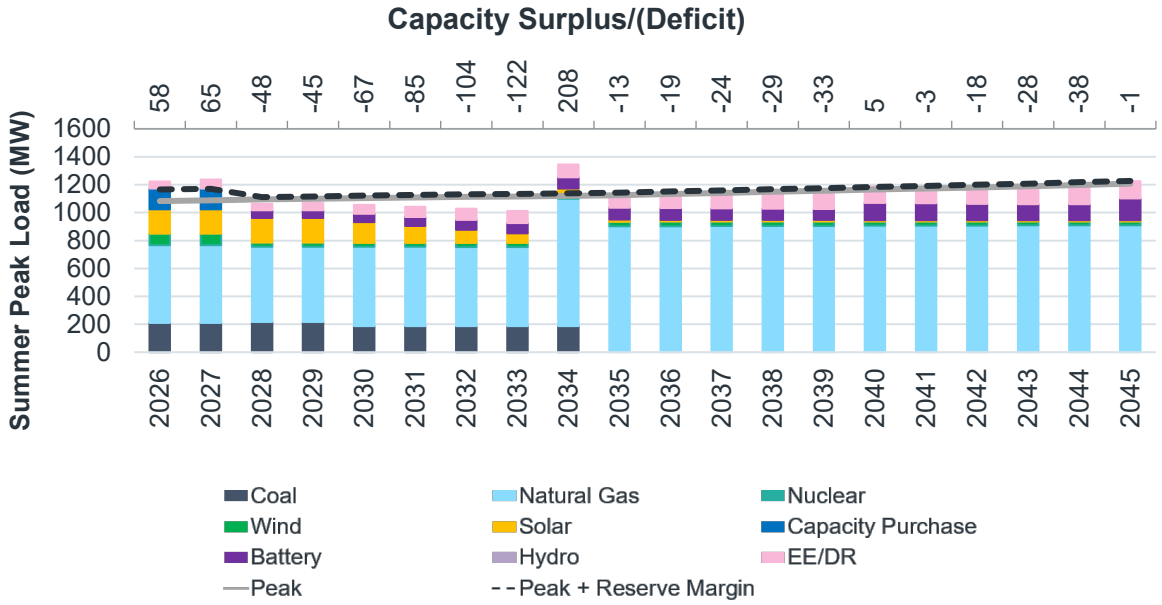
Year	Portfolio12: Delayed Reference Case *FBC2 Interconnect Expire*	Portfolio12: Delayed Reference Case *FBC2 Storage*
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)
2034	+1 AB Brown7: Fired CCGT 2034 (850 MW)	+1 AB Brown7: Fired CCGT 2034 (850 MW)
2035	-1 FB Culley:3 Retire 2035 (-270 MW) +1 50 MW 4 Hour Storage (50 MW)	-1 FB Culley:3 Retire 2035 (-270 MW)
2036		
2038	+1 50 MW 4 Hour Storage (50 MW)	
2039		
2040		+1 50 MW 4 Hour Storage (50 MW)
2044	+1 100 MW 4 Hour Storage (100 MW)	
2045		+1 50 MW 4 Hour Storage (50 MW)

Portfolio NPV ($000)	$3,735,327	$3,736,795
Delta to Min NPV	$0	$1,468
% Delta to Min NPV	0.00%	0.04%

F.B. Culley 2 Sensitivity: Portfolio 12

- The Preferred Portfolio leverages the interconnection re-use at F.B. Culley 2 to add a 90 MW storage facility reducing near-term capacity needs in 2028 and 2029
- Re-using the existing interconnection avoids additional cost exposure and mitigates risk associated with allowing the interconnection rights to expire
- Aligning the timing of the A.B. Brown conversion with the F.B. Culley 3 retirement reduces the short-term system overbuild, allowing for a smooth transition and continued evaluation.

Portfolio 12 Balance of Load and Resources



Q&A

Summary

Matt Rice

Director, Regulatory and Rates

Summary

- The Preferred Portfolio:
  - Provides rate stability in the near and long-term
  - Preserves maximum future flexibility to navigate unprecedented uncertainty
  - Provides reliable, resilient, stable, affordable, and environmentally sustainable power
  - The future of F.B. Culley 3 will be evaluated in a subsequent IRP
- The Alternate Preferred Portfolio provides necessary flexibility to quickly pivot, keeping Southern Indiana competitive for economic development and growth
- CEI South will continue to do due diligence while working through the short-term action plan

Stakeholder Questions and Feedback

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

Q&A

In-person attendees – please raise your hand to be recognized

Virtual attendees will be in listen-only mode – to participate:

- Use the “Raise” hand feature in Teams to be recognized, and your mic will be activated during the allotted time for questions, or
- Enter questions into the “Q&A” feature in Teams

Identify yourself by name prior to speaking to help us keep track of feedback and follow up actions

Appendix

General IRP Model Updates

- Increased new resource availability
- Corrected resource CapEx curves (base, high, low across scenarios)
- No longer scaling Scenario-driven portfolios and stochastic purchases/sales limits
    - Allowing for excess capacity purchases and sales to take place
    - Stochastically varying sales limit, kept purchase limit equal to current transmission limitation
- Thermal resources to seasonal capacities (applying DLOL to seasonal outputs) and heat rates
- F.B. Culley 3 conversion costs (Fixed O&M time series in the model)
- Final reference case load shape
- Fixed near term capacity contract firm capacity

Updated Resource Availability
Reference Case and Scenarios

Technology	1st Year Available	Previous Annual Limit	Previous Cumulative Addition Limit	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal					
F Class CT	2030	1 Project, 246 MW	1 Project, 246 MW	1 Project, 246 MW	1 Project, 246 MW
J Class CT	2030	1 Project, 437 MW	1 Project, 437 MW	**2 Projects, 874 MW**	**2 Project, 874 MW**
Reciprocating Engine	2030	2 Projects, 220 MW	2 Projects, 220 MW	2 Projects, 220 MW	**4 Projects, 440 MW**
Aeroderivative	2030	2 Projects, 114 MW	2 Projects, 114 MW	2 Projects, 114 MW	**4 Projects, 228 MW**
1x1 F Class CC	2032	1 Project, 454 MW	1 Project, 454 MW	1 Project, 454 MW	1 Project, 454 MW
1x1 J Class CC	2032	1 Project, 624 MW	1 Project, 624 MW	1 Project, 624 MW	1 Project, 624 MW
Renewables					
Solar	2028	2 Projects, 200 MW	5 Projects, 500 MW	**4 Projects, 400 MW**	**18 Projects, 1,800 MW**
Solar + Storage	2028	1 Project, 100 + 50 MW	3 Projects, 300 + 150 MW	**3 Projects, 300 + 150 MW**	**10 Projects, 500 + 250 MW**
Wind	2030	1 Project, 200 MW	3 Projects, 600 MW	**4 Projects, 800 MW**	**10 Projects, 2,000 MW**
Wind + Storage	2030	1 Project, 200 + 100 MW	3 Projects, 600 + 300 MW	**3 Projects, 600 + 300 MW**	**5 Projects, 1,000 + 500 MW**
Hydro	2032	2 Projects, 58 MW	2 Projects, 58 MW	2 Projects, 58 MW	2 Projects, 58 MW
Storage					
4-hour 50 MW Storage	2028	3 Projects, 150 MW	5 Projects, 250 MW	**5 Projects, 250 MW**	**10 Projects, 500 MW**
4-hour 100 MW Storage	2028	3 Projects, 300 MW	5 Projects, 500 MW	**5 Projects, 500 MW**	**10 Projects, 500 MW**
8-hour 100 MW Storage	2028	3 Projects, 300 MW	5 Projects, 500 MW	3 Projects, 300 MW	5 Projects, 500 MW
Nuclear					
Nuclear	2035	1 Project, 100 MW	1 Project, 100 MW	1 Project, 100 MW	1 Project, 100 MW

Bolded programs indicate a change from the previously shared resource availability.

Stability/Transmission Analysis

Short Circuit Ratio and Dynamic VAR Support

- Short circuit ratio (SCR) study:

$$\mathrm{SCR} = \frac{S_{\mathrm{POI}}}{P_{\mathrm{Benchmark}}}$$

  - Evaluate SCR at each bus per scenario
  - SCR is defined as the ratio of the apparent power at a point in the system following a fault to a defined benchmark value (100 MW)
- Dynamic VAR support:
  - Calculate the maximum available VAR support in four scenarios under an outage event by summing the total value per scenario and subtracting the VAR capacity of each generator individually
- Look at the worst-case scenario for both results to generate a minimum support value

Stability/Transmission Analysis
Short Circuit Ratio and Dynamic VAR Support

- Scenario with AB Brown conversion and F.B. Culley 3 on the system is the strongest case in both categories
- All scenarios had similar short circuit ratios (±0.03%)
- Best dynamic VAR support is 148 MVAR greater than the worst case

Portfolios	F.B. Culley 3 Path	A.B. Brown Path	Short Circuit Ratio [MVA/100 MW]	*Dynamic VAR Support [MVAR]
3-FBC3 Coal, 7-FBC3 NG with Renewables	Stays Online	No Conversion	3.51	626
1-Reference Case, 4-FBC3 to SMR, 5-FBC3 to SCGT, 8-Low Reg, 10-Alt High Reg, 12-Delayed Reference	Taken Offline	Conversion	3.51	665
2-FBC3 NG 2035, 11-FBC3 Co-Fire	Stays Online	Conversion	3.51	753
6-Renewable Heavy, 9-High Reg	Taken Offline	No Conversion	3.51	605

**Under outage conditions*
The color coding represents the relative ranking between the portfolios

CenterPoint 2025 IRP
4th Stakeholder Meeting Minutes Q&A
October 23, 2025, 9:30 am – 2:00 pm CDT

Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Introduced the meeting facilitator and covered meeting protocols and participation.

Shane Bradford (Vice President, Indiana Electric, CenterPoint Energy) – Shared the safety message for the meeting and the updated generation timeline.

Leslie Hamby (Manager IRP and Generation Analysis, CenterPoint Energy) – Provided an overview of the IRP process and summarized stakeholder feedback.

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Provided an overview of the Preferred Portfolio and the short-term action plan.

- Slide 17: Key Risk Considerations
  - Comment: You're saying that the cost of all types of resources is increasing. The cost of renewables is not increasing like the cost of fossil fuel generation is.
    - Response: They're both increasing at a high rate across the board as informed by the 2024 All-Source RFP. Additionally, when looking at the cost of renewables, this is generally speaking about the cost of energy while the cost of thermal and fossil fuel generators typically involves the cost of capacity and the cost of energy. There is additional benefit from thermal sources that should be accounted for costs and benefits. The full levelized rate should be considered.
  - Question: You were saying that some of the changes are due to the renewables being more expensive, but where do [you consider] climate change, our planet and the ability of our children to be of good health and have a successful life? There are other ways to address affordability like reducing return on equity that doesn't put our planet and future at risk.
    - Response: CEI South will continue to pursue renewable generation that makes economic sense. The emphasis has been on affordability for our customers, and we do not want to offer a plan that limits our flexibility and creates affordability challenges. Also, note that many of the renewables we pursue are through power purchase agreements, which offer no return to CEI South.
  - Comment: Looking at the executive orders, which would be basically from a 2 – 2.5-year period. That's a short term. This is supposed to be a 20-year plan. I think we would look at not just potential executive orders that might come right away, but for the entire 20-years of the plan's life.
    - Response: This is a long-term plan, which is exactly why something like the risk associated with policy fits with our decision to reevaluate these key decisions in the next IRP in 2028.
- Slide 18: Generation Timeline
  - Question: With the closing of the AB Brown units, I am assuming that CNP produces around 1,000 MW currently. Is that correct? Generally, of the 150,000 customers, how much of that is actively being used?

        - Response: Our customer load demand is a little more than 1 GW. Before AB Brown 1 & 2 retirement and the end of the contract with Alcoa for Warrick 4, we had extra capacity, but now we are short and have to buy required capacity. When we retired AB Brown 1 & 2, we largely replaced that capacity (megawatts) pretty much one for one with AB Brown 5&6. Following the exit of 150 MW Warrick 4, we needed capacity and energy, which we filled with about 650 MW of renewable resources. Finally, for the FB Culley 2 battery project, it is a one-for-one capacity replacement of the existing coal site for a storage resource. Please see slides 34 through 45 for the load plus planning reserve margin. It shows how much energy CEI South is predicted to produce to meet demand, including purchases. Any extra energy generation can be sold to the MISO market.
    - Question: When all the discussion over the gas plant at AB Brown was occurring, it was originally shared as a peaker plant to facilitate renewables, but now you are sharing that the conversion would make it a baseload plant due to the cost of the pipeline.
        - Response: As they are today, A.B. Brown 5 and 6 operate as peaking plants and operate for a few hours a day. The conversion that we speak about includes adding a Heat Recovery Steam Generator ("HRSG") to the combustion turbines to use waste heat to produce energy. They would become a very efficient baseload plant. Note that their role as peaking plants made sense during the last IRP cycles, but now that the market is continually changing and MISO introduced Direct Loss of Load accreditation, the use of these units as baseload generators makes sense.
- General Questions:
    - Question: You mentioned long-term contracts as one mitigation tactic against increasing costs for customers. Are there any other cost protections for existing customers if a large load customer is secured?
        - Response: In principle, we are trying to keep costs that are caused by a large load assigned to the large load customer. Beyond that, we cannot talk about specifics. No contracts are signed and conversations are highly confidential.
    - Question: Did anyone watch the Governor's energy task force that took place earlier this month?
        - Response: I saw some but not all of it.
    - Question: On the demand side management (DSM), are you going to be working towards commercial customers and big industrial customers to get them to kick in some DSM, not just households with their start thermostats?
        - Response: Currently, we have programs for energy efficiency and demand response that are for all customers regardless of market segment and we will continue to offer this in the future. Following the 2014 Indiana legislation, commercial and industrial ("C&I") customers are

able to opt out of energy efficiency and demand response. To the extent that these customers don't opt out, we will continue to offer C&I programs.

- Question: When we are talking about large load customer, you say that you have ideas on how to protect customers, but we are seeing things that haven't been seen before. These data centers are coming online and wanting power quickly. You're talking about converting to combined cycles and bringing thermal resources online. How do you think you are going to provide power to these data centers quickly?
  - Response: If a prospective large load customer is a data center, yes, they want quick speed to market. We would likely have to go to market for capacity, energy, or tolling agreements to cover the short-term capacity need until we could build our own generation.

Drew Burczyk – Shared the approach to scenario driven portfolio and presented the final 12 portfolio selections.

- Slide 30: Final Portfolios
  - Question: Can you give more detail and explanation about the bottom 3 lines?
    - Response: The first line is the average of the net present value ("NPV") of the portfolio over the 20-year study from the 200 simulations that are performed with the risk analysis. The following line is the difference between a given portfolio's net present value and the reference case portfolio in thousands of dollars. The final row is the delta from a given portfolio expressed as a percent difference.
  - Question: The Reference Case Portfolio 1 is the current situation. Correct?
    - Response: Not exactly. The portfolio is the model output for the least cost optimized capacity expansion portfolio from the Reference Case inputs, as given on slide 26.

Matt Rice – Provided a look into each portfolio's capacity and energy position, energy mix, and the benefits and challenges of each portfolio.

- Slide 35: Portfolio 2 – FBC3 on NG 2035
  - Question: Can you explain the difference between Portfolio 1 (Reference Case) and Portfolio 2?
    - Response: In the Reference Case Portfolio, FB Culley 3 would retire by 2032 without replacement. In Portfolio 2, FB Culley 3 would convert to gas-fired in 2035 and then remain online during the entire study period. Portfolio 2 has excess capacity for several years, which indicates that there is ability to support economic development.
- General Questions:
  - Question: When you're looking at a portfolio and the potential for economic development, and you're looking at demand and how much time it takes you to supply energy for the increased demand, there are three pathways to consider. First, you could increase capacity of existing aging facilities which is like

spending money on a 30-year-old car. Second, you could build a gas plant from scratch and that will take a long time to come online. Third, you could look into alternative fuel with faster build times, such as solar. You could also look at putting renewable energy at the site of the large loads so that they can serve themselves. Have you considered any of those ideas?

- Response: Following the car analogy, while we don't want to pour money into an old car, it does offer the benefit of giving you time before needing to purchase a new car. In a similar way, we are looking at F.B Culley 3 as a resource that could help us during this generation transition until we have something to replace it. In terms of ideas for serving potential economic development customers, each customer has different desires and needs for their energy sources. In general, those negotiations are all unique, and we cannot get into details of any one of them, but they do bring their own perspectives and priorities.

- Comment: Corporations are looking to make money and generally will look for lowest costs possible to be able to maximize profit.
  - Response: It depends on the industry. In southern Indiana, there is a green energy tariff which one customer takes advantage of. It depends on the customer's industry and priorities.
- Comment: You spoke about pushing the FB Culley 3 decision out until the next IRP. However, when asked about performing a study to investigate retiring FB Culley 3 in 2030, you were saying there's so much uncertainty. This seems contradictory that you are wanting near-term decisions, but you're not investigating a near-term closure of FB Culley 3.
  - Response: We do not want to close a resource without filling the gap with an additional resource because we would be heavily reliant on the market. We have several portfolios that consider retirement in 2032 because we think that it is the earliest that we could retire the resource without putting reliability at risk.
- Question: Some portfolios have "fuel costs" listed as a challenge. How would those reflect to the customer? What actions would be taken if that fuel and cost challenge came to fruition?
  - Response: CenterPoint does not make money on fuel costs, but those are recovered dollar for dollar on bills. Portfolios with heavy dependency on one particular fuel have risk with fuel cost variability. We can generally customers benefit from lower cost power whether produced or purchased.
- Question: Do you have a sense of how much tariffs have impacted the rise in solar project costs? How is that factored into these scenarios?
  - Response: In general, we've seen increases of 15 – 35%. For example, parts that were manufactured for a low cost in countries now considered a "foreign entity of concern" may experience a greater cost increase. From a modeling standpoint, the cost starting point was from the 2024 All Source RFP as the baseline since provided market insight into average, low and high costs for these technologies under current market

conditions. Then, across the different scenarios (high, base, low) we have different assumptions on how costs change over time. In the risk analysis, the selected future cost curve for each of these resources was randomly reshuffled every four years to account for further fluctuations in price.

- Question: There was a bill passed by the state house that allowed gas to be considered a renewable resource. Did that get factored into this analysis or cause things to be weighed differently?
  - Response: No.

Drew Burczyk – Presented the metrics on the risk analysis scorecard detailing each metric and key takeaways.

- Slide 49: Final Scorecard
  - Question: Are the colors meant to suggest that green is good, and red is bad?
    - Response: No. The color coding represents the relative ranking between the portfolios. Green could represent a portfolio performed better than other portfolios for a given metric but not necessarily.
  - Question: For Portfolio 6 & 7, we are looking at the equivalent CO_2 emissions that are almost 29,000 for Portfolio 6 and 45,000 for Portfolio 12. Why are SOx and NOx emissions not decreasing the same way from Portfolio 12 to Portfolio 6?
    - Response: The SOx and NOx emissions are linked to the F.B. Culley and A.B. Brown decision. The portfolios that convert A.B. Brown 5 and 6 to a combined cycle typically perform better in terms of NOx emissions.
  - Question: The costs for Portfolio 12 are external rather than internal. You are looking at affordability but are not factoring the external costs that people have to pay (e.g., health costs). For long-term sustainability, these costs should be included in this analysis.
    - Response: In an effort to capture some of those costs, we included a CO_2 emissions cost in a quarter of the stochastic runs.
  - Question: When you use the word affordability, it's a bigger picture than NPV. Does NPV include return on equity? Are you assuming that return on equity is flat?
    - Response: Yes, the return on equity is included in the NPV on the slide. And yes, the return on equity is assumed to be flat.
- Slide 52: Affordability: Annual Revenue Requirement by Portfolio
  - Comment: Renewables will perform better in the long-term than in the short-term. In the annual revenue requirement graph, we see that Portfolio 6- Renewable Heavy portfolio starts to decrease in the early 2040's while some of the other portfolios are increasing.
    - Response: The reference case (Portfolio 1) and delayed reference case (Portfolio 12) do have a lower overall NPV than the more renewable heavy portfolios. Portfolio 3 and Portfolio 7 have an increasing revenue requirement mostly due to the addition of resources in 2045.
- Slide 54: Affordability: Incremental Electric Energy Burden

- Question: You are showing the energy burden only in 2030 and 2035. Why is this not until for the entire 20-year planning period? The challenge with this is that capital investments, especially in renewables, will look worse in the near-term than in the long-term.
  - Response: The portfolio NPV captures the net present value of the portfolio over the entire planning horizon. The intention of adding the incremental energy burden metric was to provide a near to mid-term look at affordability. As such, this metric is looking at the near to mid-term impact of decisions made in this from the perspective of a customer's energy bill.

Drew Burczyk – Shared an overview of the alternative reference case and portfolio optimization results.

- General Questions:
  - Comment: There isn't much that worries me more about affordability than this section. I am not convinced that all the extra costs will be paid for by the large load.
    - Response: We understand your concern, and CenterPoint is working to make sure that doesn't happen.
  - Comment: All of these large load deals are filled with NDA and their process is not transparent. It makes it difficult for us as a community to make informed decisions. As a community partner, it is important to include the community. We recommend not making it a closed-door process.
    - Response: Thank you for your comment.

Drew Burczyk – Presented the sensitivity results for various sensitivities performed including large load, DG solar, and more.

- Slide 68: Sensitivity Modeling Summary
  - Question: Specifically for DG Solar incentive, for the comment about delaying the need for storage by one year, it seems like if you reduce the load, you'd reduce the need for storage at all, why is that not the case? Also, what does it mean that the cost of the program outweighs the benefits? Is the cost that you are referring to a loss of revenue and not necessarily a capital cost?
    - Response: If you add rooftop solar, it does decrease load. However, the model results are telling us that the load still increases just at a slower pace, and you do still need to build more resources. There is some benefit in delaying the capital investment, but not enough to offset the cost of the program. The cost of the program is similar to an Energy Efficiency plan. We would pay customers $500 per kilowatt for their distributed system, which would be a credit or check to the participating customers.
  - Question: Did any of the modeling take into account that folks are much more aware of their energy use when they add rooftop solar and then typically lower their overall energy usage?

        - Response: The load forecast takes into account rooftop solar adoption but not changes in behavior following the implementation of solar panels.

Matt Rice – Provided a summary of key takeaways from today's presentation.

- General Questions
    - Question: Can CenterPoint talk about the press release regarding affordability that was sent out this morning? Can you go into more detail about stabilizing base rates?
        - Response: Generally speaking, CenterPoint has heard the community's frustration and comments about affordability, and we want to state that we are committed to doing something real and tangible in response. There are long-term and near-term commitments that we are making. In the immediate future, we are going to commit to stabilizing base rates for things that CenterPoint Energy can control to keep the base rate at or below the rate of inflation through the end of 2027. This is about $18 per customer in avoided costs due to the cancellation of a roughly $1 billion investment in the renewable projects that have been cancelled. Additionally, there will be a $3 reduction in energy bill per customer by the end of the year, which is largely due to bringing A.B. Brown 5 and 6 online and no longer needing to purchase capacity. At the same time, we will be hosting some engagement sessions with the community to make ourselves readily available to our customers to hear their feedback and ideas. We're also going to focus on the upcoming heating season to make sure that customers are aware of different payment assistance opportunities. The press release today was just the acknowledgement of customer sentiment and commitment to offering different affordability options. The announcement can be found here: https://www.centerpointenergy.com/en-us/corporate/about-us/news/2109.
    - Question: Can you go into more detail about what stabilizing base rates means since it has already been approved at the IURC level?
        - Response: We filed for a rate case in December of 2023, received an Order in February of 2025, and then we are beholden to the implementation of the order that we received. The rates from this Order go into effect at a prescriptive cadence. Once the last phase of rates goes in, and CenterPoint has completed its' obligation to enter those rates per the Order, we will commit to the stabilization of rates thereafter through the end of 2027.
    - Question: Are you just committing to no rate cases before 2027?
        - Response: The next rate case is required by the end of 2028. We are also committed to responding to the community's frustration with affordability.
    - Question: Isn't the $3 decrease for things that you would have done anyway through trackers?

- Response: Not necessarily. It is mostly for our Reliability Cost and Revenue Adjustment (RCRA) tracker. For instance, with A.B. Brown 5 and 6 online, we have some excess system capacity that we are able to sell for the fall season. Effectively, we no longer need to rent capacity on someone else's system. We also had some MISO credits. This would reduce customer bills next year, but since there was the need for immediate relief, CenterPoint worked with the OUCC (Indiana Office of Utility Consumer Counselor) to get relief for customer bills now.

- Question: If you go to CenterPoint's website, you can find deals such as LED lights and Smart Thermostats and other equipment to reduce demand and make costs go down. There used to be the Energizing Indiana program, which was a cost-effective program, but it has stopped. Was something along the lines of "Energizing Indiana" included in your thought process?
  - Response: CenterPoint files 3-year DSM programs with the Commission. All programs, with the exception of low-income programs, have to be cost-effective. The programs from Energizing Indiana are still continuing but just in a different manner. We do have weatherization programs for income-qualified customers and a home energy assessment program for any customer to sign up for no additional cost.
- Question: Is the new weatherization program harder to qualify for when compared to the Energizing Indiana weatherization program?
  - Response: The program has adapted as building codes have been updated. In 2018, the building codes required that buildings are made more efficient and our program must result in efficiency improvements that are above and beyond that code. CenterPoint is not doing less, but the building codes have been improved.

- Comment: Ideally don't let any data centers into your service territory, especially hyperscale AI data centers, but specifically, we ask that you do not use dirty power to power large loads. The Sierra Club has a petition asking you not to do that. Also, we have a petition with additional signatures to ask you to maintain your former position to retire coal by 2027. A statement was then read.
  - [Stakeholder provided comments posted to Integrated Resource Plan (IRP) website]
- Comment: There's a reasonable chance we could see a large load in CenterPoint's area. Maybe we could form a community working group, or other incentives could be worked on.
  - Response: Understood and acknowledged. Thank you.

Stakeholder Feedback and/or Data Request

10/23/25

Sierra Club staff, members, volunteers, and supporters are deeply disappointed and troubled by CenterPoint's decision to keep FB Culley coal unit operating past 2027. In the 2022/2023 IRP, CenterPoint chose a future that moves past old, polluting, uneconomic coal towards the path of affordable, clean energy for customers[1]. Sierra Club supported CenterPoint's decision to retire all coal by 2027 and to be a leader in the state for selecting a portfolio with a significant amount of renewable energy in the previous IRP. But now, CenterPoint's decision to keep burning expensive and polluting coal in our community past 2030 shows the lack of regard for customers' wallets, our environment, and the climate.

Culley is an aging, polluting, coal plant[2] that is costing us not only in our bank accounts, but in our health outcomes every time we breathe air polluted by coal. Throwing money into the Culley coal plant will just leave us customers paying for expensive and polluting energy that results in costly harms to our health and environment. In your previous IRP, where coal burning would cease by 2027, it says: "CEI South's preferred portfolio is projected to save customers nearly $80 million over the next 20 years compared to continuing with this last existing coal unit operated by CEI South." With an extension of Culley, how much are we as CenterPoint customers projected to lose? When Culley breaks down again how much will that cost us and how long will it be down? Where will replacement parts come from? How much money, how many days of work lost, or inhalers burned through will result in this decision?

Wind and solar are now cheaper than coal plants. The average levelized cost of energy for coal is $118/MWh while utility-scale solar is $61/MWh[3]. Wind and solar do not require fuel to run, unlike coal plants, and renewable energy outputs result in energy generated without pollution. CenterPoint says they are community partners, yet fail to actualize a 20-year energy plan that is good for our community. Over 400 people have contributed to the Sierra Club Indiana Beyond Coal petition asking CenterPoint to move beyond coal and to invest in more affordable, renewable energy. Retiring coal and increasing renewables is popular and what many in the community want.

Even with this lackluster portfolio presented today, CenterPoint still has the opportunity to make the right decision. Despite a push from the Trump administration to keep coal plants online, coal plants like the New Hampshire Merrimack Station[4] are closing down, because these are common sense decisions. CenterPoint's poor reputation in our community is no secret, and by charging us more than we can afford, to buy power that pollutes our air and water is not a popular decision. CenterPoint can still retire coal before 2030 and should do everything in its

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[1] 2022/2023 CenterPoint Energy Indiana Integrated Resource Plan, https://www.centerpointenergy.com/en-us/Documents/Integrated-Resource-Plan/2022-2023-IRP-Materials/2022-2023_IRP_Non-Technical_Summary.pdf

[2] Sierra Club Comments on CenterPoint Energy Indiana South's 2022/2023 Integrated Resource Plan, https://www.in.gov/iurc/files/Sierra-Club-Comments-on-CenterPoint-Indiana-2023-IRP.pdf

[3] The Climate Reality Project, https://www.climaterealityproject.org/blog/how-do-renewables-lower-cost-electricity

[4] New England's final coal plant shuts down years ahead of schedule, https://www.canarymedia.com/articles/fossil-fuels/new-englands-last-coal-plant-shuts-down

power to do so. CenterPoint’s customers, our environment, and climate are at a breaking point. Not only is our future at risk, but so is our present, and coal is most certainly not the answer to our problems.

Signed,
Sierra Club Supporters, Members, and CenterPoint Customers

It's time for CenterPoint to move beyond coal and invest in affordable clean energy!

July 18 update: ***The Evansville Courier & Press recently covered our work*** *and what EPA rollbacks could mean for our region. Centerpoint will unveil its long-term energy plan this Fall. If you haven't already, please submit your comment now to ensure our voices are heard!*

CenterPoint Energy Indiana South is currently engaged in their Integrated Resource Planning process (IRP) where they will create their energy plan for the next 20 years. While we have seen some progress with the planned retirement of F.B. Culley 2 this year, CenterPoint can do better in moving beyond coal and bringing more renewable, affordable energy online.

CenterPoint customers have faced some of the highest utility bills in the state for years now as the utility has relied on costly coal power and neglected building out more affordable renewable energy infrastructure. The cost of wind and solar have decreased dramatically in the last decade and per Megawatt/hour utility solar and wind is cheaper than coal and gas. Investing in renewable energy infrastructure now will save us money in the long run while reducing our impact on our environment.

Submit a comment to the IURC and CenterPoint now, calling for less polluting coal and more affordable clean energy!

Take Action: Hoosiers shouldn't foot the bill for Big Tech's data centers!

Indiana leaders are welcoming data center development with open arms and that comes with unprecedented energy demand and likely higher electric rates for everyday Hoosiers.

Data centers use enormous amounts of energy and utilities and Indiana legislators are proposing keeping old, polluting coal online and building insanely expensive gas plants to power them.

Take action with the Sierra Club: Tell Indiana's electric companies, the IURC, and Governor Braun to say no to increasing electric bills to pay for dirty energy to power data centers.

Dear Governor Braun and Indiana Utility Leaders and Regulators,

Hoosiers deserve transparent processes, clean energy, and affordable and reliable power. Charging Hoosiers for the costs for an onslaught of loosely regulated and speculative data center projects sets us up to have less reliable power, higher electric bills, and more pollution in our communities.

We are opposed to extending the use of old, dirty, uneconomic coal plants and increasing the monthly energy costs of Hoosiers to fund the construction of new expensive gas plants solely to power data centers.

Our electric companies planned a transition to less polluting power, this trajectory should be maintained to make our state a place where everyone wants to live, work and invest. Utilities and state leaders should focus on making our power more reliable by:

- Deploying measures that decrease energy waste in existing energy infrastructure and focusing on renewable energy that can power our communities today.

- Encouraging data centers to procure around-the-clock clean energy and incentivize the use of on-site battery backup, solar power and geothermal energy. Without encouraging these measures, data centers are utilizing on-site diesel generators which contribute to local air pollution.

- Ensuring Big Tech pays for their power needs, not Hoosier families and small businesses by requiring data centers to have large-load tariffs with front-loaded costs or commitments prior to

committing power resources. This will protect Hoosier communities from speculative projects and power additions.

- Focusing on renewable energy that can be built today, not the use of speculative Small Modular Nuclear Reactors which will further increase electric bills and fail to meet our near-term energy needs.

- Creating space for robust public participation and feedback on how the state plans to meet challenges associated with data centers.

If unchecked, data center development will saddle Indiana families with higher energy bills and more harmful fossil fuel pollution. We need you to protect Hoosier electric customers and advance clean energy solutions instead of doubling down on dirty, expensive fossil fuels.

Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)

SEE ATTACHMENT: CONFIDENTIAL - Attachment 6.1 ALT REF Stochastics Model

Attachment 6.2 Large Load Study Results (Confidential)

SEE ATTACHMENT: CONFIDENTIAL - Attachment 6.2 Large Load Study Results

Attachment 8.1 2025 MPS Slide Decks for Stakeholders

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

PRESENTED BY GDS ASSOCIATES, INC.

2025 MPS REFRESH KICK OFF

CenterPoint Energy Indiana

December 11, 2024

AGENDA

Kick-off and Scope of Work discussion.

- Getting Started
  - *GDS Team Introductions*
  - *Past Studies and Scope Overview*
  - *Current Project Timeline*
- Energy Efficiency Overview
  - *Major Topic Areas and Activities*
  - *Methodological Considerations*
  - *Pacing of Deliverables*
- Demand Response Overview
  - *Major Topic Areas and Activities*
  - *Methodological Considerations*
  - *Pacing of Deliverables*
- DSM Action Plan
  - *Achievable Potential vs. Action Plan*
- IRP Inputs

GETTING STARTED

INDIVIDUAL INTRODUCTIONS



Jeffrey Huber
Overall Project Lead

Warren Hirons
Residential Sector & Reporting Lead





Rich Hasselman
Market Research Lead & DR Support

Melissa Tucci
Demand Response Lead





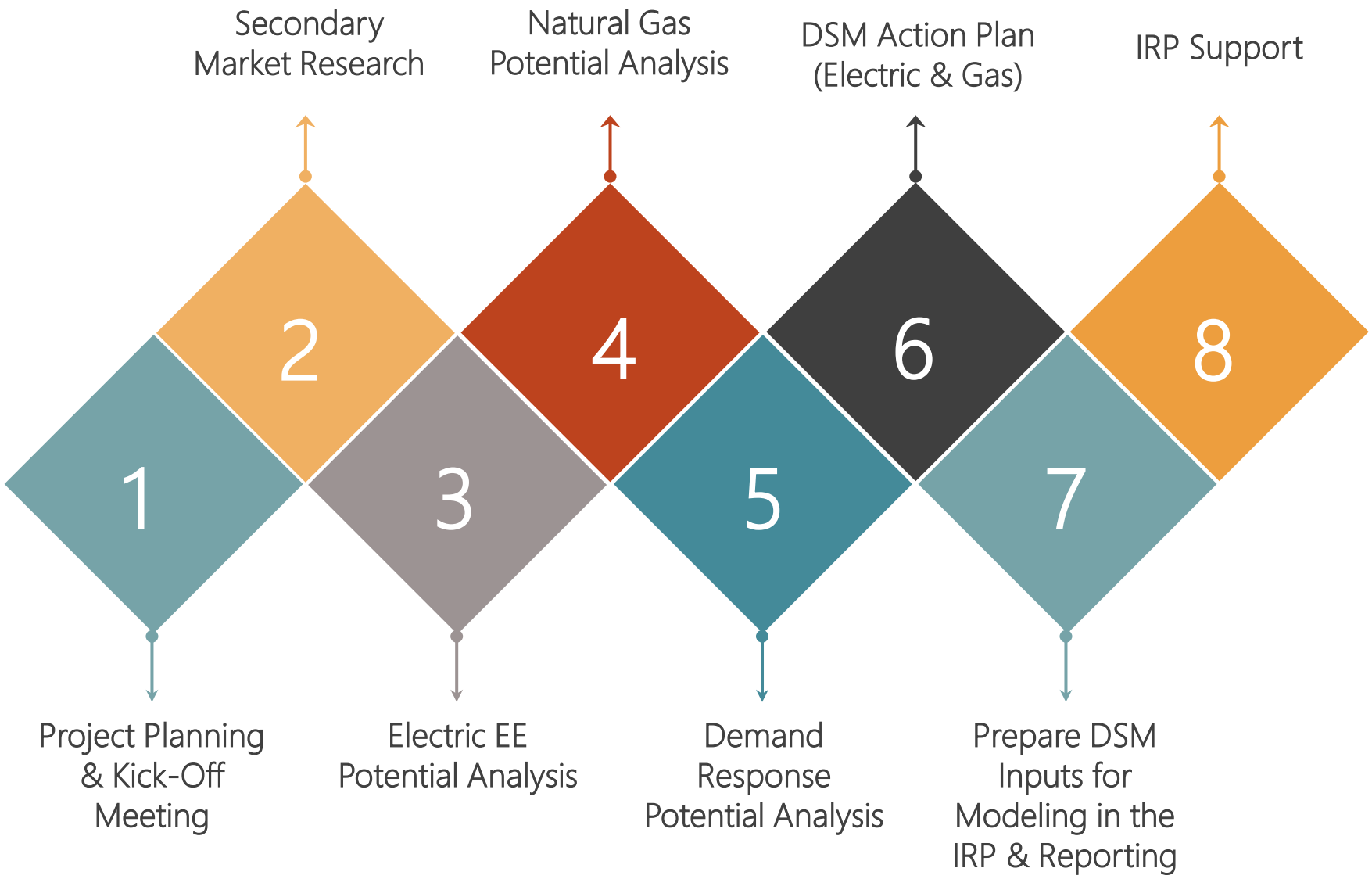
Jake Thomas
Load Forecast & Segmentation

REVISITING PAST STUDIES

- 2018 Market Potential Study
  - *Informed 2019/2020 IRP*
  - *Conducted for 2020 – 2039*
  - *Included Electric and Natural Gas Efficiency Potential*
  - *Demand Response (DLC AC, CPP, TOU)*
  - *DSM Action Plan*
  - *Included Primary Market Research*
  - *IRP bundles based on bundles of 0.25% of sales*

- 2023 Market Potential Study
  - *Coined as a "**refresh**"*
  - *Informed 2022/2023 IRP*
  - *Conducted for 2025 – 2043 (18 YR)*
  - *Electric Service Only*
  - *Demand Response (DLC AC, DLC Pool Pumps, DLC Water Heaters, CPP, PTR, TOU, RTP,)*
  - *Did **not** include primary market research*
  - *DSM Action Plan*
  - *Included an "Enhanced Realistic Achievable Potential (RAP)" scenario*
  - *Sector based bundles for IRP*

OVERVIEW OF SOW TASKS



CURRENT PROJECT TIMLINE

MPS & IRP TIMELINE REVIEW

- *IRP will cover the 2026-2045 timeframe*
- *Tentatively, CenterPoint anticipates using the filed/settled plan for 2026-2027 inputs*
- *MPS will extend from 2028-2045*
- *Action Plan will span two 3-year cycles (2028-2033)*





TASK 1

Project Initiation and Continued Stakeholder Support

1. Kick-off Meeting

- Address objectives for the 2025 DSM MPS Study. Discuss major aspects of project.
- Review approaches GDS will use.
- Debrief on previous study and discuss what can be improved

2. Project Schedule

- Discuss project schedule
- Discuss plan for status updates and key deliverables.

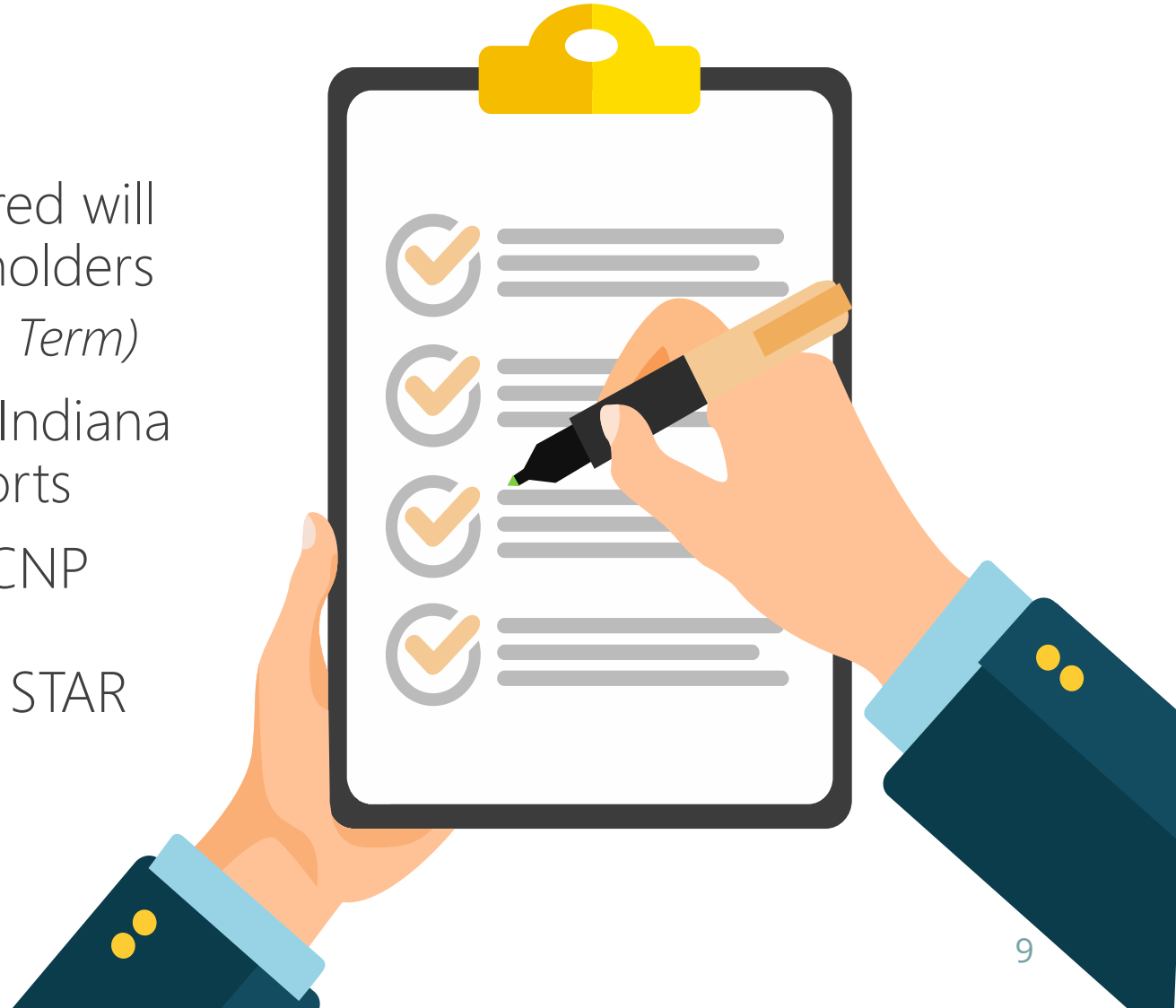
3. Stakeholder Engagement

- GDS will engage in continued communication with stakeholders via participation in periodic OSB meetings and the distribution of MPS analysis materials (i.e. measure databases, draft models, etc.).
- GDS will conduct meetings to discuss project status, any potential barriers to the schedule, and anticipated next steps.

TASK 2

Secondary Market & Measure Research

- Several hundred energy efficiency measures will be considered
- Draft list of measures to be considered will be shared with CNP staff and stakeholders
  - *Emerging Tech (Near Term and Long Term)*
- Key data sources for ***measure*** data: Indiana TRM*, MEMD, and CNP EM&V Reports
- Key data sources for ***market*** detail: CNP Customer Datasets, EIA Research & Analysis, DOE Studies, and ENERGY STAR Shipment Detail



TASK 2

OPTIONAL PRIMARY MARKET RESEARCH

- CenterPoint routinely conducts a baseline survey of its customers
  - *GDS will review and suggest potential additional questions*
  - *Typically focuses on residential equipment stock*
  - *Opportunity to include nonresidential customers*

*Note: limited opportunity ; need to add **too much** and limit response rate and impede original intent of survey*

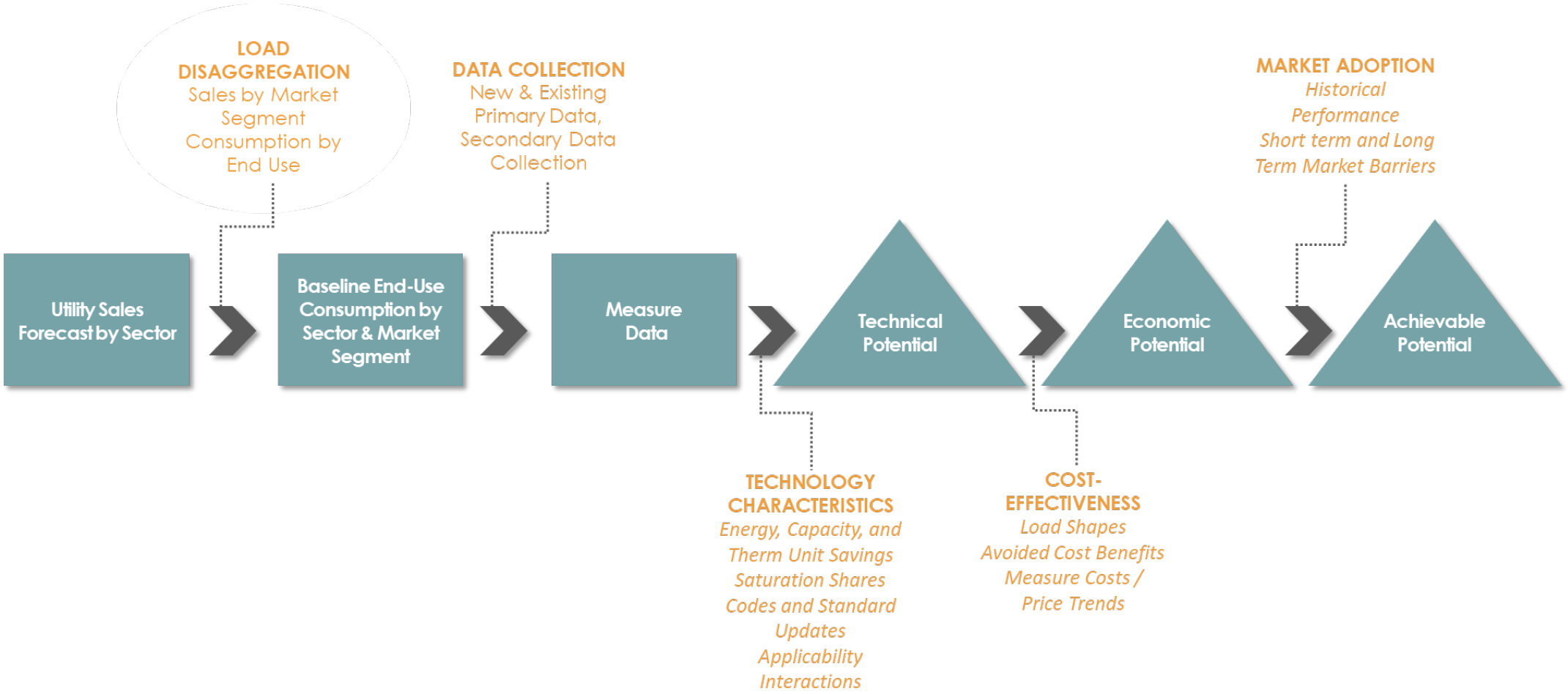
POTENTIAL RESEARCH AREAS:

- Impacts of Investment Recovery Act (IRA) and other federal funding sources
  - *Is there too much uncertainty currently?*
- Market Research targeting income-eligible communities to better understand barriers to participation
- Commercial lighting saturation and sector gaps
- Research on targeted demand response opportunities and willingness to participate

ENERGY EFFICIENCY OVERVIEW

TASK 3

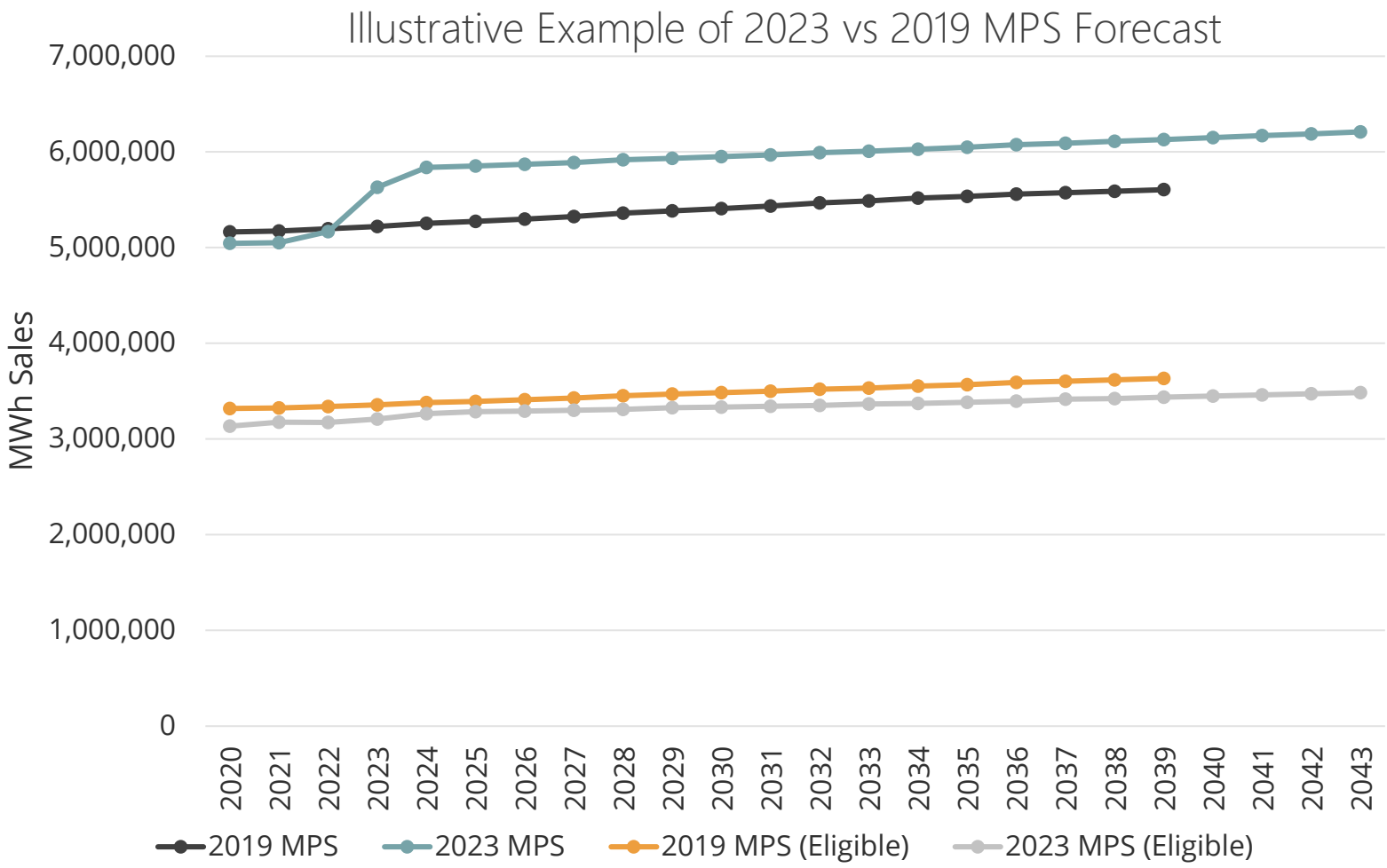
Energy Efficiency Potential Analysis



TASK 3

Energy Efficiency Potential Analysis: Load Forecast

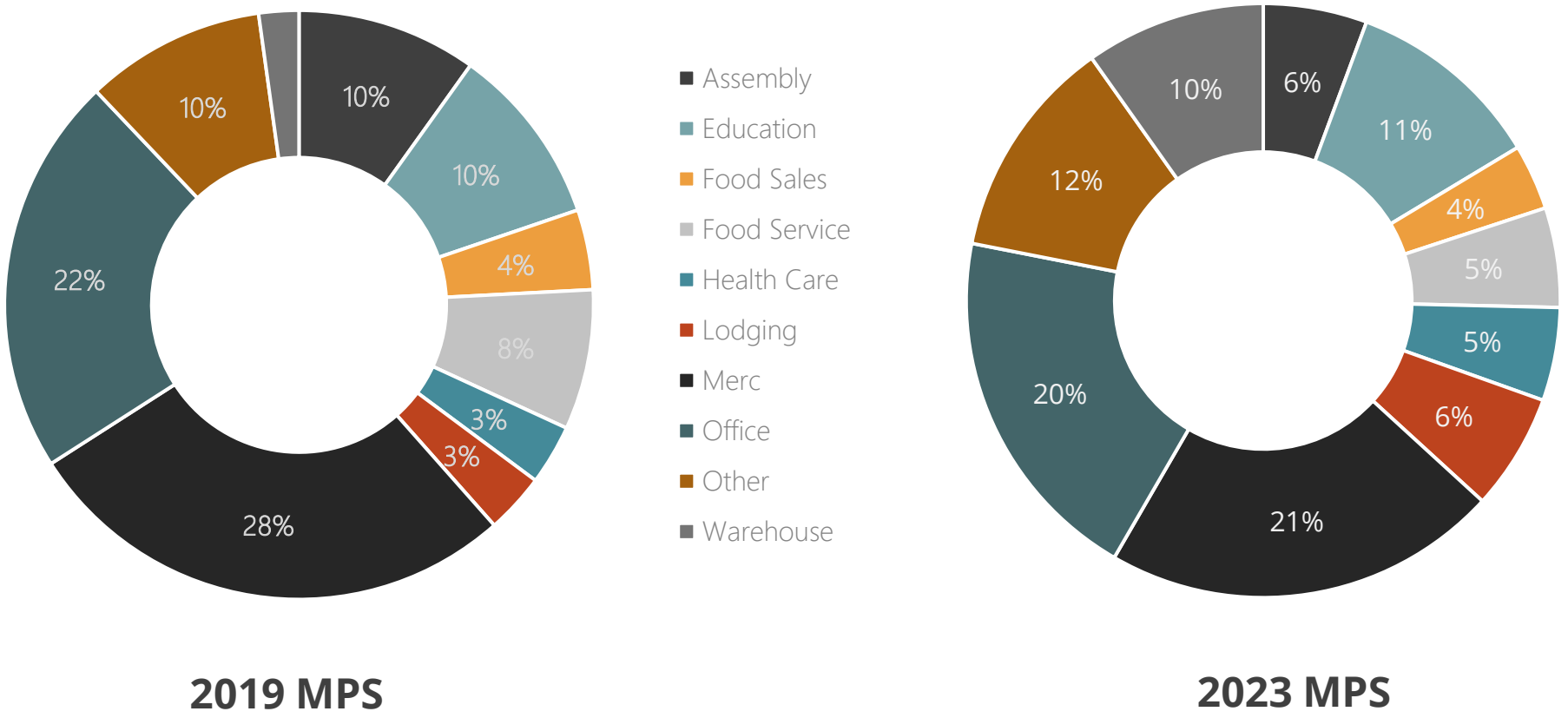
- Similar overall forecast *(with the exception of new large industrial customer)*
- 2023 MPS demonstrated similar overall eligible sales (excluding current opt-out sales) than the 2019 MPS.



TASK 3

Energy Efficiency Potential Analysis: Forecast Segmentation (C&I)

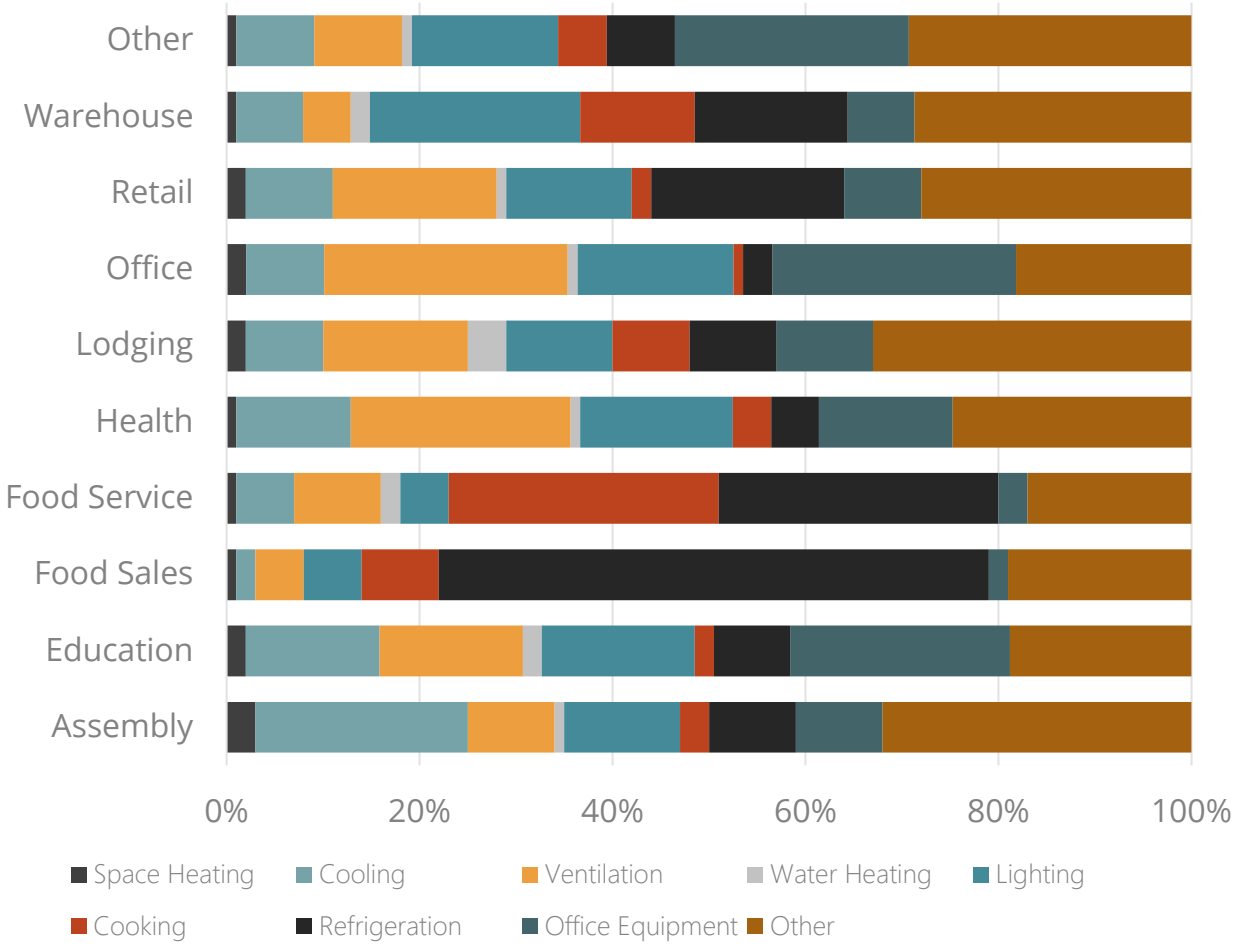
Illustrative Example of 2023 vs 2019 Segmentation



2019 MPS **2023 MPS**

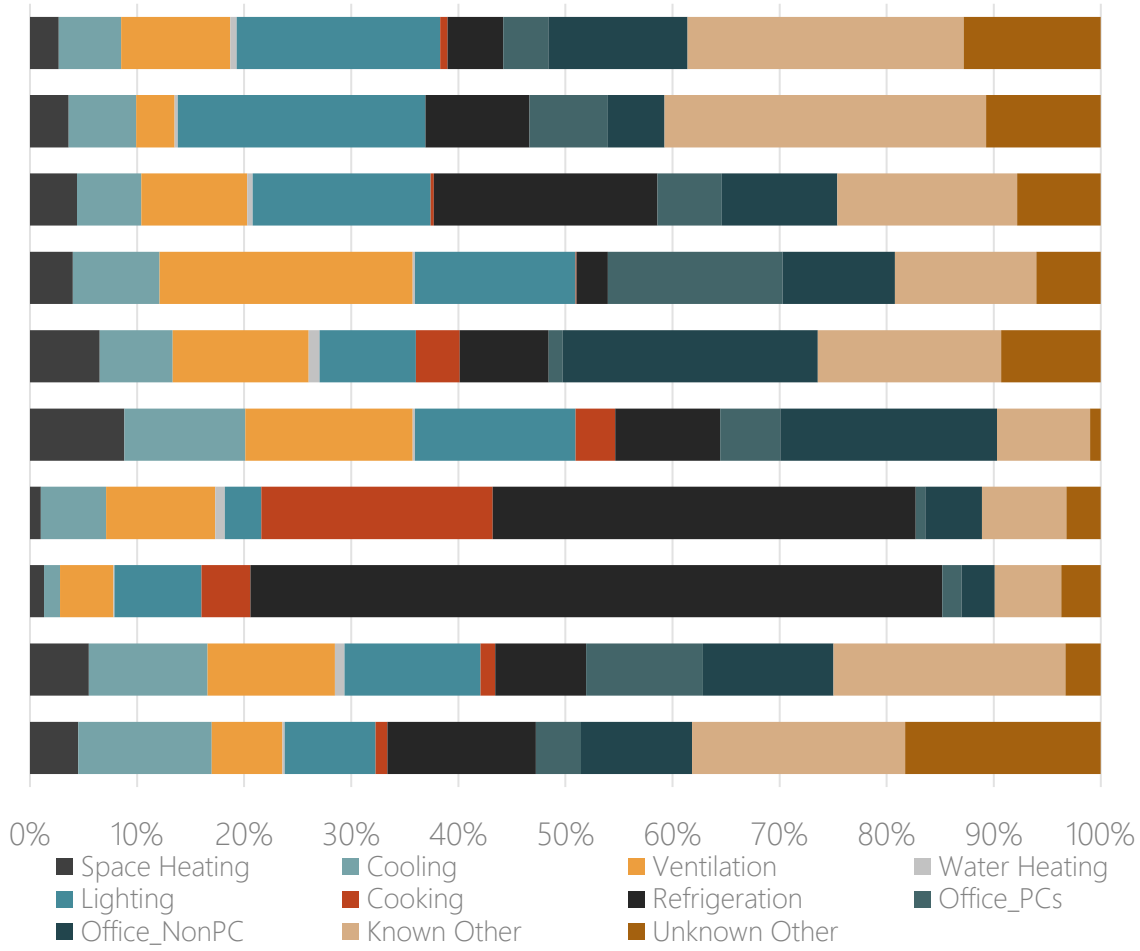
TASK 3

Energy Efficiency Potential Analysis: Forecast Segmentation (C&I)



2019 MPS

(CBECS 2012)



2023 MPS

(EIA AEO Proj)

TASK 3

Energy Efficiency Potential Analysis: Types of Potential

TECHNICAL POTENTIAL

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

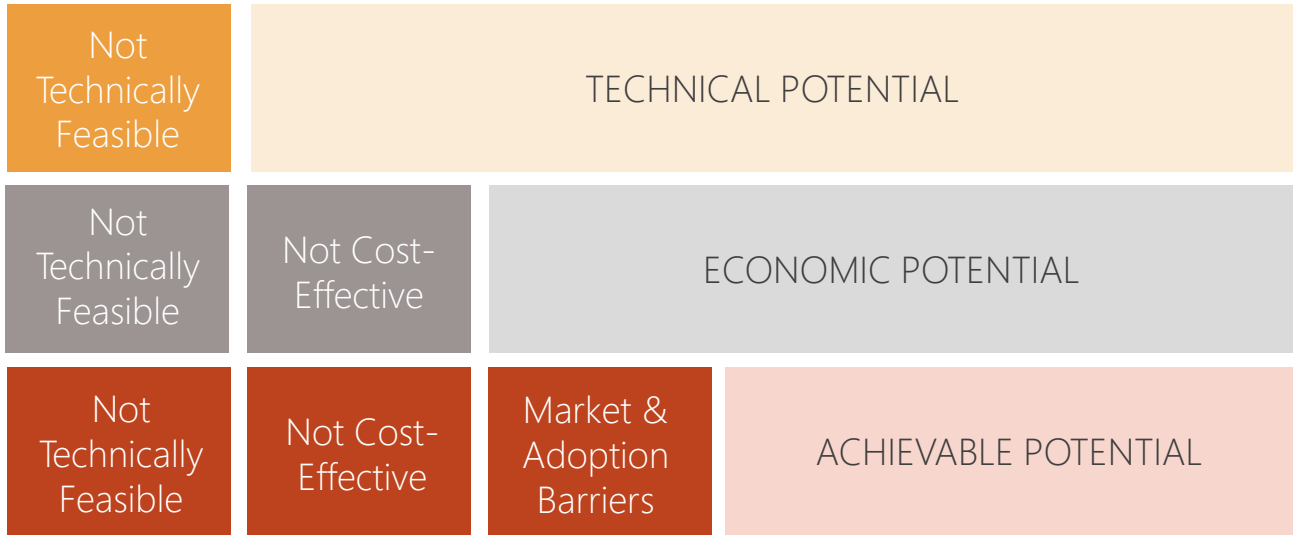
ECONOMIC POTENTIAL

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



TASK 3

Energy Efficiency Potential Analysis : Achievable Scenarios



Maximum and Reference Case Achievable Potential

Heavily influenced by energy efficiency adoption curves developed from market research.

Maximum Achievable Potential (MAP) estimates achievable potential under the most aggressive program case. In this study case, GDS will assume incentives based on *up to* 100% of measure incremental costs.

- *No decrease in incentive levels to allow measures to become cost-effective*
- *30% Increase to long-term adoption rates (if current EE saturation is > initial long-term level)*
- *Adoption curve = 20 years for traditional EE ; 30 years for Emerging Tech*
- *Individual measure cost equal to RAP timeframe*

Reference Case Achievable Potential (RAP) estimates achievable potential based on specific program funding levels/incentives. Incentives for the reference case will be based on typical CNP incentive levels in recent program years.

- *20% Increase to long-term adoption rates (if current EE saturation*
- *Adoption curve = 20 years for traditional EE ; 30 years for Emerging Tech*

TASK 3

Energy Efficiency Potential Analysis: Additional Considerations



- Potential Elements for Discussion/Consensus
  - *Use of prior market adoption research to inform long-term market adoption rates*
  - *Treatment of Emerging Technologies on future loads*
  - *Impact of re-upping technologies on savings/budgets (and benefits/costs)*
  - *Current implementation team input on near-term savings*
  - *MAP/RAP/Enhanced RAP Achievable Scenarios*
  - *Incentive level assumptions*
    - Current Incentives
    - Incentive Floors

NATURAL GAS POTENTIAL ANALYSIS

TASK 4

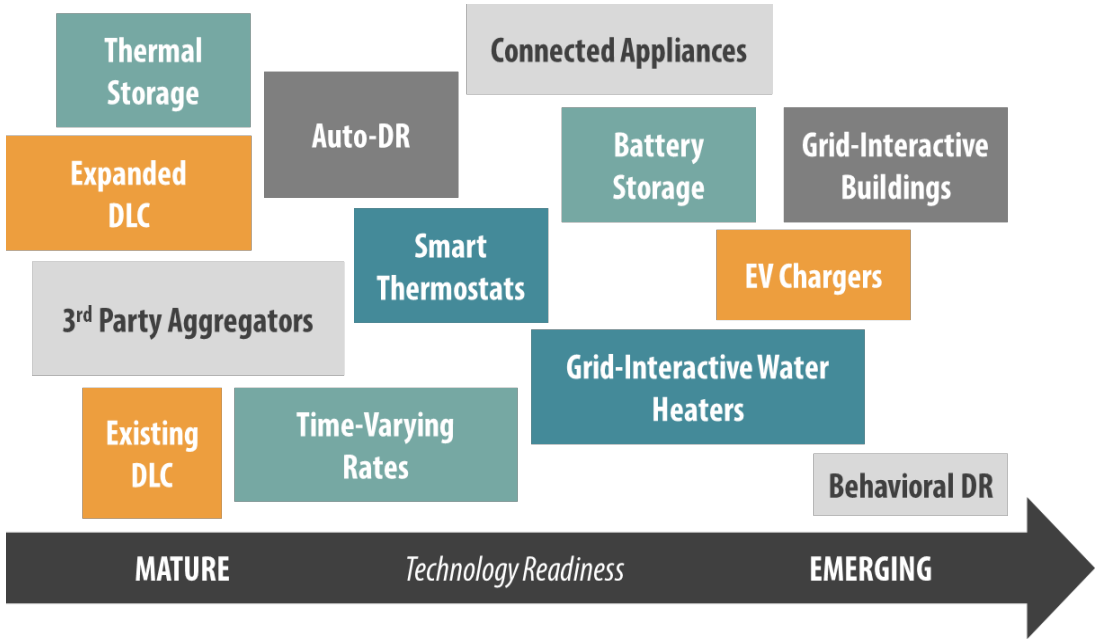
Natural Gas Potential Analysis

- Not conducted since 2018 MPS
- Does not consider fuel-switching
- Territories not a direct overlap
- Most measures will either be electric or gas measures
  - *Low flow devices opportunities will be based on the water heater fuel type*
  - *Building Shell measures may be either electric or gas, or costs and benefits will need to be shared/split if there are joint delivery opportunities*
  - *No converted fuel savings*
- NG MPS analysis will follow same methodology as the electric MPS

DEMAND RESPONSE OVERVIEW

TASK 4

Demand Response Potential Analysis



Demand Response Study

GDS uses a systematic methodological approach for demand response potential studies

- Examine demand response programs through both traditional load control strategies as well as several rate option strategies.
- Will focus on DR options that are expected to be most impactful, but will also include specific DR that is of interest to CenterPoint and/or stakeholders
- Similar to EE, at least two achievable potential scenarios will be included

TASK 4

Demand Response Potential

- DR Program Options
  - *Direct load control of air conditioners*
  - *Direct load control of electric space heating*
  - *Direct load control of electric water heaters*
  - *Direct load control of electric vehicle charging*
  - *Direct load control of room air conditioners*
  - *Direct load control of smart appliances*
  - *Curtail agreements / interruptible*
  - *Battery energy storage*
  - *Time of use rate*

- Seasonal Analysis
  - *As appropriate, DR programs will be assessed across multiple seasons*

- Hierarchy
  - *The DR analysis will account for interactive effects as additional types of demand response programs are added to the mix*

DSM ACTION PLAN

ACTION PLAN DEVELOPMENT

- Anticipated to be based on achievable potential identified in IRP (and, ultimately, selected in the IRP).
- **Consistent, but not identical**
- Action plan will cover 6-years

- Demonstrate program-level cost-effectiveness and sector/portfolio totals
- Back into "participant/project" counts based on historical average participant/project savings



IRP INPUTS

TASK 7

Prepare DSM Inputs for Modeling in the IRP



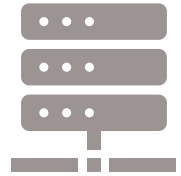
Discuss potential changes to the inputs for DSM selection.

Prior inputs were based on Enhanced RAP and were generally sector-based bundles.

CenterPoint models incremental annual savings and an associated levelized cost.



GDS typically transfers information such as the hourly load impacts of energy efficiency and demand response measures or programs and the costs to achieve these load impacts to IRP planning models.



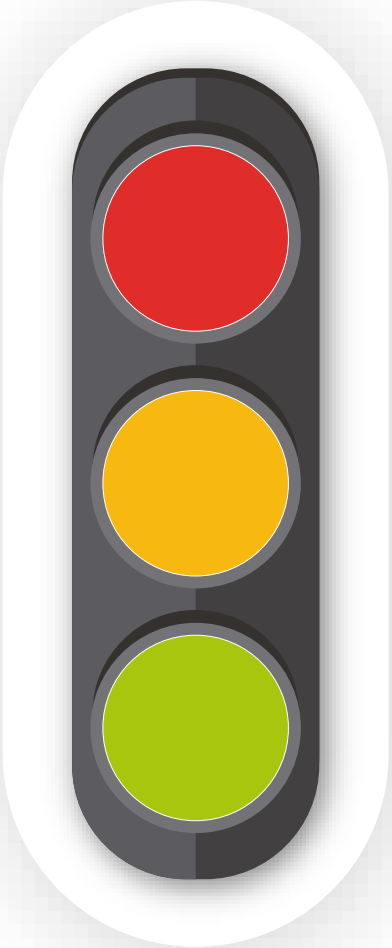
The hourly load data that we transfer is often voluminous and extends over the entire IRP planning horizon.

SCHEDULE



- Measure/Market Characterization in March 2025
- Draft MPS Estimates and IRP Inputs in May 2025
- Final MPS Data in June 2025
- Final IRP Inputs in July 2025
- Final Reports in August 2025

NEXT STEPS



- Data Request Responses
- Review Existing Load Forecast and Customer Data
- Determine Primary Market Research (if any)
- Develop measure list for resource (EE/DR/DER) review
- Establish calendar for continued engagement

Questions

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

PRESENTED BY GDS ASSOCIATES, INC.

2025 MPS CHECK IN MEETING - FEBRUARY

CenterPoint Energy Indiana

February 05, 2024

AGENDA



- Data Request Review
- Measure List Review
- Offered Items

SALES FORECAST

- **Review of sales forecast is underway**
  - *Ensuing future DSM is removed and understanding other components of what is or isn't included.*
  - *Will provide a comparison at subsequent meeting*

- **Current Opt-Out Total**
  - *42% of nonresidential sales, based on 2023 opt-out*
  - *Could change depending on final forecast used*

RESIDENTIAL ACCOUNTS

% OF ACCOUNTS

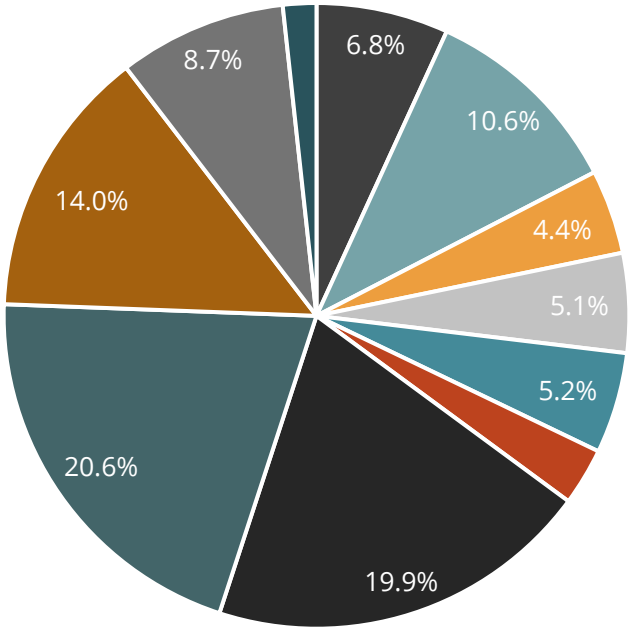
	2022 MPS	2025 MPS
SF	90%	tbd
MF	10%	tbd
SF-NC	71%	72%
MF-NC	29%	28%
LI SF	26.7%	tbd
LI MF	67.6%	tbd

NOTES

- **% of SF/MF will either come from updated residential survey and/or American Community Survey Data**
- **% of LI households (by housing type) will come from American Community Survey Data**
  - *Same source used prior study*

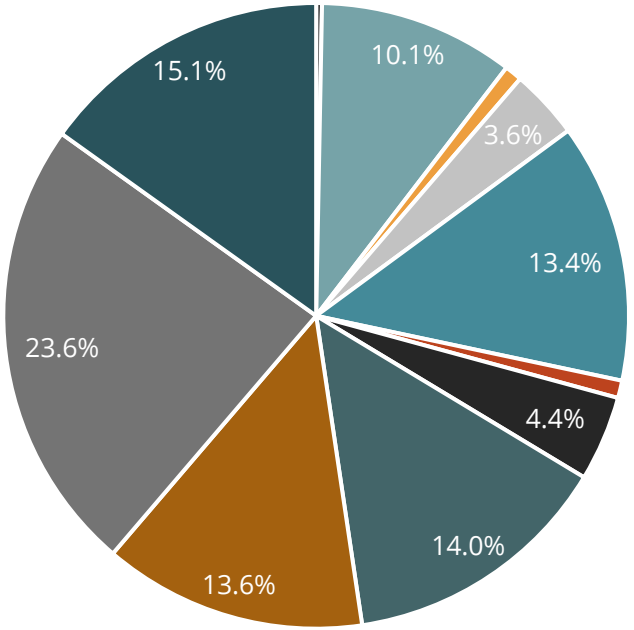
COMMERCIAL BUILDING TYPE SEGMENTATION

2022 MPS



Assembly
Education
Food Sales
Food Service
Health Care
Lodging
Merc
Office
Other
Warehouse
TCU

2025 MPS



Data Center
Education
Food Sales
Food Service
Health Care
Lodging
Retail
Office
Misc
Warehouse
TCU

COMMERCIAL BUILDING TYPE SEGMENTATION

- **Currently working to better understand differences in segmentation**
- **May need to get full nonresidential customer dataset to better align with 2022 MPS methodology for:**
  - *reclassifying commercial/industrial load*
  - *With and without opt-out sales*
- **Commercial end-use disaggregation will rely on latest available 2023 Annual Energy Outlook data**

AVOIDED COSTS

2022 MPS

	Energy ($/MWh)	Capacity ($/kw-yr)	T&D ($/kw-yr)
2025	38.82	134.44	6.8
2026	39.80	137.40	7.0
2027	44.04	140.42	7.1
2028	46.36	143.51	7.3
2029	48.37	146.66	7.5
2030	50.18	149.89	7.6
2031	51.76	153.19	7.8
2032	52.59	156.56	8.0
2033	54.94	160.00	8.2
2034	56.60	163.52	8.3
2044	89.84	203.28	10.4
2054	139.72	252.70	12.9

2025 MPS

	Energy ($/MWh)	Capacity ($/kw-yr)	T&D ($/kw-yr)
2025	47.17	125.05	8.8
2026	47.48	127.92	8.9
2027	41.96	130.85	9.2
2028	41.14	133.85	9.4
2029	40.28	136.92	9.6
2030	41.62	140.06	9.9
2031	40.86	143.27	10.2
2032	39.79	146.56	10.4
2033	40.31	149.92	10.6
2034	42.31	153.36	10.9
2044	60.90	192.09	13.59
2054	75.82	239.15	16.92

OTHER ECONOMIC FACTORS

NOTES

- **Avoided Energy Costs are lower than 2022**
- **Capacity costs are slightly lower than 2022**
- **T&D Costs are higher than 2022**

- **Similar discount rate and inflation rate**
- **Similar reserve margin (but RMR is now seasonal)**
- **Line loss factor – 8.4% or 1.092**
  - *will use 1/(1-LLF) to develop multiplier*

COMPARISON

	2022 MPS	2025 MPS
Discount Rate	6.19%	6.03%
Inflation Rate	2.3%	2.3%
Reserve Margin	1.09	1.079 (Summer)
Line Loss	6%	8.4%

EXISTING DR PROGRAM PARTICIPATION

2022 MPS

- **Residential DLC AC Switch**
  - *19,596 participants*
  - *Transitioning to thermostats*
- **Residential Smart Cycle Thermostats**
  - *1,816 participants*
- **Residential BYOT**
  - *3,691 participants*
- **Residential DLC Pool Pumps**
  - *74 participants*
- **Residential DLC Water Heaters**
  - *5,651 participants*
- **Non-Res DLC AC Switch**
  - *1,460 participants*
- **Non-Res DLC Water Heaters**
  - *45 participants*

2025 MPS

- **Residential DLC AC Switch**
  - *18,258 participants*
  - *Transitioning to thermostats*
- **Residential Smart Cycle Thermostats**
  - *1,352 participants*
- **Residential BYOT**
  - *7,308 participants*
- **Residential DLC Pool Pumps**
  - *74 participants*
- **Residential DLC Water Heaters**
  - *5,520 participants*
- **Non-Res DLC AC Switch**
  - *391 participants*
- **Non-Res DLC Water Heaters**
  - *0 participants*

EXISTING DR PROGRAM INPUTS PROVIDED BY CENTERPOINT

2022 MPS

- **Load reduction per DLC AC switch/thermostat:**
  - *Residential DLC AC Switch: 0.268 kW per switch*
  - *Residential DLC AC Thermostats: 0.92 kW per thermostat*
- **Incentives paid per participant**
  - *DLC AC Switch: $20/year*
  - *DLC WH: $8/year*

2025 MPS

- **Load reduction per DLC AC switch/thermostat:**
  - *Residential DLC AC Switch: 0.214 kW per switch*
  - *Residential DLC AC Thermostats: 0.95 kW per thermostat*
- **Incentives paid per participant**
  - *DLC AC Switch: $15/year*
  - *DLC AC Thermostat: $67.50/year*
  - *DLC WH: $6/year*

ENERGY EFICIENCY MEASURE LIST

- Typical measures from Indiana TRM
- Plan to add emerging / innovative technologies
- Other measures, if needed…

EMERING/INNOVATIVE TECHNOLOGIES

RESIDENTIAL

- **Emerging**
  - *Ozone Laundry, Smart Sockets, Integrated HVAC Controls, Smart Vents/Sensors, Energy Recovery Ventilator, Heat Pump Pool Heater, HVAC Economizer, Ultra-Efficient LED, Insulated Cellular Shades, Multifamily Whole Building Aerosol Sealing, Phase Change Blanket*
- **Innovative**
  - *Ultrasonic Clothes Dryer, Eco-Snap Air Conditioning, Electro Caloric Heat Pump, Integrated Design, Nanoinsulation*

NONRESIDENTIAL

- **Emerging**
  - *Triple Pane Windows, ERVs, Spring Loaded Garage Door Hinge, UPS, Switch Reluctance Motors, Server Virtualization, Data Hold/Cold Aisle Configuration, Aerofoils for Open Display Cases, High Efficiency DOAS, Commercial Behavior Options*
- **Innovative**
  - *Advanced Cooking, Advanced Lighting, Advanced IT, Advanced Motors, Advanced Refrigeration, Advanced HVAC, Advanced Lighting Controls, Process Improvements*

IMPLEMENTOR SUGGESTED MEASURES

RESIDENTIAL

- Room Heat Pump
- Induction Cooktop
- Heat Pump Clothes Dryer*
- Dishwasher*
- Refrigerator*
- Freezer*
- Water Cooler
- Smart Plugs*
- Dryer Vent Cleaning

NONRESIDENTIAL

- **HVAC**
  - *VRFs*
- **Cybersecurity**
  - *Cybersecurity and Power System Stability*
- **Buildings**
  - *Grid-Interactive Efficient Buildings, Tunable Thermal Storage, Thermochemical Storage*
- **Transportation**
  - *Urban Mobility Modeling, High-Performance Computing, Long-Haul Trucks*
- **Water-Energy**
  - *Low Energy Water Desalination, Enhanced Solar Evaporation for Zero Liquid Discharge*
- **Energy Storage**
- **Other**
  - *Opaque Envelope, SSL R&D Opportunities Report, Air to Water Heat Pump*

DEMAND RESPONSE PROGRAM LIST

- DLC AC Switch
- DLC Smart Cycle Thermostat
- DLC BYOT
- DLC Water Heaters
- DLC Pool Pumps
- DLC Electric Vehicles
- TOU with CPP
- TOU only
- CPP only
- Real Time Pricing Rate
- Battery Storage

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

PRESENTED BY GDS ASSOCIATES, INC.

2025 MPS CHECK IN MEETING - MARCH

CenterPoint Energy Indiana

March 06, 2024

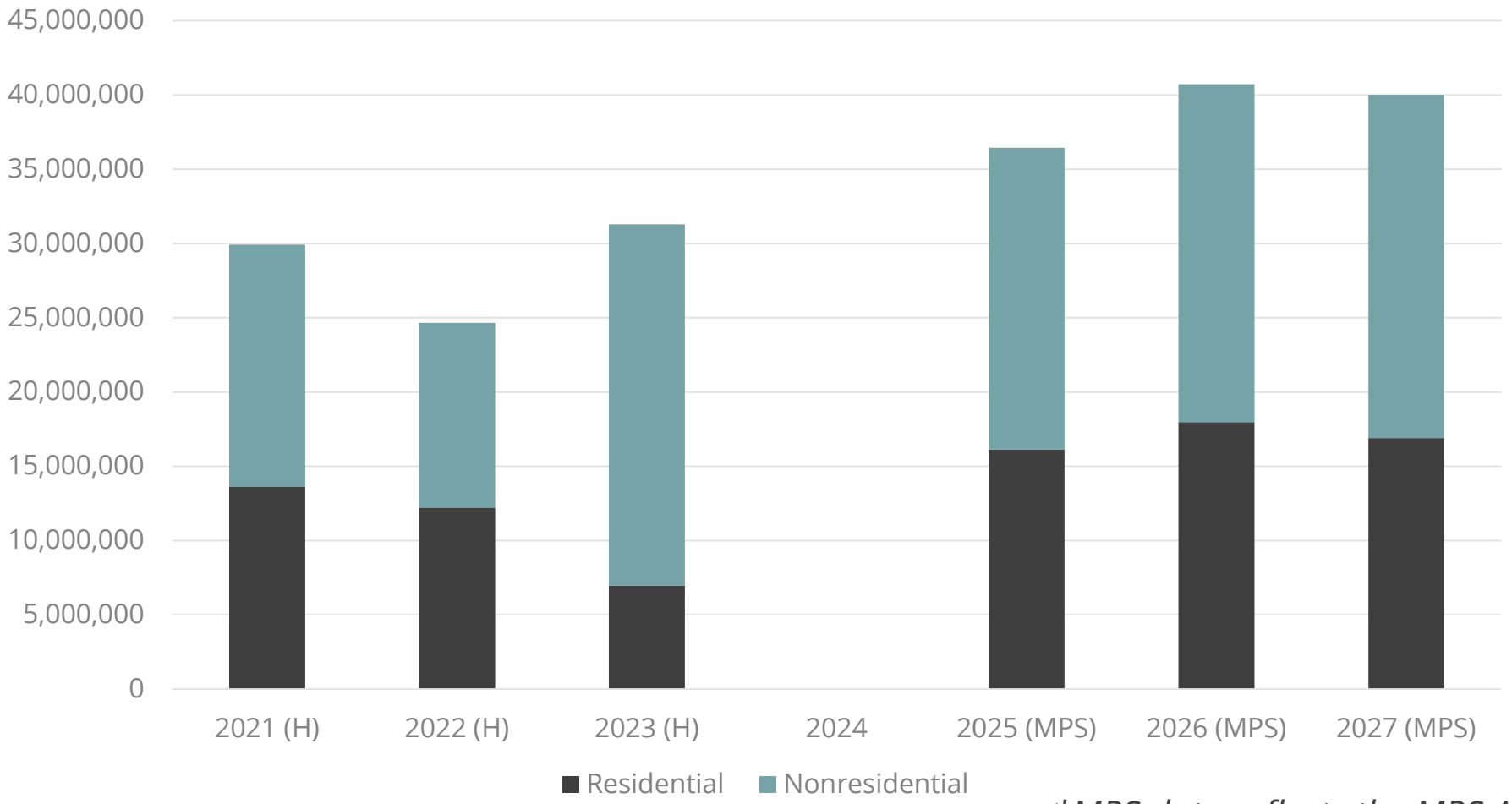
AGENDA



- Historical Performance Review / MPS Benchmarking
- Demand Response Program Assumptions Review
- Offered Items

NET KWH COMPARISON

Portfolio and Sector Level

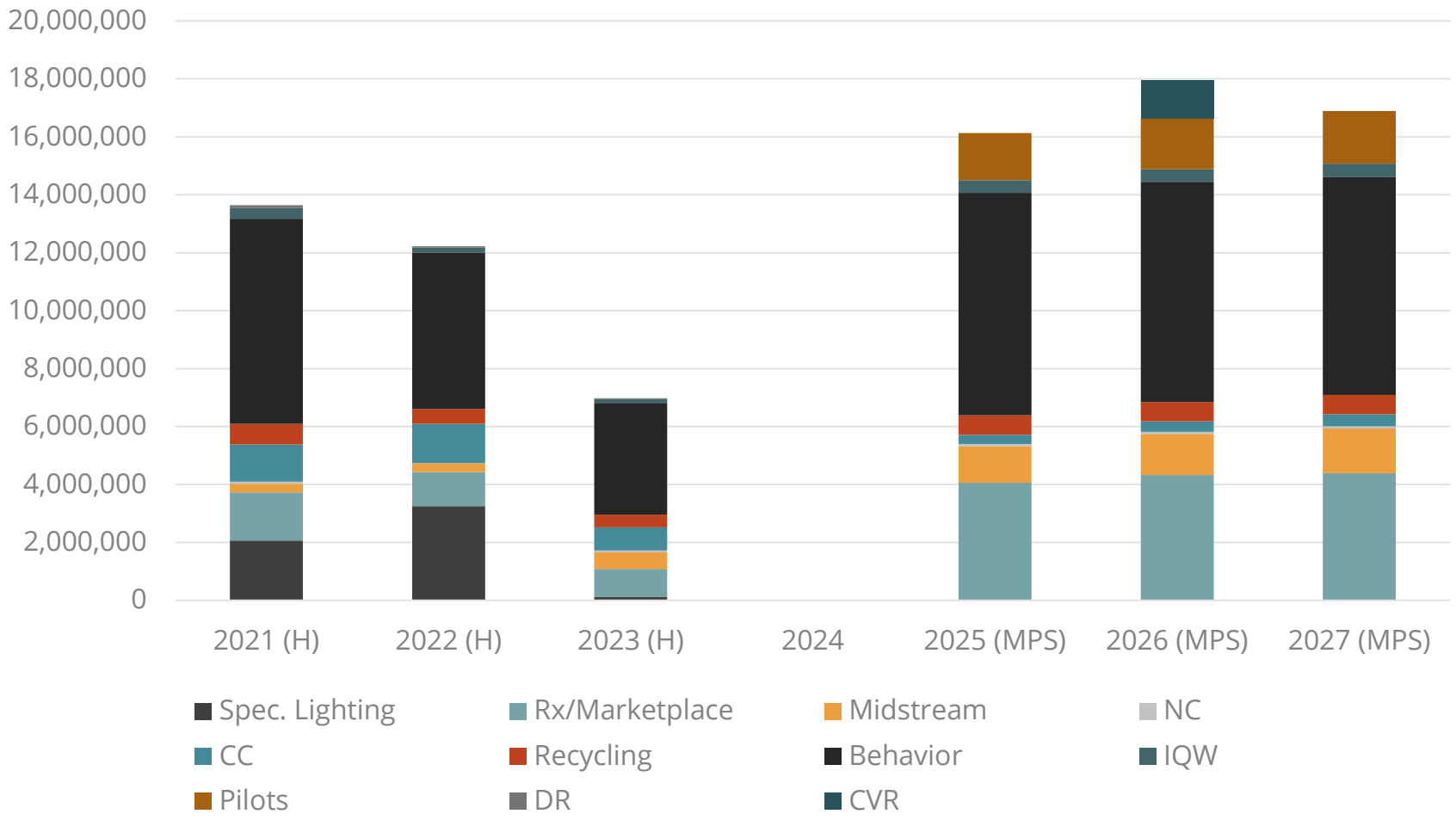


- *Historical includes specialty lighting (2021,2022) ; not included in MPS*
- *MPS includes CVR in 2026 (~1.8 million kWh)*
- *MPS also includes ~ 1.7 million in residential pilots each year)*
- *Limited smart cycle energy savings in historical data.*

**MPS data reflects the MPS Action Plan ; ultimate IRP selections and Operating Plan produced reduced impacts*

NET KWH COMPARISON

Residential Sector

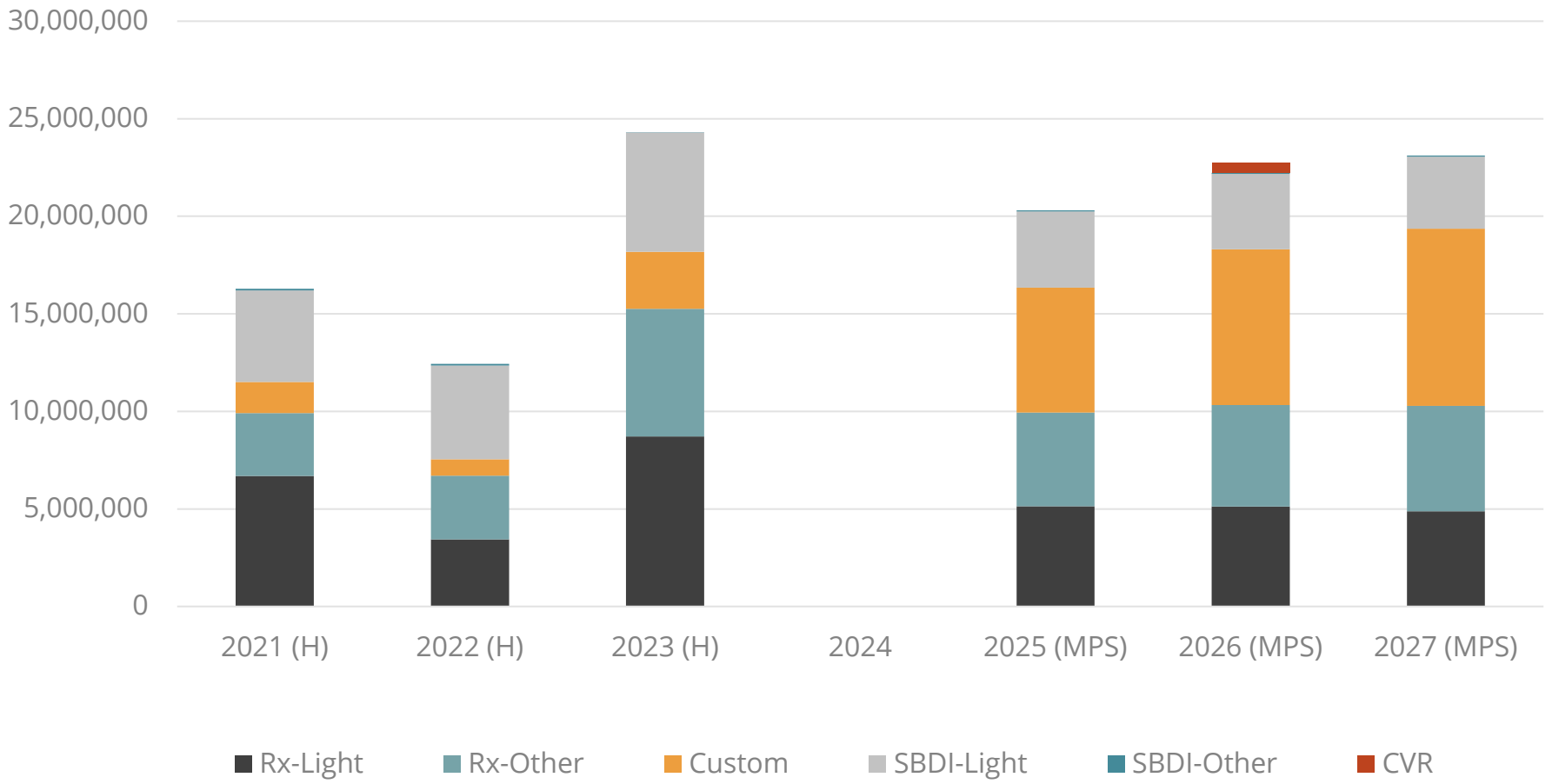


- *Largest differences are in behavior savings and Rx/Marketplace*
- *MPS behavioral levels similar to 2021 levels, but not 2022 and 2023 levels*
- *Largest differences in Rx/Marketplace include:*
  - *Nearly 2x thermostats in MPS/Action Plan*
  - *Nearly 10,000x Low Flow savings in MPS/Action Plan*

- *Note: Some differences driven by differences in NTG assumptions (see later slide)*

NET KWH COMPARISON

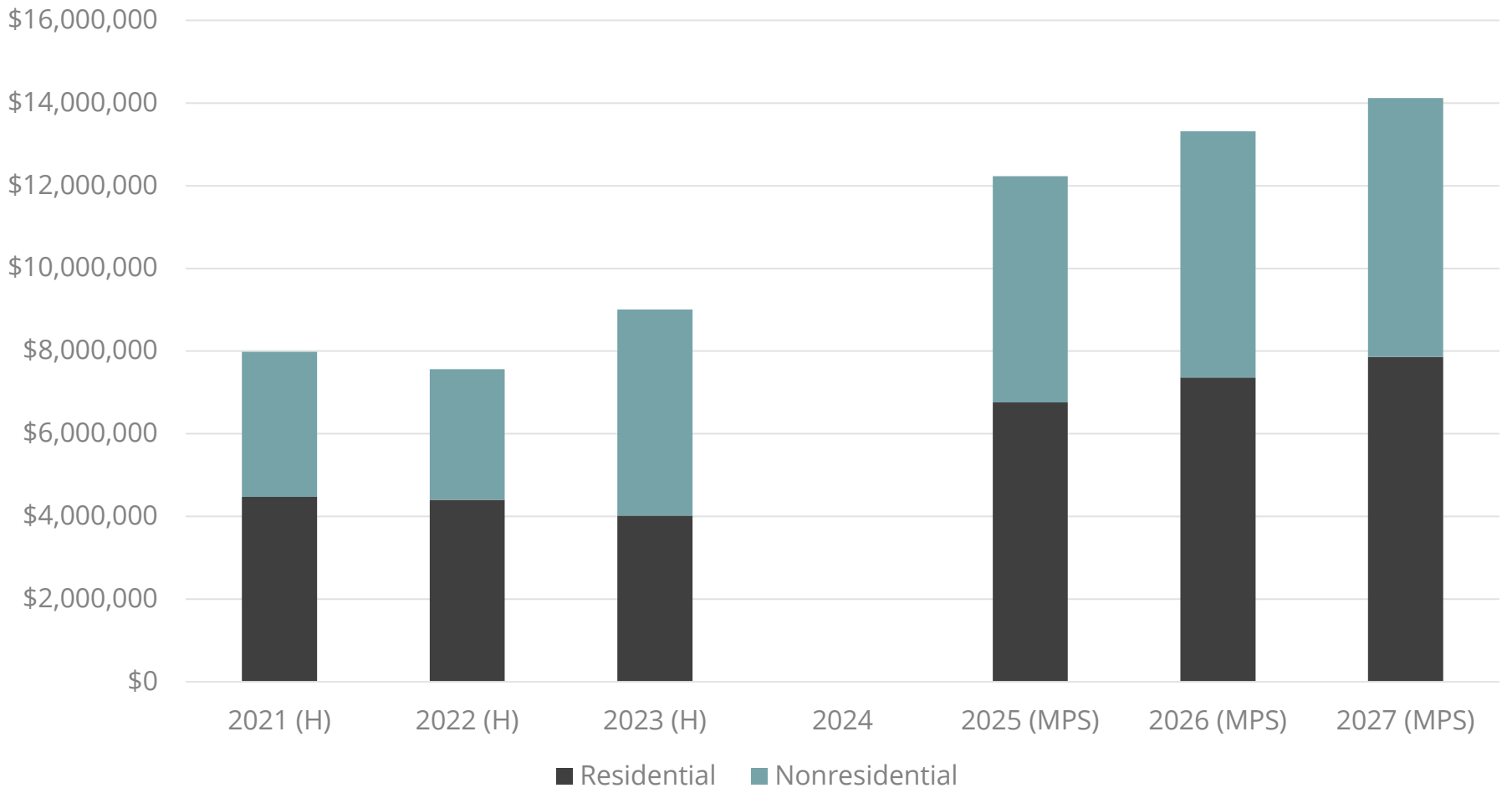
Non-Residential Sector



- *MPS levels are based on "enhanced" scenario reflected in action plan*
- *More custom savings identified in MPS than seen in historical performance*
- *Custom MPS savings include some lighting (unclear the extent of custom lighting in historical data)*

TOTAL COST COMPARISON

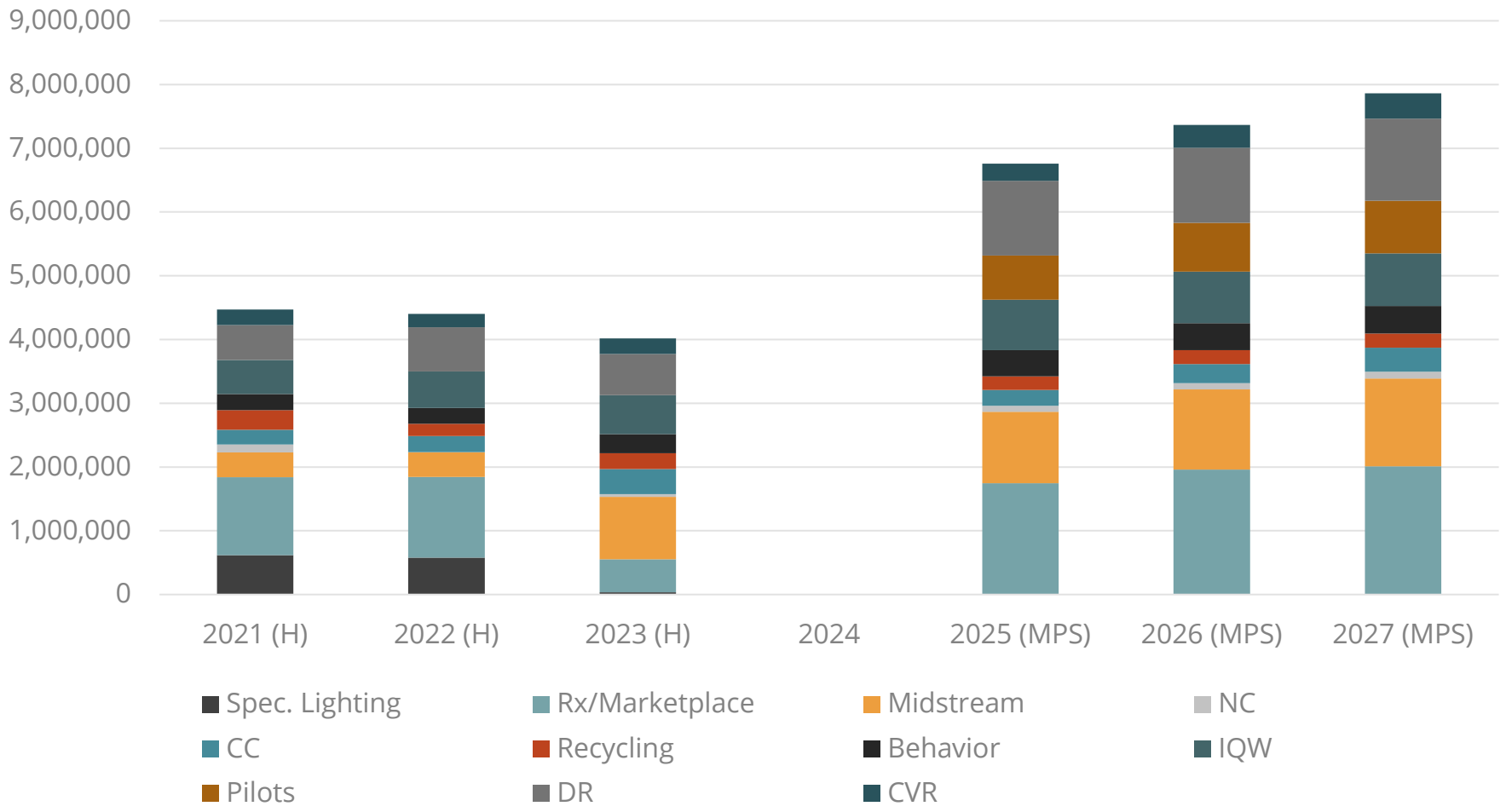
Portfolio and Sector Level



- *Overall high MPS Costs*
- *But higher savings also, particularly in residential sector*

TOTAL COST COMPARISON

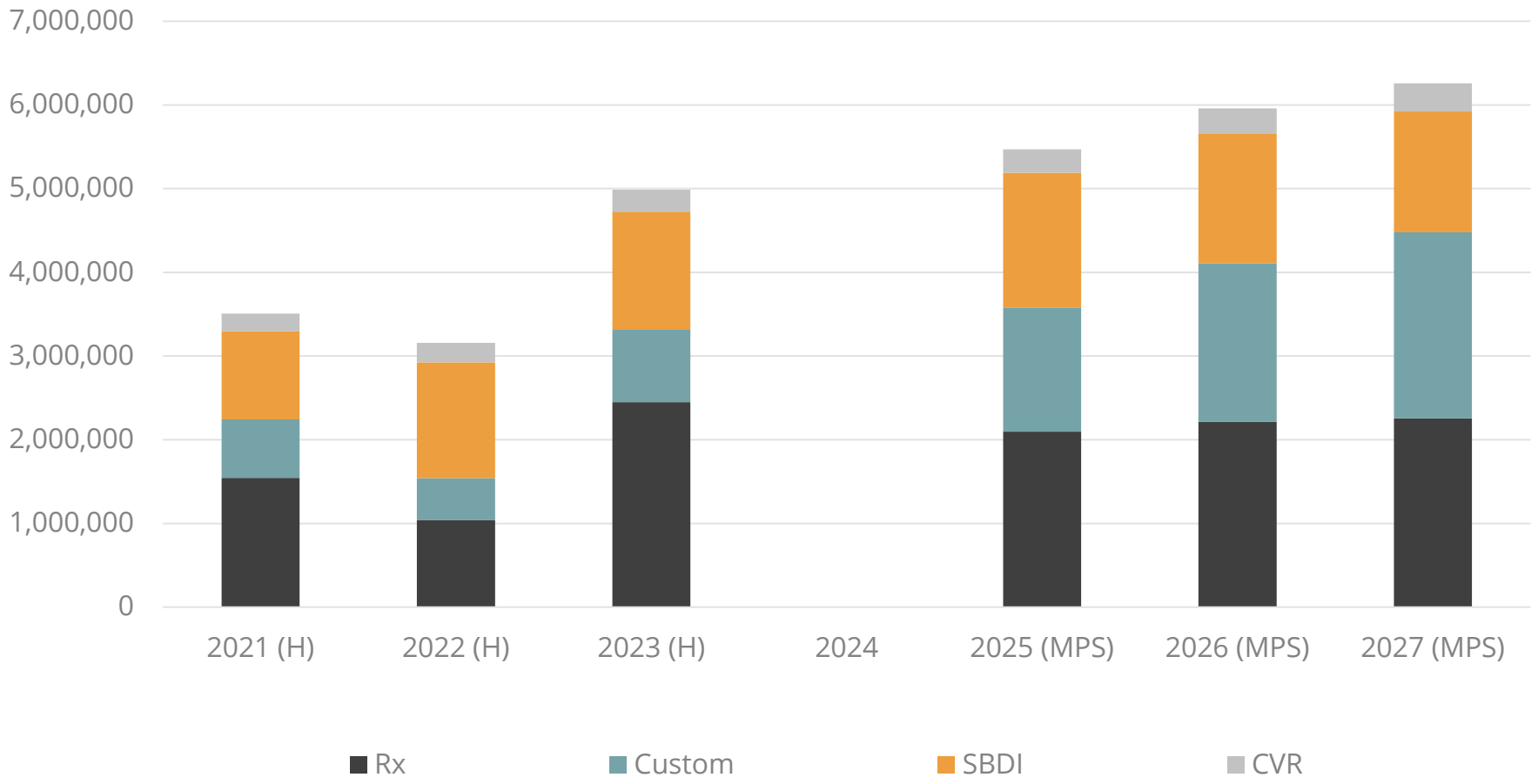
Residential Sector



- *Largest differences are in Rx/Marketplace (same as savings)*
- *Midstream costs in 2023 are more aligned with MPS (savings also increased in 2023)*
- *Other differences include emerging pilot costs in MPS and higher Smart Cycle/BYOT costs*

TOTAL COST COMPARISON

Non-Residential Sector



- *Costs generally well aligned, particularly 2023 historical costs*
- *Higher custom program costs (but also higher savings)*

INCENTIVE AND NON-INCENTIVE COST / KWH (GROSS)

Incentives	2021	2022	2023	MPS	2025 OP
Res. Behavior	$0.00	$0.00	$0.00	$0.00	$0.00
Res. Prescriptive	$0.26	$0.30	$0.27	$0.35	$0.26
Res. Appliance Recycle	$0.06	$0.05	$0.07	$0.05	n/a
Res Income Eligible	$0.00	$0.00	$0.00	$1.33	$0.61
NonRes Prescriptive	$0.07	$0.05	$0.08	$0.11	$0.12
Nonres SBDI	$0.12	$0.19	$0.14	$0.26	$0.25
Nonres Custom	$0.23	$0.15	$0.13	$0.10	0.15

Non-Incentive	2021	2022	2023	MPS	2025 OP
Res. Behavior	$0.04	$0.05	$0.06	$0.04	$0.06
Res. Prescriptive	$0.22	$0.37	$0.21	$0.31	$0.16
Res. Appliance Recycle	$0.16	$0.14	$0.21	$0.16	n/a
Res Income Eligible	$1.43	$3.14	$3.44	$0.41	$1.02
NonRes Prescriptive	$0.05	$0.05	$0.06	$0.06	$0.08
Nonres SBDI	$0.07	$0.05	$0.08	$0.08	$0.12
Nonres Custom	$0.18	$0.20	$0.15	$0.12	$0.10

TOTAL COST / KWH (GROSS)

Total	2021	2022	2023	MPS	2025 OP
Res. Behavior	$0.04	$0.05	$0.06	$0.04	$0.06
Res. Prescriptive	$0.48	$0.67	$0.48	$0.66	$0.42
Res. Appliance Recycle	$0.22	$0.19	$0.29	$0.21	n/a
Res Income Eligible	$1.43	$3.14	$3.44	$1.74	$1.64
NonRes Prescriptive	$0.12	$0.10	$0.14	$0.17	$0.21
Nonres SBDI	$0.19	$0.25	$0.22	$0.34	$0.37
Nonres Custom	$0.41	$0.35	$0.29	$0.22	$0.25

- *Admin costs generally well aligned*
- *Overall residential total program costs /kWh generally well aligned, with the exception of IQW.*
  - *2022/2023 total acquisition cost has been more expensive*
- *More variation across nonresidential*
- *Prescriptive MPS costs were above recent historical (but less lighting)*
- *Nonresidential SBDI costs were higher (will dive deeper)*
- *Custom total acquisition cost in MPS was cheaper than recent historical (current application specifies $0.14 per kWh)*

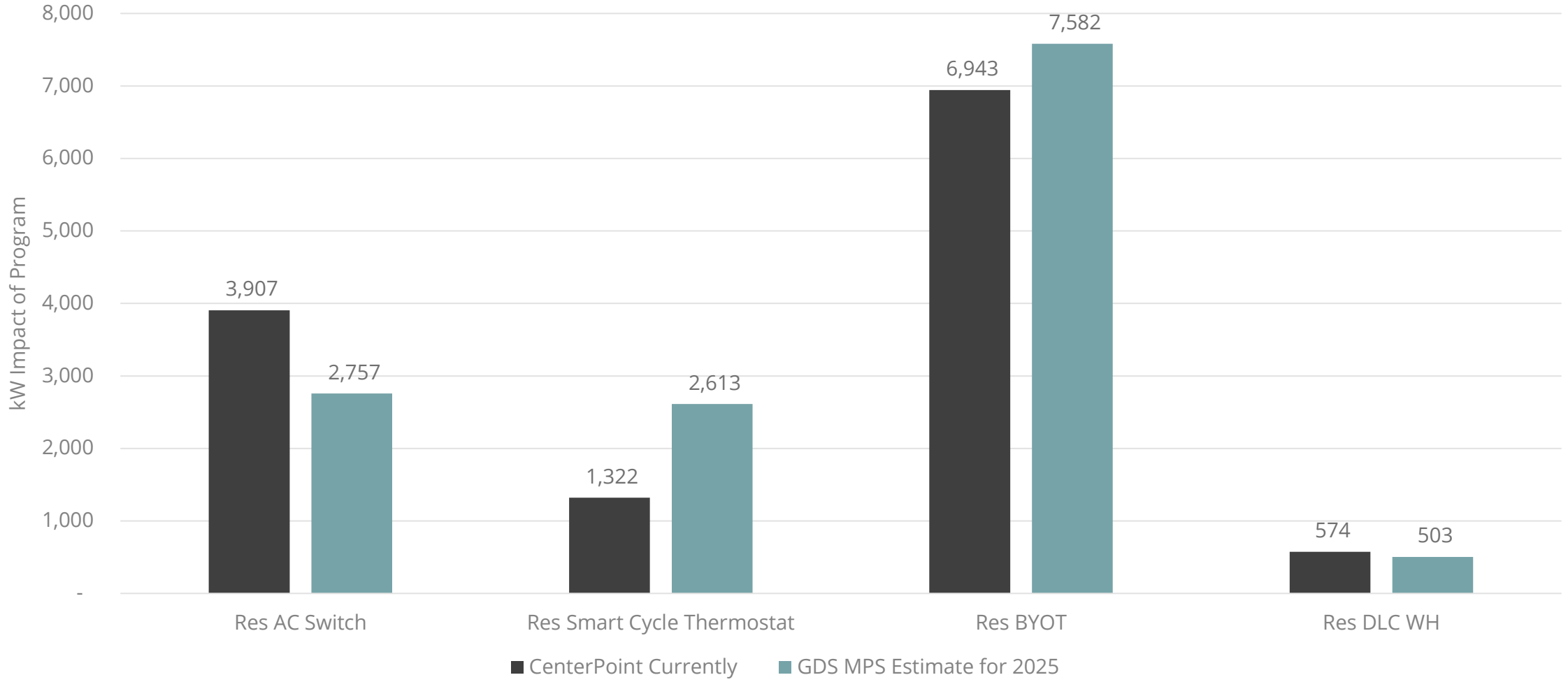
NTG BENCHMARKING

Total	2021	2022	2023	MPS	2025 OP
Res. Behavior	100%	100%	100%	100%	100%
Res. Prescriptive	58%	60%	62%	78%	77%
Res. Appliance Recycle	52%	52%	52%	62%	n/a
Res Income Eligible	100%	100%	100%	100%	100%
NonRes Prescriptive	76%	63%	85%	84%	84%
Nonres SBDI	88%	88%	95%	84%	84%
Nonres Custom	93%	58%	97%	93%	84%

- *Residential Prescriptive (includes marketplace, midstream, instant) 2021-2023 has been below the MPS estimate*
- *Appliance Recycling also below MPS estimate*

- *Nonresidential prescriptive below MPS (but 2023 is well aligned)*
- *SBDI 2021-2023 NTG higher than MPS estimate*
- *Custom well aligned (2022 NTG is an outlier)*

HISTORICAL BENCHMARKING FOR DR PROGRAMS



DR MEASURE ASSUMPTIONS

DLC AC Switch – Res

- *2027 Participation: 9,258 (currently 18,258)*
- *Annual incentive: $15/participant*
- *Load reduction per participant: 0.214 kW*
- *Participation rate: decreasing by ~3,000 switches per year*

DLC Thermostat – Res

- *2027 Smart Cycle Participation: 10,352 (currently 1,352)*
- *2027 BYOT Participation: 11,208 (currently 7,308)*
- *Annual incentive: $67.50/participant*
- *Load reduction per participant: 0.95 kW in summer, 1.37 kW in winter*
- *Participation rate: 45% MAP, 20% RAP*

DLC Thermostat – C&I

- *Annual incentive: $67.50/participant*
- *Load reduction per participant: 1.95 kW in summer, 2.54 kW in winter*
- *Participation rate: 25% MAP, 8% RAP*

Key:
Provided by CenterPoint
Outside Source

DR MEASURE ASSUMPTIONS

- **DLC Water Heater Switch – Res**
  - *2027 Participation: 4,485 (currently 5,520)*
  - *Annual incentive: $6/participant*
  - *Load reduction per participant: 0.104 kW in summer, 0.185 kW in winter*
  - *Participation rate: decreasing to 0 by 2040*

- **DLC Grid Enabled Water Heater – Res**
  - *Annual incentive: $26/participant*
  - *Load reduction per participant: 0.104 kW in summer, 0.185 kW in winter*
  - *Participation rate: 50% MAP, 25% RAP*

- **DLC Grid Enabled Water Heater – C&I**
  - *Annual incentive: $30/participant*
  - *Load reduction per participant: 1.5 kW in summer and winter*
  - *Participation rate: 50% MAP, 25% RAP*

Key:
Provided by CenterPoint
Outside Source

DR MEASURE ASSUMPTIONS

- **DR Battery Storage - Res**
  - *Annual incentive: $400/participant*
  - *Load reduction per participant: 3 kW (assumes utility could use 60% of 5 kW battery)*
  - *Participation rate: 60% MAP, 50% RAP*
  - *Eligible customers: 28% of customers with solar PV (pending additional review)*

- **DR Battery Storage – C&I**
  - *Annual incentive: $1500/participant*
  - *Load reduction per participant: 11.25 kW (assumes utility could use 45% of 25 kW battery)*
  - *Participation rate: 60% MAP, 50% RAP*
  - *Eligible customers: 28% of customers with solar PV (pending additional review)*

Key:
Provided by CenterPoint
Outside Source

DR MEASURE ASSUMPTIONS

- **DLC Electric Vehicles - Res**
  - *Annual incentive: $35/participant*
  - *One-time enrollment incentive: $155/participant*
  - *Load reduction per participant: 0.304 kW in summer, 0.295 kW in winter*
  - *Participation rate: 25% MAP, 20% RAP*
- **DLC Electric Vehicles – C&I**
  - *Load reduction per participant: 0.02 kW in summer, 0.03 kW in winter*
  - *Participation rate: 20% MAP, 10% RAP*
- **Real Time Pricing (RTP) Rate – C&I**
  - *Load reduction per participant: 8% of CP load in summer, 4.2% in winter*
  - *Participation rates: 8% MAP, 4% RAP*

Key:
Provided by CenterPoint
Outside Source

DR MEASURE ASSUMPTIONS

- **TOU**
  - *Residential load reduction per participant: 5.5% of CP load in summer, 2.5% in winter*
  - *C&I load reduction per participant: 2% of CP load in summer, 1% in winter*
  - *Residential participation rates: 28% MAP, 10% RAP*
  - *C&I participation rates: 13% MAP, 10% RAP*

- **CPP**
  - *Residential load reduction per participant: 12.8% of CP load in summer, 7.7% in winter*
  - *C&I load reduction per participant: 7.9% of CP load in summer, 6% in winter*
  - *Residential and C&I participation rates: 18% MAP, 15% RAP*

- **TOU + CPP**
  - *Blend of the separate rates*
  - *Will use CPP load reduction during critical peak days, TOU load reduction for all other days*
  - *Current rate structure:*
    - Off peak 7pm to 1pm ($0.07054/kWh)
    - TOU on peak weekdays 1pm to 7pm ($0.028214/kWh)
    - Critical peak when notified ($0.5643/kWh)

Key:
Provided by CenterPoint
Outside Source

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

PRESENTED BY GDS ASSOCIATES, INC.

2025 MPS CHECK IN MEETING - APRIL

CenterPoint Energy Indiana

April 17, 2025

AGENDA



- Demand Response Memo Review
- Demand Response Initial Draft Results Summary
- EE Measure Lists & Select Methodology Discussions
- Other Offered Items

DEMAND RESPONSE MEMO DISCUSSION

DR INITIAL DRAFT RESULTS SUMMARY

DEMAND RESPONSE

DR Program Options

- **Direct load control**
  - *Central AC switch (current program, assumed to decline to 0)*
  - *Thermostat – Smart Cycle (transitioning from switches)*
  - *Thermostat – BYOT*
  - *Water heater switch (current program, assumed to decline to 0)*
  - *Grid-enabled water heater*
  - *Electric vehicle chargers*
- **Rates**
  - *Time of use with critical peak pricing*
- **Other**
  - *Battery storage*

Notes

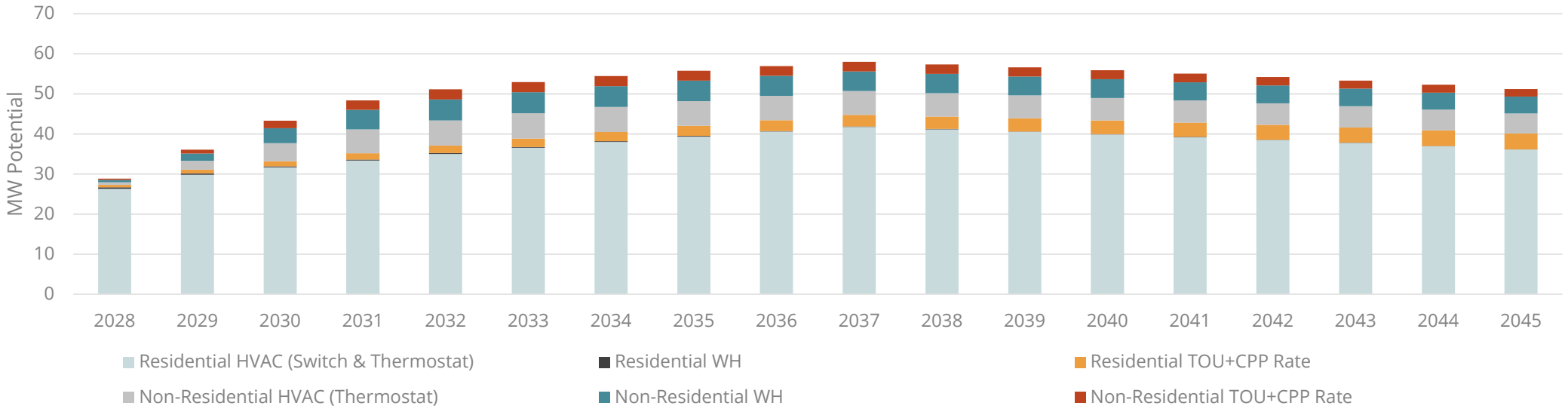
- **Updates**
  - *Now assuming that AC and WH switches can continue program participation until switch failure.*
- **Seasonality**
  - *Summer Cycler AC & WH switch program will run June through August.*
  - *Thermostat programs will run March through November.*
  - *TOU+CPP, EV chargers, and battery storage will run year-round.*
- **Time of Use / Critical Peak Pricing**
  - *CNP plans to offer a combined TOU+CPP rate but will not offer individual TOU and CPP rates. For this reason, we are only analyzing the combined rate.*

DEMAND RESPONSE COST-EFFECTIVENESS

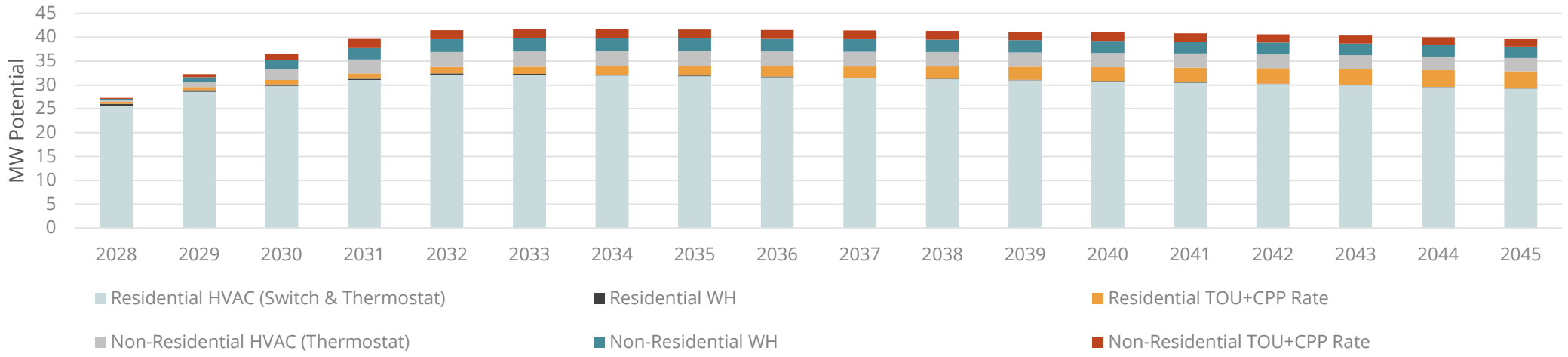
Sector	Program	MAP UCT	RAP UCT
Residential	DLC Central AC Switch	2.00	2.06
	DLC Thermostat (Smart Cycle)	1.15	1.22
	DLC Thermostat (BYOT)	1.46	1.61
	DLC Water Heater Switch	0.24	0.24
	DLC Grid-Enabled Water Heater	0.76	0.79
	DLC Electric Vehicle	0.78	0.74
	TOU + CPP Rate	5.20	5.05
	Battery Storage	0.87	0.84
C&I	DLC Thermostat (BYOT)	2.63	2.71
	DLC Grid-Enabled Water Heater	2.97	2.70
	DLC Electric Vehicle	0.00	0.00
	TOU + CPP Rate	6.59	5.38
	Battery Storage	0.60	0.55

DEMAND RESPONSE RESULTS

Summer MAP



Summer RAP

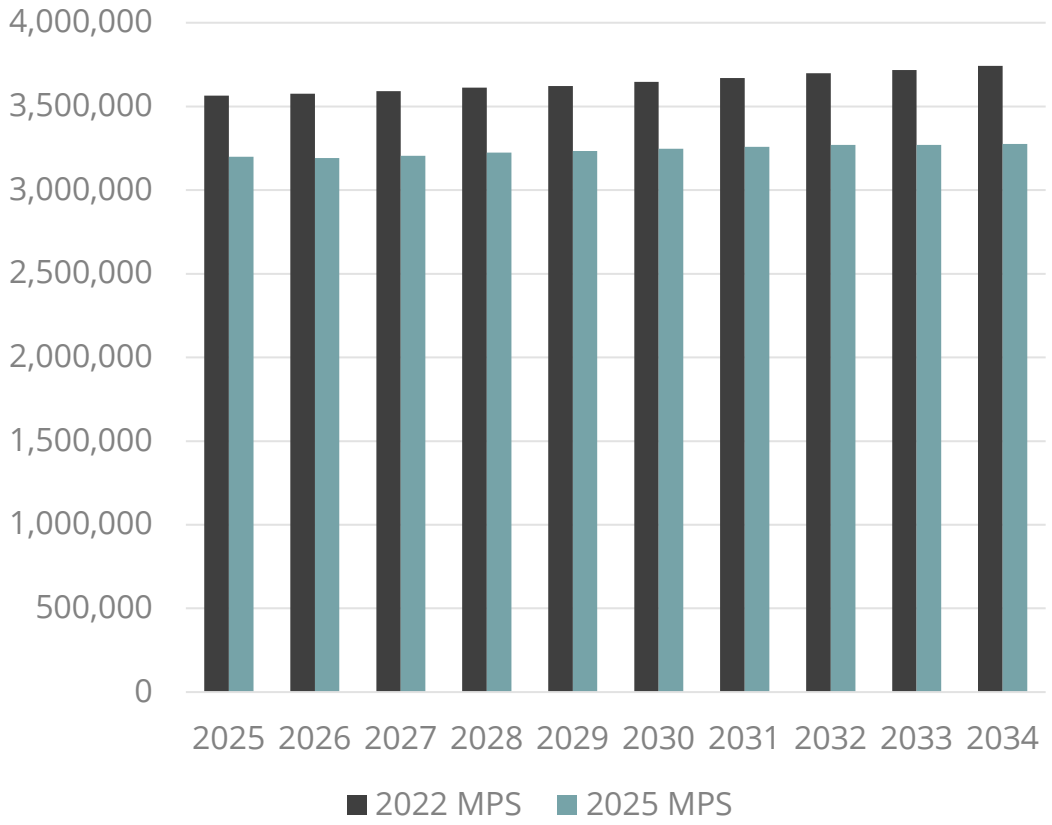


*Slight decline over time is due to efficiency increasing from EE programs

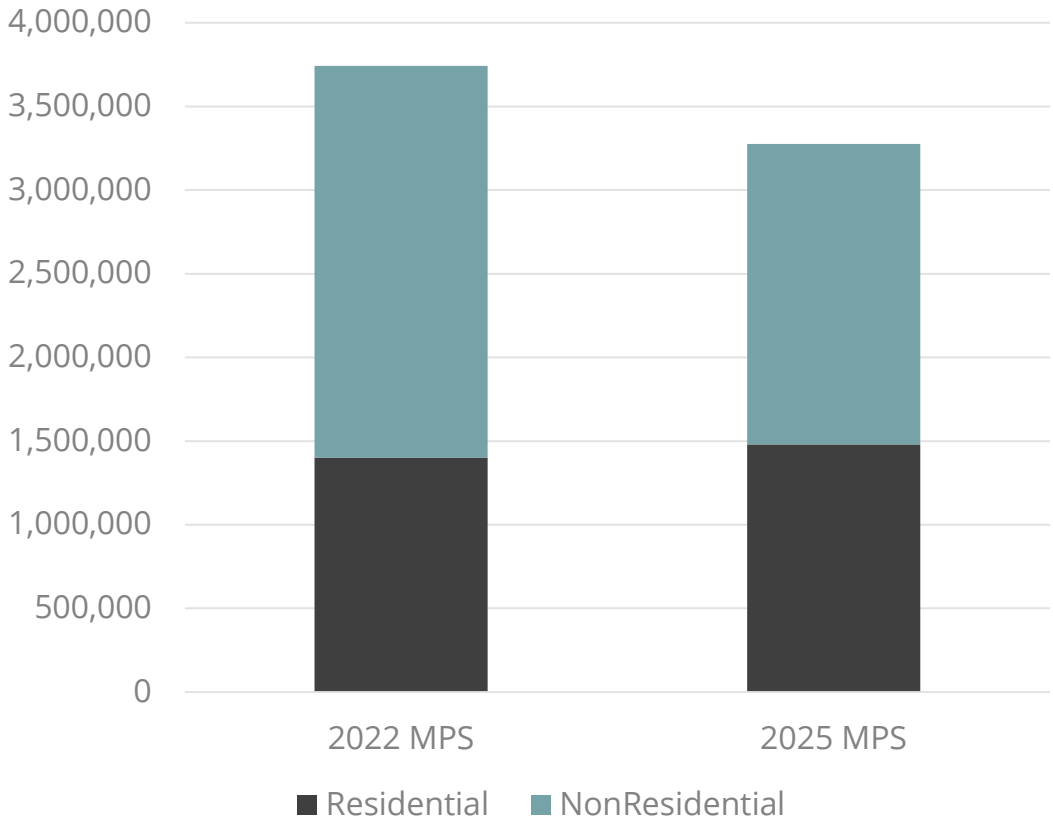
EE MEASURE LISTS & SELECT METHODOLOGY

SALES FORECAST

OVER ALL SALES FORECAST – EXCLUDING "OPT-OUT" SALES



2034 SALES BY SECTOR – EXCLUDING "OPT-OUT" SALES

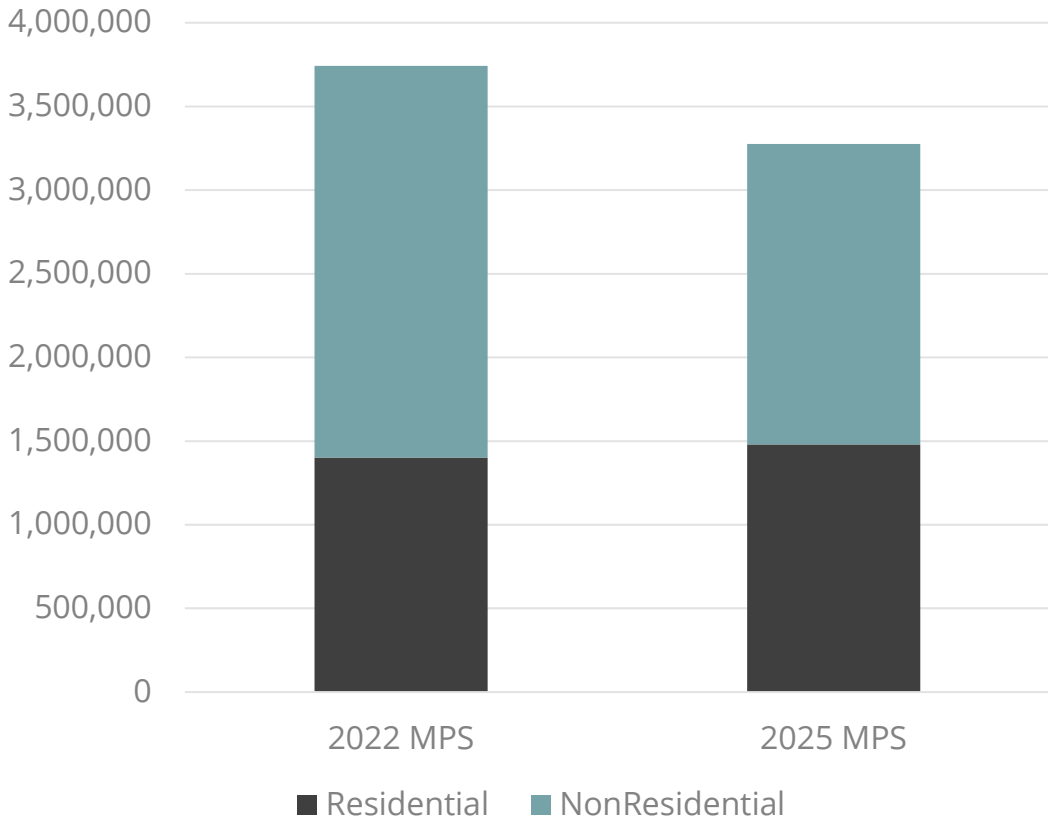


SALES FORECAST

NOTES

- 14.7% of Commercial sales are assumed to be opt-out
- 70.6% of industrial sales are assumed to be opt-out
- Or…48% of all C&I sales

2034 SALES BY SECTOR – EXCLUDING "OPT-OUT" SALES



RESIDENTIAL ACCOUNTS

% OF ACCOUNTS

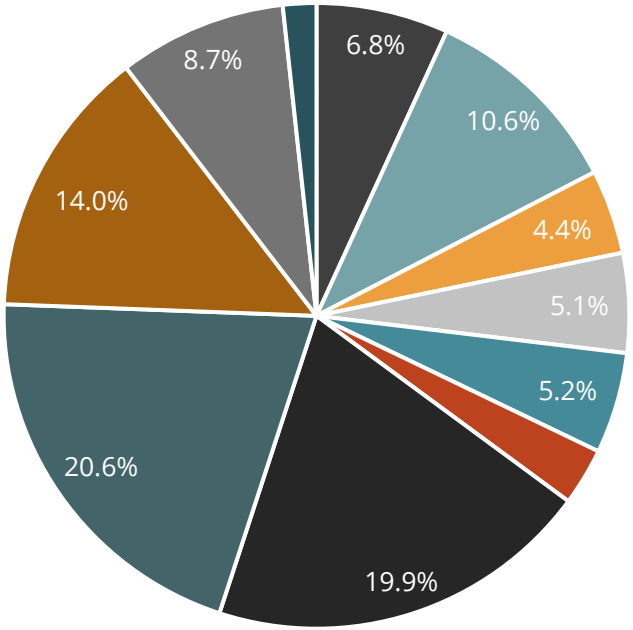
	2022 MPS	2025 MPS
SF	90%	87%
MF	10%	13%
SF-NC	71%	72%
MF-NC	29%	28%
LI SF	26.7%	tbd
LI MF	67.6%	tbd

NOTES

- SF/MF will either come from updated residential survey
- % of LI households (by housing type) will come from American Community Survey Data

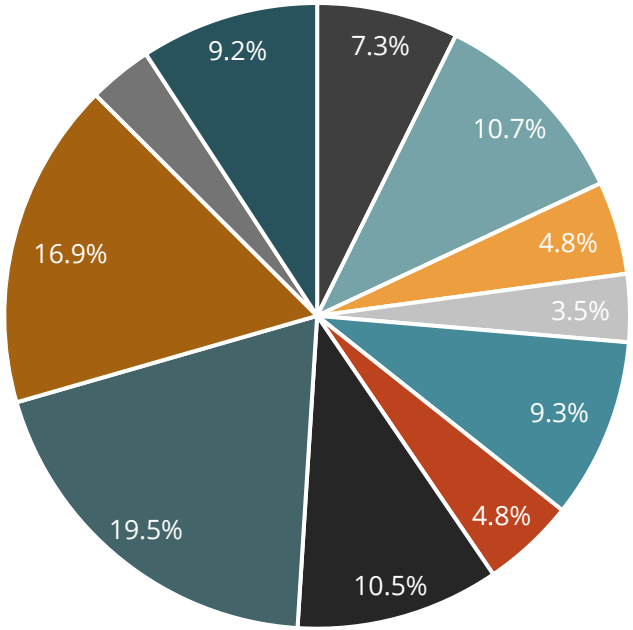
COMMERCIAL BUILDING TYPE SEGMENTATION

2022 MPS



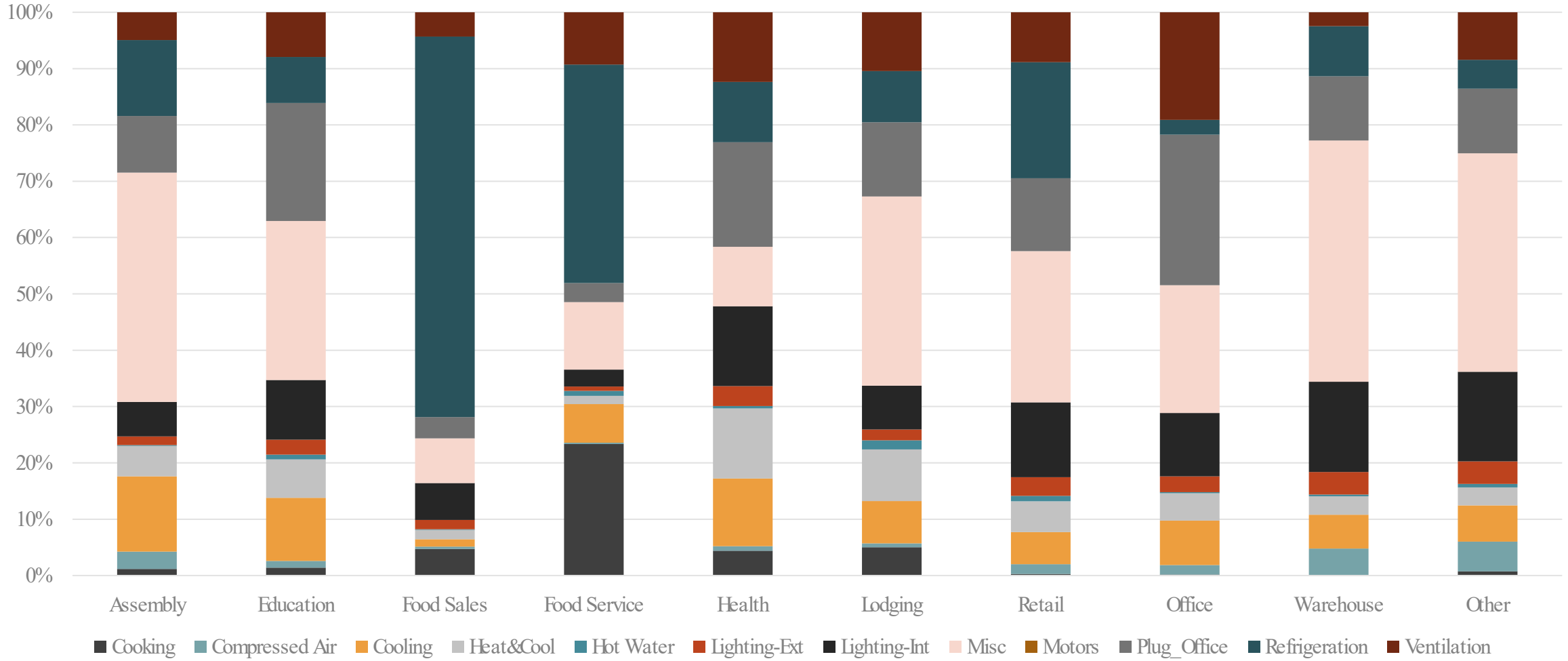
Assembly Education Food Sales Food Service
Health Care Lodging Merc Office
Other Warehouse TCU

2025 MPS

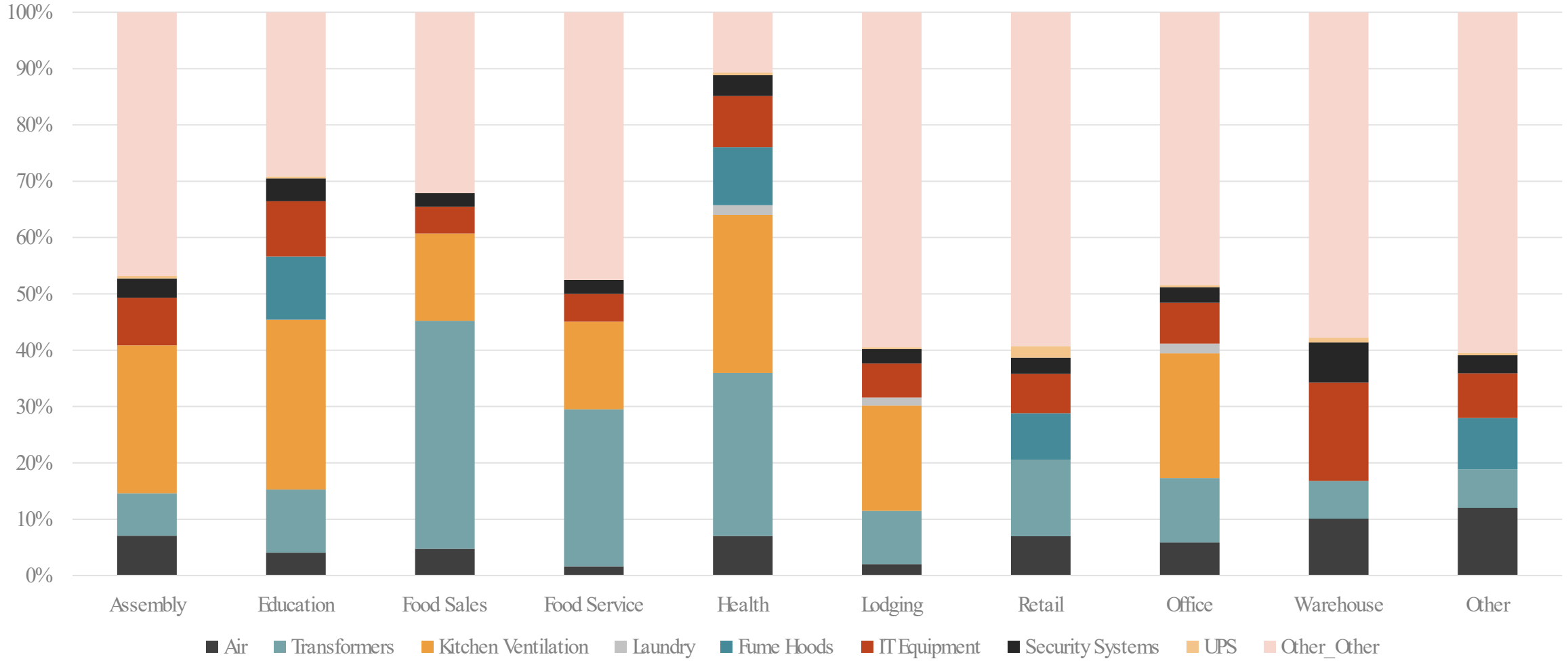


Assembly Education Food Sales Food Service
Health Care Lodging Retail Office
Misc Warehouse TCU

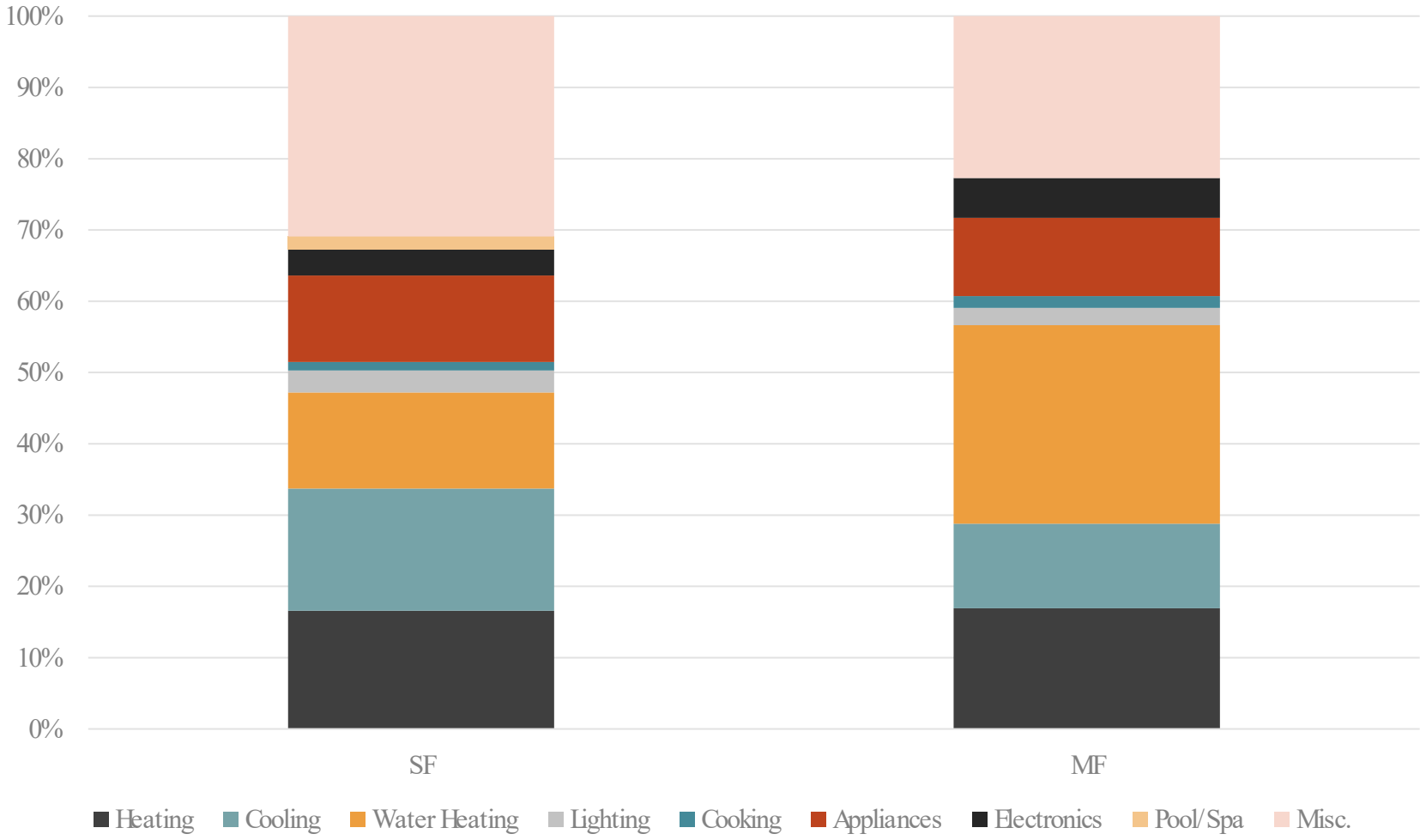
END USE SEGMENTATION BY BUILDING TYPE



MISC. SEGMENTATION BY BUILDING TYPE



RESIDENTIAL END USE SEGMENTATION



- From EIA 2023 AEO
- Data is for East South Central
  - *Consistent with Itron's regional consideration*

ENERGY EFICIENCY MEASURE LIST

- Typical measures from Indiana/Illinois TRM
- Select emerging / innovative technologies
- Program Assignments and Incentive Mapping (for RAP)
  - *Enhanced RAP incentives TBD*

- C&I List following the call (residential, next week)

COMMERCIAL LED LIGHTING

- **Increased Saturation from prior Study**
- **Recent studies show 2024 LED saturation of 50-70%**
  - *What will they be in 2028??*
- **But..** These are often estimating of % of sockets, not always connected load, and end-use segmentation also reflects some level of LED saturation.



- **Strawman: Assume 60% of 2028 lighting consumption (low bay) and 50% (high bay) to be efficient**

MEASURE REFILL

- **How to treat (most) measures that are:**
  - *Already efficient*
  - *Become efficient in early study timeframe and burnout*
- **Impacts**
  - *Annual savings and costs*

- **Strawman:**
  - *Current EE saturation: Allow 40% backsliding for most TOS measures and 10% for retrofit/custom measures.*
    - **More limiting because impacts may already be captured in forecast**
  - *Future install and decay: Use NTG as proxy for refill. (80% NTG = 80% refill)*

OTHER OFFERED ITEMS

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

PRESENTED BY GDS ASSOCIATES, INC.

2025 MPS CHECK IN MEETING - MAY

CenterPoint Energy Indiana

May 22, 2025

AGENDA



- Energy Efficiency Initial Draft Results Summary
- Demand Response Results Review
- Next Steps

EE INITIAL DRAFT RESULTS SUMMARY

ENERGY EFFICIENCY

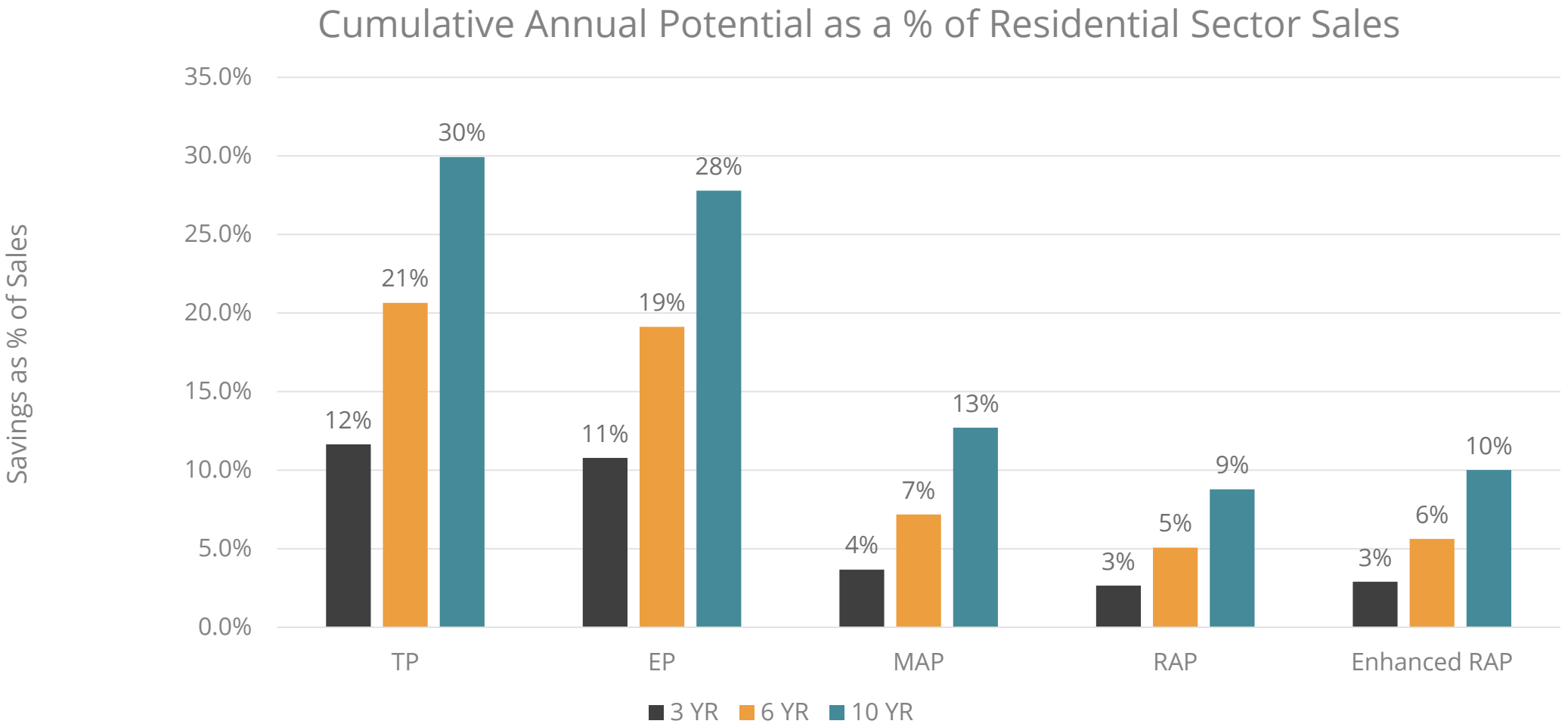
Results Overview – Sector-level results

- *Summary of cumulative annual savings over the timeframe of the study*
  - **Technical, Economic, MAP, RAP, Enhanced**
- *Annual achievable savings potential*
  - **MAP, RAP, Enhanced**
- *Overview of savings by end-use*
  - **RAP**

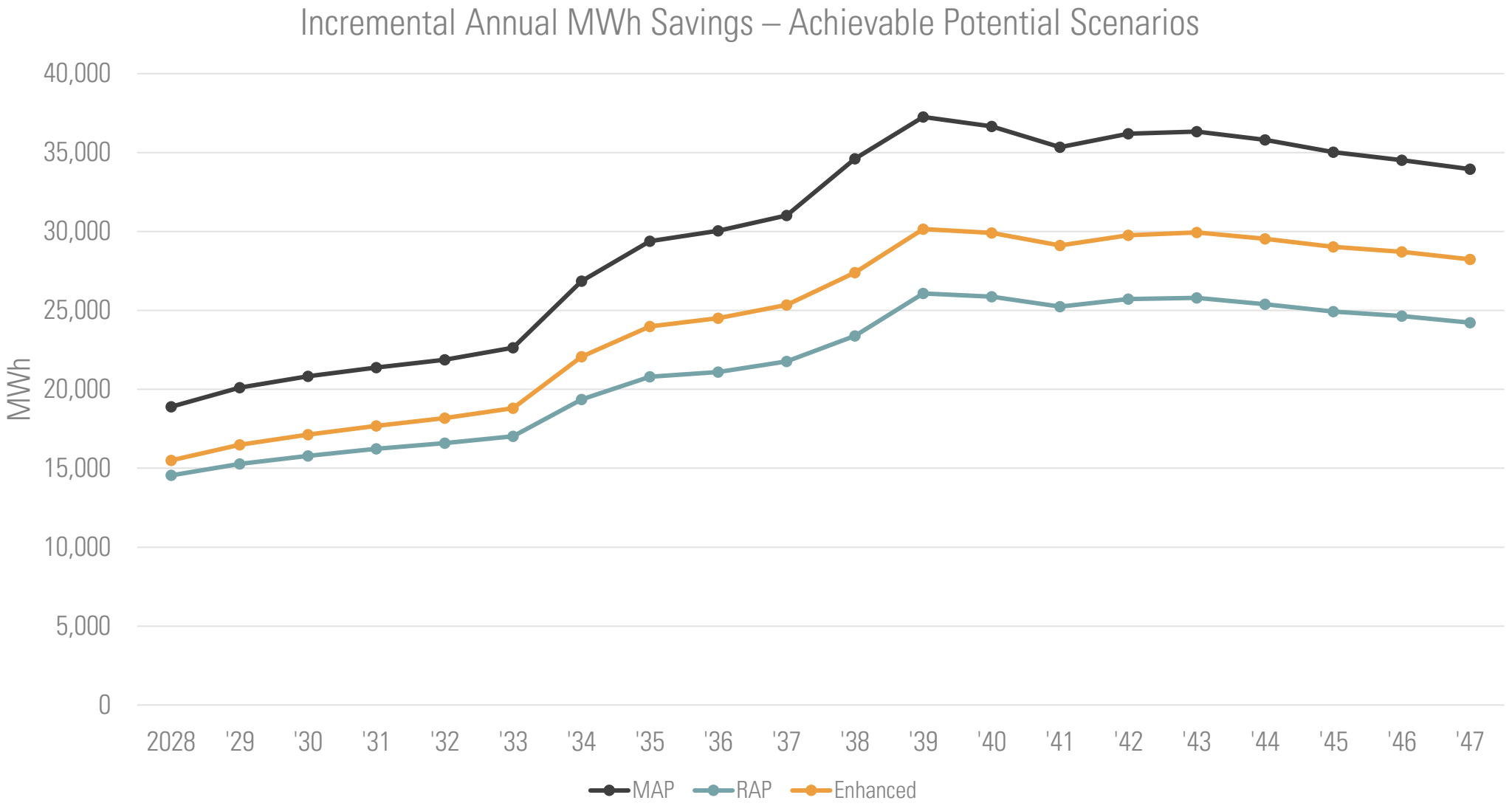
Program savings and costs – Sector-level results

- *Annual program-level savings*
  - **RAP, Enhanced**
- *Annual program costs and acquisition costs*
  - **RAP, Enhanced**

EE DRAFT RESULTS – RESIDENTIAL SECTOR

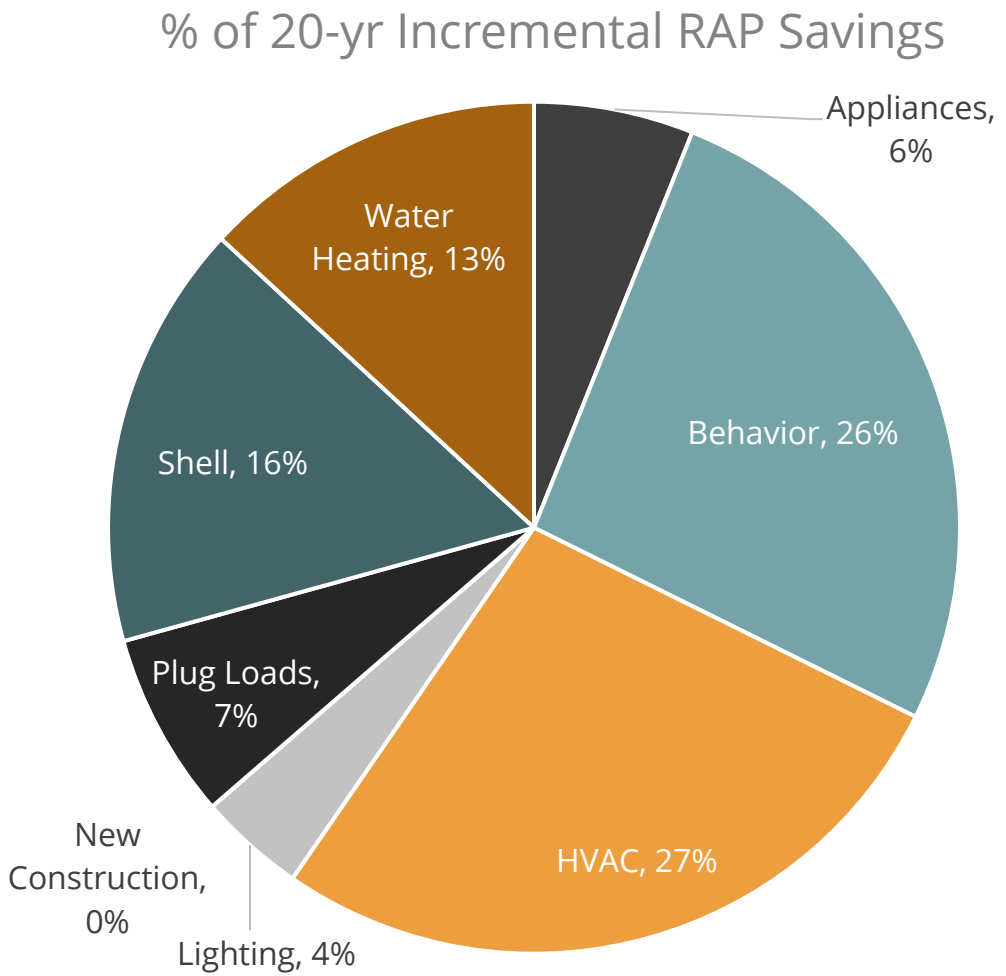


EE DRAFT RESULTS – RESIDENTIAL SECTOR



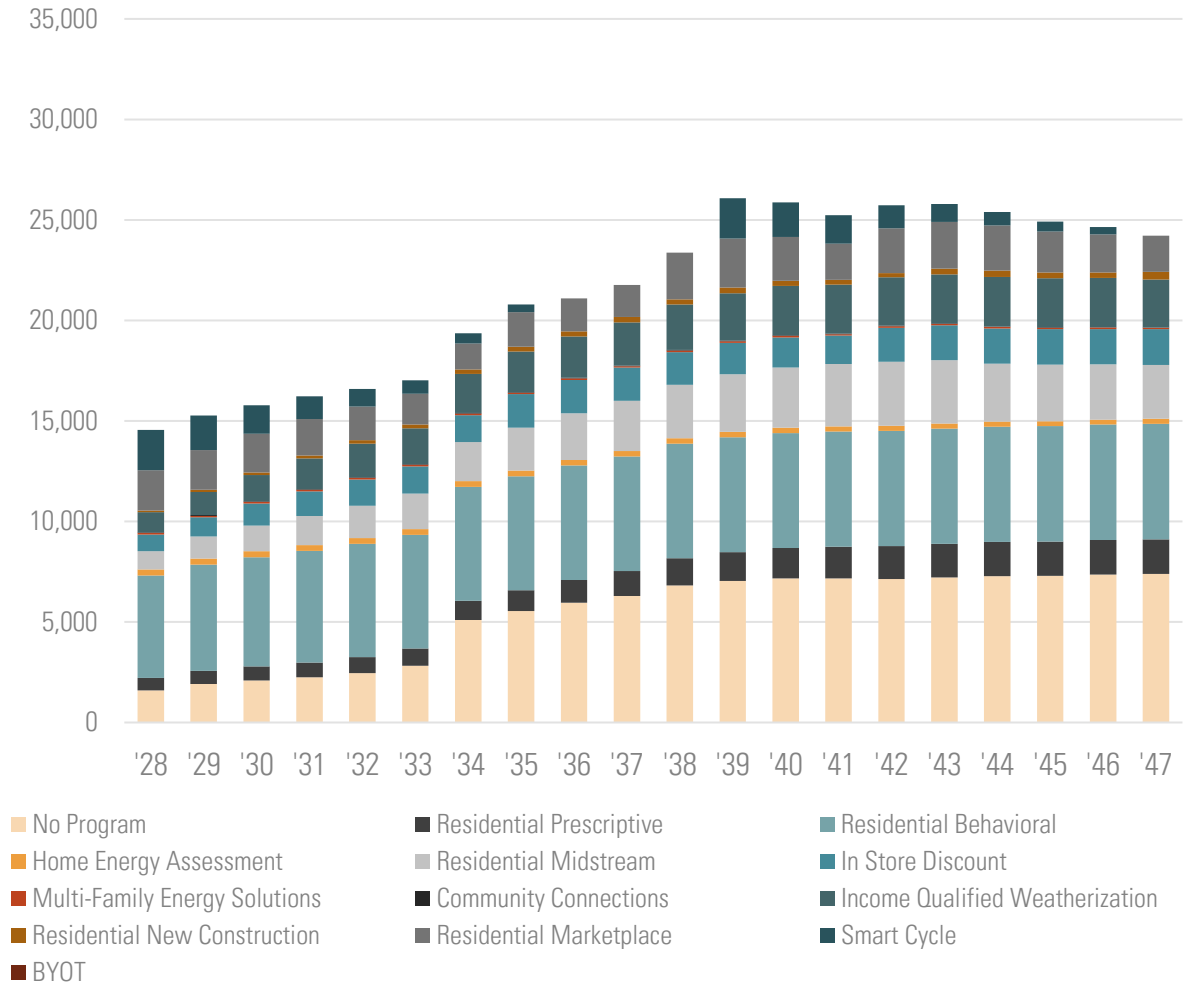
EE DRAFT RESULTS – RESIDENTIAL SECTOR

- Savings from the residential sector span 9 primary end-uses
- Behavior measures account for 26% of RAP savings
- HVAC (27%) and Shell (17%) account for another 44% of the savings
- The final 30% of savings are attributable to Water Heating (13%), Plug Loads (7%), Appliances (6%), Lighting (4%), New Construction (<1%), and Pools/Pumps (0%).

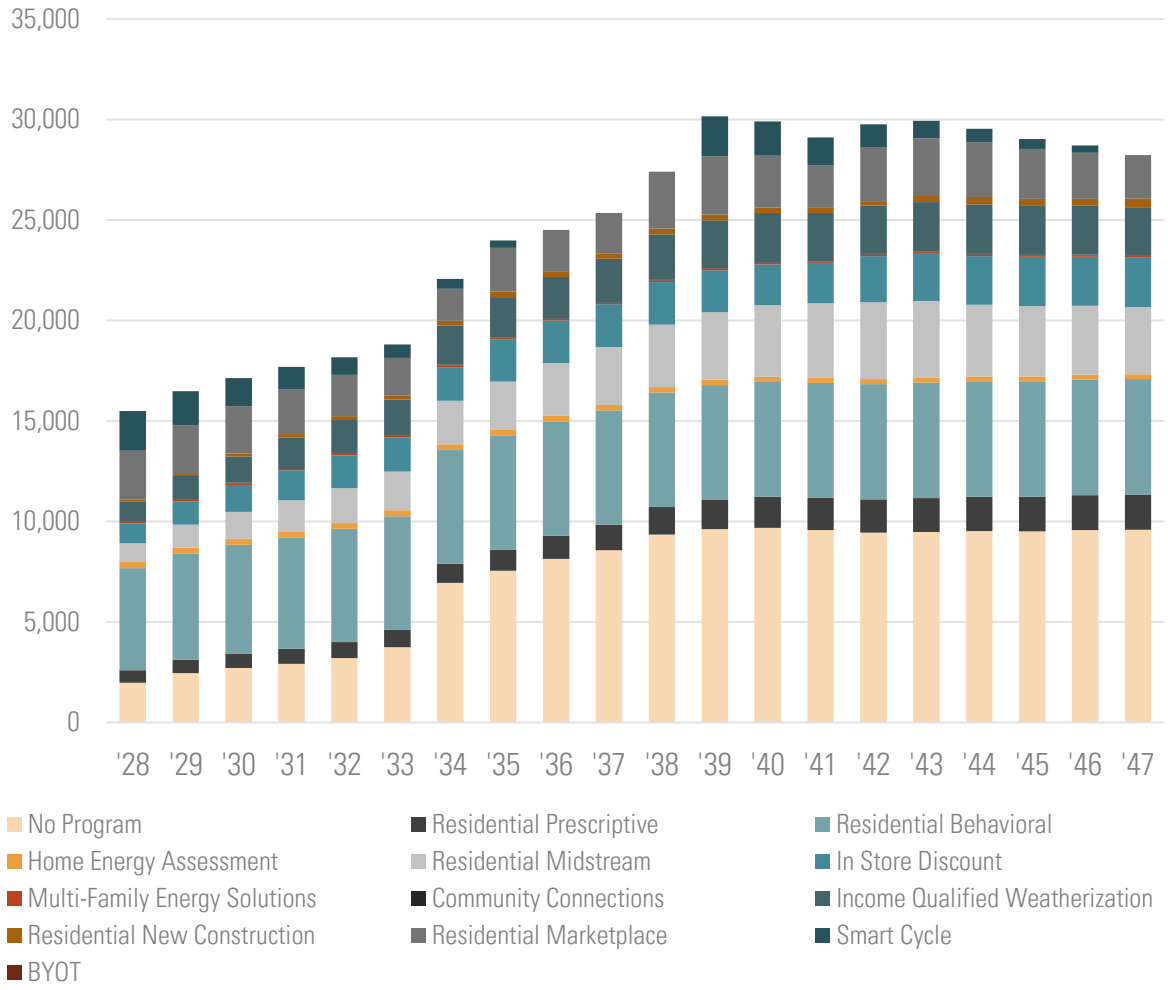


EE DRAFT RESULTS – RESIDENTIAL SECTOR

RAP Incremental Annual MWh Savings

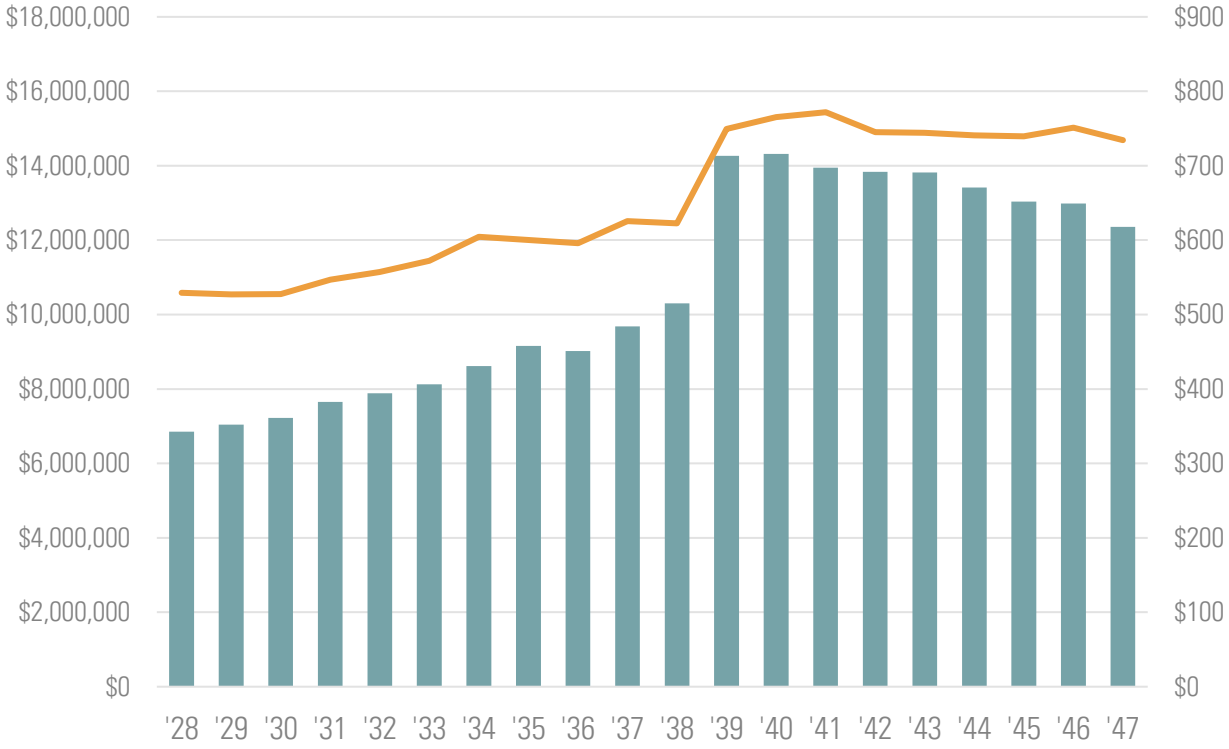


Enhanced RAP Incremental Annual MWh Savings

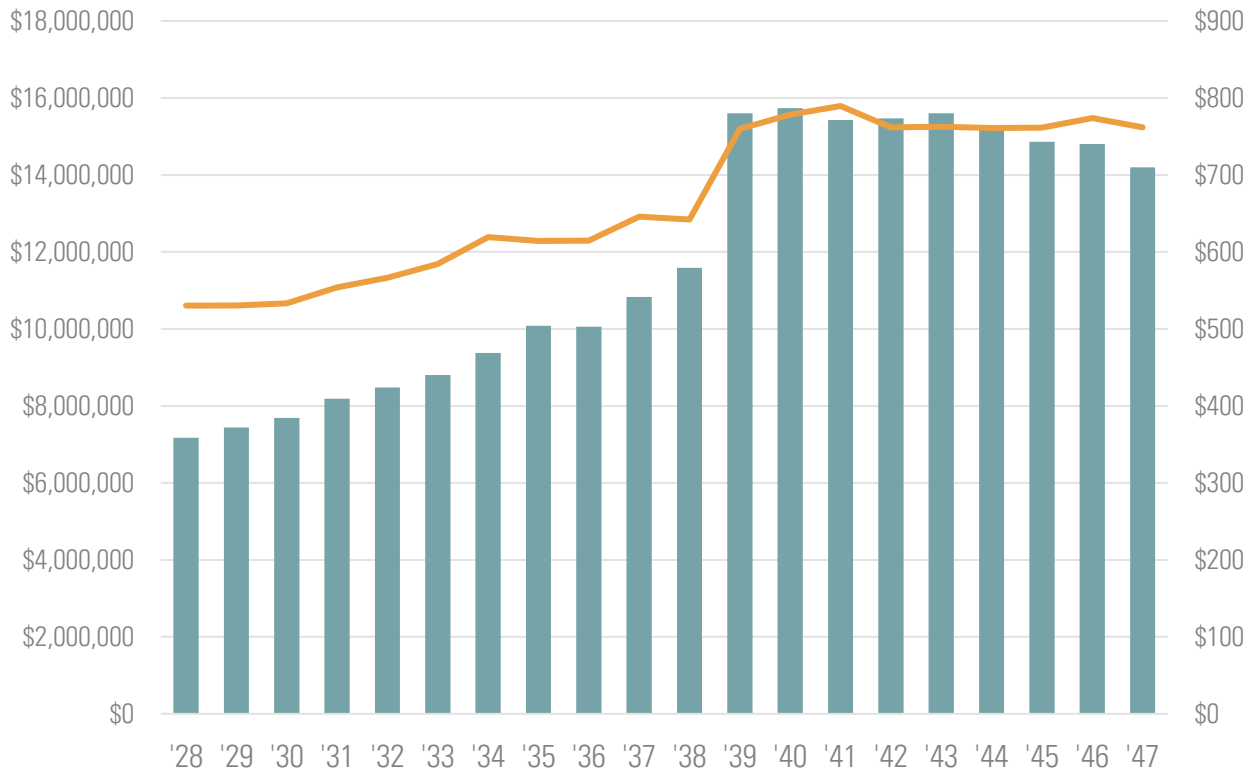


EE DRAFT RESULTS – RESIDENTIAL SECTOR

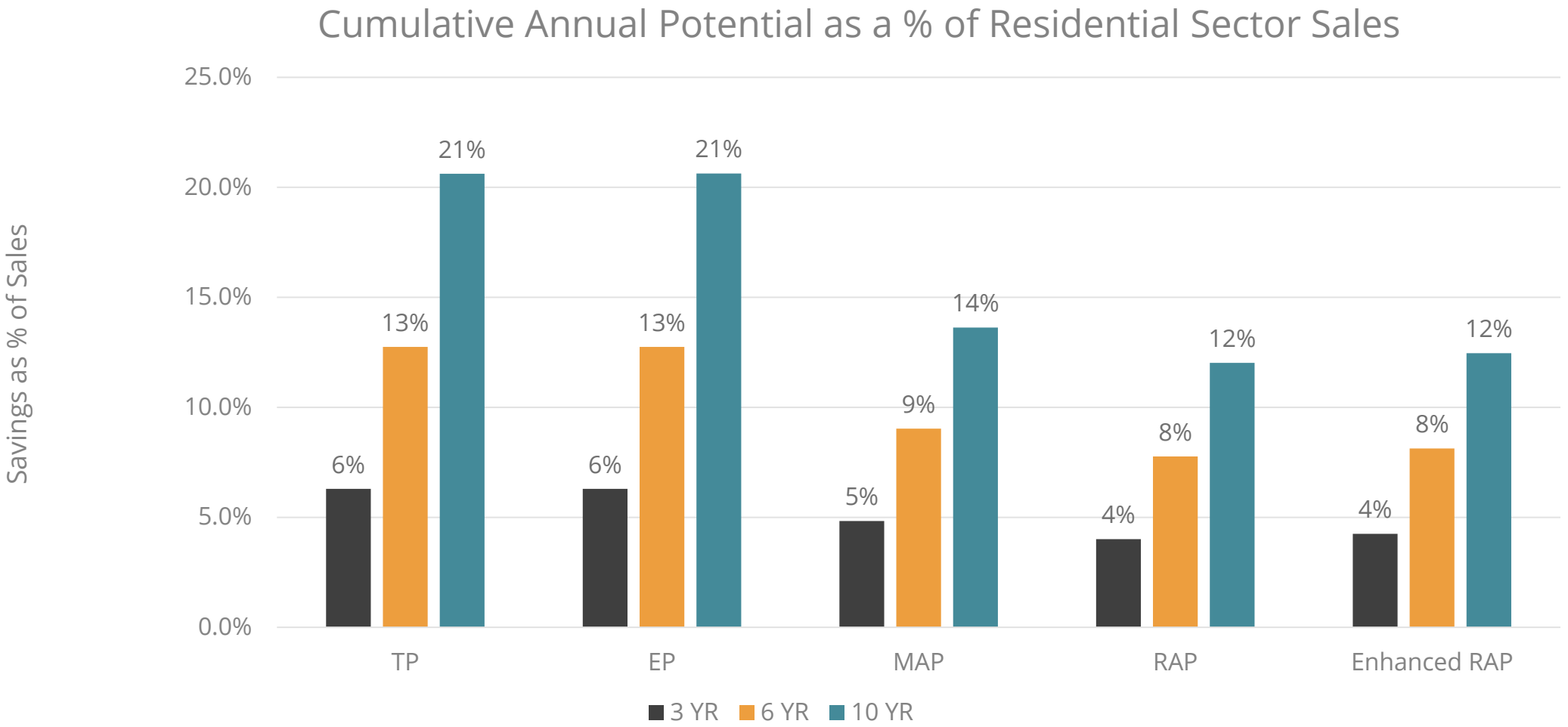
RAP Program Budgets and Acquisition Cost per MWh



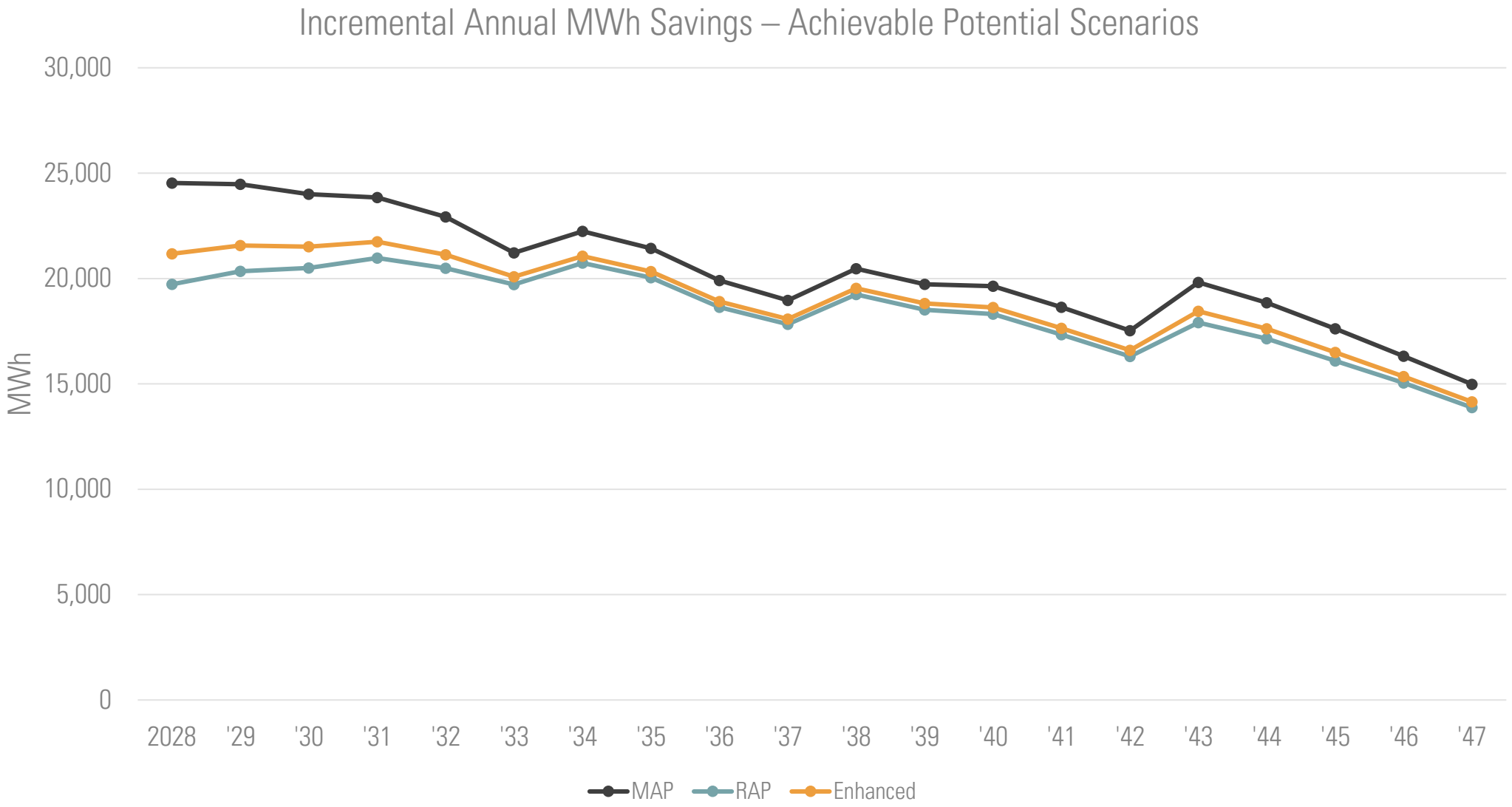
Enhanced RAP Program Budgets and Acquisition Cost per MWh



EE DRAFT RESULTS – C&I SECTOR

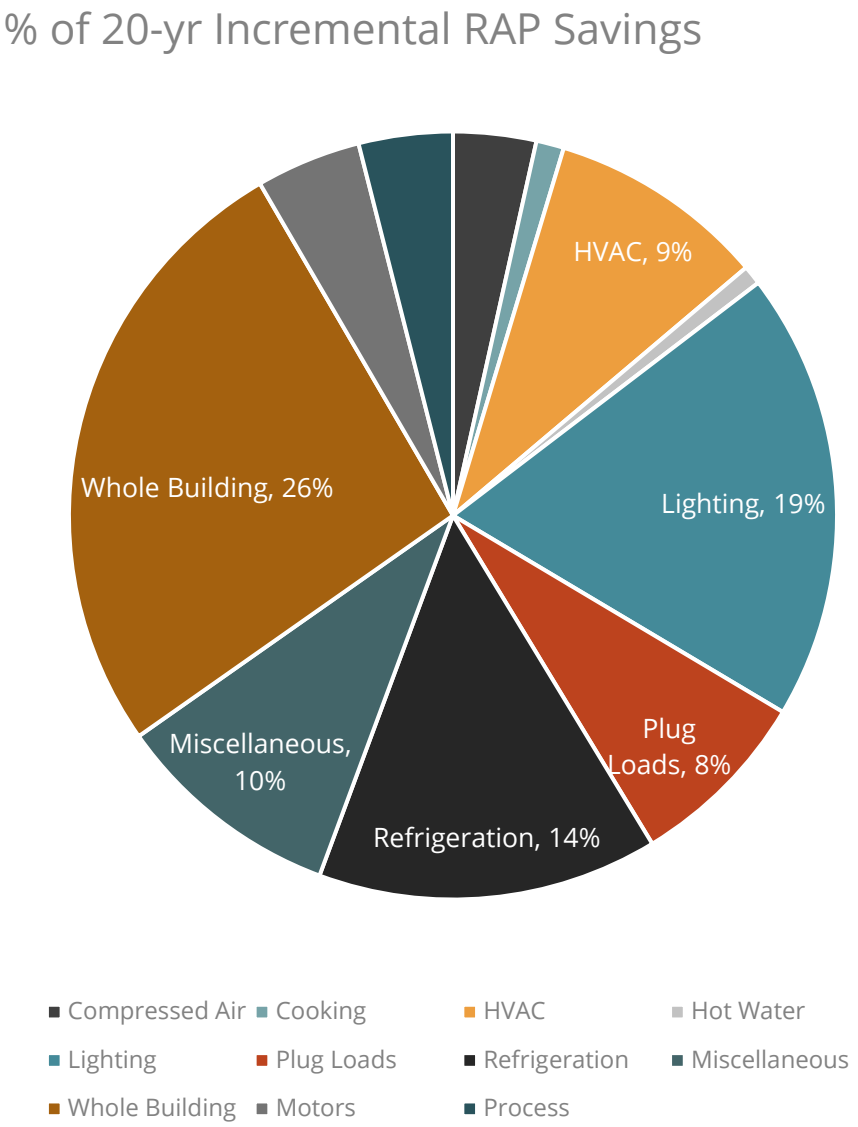


EE DRAFT RESULTS – C&I SECTOR

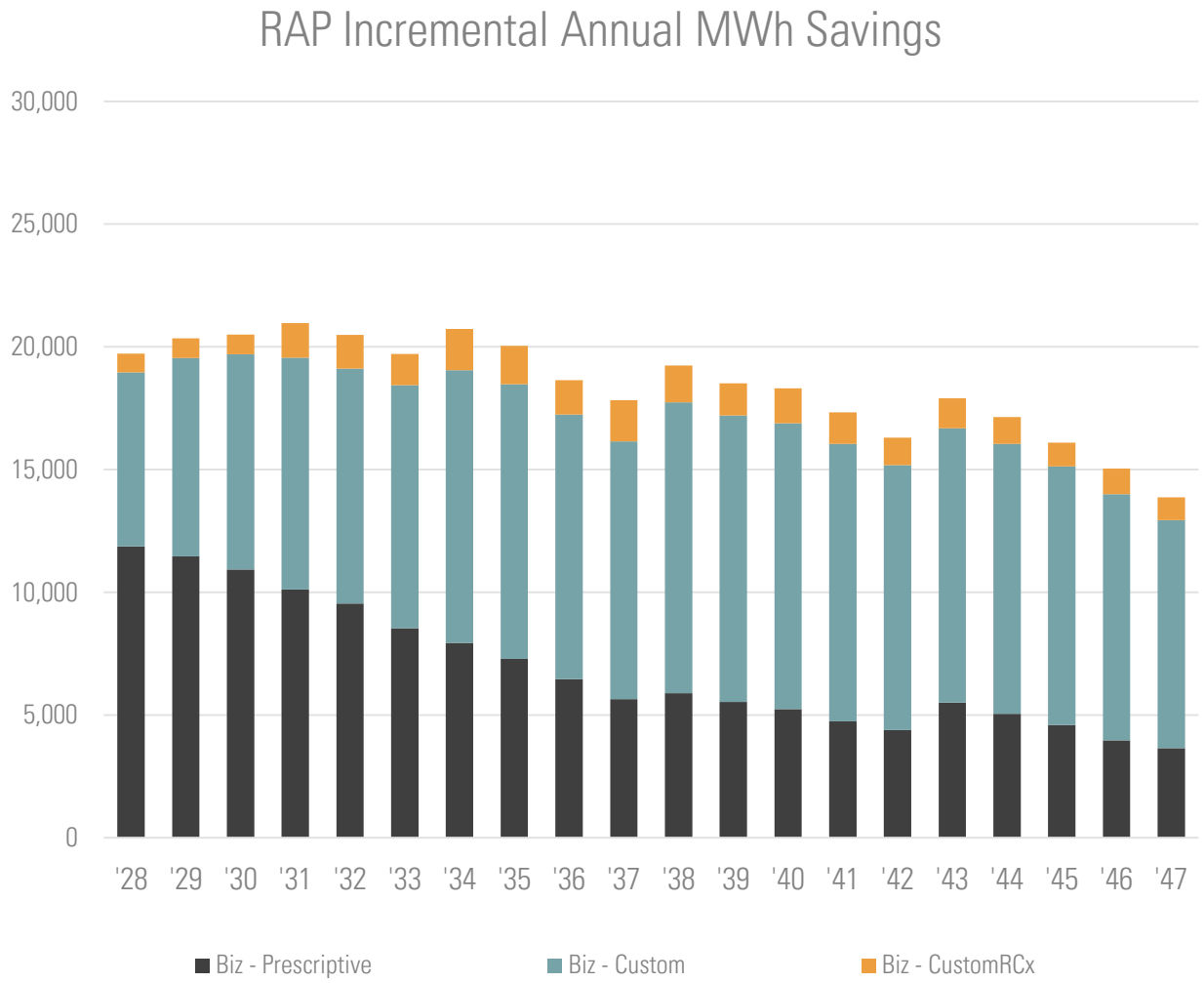


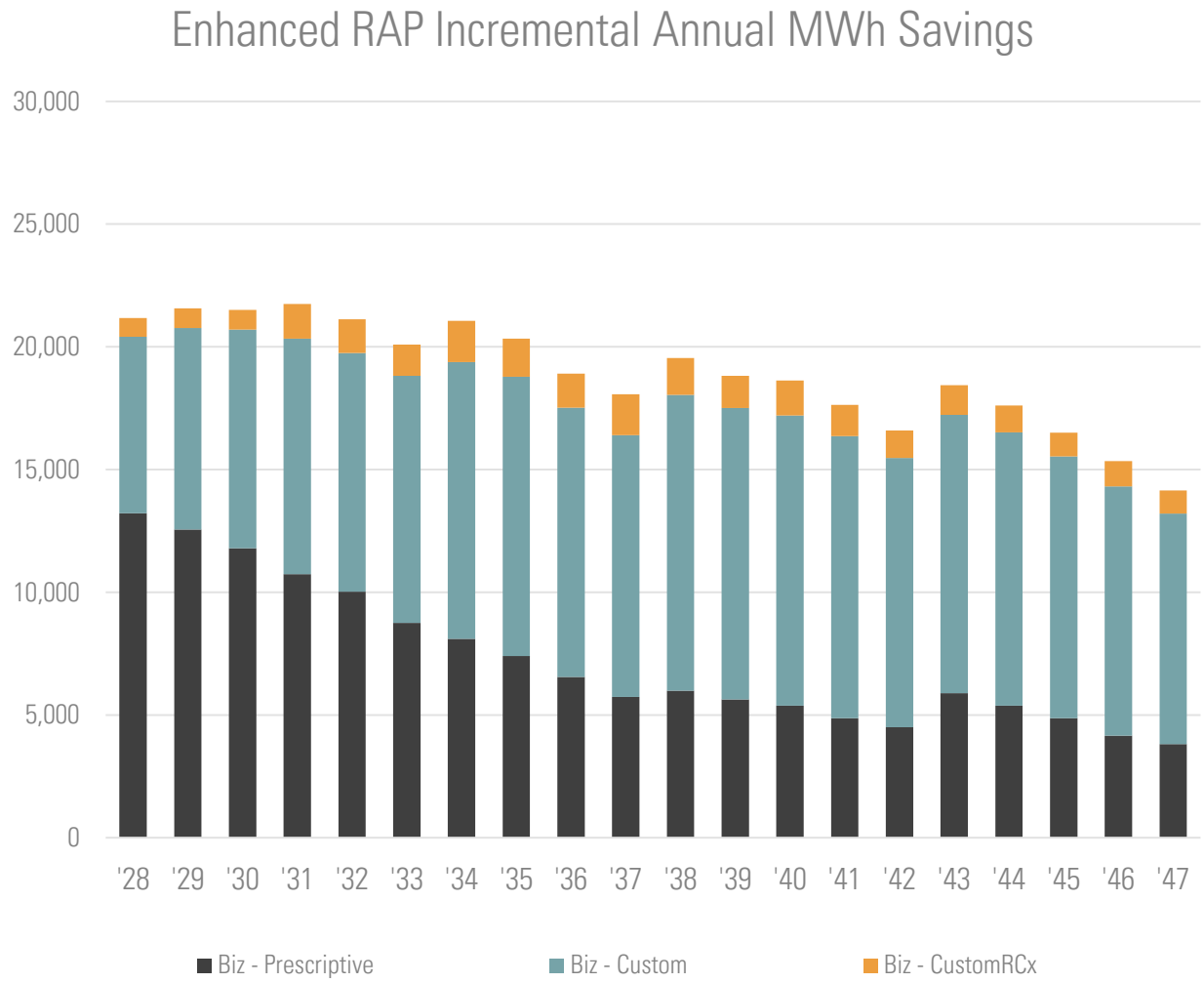
EE DRAFT RESULTS – C&I SECTOR

- Savings from the C&I sector span 11 primary end-uses
- Whole Building measures account for 26% of RAP savings
- Lighting (19%), Refrigeration (14%), Miscellaneous (10%), HVAC (9%), Plug Loads (8%) account for another 60% of the savings
- The final 14% of savings are attributable to Compressed Air (3%), Cooking (1%), Hot Water (1%), Motors (4%), and Process (4%).



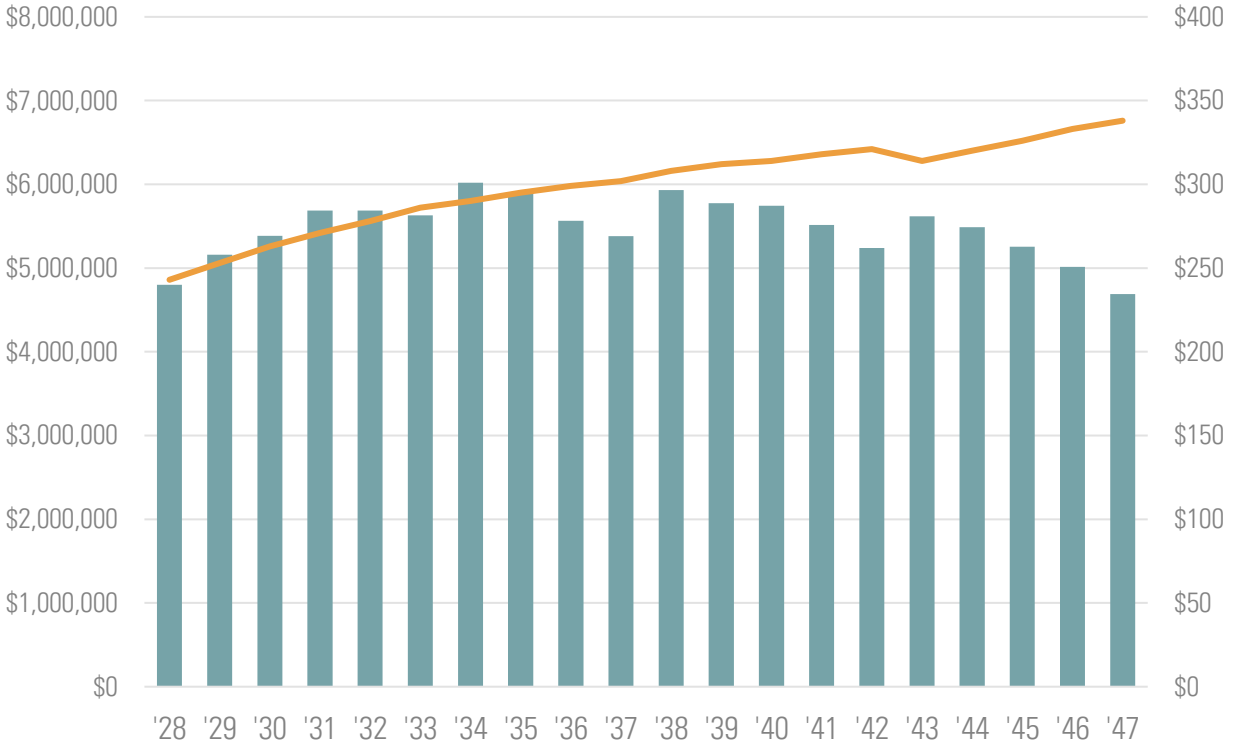
EE DRAFT RESULTS – C&I SECTOR



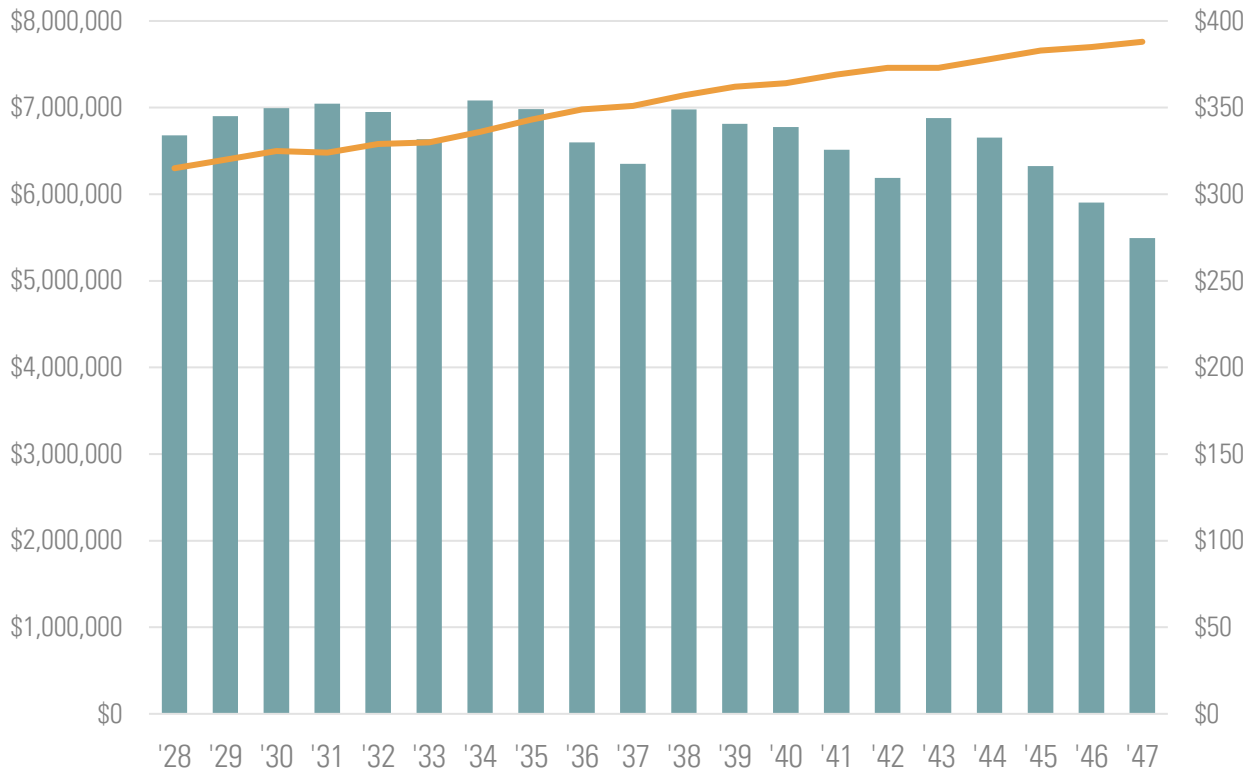


EE DRAFT RESULTS – C&I SECTOR

RAP Program Budgets and Acquisition Cost per MWh



Enhanced RAP Program Budgets and Acquisition Cost per MWh



NTG BENCHMARKING

Total	2021	2022	2023	MPS	2025 OP
Res. Behavior	100%	100%	100%	100%	100%
Res. Prescriptive	58%	60%	62%	78%	77%
Res. Appliance Recycle	52%	52%	52%	62%	n/a
Res Income Eligible	100%	100%	100%	100%	100%
NonRes Prescriptive	76%	63%	85%	84%	84%
Nonres SBDI	88%	88%	95%	84%	84%
Nonres Custom	93%	58%	97%	93%	84%

- *For draft results, used 2025 Operating Plan estimates*

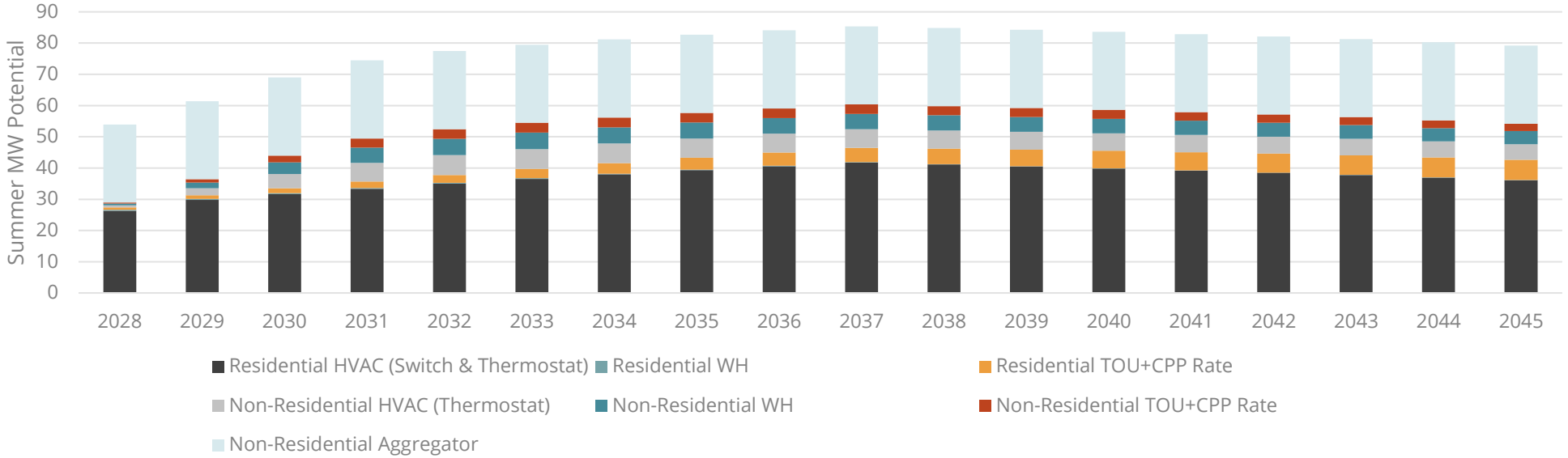
DEMAND RESPONSE RESULTS

DEMAND RESPONSE COST-EFFECTIVENESS

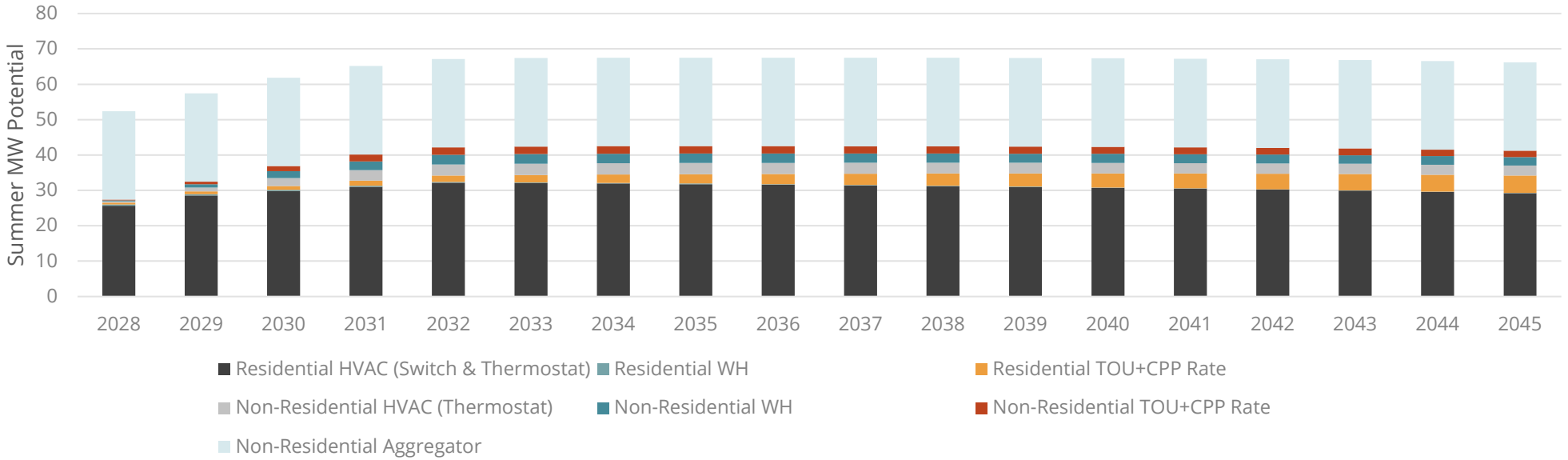
Sector	Program	MAP UCT	RAP UCT
Residential	DLC Central AC Switch	2.09	2.16
	DLC Thermostat (Smart Cycle)	1.18	1.25
	DLC Thermostat (BYOT)	1.51	1.66
	DLC Water Heater Switch	0.24	0.25
	DLC Grid-Enabled Water Heater	0.70	0.73
	DLC Electric Vehicle	0.67	0.64
	TOU + CPP Rate	6.54	6.28
	Battery Storage	0.69	0.69
C&I	DLC Thermostat (BYOT)	2.72	2.80
	DLC Grid-Enabled Water Heater	2.69	2.49
	DLC Electric Vehicle	0.00	0.00
	TOU + CPP Rate	8.23	6.24
	Battery Storage	0.52	0.49

DEMAND RESPONSE RESULTS - SUMMER

Summer MAP

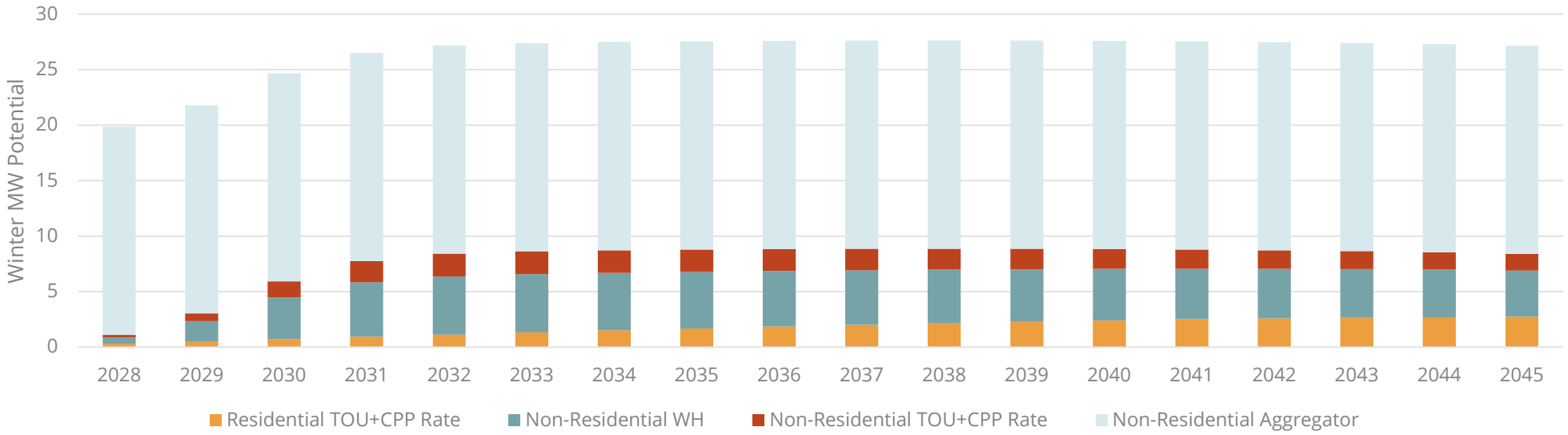


Summer RAP

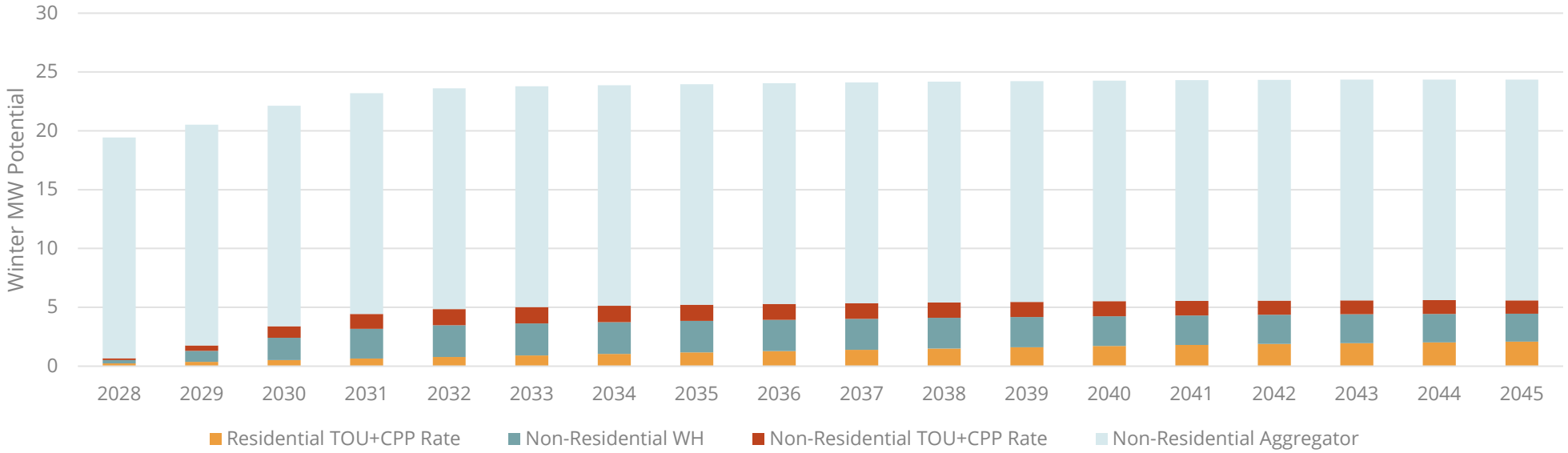


DEMAND RESPONSE RESULTS - WINTER

Winter MAP



Winter RAP



NEXT STEPS?

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

PRESENTED BY GDS ASSOCIATES, INC.

2025 MPS CHECK IN MEETING - JUNE

CenterPoint Energy Indiana

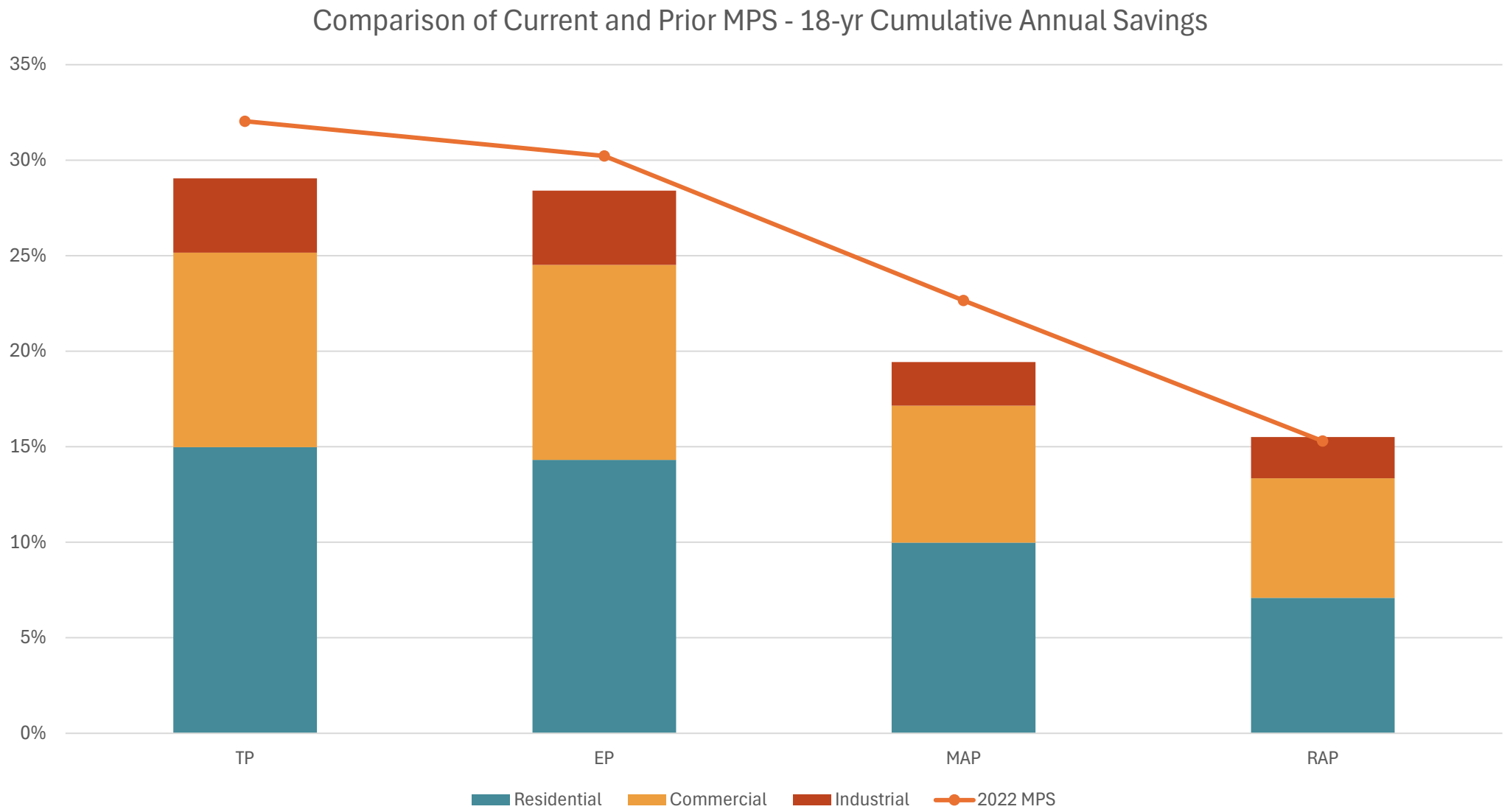
June 30, 2025

AGENDA

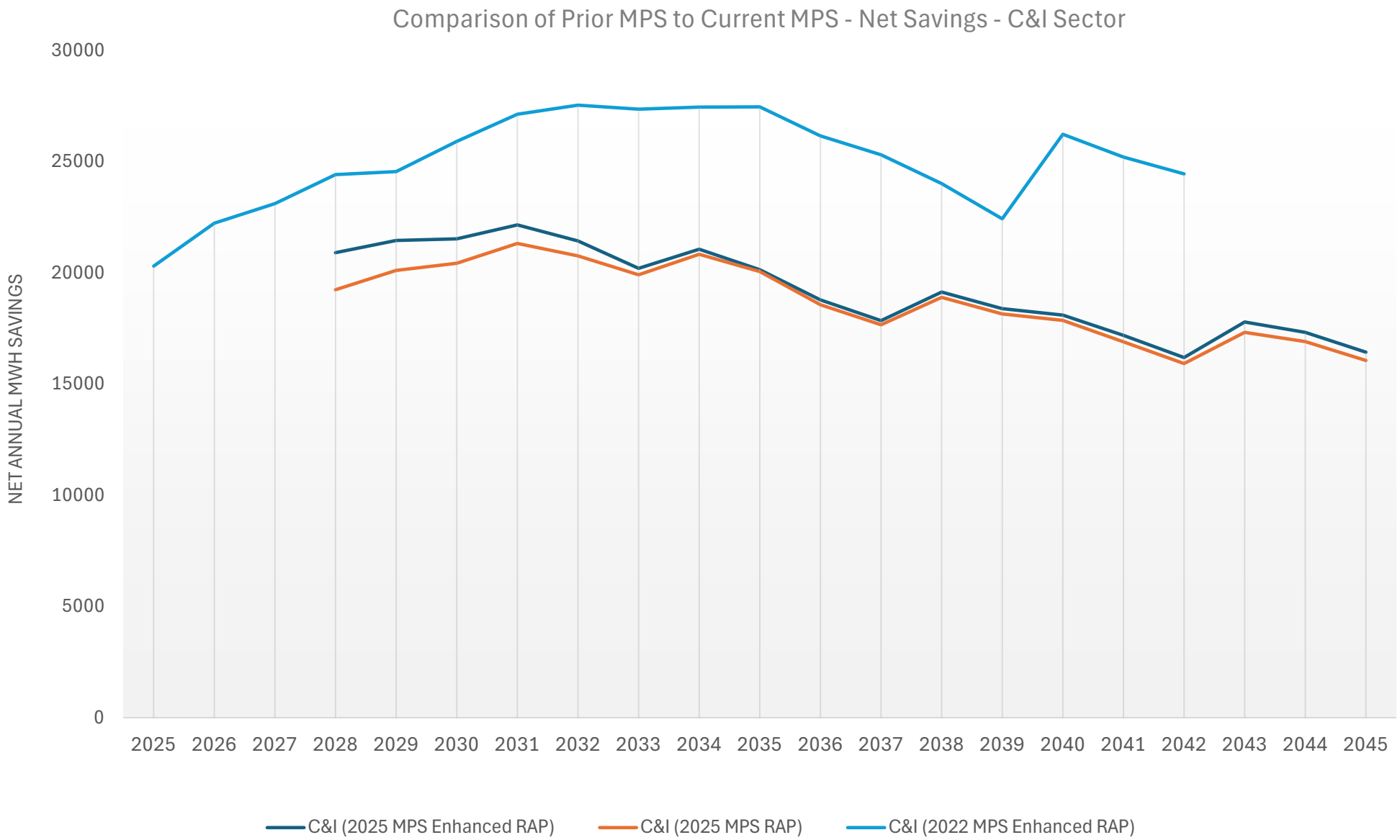
- Energy Efficiency Second Draft Results Summary
- Comparison of Current Study to Prior Study
- Comparison of MPS Estimates to Historical Results
- Comparison of RAP and Enhanced RAP
- Overview of IRP Bundles
- Demand Response Second Draft Results Review
- Next Steps

EE SECOND DRAFT RESULTS SUMMARY

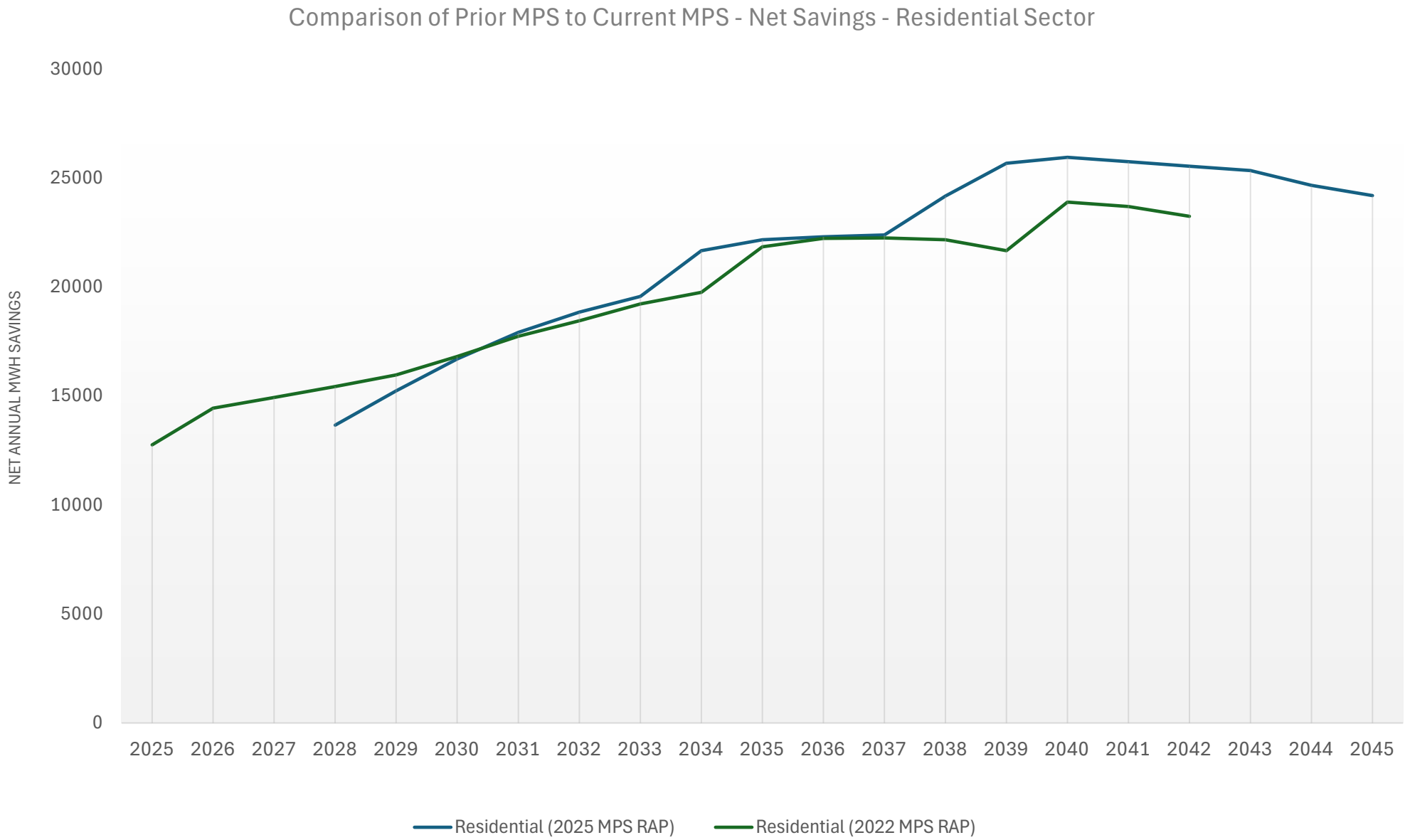
EE RESULTS – CURRENT MPS VS PRIOR MPS



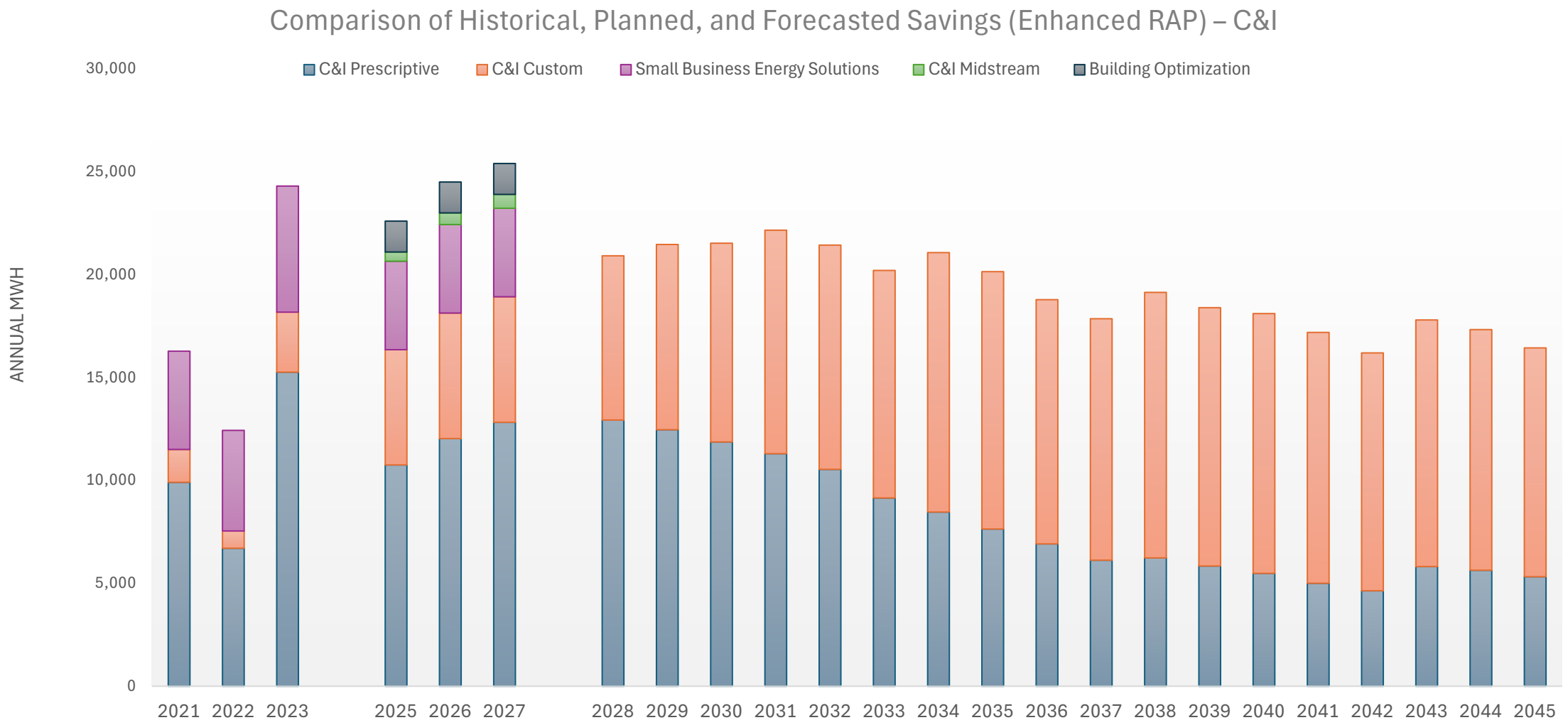
COMPARISON OF PRIOR MPS TO CURRENT MPS



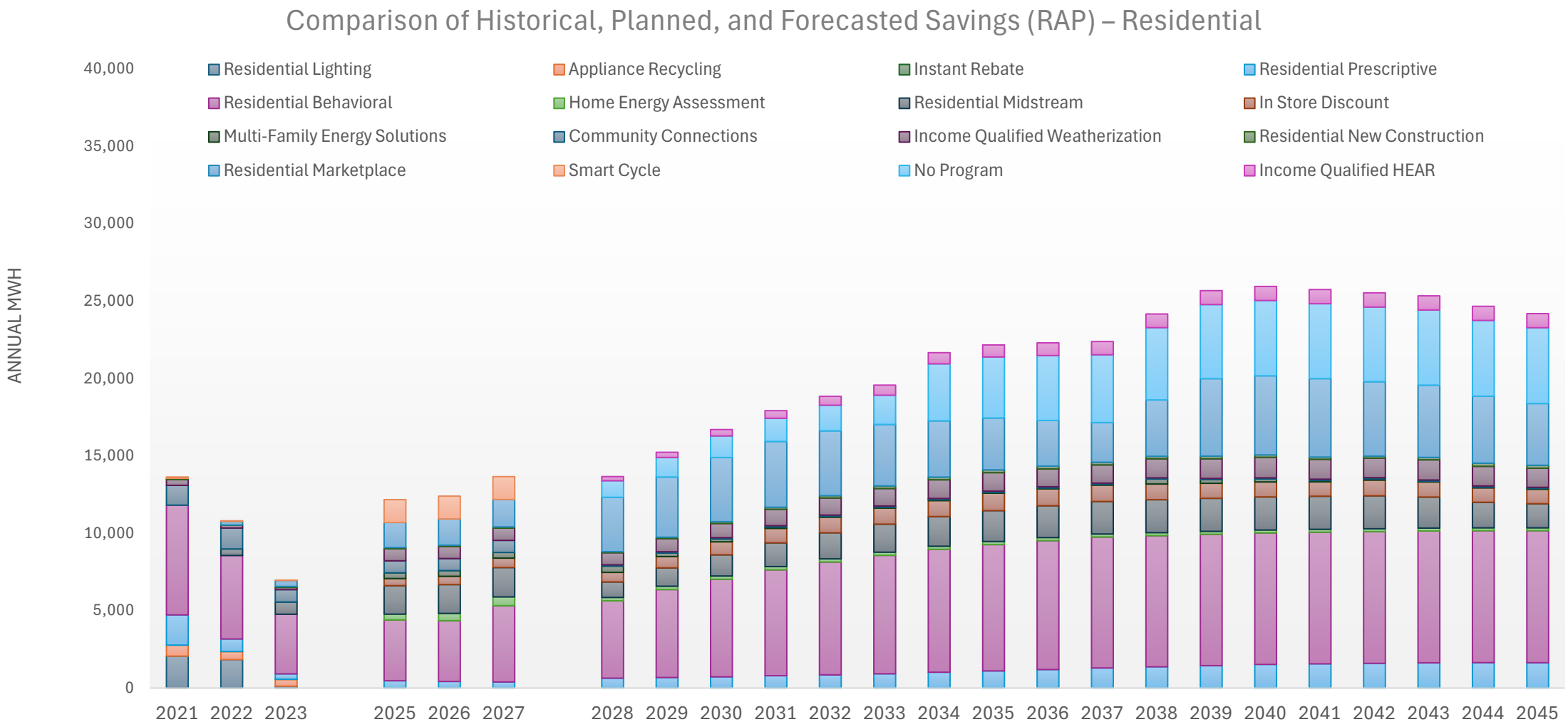
COMPARISON OF PRIOR MPS TO CURRENT MPS



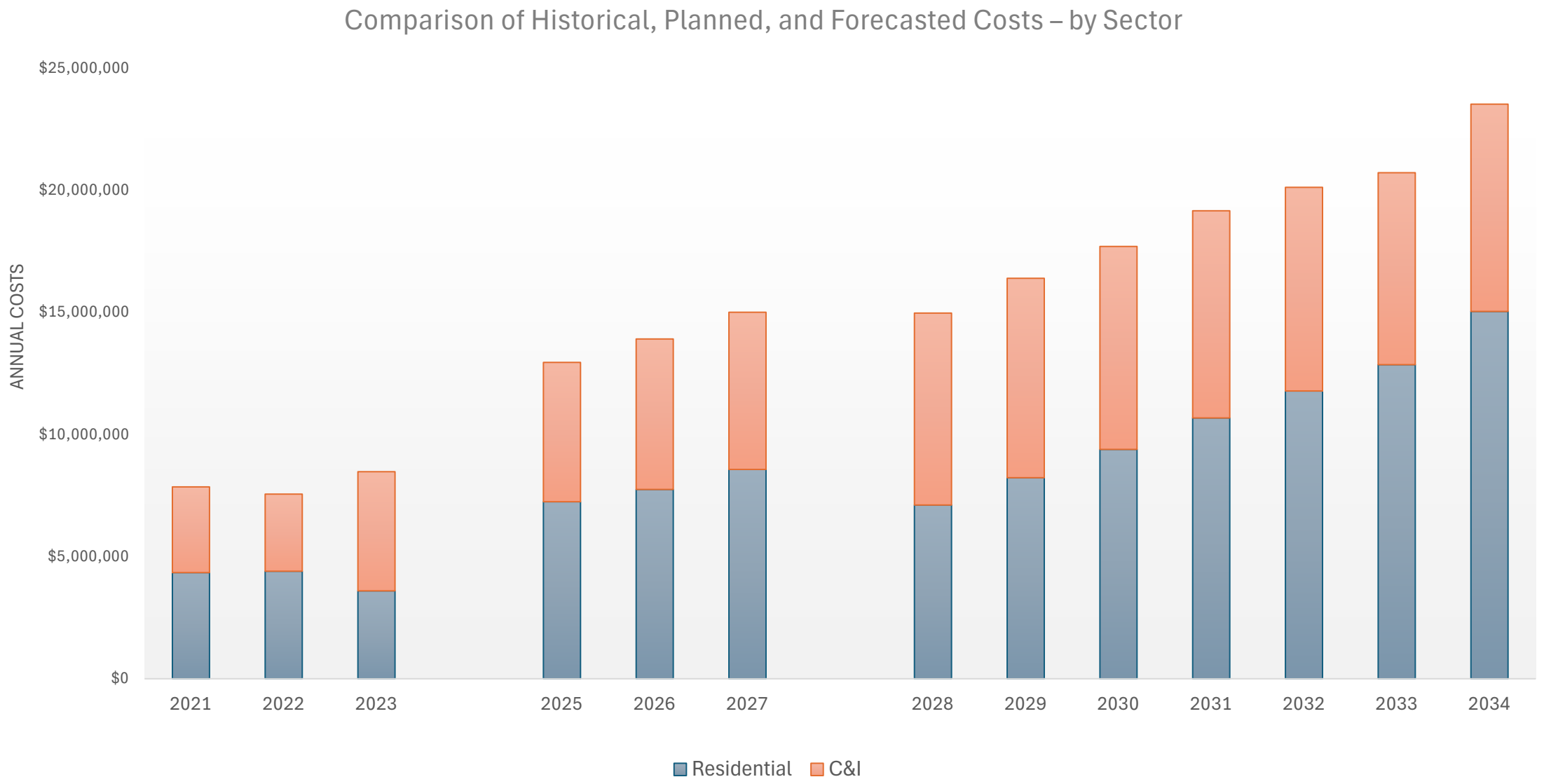
COMPARISON OF HISTORICAL, PLANNED AND FORECASTED SAVINGS



COMPARISON OF HISTORICAL, PLANNED AND FORECASTED SAVINGS



COMPARISON OF HISTORICAL, PLANNED AND FORECASTED ANNUAL COSTS



IRP BUNDLE OVERVIEW

IRP BUNDLES

Bundles included

- *C&I sector inputs form a single bundle (based on Enhanced RAP)*
- *Residential sector inputs split across 5 bundles:*
  - **Tier 1: (non-income qualified / non-behavioral measures with lifetime cost of energy saved of < $70/MWh)**
  - **Tier 2: (non-income qualified / non-behavioral measures with lifetime cost of energy saved of > $70/MWh)**
  - **Behavioral (home energy reports)**
  - **Income Qualified Weatherization**
  - **Income Qualified Home Electrification and Appliances Rebates (HEAR) – federally funded**

Scenarios modeled

- *IRP inputs provided for Residential RAP and C&I Enhanced RAP*

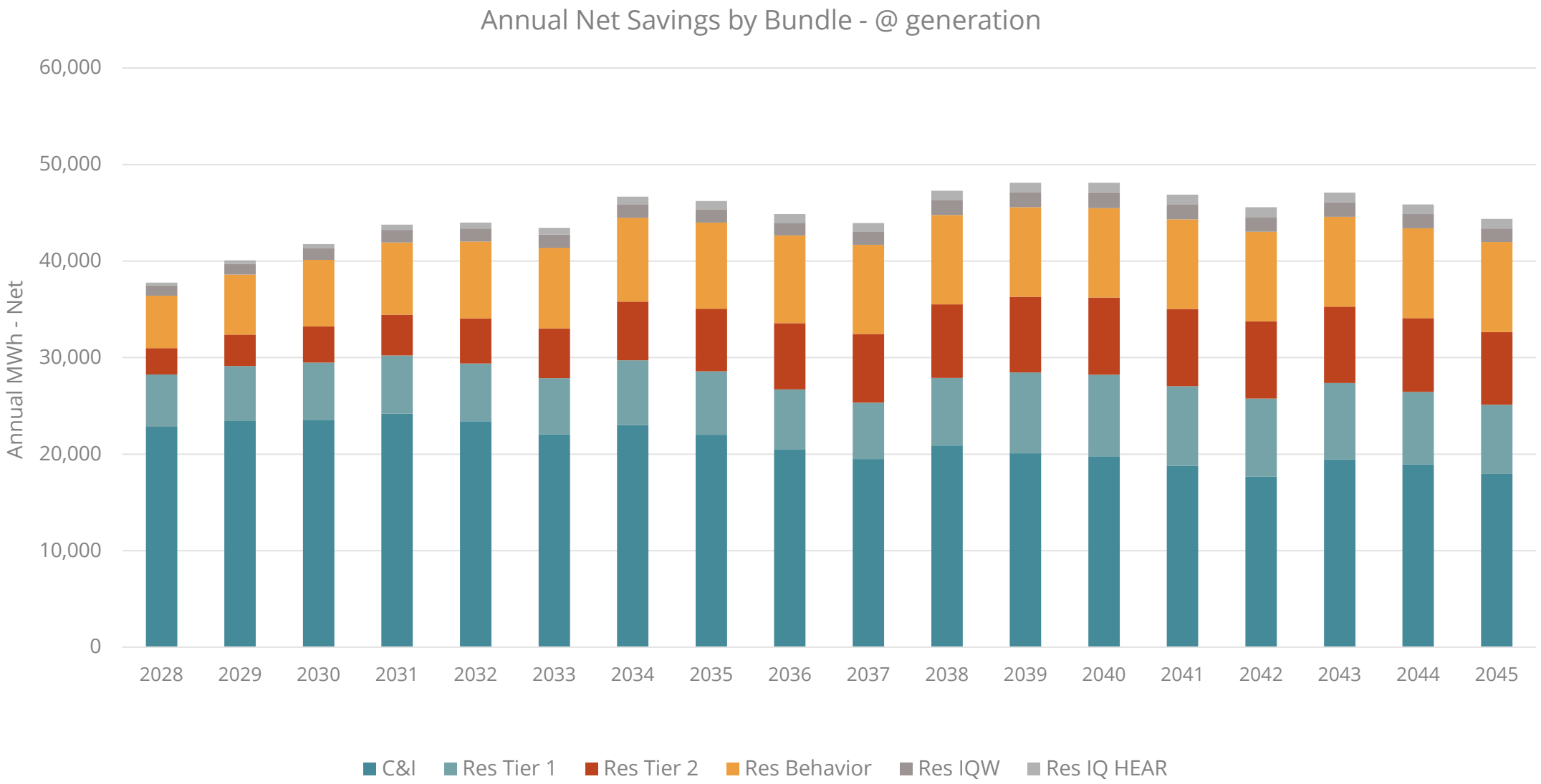
Line Loss

- *Line loss factor of 1.092*

T&D Adjustment

- *Annual costs were adjusted to recognize value of avoided lifetime T&D benefits*

ANNUAL SAVINGS BY BUNDLE



LEVELIZED COST OF ENERGY – RAP AND ENHANCED RAP

RAP	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Enhanced C&I	$0.038	$0.039	$0.040	$0.041	$0.042	$0.042	$0.044	$0.045	$0.046	$0.047	$0.049	$0.050	$0.051	$0.052	$0.052	$0.051	$0.051	$0.051
Res Tier 1	$0.030	$0.031	$0.032	$0.033	$0.034	$0.035	$0.035	$0.036	$0.037	$0.038	$0.036	$0.037	$0.038	$0.039	$0.040	$0.040	$0.041	$0.042
Res Tier 2	$0.084	$0.085	$0.087	$0.089	$0.092	$0.094	$0.095	$0.098	$0.101	$0.104	$0.106	$0.108	$0.111	$0.113	$0.115	$0.118	$0.122	$0.123
Res Behavior	$0.074	$0.076	$0.077	$0.079	$0.081	$0.082	$0.084	$0.086	$0.088	$0.090	$0.091	$0.093	$0.095	$0.097	$0.100	$0.102	$0.104	$0.106
Res IQW	$0.167	$0.175	$0.185	$0.201	$0.213	$0.226	$0.244	$0.258	$0.272	$0.290	$0.268	$0.276	$0.287	$0.296	$0.303	$0.316	$0.323	$0.329
Res IQ HEAR	$0.332	$0.340	$0.347	$0.356	$0.365	$0.375	$0.385	$0.396	$0.408	$0.420	$0.431	$0.442	$0.453	$0.463	$0.472	$0.481	$0.489	$0.497

Res Behavior

- *Residential behavior will be grouped with Tier 1*

DEMAND RESPONSE RESULTS

DEMAND RESPONSE PROGRAMS

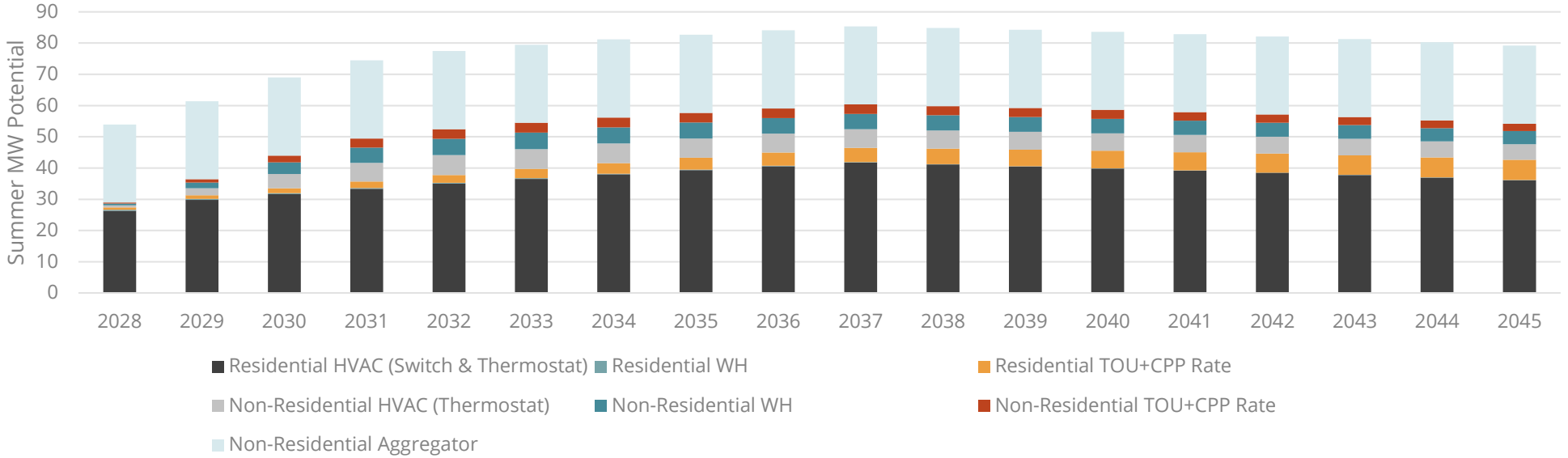
- Direct load control of air conditioners with switch
- Direct load control of thermostats
- Direct load control of electric water heaters with switch
- Direct load control of grid-enabled electric water heaters
- Direct load control of electric vehicle charging
- Battery energy storage
- Time of use + critical peak pricing rate

DEMAND RESPONSE HIERARCHY / BUNDLES

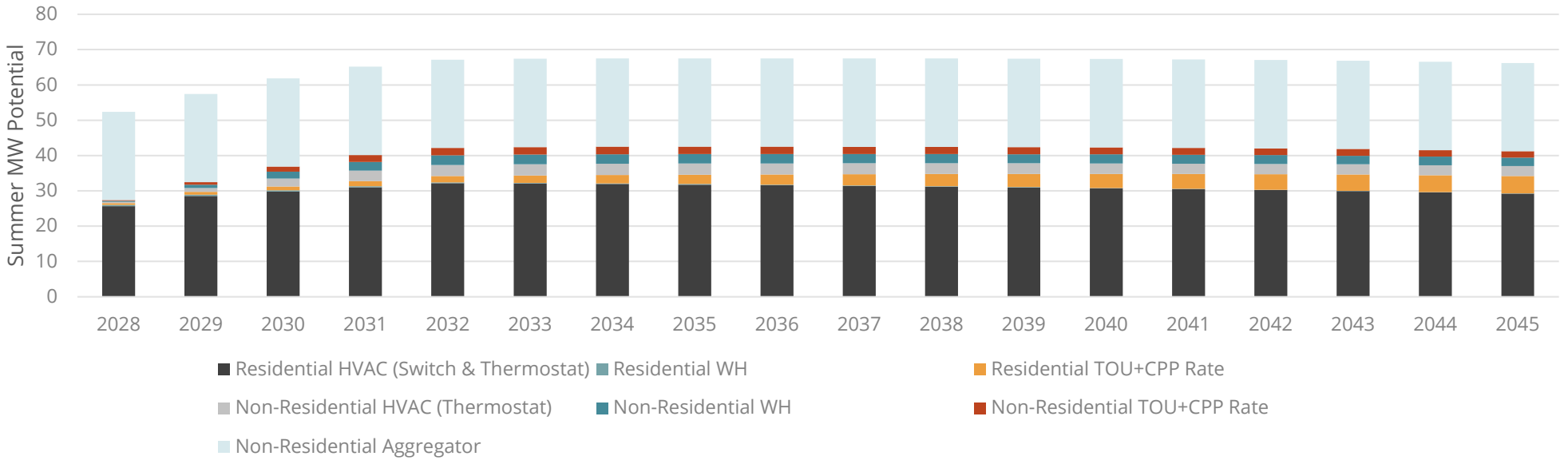
- **The hierarchy prevents double-counting for programs that affect the same end-use.**
- **DR Hierarchy:**
  - *1. Direct load control*
  - *2. TOU + CPP rate*
- **All programs/sectors were bundled individually for the IRP inputs**

FINAL DEMAND RESPONSE RESULTS - SUMMER

Summer MAP

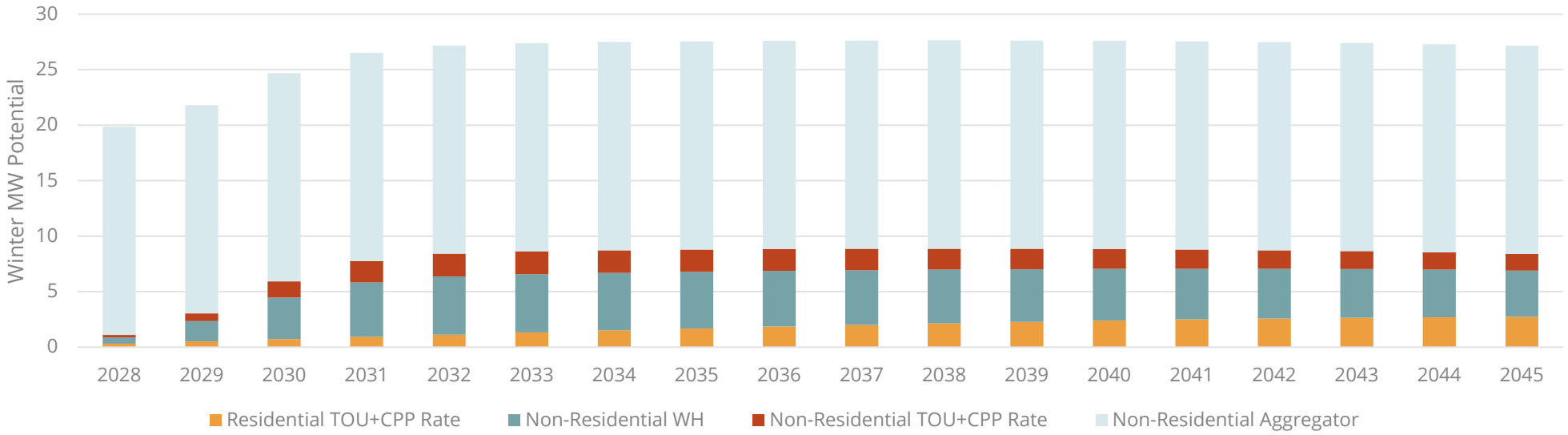


Summer RAP

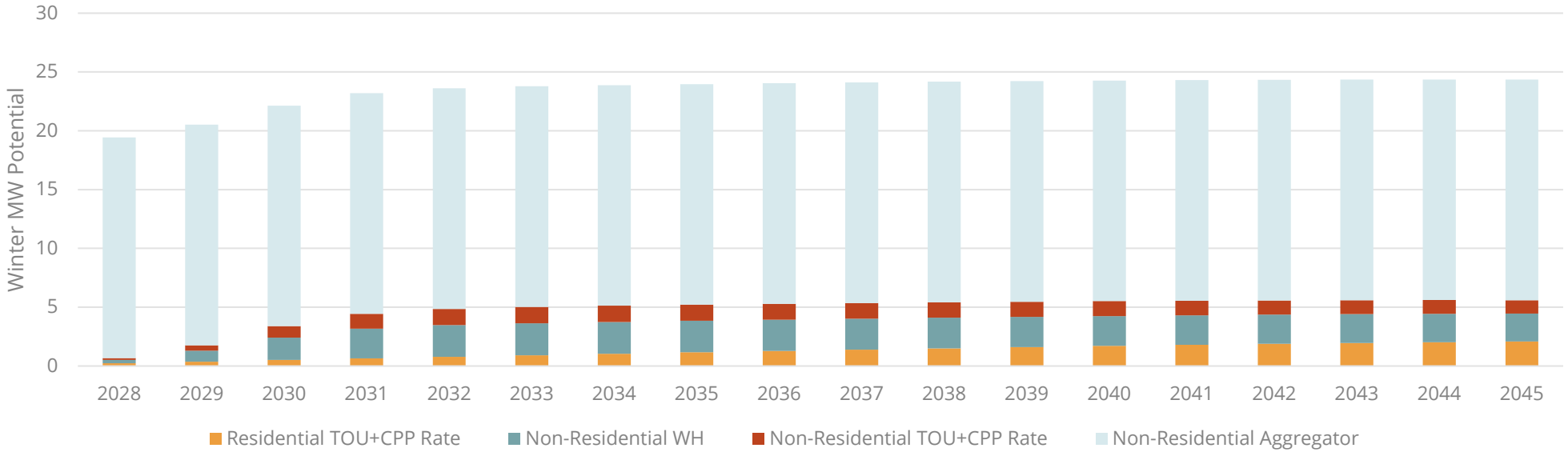


FINAL DEMAND RESPONSE RESULTS - WINTER

Winter MAP



Winter RAP



NEXT STEPS?

Attachment 8.2 2025 DSM Data Requests and Responses

CAC et al.'s DER Related Comments on CEI MPS Kick-Off Meeting on 12/11/2024

Thank you for the opportunity to provide some additional comments in writing about how we'd like to see Centerpoint better integrate DG solar and DERs more generally into your 2025 MPS process.

As SUN, CAC, and Vote Solar noted in our comments on Centerpoints 2023 IRP, we believe that Centerpoint is missing an opportunity to strengthen the IRP process by allowing DG solar and other DERs to be included as resources eligible for selection in modeling. As we lay out in detail in the comments, other utilities around the country have found that incentivizing DERs and making them available as a selectable resource can reduce costs while improving system resilience and reliability. Since our original comments were submitted, that case has only grown stronger as more utilities (notably Xcel Energy in Minnesota, see page 99 for discussion of modeling DG solar growth in their IRP) have adopted this method in their preferred portfolios.

Given that Centerpoint has had nearly two years to consider our previous comments, and the Director's response to our comments (see pg. 22) that "Much thought and discussion need to be given to how best to implement this type of improvement," we're disappointed by the lack of interest displayed by Centerpoint in including DG solar and DERs in the 2025 MPS. We believe that Centerpoint should add the following elements to the MPS process so that DG solar and aggregated DERs can be properly included as selectable resources in the IRP next year:

1) Collect data to demonstrate the potential market impact of rooftop solar incentives, as outlined in our previous comments.
2) Develop a model to demonstrate distributed solar and battery storage growth based on current market conditions, to incorporate into an IRP as a resource
3) Collect data to demonstrate the potential market impact of battery storage incentives.
4) Develop a model to demonstrate the potential impact and cost effectiveness of coordinating DERs (including battery storage, smart thermostats, and other resources) in a distributed power plant as a resource.

We would welcome the opportunity for further discussion. Thank you.

CenterPoint Energy Response to CAC's Request on December 20, 2024

January 17, 2025

1. CenterPoint Energy Indiana South ("CEI South") will explore conducting a sensitivity in the IRP model for DG Solar, similar utilizing dGEN model results, to see what impact a $500 per KW incentive would have on participation.

2. CEI South will also add a DR option in the MPS for a Bring Your Own Battery DR program.

3. CEI South filed for C&I Third-party Aggregation ("Rider ADR") in the rate case (Cause No. 45990). If C&I aggregation is approved in the rate case, CEI South will explore the potential for Residential third-party aggregation in the MPS.

4. CEI South filed modifications to the Interruptible Contract rider ("Rider IC") and Interruptible Option Rider ("Rider IO") in the rate case (Cause No. 45990), we need to see what impact the proposed program will have before adding additional interruptible riders in the MPS.

5. CEI South will not be including a distributed power plant, also known as virtual power plants, as a resource. Most of these resources such as thermostats, battery, DG Solar, and Direct Load Control switches will be modeled separately within the MPS or via IRP sensitivities.

CAC Comments on CNP Demand Response MPS:

Aggregation

Questions:

- For C&I, we would like to clarify updates to non-residential DR options, specifically aggregation, as discussed on our 3/13 call. In addition to other non-residential products being proposed, please provide additional detail about the non-residential aggregation program design, including key segments, end uses, and technologies assumed.
    - CNP Response: The Aggregator will work with CEI South to educate and recruit C&I customers. The Aggregator manages a large DR portfolio globally and currently works with more than 20 integrated utilities in the U.S. The Aggregator has developed a large database from more than 20,000 C&I sites they manage across multiple different industries. The Aggregator will leverage this database, along with US Census data, EIA data and CEI South data to help recruit. Post recruitment, a facility assessment will be completed followed by the development of a site-specific curtailment plan. A few applications used by the Aggregator for customizable load curtailment strategies are air handlers, anti-sweat heaters, chiller controls, chilled waters systems/thermal storage, defrost elements, elevators/escalators, external lighting, external water features, HVAC systems, internal lighting, irrigation pumps, motors, outside signage, parking lot lighting, production equipment, processing lines, pool pumps/heaters, recharging stations, refrigeration systems and water heating. The Aggregator has implemented strategies across multiple industry types, such as agricultural, beverage bottling, commercial office buildings, dairy manufacturing, farms, grocery store chains, parking garages, public schools, shopping malls and many other manufacturing customer types. The Aggregator is able to support C&I customers before, during and after events utilizing their metering and control technologies. The Aggregator, the customer and CEI South will be able to monitor curtailment in real time during an event utilizing Aggregator provided software. Upon completion of a DR event, the Aggregator will send out event reports to the customer and CEI South.

1. Water Heating – DLC and Grid-Enabled

Questions:

- What is the saturation of water heating by fuel, equipment type (ERWH, HPWH), and customer segment? (Assuming this is or will be available via recent baseline survey results).
    - GDS Response: 30% for ERWH, 6% for HPWH for residential. 40.1% for all electric WH commercial (don't have breakdown).
- How are the current DR water heating product designs and associated inputs (e.g., adoption) accounting for end use loads by vintage (existing vs. new equipment), technology (ERWH vs HPWH), and different customer segments (e.g., SF vs. MF)?
    - GDS Response: We are currently only looking at ERWH and not HPWH due to the low penetration of HPWH and smaller load reduction per participant. If you think this would be impactful to add HPWHs, we can look into it.
- How are the current DR products accounting for co-deployment, leveraging other programs to install devices at reduced costs, higher adoption rates, etc.?
    - GDS Response: We are assuming that the grid-enabled water heaters are being installed by the customer, either on their own are through an EE program. The full cost of installing the water heater is not included in the DR program.
- Is the grid-enabled water heating option only considering device controls for new equipment? What opportunities are there for customers with existing water heaters to participate in future DR products?
    - GDS Response: This program is assuming a one-time $400 incentive to join the program. This could be for customers who already have a grid-enabled WH or not.
- Why is the switch-based DLC product for water heating being discontinued? Is this based on age and failure rate of the existing switch technology? Have you considered a revised model for switch-based DLC that utilized new meter technology or revised cost assumptions (based on similar programs or recent vendor proposals)?
    - GDS Response: While CenterPoint does not plan to replace switches that fail, we have changed our assumption to carry out the existing WH switches longer. We are now assuming that approximately 10% of remaining switches per year will fail, or WH equipment will be replaced, causing the switch to no longer be active. This will allow participants who may not have sufficient internet access to still participate with a switch until it fails.

2. HVAC DLC

Questions:

- What is the saturation of HVAC equipment by fuel, equipment type, and customer segment? (Assuming this is or will be available via recent baseline survey results).
    - GDS Response: Residential AC: 87% central AC, 9% central heat pump, 1% ductless mini split, 6% room AC, 1% ground source heat pump. Residential heating: 21% electric furnace, 11% electric heat pump, 0% ductless heat pump, 1% electric space heater, 1% electric baseboard heater, 2% air source heat pump, 1% dual fuel heat pump, 1% geothermal heat pump. Commercial AC: 33.1% packaged AC unit, 31.5% residential-type central AC. Do not have this breakout by fuel type for commercial.
- What is the saturation of homes with electric heating and/or cooling, and that have smart thermostats?
    - GDS Response: Residential: 87% with central AC, 39% with electric heating, 38% with smart thermostats (CNP baseline study). Commercial: 64.6% AC, 31.1% electric heating, 3% with smart thermostats (CBECS).
- How does CNP plan to utilize the smart thermostat DLC resource, with assuming 100 hours of control (25 events, 4 hrs each) – is this for MISO emergency response or for other applications? Please explain and highlight each of the specific use cases being assumed for this resource.
    - GDS Response: The DR model uses the hours of control to calculate the annual energy benefits. The total hours accounted for in the model would be the maximum number of hours the program would run, 64 hours (5 times in summer and winter, 3 times in spring and fall). The model does consider this to be a MISO emergency response resource.
- How is the modeling of this program accounting for thermostats coming into this program through EE – both in terms of adoption and costs? Do current adoption rates account for these efficiencies?
    - GDS Response: As we get the participation counts from the EE programs, we will re-examine the DR participations to see if they are aligned. We don't have these numbers yet, so will look when the forecast is available.
- What C&I segments are assumed will participate in these programs? Is this consistent with the participation rates cited from other utility programs used for MAP and RAP?
    - GDS Response: All commercial customers with applicable types of AC are assumed to be eligible to participate. This would include business customers with packaged AC units and residential-type central AC. This does not

include business customers with chillers. We believe this is consistent with the participation rates other utility programs used for MAP and RAP.

3. Time Varying Rates: TOU, CPP, PTR

Questions:

- CPP+TOU:
  - Are the load impacts additive (e.g., 12.8% + 5.5% = 18.3%)?
    - GDS Response: No, the load impacts for CPP would occur during critical peaks, and the load impacts for TOU would occur during non-critical peaks.
  - Why propose modeling the potential associated with the pilot program cohort of 500 customers rather than considering what these hybrid options could look like at scale for the MPS?
    - GDS Response: We are not suggesting this and will be scaling this to be a regular program. It is only starting as a pilot and assumed to increase in participation at the start of the MPS period.
- TOU:
  - What are the rate design assumptions associated with the estimated load reduction and adoption rates? Specifically, did you have an underlying peak to off-peak ratio in mind?
  - How do these assumptions reflect participation populations with enabling technologies like smart thermostats?
- CPP
  - What are the rate design assumptions associated with the load reduction and adoption rates? Specifically, did you have an underlying peak to off-peak ratio in mind?

5. Battery Storage DLC

Questions:

- What is the current saturation of battery owners in CNP territory, for both residential and C&I?
  - GDS Response: 8% of residential customers with solar also have a battery. We are assuming the same for C&I, which aligns with a recent LBL report[1].

- What is the current saturation of customers with solar, by sector?
    - GDS Response: 1.3% of CenterPoint's residential customers currently have solar. We are using a solar forecast supplied by Itron to estimate the number of batteries that will exist in future years.

9. Irrigation Load Control

Questions: Does CNP currently have data on the number of agricultural customers and associated irrigation loads that could be used to estimate potential load impacts for this segment?

- GDS Response: CNP does have data on the agricultural customers, but not the irrigation loads.

CAC Comments on CNP Demand Response MPS: Products List and Initial Input Assumptions

On March 6, 2024, GDS presented an overview of demand response program assumptions used in development of the current CenterPoint MPS. On behalf of Citizen's Action Coalition (CAC), we have several clarifying questions and suggestions, covering three specific topic areas:

1) DR products being considered within the MPS
2) Configuration or design assumptions associated with DR products being considered
3) Input assumptions for some of the specific DR products (e.g., adoption, per unit savings).

Proposed DR products

Through the presentation and subsequent Excel assumptions workbook, GDS presented a set of DR products being considered for the MPS. In Table 1, we have included a list of the product by sector form the workbook, along with a list of DR products we are proposing to add as part of the MPS.

Table 1. List of Existing and Proposed MPS DR Products by Sector

DR Products by Sector - Listed	Proposed
Residential	
DLC AC Switch	Peak Time Rebate (PTR)
DLC Thermostat	EV Managed Charging / TOU
DLC Water Heater Switch	Behavioral Demand Response (BDR)
DLC Grid Enabled Water Heater	Default TOU
DR Battery Storage	
DLC Electric Vehicles	
TOU	
CPP	
TOU+CPP	
Non-Residential	
DLC Thermostat	Interruptible Rates
DLC Grid Enabled Water Heater	Auto-DR or ADR (lighting, HVAC)
DR Battery Storage	Irrigation Load Control

DLC Electric Vehicles	Lighting DLC
Real Time Pricing (RTP) Rate	Thermal Energy Storage
TOU	Peak Time Rebate (PTR)
CPP	EV Managed Charging / TOU
TOU+CPP	

To accurately estimate the potential of demand flexibility, a potential assessment will need to consider the full scope of end use loads available for control. For demand response, this process is often focused on first developing a list of specific DR products as prototypical programs that can be used to achieve load impacts. However, this effort can fall short of capturing the true potential by only considering a narrow set of programs that may limit the potential for participation by customer segment, end use, or specific types of technology. We believe there should be a more expansive view of accounting for end use loads available to be controlled or shifted to achieve these demand savings, closer to how potential is considered for energy efficiency. For the DR MPS, we would like to understand what the full potential for demand reduction or load shifting is through various types of DR products, including price signals, dispatchable controls, and callable resources.

That said, there will be different programmatic pathways where customers will be more likely to enroll and participate in demand response programs. Likelihood of enrollment for a given product will vary by sector, customer segment, end use technologies, and customer preference. For this reason, we are proposing CNP and GDS consider a broader scope of DR products with the assumption that different customer segments will have opportunity to participate in products that best suit their preferences and building/equipment conditions.

The list of additional DR products CAC is proposing is not new. CAC Comments on CNP's 2022/2023 IRP (submitted 9/29/23) highlight similar issues regarding the omission of program offerings that will lead to inaccurate estimation of resource potential.[1] CAC testimony filed on 3/12/23 also included discussion supporting evolution of DLC programs and comprehensive dynamic pricing options that include PTR.[2] Of the 12 products suggested in the IRP comments, several have been addressed in the current MPS draft, though some only in part, while others remain omitted. CAC testimony

[1] https://www.in.gov/iurc/files/CEIS-2022-IRP-CAC-EJ-SUN-VS-Comments-9-29-2023FINAL.pdf
[2] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/58a04bc5-5be1-ee11-904d-001dd80a8a32/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=CN%2045990--%20CAC%20Public%20Exhibit%202--3-12-24FINAL.pdf

Table 2. List of DR Products from 2023 CAC Comments and Status in Current MPS

Proposed Additions (9/2023)	Status
Interruptible Rates	Not currently included
Electric Vehicle TOU / Managed Charging	Added EV DLC
Behind the Meter Storage	Added DR Battery Storage
Behavioral Demand Response (BDR)	Not currently included
Peak Time Rebates (PTR) Opt-Out	Not currently included
TOU with Enabling Technology	Added TOU; unclear whether pathways include enabling devices
Non-Residential Water Heater DLC	Added Non-Res Grid-Enabled WH
Non-Residential Lighting DLC	Not currently included
Non-Residential Auto-DR	Not currently included
Non-Residential Time-Varying Rates (TOU, real time pricing [RTP])	Added Non-Res TOU and RTP
Thermal (Ice-Based) Energy Storage	Not currently included
Winter potential for DLC and Rate options	Added winter DR values

Recommendation:

- Propose incorporating these additional DR products within the current MPS.

Note on Aggregation

On 3/13, CNP discussed receiving a proposal from an aggregator for non-residential DR opportunities. In general, aggregators will often utilize a spectrum of DR products across different industry types, including many of the control strategies discussed here. We assume that the estimate of potential proposed by the aggregation bid reflects a subset of full resource potential across a range of DR products.

Questions:

- For C&I, we would like to clarify updates to non-residential DR options, specifically aggregation, as discussed on our 3/13 call. In addition to other non-residential products being proposed, please provide additional detail about the non-residential aggregation program design, including key segments, end uses, and technologies assumed.

Product Specific Feedback

In the subsequent section, we discuss specific DR products or groups of products and include questions/comments on both product design and input assumptions.

1. Water Heating – DLC and Grid-Enabled

The GDS DR assumptions spreadsheet outlines two options for water heater DLC:

- ***DLC Water Heater Switches*** – appears to reflect the existing program being sunset, projecting participation and savings decreasing to zero.
- ***DLC Grid Enabled Water Heaters*** – appears to assume installation of new water heating equipment paired with installation of communication module.

For the current study, as noted, we believe it is important to consider the full potential of controllable end use water heating loads and how CNP can access these through different strategies. The current assumptions appear to limit new DR opportunities to new equipment and may not consider pathways for controlling existing equipment, nor differentiate between equipment type (ERWH vs. HPWH) or customer segment (single family vs. multifamily). Additionally, there are opportunities to co-deploy the installation of water heater controls as part of energy efficiency programs, which will reduce costs of acquisition and increase enrollment rates.

Finally, while opportunities to control devices directly through grid-enabled equipment are increasing, there are recent examples of water heater DLC programs that utilize different control technologies, including switches, based on compatibility with the end use equipment. For example, PGE's Multifamily Water Heater DLC program is using both switch-based Wi-Fi controls and grid-enabled CTA-2045 communication modules.[3] Ideally, the MPS will use an approach to model achievable potential of water heater loads that balance strategies and provide sufficient coverage for different types of devices, new and existing equipment, and different customer segments.

Questions:

- What is the saturation of water heating by fuel, equipment type (ERWH, HPWH), and customer segment? (Assuming this is or will be available via recent baseline survey results).

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[3] https://assets.ctfassets.net/416ywc1laqmd/6plT6yeMe8t2aWdDlbLqfb/676e555dbc58eea8858803b6629cf879/Flex_Load_MYP_2024_-_Full_Document.pdf

- How are the current DR water heating product designs and associated inputs (e.g., adoption) accounting for end use loads by vintage (existing vs. new equipment), technology (ERWH vs HPWH), and different customer segments (e.g., SF vs. MF)?
- How are the current DR products accounting for co-deployment, leveraging other programs to install devices at reduced costs, higher adoption rates, etc.?
- Is the grid-enabled water heating option only considering device controls for new equipment? What opportunities are there for customers with existing water heaters to participate in future DR products?
- Why is the switch-based DLC product for water heating being discontinued? Is this based on age and failure rate of the existing switch technology? Have you considered a revised model for switch-based DLC that utilized new meter technology or revised cost assumptions (based on similar programs or recent vendor proposals)?

Recommendations:

- ***Product structure***. We suggest building out a set of water heating DR products that account for both vintage (new vs. existing equipment) and technology (ERWH, HPWH), which may involve retrofitting grid-enabled devices or switches, depending on the existing equipment. New device installation may be more focused on grid-enabled devices, assuming the products being promoted allow for easy adaptation of control modules or through smart devices settings. Assuming there are both EE programs that install water heaters or offer incentives for approved efficiency products (e.g., marketplace), ensuring these are units that have Wi-Fi or ideally eco-ports for universal control modules could serve as a unique channel for co-deployment of EE/DR and achieve higher adoption at lower cost.
- ***Load Impacts***. Estimates of demand savings will vary based on several factors, including type of equipment (electric resistance, heat pump) and size.
    - For residential savings, the current assumptions rely on the same value (0.104 kW) for both switch and grid-enabled programs, based on a 2024 Cadmus evaluation report (which references analysis conducted in the 2019 evaluation). Upon review, the 2019 evaluation indicates that higher savings were expected but they observed at 70% failure rate of switch devices.
    - For this MPS, we suggest updating this value and, ideally, differentiating impacts by program (and equipment type if possible). Several recent studies show impacts for electric resistance closer to **0.35 kW** (summer) and **0.4-0.5 kW** (winter) for grid-enabled devices, and slightly less for switch-based

controls (0.25 kW summer, 0.3 kW winter). Impacts for heat pump water heaters will be lower (0.1 kW summer and 0.2 winter).[4]

- ***Participation Rates.*** The current assumptions show no future adoption for DLC switches, and MAP and RAP of 50% and 25% for Grid-Enabled. We would like to confirm the eligible customer population for these different groups to align on the specific populations being considered.
    - Assuming there is an opportunity for achieving DR through retrofitting existing equipment (including grid-enabled and switch options) and new equipment, we would like to confirm appropriate assumptions for participation by these different options.
    - Additionally, we suggest increasing adoption rates for any DR enrollment occurring through other programs. For example, a Connecticut pilot leveraging its low-income retrofit program achieved a conversion rate of 90% enrollment in water heater DR of homes with water heaters installed through the program.[5] Uplight also claims that co-enrollment approaches can increase program conversion rates in DR programs from 10-20% to 60-80%.[6]

2. HVAC DLC

Similar to water heater DLC, the current DR assumptions spreadsheet outline two options for HVAC DLC:

- ***DLC HVAC Switches*** – appears to reflect the existing program being sunset, projecting participation and savings decreasing to zero.
- ***DLC Thermostat*** – modeled after existing BYOT and Smart Cycle products offering smart thermostat DLC, the latter including direct install of smart thermostat.

As noted above, limiting HVAC DLC offerings to products relying on smart thermostats will restrict estimation of true resource potential associated with HVAC loads. There may be opportunities to deploy switch-based controls for some customer segments that are averse to smart thermostat adoption, have limited or intermittent internet access, or for specific building segments (e.g., multifamily).

There have been recent examples of programs returning to using switch-based HVAC DLC to access harder to reach customer segments, whether rural and without internet, averse to smart thermostats, or low income. Currently, I&M is offering a DLC switch program

[4] Xcel (Xcel Energy Colorado Demand Response Study: Opportunities in 2030); BPA CTA 2045 (Demand Response report - FINAL REPORT WORKING VERSION)
[5] https://www.aceee.org/sites/default/files/pdf/conferences/hwf/2019/7d-rodrigues.pdf
[6] https://uplight.com/wp-content/uploads/2021/06/U_eBook_DRPE_ExperienceAndGridFlexibility-1.pdf

targeting low-income and rural customers.[7] SMUD's Peak Conserve program is evolving its Central AC cycling program using new 2-way load control switches leveraging GenX AMI network connectivity. Load impacts from a 2023 evaluation show 0.77-0.93 kW savings per device for events over 90 degrees using 40 min cycling.[8]

Questions:

- What is the saturation of HVAC equipment by fuel, equipment type, and customer segment? (Assuming this is or will be available via recent baseline survey results).
- What is the saturation of homes with electric heating and/or cooling, and that have smart thermostats?
- How does CNP plan to utilize the smart thermostat DLC resource, with assuming 100 hours of control (25 events, 4 hrs each) – is this for MISO emergency response or for other applications? Please explain and highlight each of the specific use cases being assumed for this resource.
- How is the modeling of this program accounting for thermostats coming into this program through EE – both in terms of adoption and costs? Do current adoption rates account for these efficiencies?
- What C&I segments are assumed will participate in these programs? Is this consistent with the participation rates cited from other utility programs used for MAP and RAP?

Recommendations:

- ***Program Structure.*** Depending on the customer distribution with electric HVAC and smart thermostats, we suggest including a DLC pathway to control HVAC loads for customers that will not likely adopt smart thermostats. This could be a DLC program that relies on switches or grid-enabled devices, including retrofits for existing equipment as well as new equipment.
- ***Participation Rates.*** Adoption rates for HVAC DLC options should account for increased likelihood of enrollment for customers participating in EE programs, including installations of qualifying smart thermostats. It is unclear whether values benchmarked from other sources account for these efficiencies. We suggest developing assumptions that scale the current adoption rates based on an increase in deployment of thermostats through EE program activity.
- ***Participant Costs.*** DLC Thermostats outlines cost assumptions for utility purchase of new thermostats (Smart Cycle) and BYOT pathways. The underlying rationale for

[7] I&M DSM Plan, Walter Testimony. Cause No. 45701 – Residential AMI HVAC Direct Load Control
[8] PLMA 2024 presentation. *SMUD: The Next DR Chapter.*

BYOT is that a customer has purchased a thermostat prior to enrolling in the DR program, thus the cost of the BYOT is either incurred by the participant outside of the accounting of DR program costs OR, if purchased through EE programs, would be accounted for through the EE portfolio and should not be double counted. Either way, BYOT costs appear to be overstated and should be reduced.

3. Time Varying Rates: TOU, CPP, PTR

The current DR assumptions spreadsheet outlines two options:

- ***TOU rate*** – provided for both residential and non-residential sectors, assuming a 6-hour peak period (weekday for full year), with load impacts ranging from 2.8-5.8% for residential and 1-2% for C&I. Assuming an opt-in rate
- ***CPP rate*** – provided for both sectors, assuming 15 events per year (4 hrs each), with load impacts ranging from 7.7-12.8% for residential and 6-7.9% for C&I.
- ***TOU + CPP rate*** – limited to a 500 customer pilot.

Questions*:*

- CPP+TOU:
  - Are the load impacts additive (e.g., 12.8% + 5.5% = 18.3%)?
  - Why propose modeling the potential associated with the pilot program cohort of 500 customers rather than considering what these hybrid options could look like at scale for the MPS?
- TOU:
  - What are the rate design assumptions associated with the estimated load reduction and adoption rates? Specifically, did you have an underlying peak to off-peak ratio in mind?
  - How do these assumptions reflect participation populations with enabling technologies like smart thermostats?
- CPP
  - What are the rate design assumptions associated with the load reduction and adoption rates? Specifically, did you have an underlying peak to off-peak ratio in mind?

Program Structure.

Time varying rates (TVR) provide a good example of a suite of resources that offer different pathways for participation in DR based on different product strategies, designs, and customer preferences. Ultimately, the goal for the MPS should be to consider the full scope of different options that may be adopted, rolling up to total estimate of resource potential.

We would like to propose a revised structure for considering opportunities for customers to participate in these programs, including these additional treatments and considering default, opt-in, and opt-out participation options. As noted, CAC has previously recommended CNP consider additional pricing and behavioral treatments, including PTR and BDR, as well as more comprehensive TVR offerings and alternative rate designs.[9] We recognize that there are interactions between DR products that can limit eligibility or create complimentary or competitive impacts on achieving potential savings. We believe these factors can be taken into account while modeling a more holistic suite of TVR to achieve a more accurate and comprehensive estimation of resource potential. For these pricing treatments, we would like to suggest two options that consider combinations of these DR products and options for participation.

- **TVR Scenario 1:** Default TOU, with opt-in options for CPP, PTR, and a more aggressive TOU rate (i.e., higher peak to off-peak ratio)
- **TVR Scenario 2:** Opt-Out PTR, with opt-in options for CPP and the more aggressive TOU

TVR Scenario 1. The first option considers a default TOU rate with design assumptions focused on a small peak to off-peak pricing ratio. This could be similar to default TOU offered by Consumers Energy, which is offered in summer at a ratio close to 2:1. The MPS would model sector-level impacts associated with a default TOU rate, and then consider additional options for (1) a more aggressive TOU rate that customers could opt-in, and (2) either opt-in CPP or PTR, which would be incremental to TOU rates. The opt-in TOU should have a more aggressive peak to off-peak ratio (e.g., 3:1 to 5:1) and may appeal to a variety of customer segments, including EV owners. The opt-in PTR and CPP options could complement either TOU rate, but are in conflict with each other (i.e., a customer could enroll in either CPP or PTR, but not both).

TVR Scenario 2. This option leads with an opt-out PTR, where eligible customers would be auto-enrolled in a PTR program. Eligibility may depend on participation in other DR programs (e.g., customers not in HVAC DLC), but PTR is generally equal opportunity

[9] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/58a04bc5-5be1-ee11-904d-001dd80a8a32/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=CN%2045990--%20CAC%20Public%20Exhibit%202--3-12-24FINAL.pdf

offering, not restricted to specific equipment type. Other pricing options, including opt-in TOU and CPP, would be then available.

In general, both scenarios provide opportunities for all customers to begin learning more about the time varying cost of energy. These products can also serve as a platform for increased adoption or migration to firmer DR products. We are happy to continue this discussion with CNP and GDS to figure out whether the proposed scenarios or an alternative scenario will be the best option for modeling TVRs, providing a comprehensive and strategic approach to deployment that reflects a holistic opportunity for achievable resource potential. Based on the selected scenario, we are also happy to provide suggestions for input assumptions for a revised set of TVR products.

Current Product Assumptions – Load Impacts and Adoption

Upon review of product assumptions, we have several suggestions to refine adoption and savings percentages that consider rate structure, customer segment, and assumptions about paired technologies.

Opt-Out TOU

The current DR assumptions cite percentage savings of 5.6% summer and 2.8% winter (assuming for on-peak hours, 1-7pm) which appear a bit low compared to several recent evaluation studies. Load impacts from TOU are a function of several factors, including marketing/education, rate design (e.g., peak/off-peak price ratio, on-peak duration), opportunities for load shifting vs. conservation, and availability of enabling technology, like smart thermostats. Customer segmentation is also important, such as saving opportunities provided for customers with EVs or solar/storage. We suggest modeling TOU potential to account for co-deployment of other programs and interactions with adoption of smart thermostats and EVs.

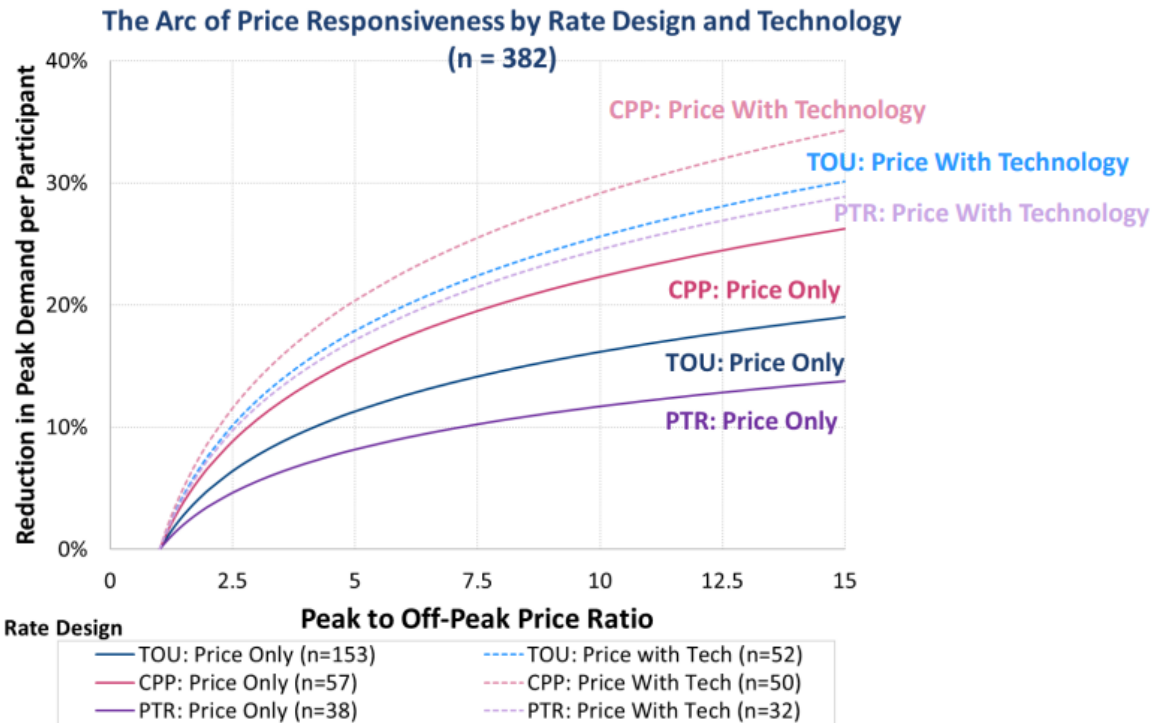
- A 2020 evaluation of Maryland TOU pilots (with on/off ratios of 4:1 to 6:1) shows summer on-peak reductions of 10-15% (2-7pm) and winter from 5-6% (6-9am). This also includes a segment of low to moderate income customers (LMI) that saved between 8-14% of summer peak (non-LMI saving between 10-17%). [10]
- A 2022 evaluation of Dominion VA's Off Peak Plan (TOU Rate) saw 9.4% summer season reduction (3-6pm) and 2.9% winter (6-9am, 5-8pm) with a price ratio of 2:1.[11]
- A preview of the next draft of Brattle's long-run time-varying rate research (Arcturus 3.0) continues to show the potential for TOU savings at various on/off peak ratios,

[10] https://www.brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf

[11] https://www.scc.virginia.gov/docketsearch/DOCS/7prc01!.PDF

showing CPP, PTR, and TOU (with ratios 2.5:1 to 5:1) ranging from 10% to 18-20% when paired with technology, and 5-10% to 8-15% without (see Figure 1).[12]

Figure 1. Arc of Price Responsiveness by Rate Design and Technology – Brattle 2023



Regarding offerings and adoption, a number of utilities are moving toward having more options for different customer segments, including a default base TOU that provides a small differential (Xcel, Consumers Energy). We suggest considering a more comprehensive structure that gives options for (1) default TOU to increase fluency of time-varying energy pricing, (2) a more aggressive TOU to optimize bill savings, and potentially (3) optimizing savings for EV owners, if not covered by other rate structures.

Brattle cites examples of several utilities with multiple rate options and higher adoption rates than the current assumptions:[13]

- SRP – 33% residential enrolled in opt-in TOU (3 options)
- APS – 56 % residential enrolled in opt-in TOU (3 options)

[12] https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf
[13] https://www.brattle.com/wp-content/uploads/2021/05/18500_moving_ahead_with_time-varying_rates_tvr_-_us_and_global_perspectives.pdf

- CA – nearly 99% in TOU plans once shifted to opt-out
- MI Consumers – in 2020 default all residential into a 1:1.5 summer TOU (2-7pm)
- OGE – 20% res customers on TOU paired w/ smart tstats

Based on the selection of a proposed TVR rate scenario, we recommend CNP/GDS utilize these sources to update seasonal load impact estimates and participation rates. We suggest that each pricing treatment should consider segmentation for those customers with and without enabling technology (smart thermostats), EVs, and behind-the-meter solar and/or storage where relevant differences in load impacts and participation rates exist.

PTR

As noted, we suggest adding the PTR product to this MPS as either an opt-out or opt-in option. Here are several sources for assumptions to estimate load impacts and participation rates.

- PTR Opt-In
    - Adoption: 15% residential sector (PGE) [14]
    - Savings: 6.3% (0.13 kW) summer and 3.6% (0.07 kW) winter per participant[15]

- PTR Opt-Out
    - Adoption: 93.7% retention of auto-enrolled participants (PGE)[16]; 90% (Xcel)[17]
    - Savings: 2-5% (0.02-0.09 kW, avg. 0.058 kW) summer and 0.016 kW winter per participant[18]

Recommendations:

- Suggest modeling TVR scenario options proposed above, including additional pricing treatments.
- Suggest revising input assumptions for TOU and CPP as noted, along with considering segmentation where relevant.

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[14] https://assets.ctfassets.net/416ywc1laqmd/6plT6yeMe8t2aWdDlbLqfb/676e555dbc58eea8858803b6629cf879/Flex_Load_MYP_2024_-_Full_Document.pdf

[15] https://edocs.puc.state.or.us/efdocs/HAQ/um2141haq333456024.pdf

[16] https://edocs.puc.state.or.us/efdocs/HAD/um1976had1636.pdf

[17] https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf

[18] https://edocs.puc.state.or.us/efdocs/HAQ/um1708haq124912.pdf

4. EV Managed Charging / DLC

The participant share of equipment labor cost indicates that the program is only considering new customers, but existing non-networked charger EV owners can participate through car telematics. Utilities that have set up EV DLC or managed charging programs in the last years are including both chargers and telematics for this purpose. This would enable a larger share of the population with EVs to participate in the program and provide grid services to CNP. Examples of these program include Puget Sound Energy Flex EV program and Eversource Managed Charging Program.[19,20] The PSE program is a DLC program with maximum 20 events per season and the Eversource program is a managed charging program requiring to charge the vehicle at least 80% of the time outside designated hours.

For C&I customers a managed charging program or an EV-TOU option could be more applicable as these customers have strong interests in reducing operating cost on a regular basis and sometimes might have a separate meter or submeter for the EV load.

Recommendation: At a minimum, include existing residential EV-owners in DLC EV potential through telematics. This will increase the potential for load reduction and reduce equipment costs.

5. Battery Storage DLC

The Battery Storage assumptions appear to include options for both bring-your-own-device and customer battery incentives. We agree that offering both tracks is a good model to capture both customers with existing batteries and encourage battery adoption either through incentives for purchase or leasing. A recent RMI report on VPPs highlights a number of states with BTM storage programs used for demand response and includes design details[21] – a few highlights include two programs less than five years old: Green Mountain Power, which includes BYOD and leasing options with over 3,000 participants at approximately 30 MW of load reduction; and Rocky Mountain Power, that offers a BYOD option with 3,200 participants at 20 MW and is used daily for managing both peak load and frequency response.

Input assumptions for load reductions seem standard with other existing programs for both sectors. While residential sector costs seem appropriate, C&I costs appear high. Based on the NREL site for commercial batteries the cost seems to be half of the proposed amount

[19] PSE | Flex EV
[20] Electric Vehicle Charging Program
[21] Virtual Power Plant Flipbook - RMI

in the excel file. [22] Cost for a 30-kW system in an EPRI study range from $1,400/kW to $3,000/kW.[23]

Questions:

- What is the current saturation of battery owners in CNP territory, for both residential and C&I?
- What is the current saturation of customers with solar, by sector?

Recommendations:

- Review and revise C&I cost assumptions.
- Consider modeling both BYOD and battery rebate or leasing pathways.

6. Interruptible Rates

Interruptible rates are currently not listed as part of the MPS study. Per discussions with CNP team on 3/13, the focus for C&I sector relies on the aggregation of different end uses (e.g., HVAC loads, lightning, etc.). It seems like additional curtailable opportunities are not accounted for under this structure. For instance, a manufacturer could stop one of its production lines during the curtailment period providing additional capacity to respond to MISO events. Similarly, a shopping mall could stop the operation of one or more elevators.

Interruptible opportunities are industry specific and custom solutions can be identified by working directly with larger commercial and industrial customer. We understand that the interruptible rates have not been successful in the past in CNP service territory, but rate design was not favorable for customer participation. CAC has requested in the past to update interruptible tariffs to cater to a wider range of customers in these sectors.

Based on EIA Form 861 2023, the industrial sector represents 44% of total electricity sales, while the commercial sector accounts for 26%. These includes warehouses, assembly, and manufacturing, which could be great candidates for these tariffs.

On 3/13, CNP also discussed receiving a proposal from an aggregator for non-residential DR opportunities. In general, aggregators will often utilize a spectrum of DR products

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[22] Commercial Battery Storage | Electricity | 2024 | ATB | NREL

[23] https://www.bing.com/ck/a?!&&p=bb824eec6c107c9761362e63c3f3e55574761be2af43e8bde5e06624ab0662c7JmltdHM9MTc0MjI1NjAwMA&ptn=3&ver=2&hsh=4&fclid=251ab75b-3884-6dff-39c2-a21839a96c0b&psq=sgip+2017+energy+storage+instllation+cost+evaluation&u=a1aHR0cHM6Ly9yZXN0c2VydmljZS5lcHJpLmNvbS9wdWJsaWNkb3dubG9hZC8wMDAwMDAwMDMwMDIwMTIwNDYvMC9Qcm9kdWN0&ntb=1

across different industry types, including many of the control strategies discussed here. We assume that the estimate of potential proposed by the aggregation bid reflects a subset of full resource potential across a range of DR products.

Recommendation: Include interruptible rates as a measure in the MPS at least for industrial customers using common assumptions for this type of program/rate. With more time, CNP could benefit from conducting a jurisdiction specific study to estimate the potential of interruptible load in the C&I sector based on interruptible opportunities that require manual operation and are industry specific.

7. ADR (HVAC+Lighting)

While ADR uses some of the same end use loads that are proposed in GDS's excel file such as DLC (grid water heaters and thermostats), we believe that some C&I customers will prefer to engage in an ADR program versus a traditional DLC-specific program. Some of these customers may already have a building management system or local control that can receive an event signal and automatically curtail load by adjusting levels to a preset amount.

Recommendation: Include potential for ADR program participation assuming different percentage of the population to traditional DLC program participants.

8. Non-Res Lighting DLC

According to EIA's 2018 Commercial Buildings Energy Consumption Survey, lighting represents about 17% of commercial building electricity consumption.[24] While LED adoption has increased energy efficiency of this end use, there is potential for demand response in this sector. For instance, a case study from NYSERDA Peak Load Reduction Program shows how Home Depot was able to achieve 130kW load reduction per store with DLC lighting. Since then, Home Depot has enabled DLC lighting in 36 stores for a total of 4.7 MW of peak load reduction if called upon by NYISO. This seems relevant to the CNP service area given that Merc segment comprises 21% of the C&I electricity forecast sales for CNP. As another example, the California building code introduce in 2013 a requirement that buildings larger than 10,000 sq ft should be able to reduce lighting power by at least 15%.[25]

[24] Table E3. Electricity consumption (in British thermal units [Btu]) by end use, 2018
[25] 2013 Nonresidential Indoor Lighting

Recommendation: We recommend including C&I DLC lighting in the MPS.

9. Irrigation Load Control

Indiana is the 9th largest farming state in the nation,[26] with Center Point service area having several irrigated hectares and substantial users of ground water for agriculture.[27] [28] Irrigated areas are projected to increase as precipitation patterns become more erratic and the state experiences higher temperatures.[29] Several programs across the country have demonstrated large savings from irrigation load control programs. For instance, Idaho Power achieved 125 MW across 8 load control events in 2023. Detail on program costs and savings can be fond here. A PG&E study assess two different irrigation load control program designs with an expected delivery of 11.3 and 6.2. MW per year.[30] Similarly, Pacific Power in Oregon requested the expansion of an irrigation pilot program based on pilot results and a potential study estimating 20 MW of demand capacity in 2022 and 42 MW in 2026.[31]

Questions: Does CNP currently have data on the number of agricultural customers and associated irrigation loads that could be used to estimate potential load impacts for this segment?

Recommendation: We suggest including an irrigation load control program in the MPS.

10. Thermal Energy Storage

Ice energy storage is being used in the C&I sector to reduce the load requirements of cooling buildings. For C&I customers, Ice Energy Storage can provide grid services and response to demand response events or real time prices. Other utilities are also considering Ice storage in their estimates of DR potential, though limited to summer only. For example, Avista found thermal storage potential in their service area of up to 0.6 MW for 2045.[32] We suggest additional research may be needed to determine the size of potential

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[26] https://www.in.gov/isda/files/Indiana-Agriculture-Infographic-2024.pdf
[27] https://www.slideserve.com/lionel-trujillo/water-and-economic-development-in-indiana
[28] Trends and future of agricultural irrigation in Michigan and Indiana - Dong - 2024 - Irrigation and Drainage - Wiley Online Library
[29] Trends and future of agricultural irrigation in Michigan and Indiana - Dong - 2024 - Irrigation and Drainage - Wiley Online Library
[30] PGE Emerging Technologies
[31] https://edocs.puc.state.or.us/efdocs/HAU/adv1383hau165518.pdf
[32] Integrated Resource Planning | Avista

customer segment where this technology would be best suited, to estimate the size and scope of this opportunity in CNP service territory.

Recommendation: Consider assessing the potential of thermal energy storage in CNP service territory, particularly if technology improvements increase the adoption appeal.

CenterPoint Energy Indiana ("CEI South") Response to CAC Comments on CNP Demand Response MPS: Products List and Initial Input Assumptions

April 25, 2025

On March 26, 2025, Scott Reeves from Energy Futures Group, on behalf of CAC, provided a summary of DR products. This summary included DR products that CenterPoint is including in the MPS, along with additionally proposed DR products. Two tables within the 'Proposed DR Products' section, Table 1: List of Existing and Proposed DR Products and Table 2: List of DR Products from 2023 CAC Comments and Status in Current MPS, both omit the inclusion of Commercial & Industrial ("C&I") Aggregation as a DR product that CEI South included in the 2023 IRP, received approval for in Cause No. 45990 and has already committed to including within the 2025 IRP. By omitting this DR product, the benefits of Aggregation technologies and customer segments is not recognized as a valuable tool that helps enable many of the options pursued by the CAC. Further, as part of its continuous improvement efforts, CEI South has committed to expanding DR products to include the following:

Residential

- DLC Thermostat
- DLC HVAC Switches
- DLC Water Heaters
- DLC Grid Enabled Water Heater
- DR Battery Storage
- DLC Electric Vehicles
- TOU with CPP

C&I

- DLC Thermostat
- DLC Grid Enabled Water Heater
- DR Battery Storage
- DLC Electric Vehicles
- Aggregation
- TOU with CPP

1. **Grid Enabled Water Heater vs DLC Water Heater Switch**

CEI South is expanding the DR products covering water heaters to acknowledge certain water heaters with Wi-Fi capability. These products offer two-way communication that lowers administrative efforts and increases Evaluation, Measurement, and Verification ("EM&V") accuracy. The ability to call events and quantifying DR impacts without the need for manual data loggers to be install and then collected at the end of the DR season reduces costs and improves EM&V accuracy. DLC switches are an older technology that will not be replaced as Water Heater switches fail, however CEI South will assume that DLC Water Heaters will continue to be modeled until switch failure occurs.

2. **HVAC DLC**

Similar to Water Heater switches, HVAC switches are being phased out as Smart Thermostats offer DR benefits while keeping customers comfortable due to pre-cooling functionality while avoiding the need for data loggers. Excluding switch failures, HVAC DLC switches will still be available to customers who do not have access to DLC Thermostat options either due to building segment or access to Wi-Fi. For C&I customers, aggregation utilizes HVAC controls to customers as a method to reduce peak demand.

3. **Time Varying Rates: TOU, CPP, PTR**

CEI South received approval in Cause No. 45990 to conduct a pilot of TOU with CPP rates in order to shift loads to off-peak periods. The Pilot will evaluate the effectiveness of TOU rates, CPP, and the combination of both rate options. CEI South will utilize the results to help determine the pathway that best maximizes demand response while understanding customer preference of these time varying rates. CEI South will be providing educational resources to customers to maximize demand response benefits and customer satisfaction. To evaluate this program, the EM&V vendor will need approximately 10,000 non-participating customers to measure actual demand response in the pilot. While Behavioral Demand Response and Peak Time Rebates are additional rate options, Behavioral Demand Response programs are short-term in nature and encourage customers to change behavior to see benefits. This is the same goal as what the TOU and CPP pilot, utilizing actual customer demand reduction through deployment of technology and changing customer of behavior during on-peak periods. Peak Time Rebates is a complicated time varying rate option that requires evaluating each unique customers response to changes in demand at the time a peak rebate is offered. CEI South needs to demonstrate that customers will embrace time varying rates through the pilot before pre-determining demand reductions

for additional programs that require significant evaluation activities and changes to the billing system.

4. **EV Managed Charging / DLC**

CEI South will be evaluating DLC for Electric Vehicles for residential and C&I customers who have the network capability to respond to DR events. Aggregation will also allow for strategies to reduce load through managed charging stations. Further, customers charge EV's during off-peak hours as shown in the 1st Stakeholder Meeting Materials on slide 61 "Electric Vehicle Charging Profiles". CEI South's TOU/CPP is more encompassing than an EV specific TOU rate. An EV, just like any other appliance/equipment, is encouraged to charge equipment (use energy) in off peak hours.

5. **DR Battery Storage**

The DR Battery Storage for residential and C&I will function in a similar way to our existing Bring Your Own Thermostat ("BYOT") program. Customers will receive an incentive by enrolling their existing battery. CEI South will allow customers to choose how they acquire their battery, either though customer owned batteries or if they choose to lease batteries. CEI South will not be leasing equipment to customers. Further, Aggregation will allow for C&I customers to reduce peak demand through load control strategies such as discharging battery assets.

6. **Interruptible Rates**

CEI South had one large C&I customer on an interruptible rate, until a MISO event was called in June 2021. After the event was called, the customer requested to be removed from the interruptible rate. From that time until now, we do not currently have any customers participating in interruptible rates despite many changes made in CEI South's recent rate case that removed barriers to participation and aligned language with MISO's evolving business practice manual based on feedback from CAC. Changes included lowering the applicability from 1,000 kVA to 100 kW, decreasing the contract term from five years to two years, decreasing the interruption duration from eight hours to four hours, and basing the penalty customers receive for failure to interrupt on the costs incurred by CEI South. Since these changes have been made, CEI South does not have any customers on interruptible rates. These types of rates place the burden on the customers to develop their own energy plan, by identifying and implementing technologies and/or controls, and

subjecting them to risk for failure to interrupt when called upon. CEI South believes customers will economically be incentivized to work with an aggregator who will develop a custom energy plan, identify technologies and/or controls to implement, provide software for managing load reduction in nearly real time, and removing the penalty for non-performance and basing the customer incentive on a pay for performance methodology. CEI South placed 25 MW in the 2022/2023 IRP and believes this amount still represents an achievable potential of DR, based on a market potential study conducted by the only DR aggregator to submit a bid in CEI South's two most recent All-Source RFPs. We believe CAC has been under a false premise of how the 25 MW was modeled in the 2022/2023 IRP. CAC stated that 25 MW was the amount for a single customer enrollment. In that IRP, CEI South stated that we would work with an aggregator to capture the potential C&I demand response to further diversify our resource mix. Upon receiving approval from the Commission in Cause No. 45990, CEI South is actively pursuing this option and excited to offer this option to our customers as a potential new revenue stream that can help with affordability and customer satisfaction.

7. **ADR (HVAC+Lighting)**

CEI South will continue to implement programs that automate buildings with Building Automation Systems through our Building Optimization program in addition to our C&I Prescriptive program which contains lighting control measures. Automated demand response programs for lighting and HVAC measures will be offered through C&I Aggregation.

8. **Non-Res Lighting DLC**

CEI South discontinued energy efficiency lighting programs in 2023 as LED became baseline for general service lighting (GSL). CEI South offers lighting controls which have demand savings through our C&I Prescriptive and Small Business programs. Further, lighting controls will be an opportunity to reduce peak demand through Aggregation.

9. **Irrigation Load Control**

While CEI South's service territory has a segment of agriculture customers, CEI South has had zero participation in any agriculture energy efficiency measure since these measures were first offered in 2018 through 2025. Irrigation Pump Controls is a strategy offered under Aggregation for agricultural customers.

10. Thermal Energy Storage

CEI South's Aggregation Demand Response rider allows the aggregator to implement thermal energy storage DR resources for C&I customers as a part of a demand reduction plan. The aggregator we are pursuing a contract with has implemented these projects in the U.S.

CAC Comments on CNP DR MPS: CNP Response and Cost Effectiveness

The EFG team, on behalf of CAC, again appreciates the opportunity to collaborate with CenterPoint and GDS on the current MPS. We have prepared a few follow-up responses to CNP comments sent 4/25/25 regarding the modeling of Demand Response (DR) potential, and in reference to the GDS DR Workbook Calculations sent 4/29/25.

DR Products: Aggregation and Interruptible Rates

We fully support the use of third-party aggregators as implementation strategies to solicit customer in DR programs. Benefits include relationships with national accounts, direct knowledge of DR products well suited for different industries and customer segments, and ability to customize DR options for different customer types. These efficiencies can increase the likelihood of enrollment, improve customer experience, and yield cost effective DR savings.

Where we differ is in how we differentiate aggregation from the list of DR measures or products on the potential study. Aggregators will control the same end uses (and may use similar curtailment strategies) typically included under interruptible loads, like stopping production lines, escalators, etc.

We want to highlight that the C&I DR products included in the MPS are some of the measures that an aggregator would control. The MSP currently did not include an exhaustive list, so we flagged the inclusion of some additional measures like non-res lighting, interruptible tariffs, etc. The intent of looking across all products is to explore the full market potential in the CNP service area.

We are supportive of CNP moving forward with the aggregation bid it has received and are open to including this with the MPS as its own standalone product. However, we want to point out that the single DR bid CNP has received does not reflect the full DR potential for commercial and industrial customers. Due to the nature of the bid, this represents what the aggregator believes can confidently achieve within a given timeframe.

Additionally, our understanding based on conversations with aggregators is that some customers may be more likely to participate in DR through working with an aggregator, while other will be more willing to enroll in an interruptible program directly with the utility. This was effectively the premise for some of the recent tariff changes proposed by CNP and we believe that, given updates to its interruptible tariffs, there are more opportunities for

customers to choose to participate in interruptible rates. As such, we recommend the current MPS also includes modeling for these interruptible rate offerings as well. For future potential studies, we also suggest assessing segment-specific potential in the C&I sector given the variability in curtailable loads by customer types. Finally, we would be open to and interested in collaborating in future solicitations for demand response programs, to explore ways we may enable more bidders and variable applications.

- **CNP Response:** Please see response document 'CNP DR MPS Assumptions_CAC Comments_CNP Response 4.25.2025' sent on 4/25/2025

DR Products: Time Varying Rate (TOU, PTR, CPP)

In response to CAC's request to further explore modeling time-varying rate (TVR) products through the current potential study, CNP has indicated that it has approve to conduct a TOU pilot with CPP rates. While this is a great step to assess nuances of program delivery, load impacts, and customer experience, we feel this is very much separate from the MPS exercise, which is focused on identifying DR potential at scale, rather than modeling either existing pilots or programs on a business-as-usual basis.

We strongly support CNP and GDS modeling the potential for the TVR options initially proposed. CAC initial comments provided numerous examples of utilities that have run successful TOU or PTR programs at scale. The complexity of evaluating TVR programs is something most evaluation consulting firms are well suited to address through different methods.

While CPP is an effective strategy, its higher critical peak period rate can be punitive for some customers that will incur higher energy charges. PTR, by comparison, provides an equal opportunity to participate, leads with only incentives, and has been shown to be an effective way to increase fluency of DR and peak-related issues, which then has helped increase adoption of firmer DR products like DLC. TOU have similarly shown high savings potential and success rates for participation, including for low to moderate income segments. There is a real savings potential to consider in modeling default TOU – where if anything like other programs, could save approximately 7% of CNP peak load. In particular, TOU rates are very cost effective to consider at scale – we think modeling of potential within an MPS should look beyond existing strategies, especially pilots, and consider what scalable DR resources could look like.

We would be open to discussing with CNP and GSD further regarding options for considering TVRs to include in the current study.

GDS Response: Low to moderate income customers are eligible to participate in any of the DR programs. This program is not being modeled as business as usual. The program is starting as a pilot, but being scaled to a full-scale program over the study period.

DR Cost Effectiveness Models

In reviewing the GDS workbook for DR cost effectiveness modeling, we had a few questions/comments.

- **General** – Do these results reflect any updates to modeling inputs based on (1) initial CAC comments, (2) OSB discussion, or (3) interactions with EE measures/programs? Per our prior OSB meetings, we knew that some of these may have been in progress, but it was under what updates have been applied. Please clarify.
- **GDS Response**: Yes, the following updates have been made based on CAC/OSB discussion. Interactions with EE programs have not yet been updated.
    - AC and WH switches are no longer being fully phased out, and some remaining switches are assumed to still participate in the DR programs until switch or equipment failure.
    - Load reduction for grid-enabled WHs was updated based on CAC recommendation.
    - EV telematics are being included as an option for EV control.
    - Load reduction per participant was updated for residential TOU to include studies suggested by CAC.
- **MAP vs. RAP** – We would like to further discuss the rationale in setting adoption rates for MAP and RAP. My understanding is the MAP/RAP construct for EE reflects different incentive levels, changing payback and driving increased adoption. I'm not clear how this relates to decisions for DR. For example, the CPP adoption rates for MAP and RAP appear to be based on several studies. While these several data points can serve as bounds, there may be underlying details (e.g., rate design, DR fluency, marketing) that inform the outcomes - it is unclear why a lower adoption rate should automatically represent RAP. It may be helpful to discuss rationale for this and implications for IRP model selection.
    - **GDS Response**: GDS reviewed program performance for other jurisdictions. Top-performing programs' participation was used for MAP. RAP is more of an "industry average" or what is realistic. All lower adoption rates do not necessarily get lumped into the RAP average. GDS uses judgement to determine appropriate adoption rates and remove outliers of some low-performing programs. The marketing costs are higher for MAP in the model,

assuming the utility would need to do more marketing to get a higher participation.

- **Peak Demand Line Loss** – Models are currently using 4.2% for peak demand line loss, which seems low. Could we confirm this is the correct value, and how peak demand LL differs from average and marginal LL values?
    - **GDS Response**: This has been updated to the correct 8.4% value.

DR Modeling for IRP –

In advance of finalizing the MPS, we had a few questions/considerations to begin thinking about how DR products are modeled within the IRP.

- Through OSB meetings, we had discussed not screening DR measures using UCT in advance, but instead including all DR products within the IRP for selection. Since many design assumptions are required for developing DR measures, it will be important to present the levelized costs of these resources alongside BCA outputs. This will also be helpful in further discussing the idea of bundling certain DR products vs. modeling each as standalone resources in the IRP.
    - **CNP Response:** All DR products will not be screened out. Regarding bundling, please see response document 'CenterPoint Energy Response to Feedback 1.17.25' sent on 1/17/2025
- Related to bundling, we wanted to further understand how CNP is considering pathways for DR participation for low-income customers. In the case of energy efficiency programs targeting this customer segment, these programs are typically forced in or considered as must select options, despite not being cost effective. We would like to ensure there is a similar differentiation for DR programs to ensure there are explicit pathways for participation of customer segments that may have increased barriers to participation, such as low to moderate income and renters.
    - **CNP Response:** CEI South allows low to moderate income customers the opportunity to participate in all our DR product offerings.

CAC / EFG Comments on CenterPoint MPS EE Measure Assumptions

May 14, 2025

Residential

1. The residential measure assumptions table lacks references to sources for savings and saturation. Can this information be provided?

RESPONSE: GDS will provide an updated file which includes a list of sources used to develop the residential measure assumptions.

2. Units are not specified. For example, Air Source Heat Pumps show costs and savings, but it is unclear if those values reflect per-household, per-unit, or per-ton. Can you please add units to the assumptions table?

RESPONSE: GDS will provide an updated file which includes a list of sources used to develop the residential measure assumptions.

3. The following measures have negative savings. Why would insulation measures increase electricity consumption? Unless these measures have a mistake in the savings calculation, they should be removed from the study.

Measure #	End-Use	Measure Name
8095	**Shell**	Basement Sidewall Insulation - Gas Heating
8101	**Shell**	Floor Insulation Above Crawlspace - Gas Heating

RESPONSE: Some measures included in the analysis have estimated savings during one season (i.e. Summer or Winter) but also yield an estimated increase in consumption in the opposite season, which can lead to an overall increase in consumption. These measures are screened out of the potential when the overall estimated impact is an increase in consumption.

4. Can you please provide the residential electric rate that will be used to calculate the customer payback (for purposes of the adoption curve)?

RESPONSE: The residential electric rate is not used in the adoption curves for the residential sector. The adoption curves are based on customer willingness to participate in energy efficiency programs at various incentive levels.

5. Numerous measures have very high incentives (greater than 75% of IMC) despite already having a short payback period (< 1 year). In these cases, the incentive cost is unnecessarily high for very little gain. We recommend that incentives be capped at a 1-year payback if the WTP results show little gain beyond that point.

RESPONSE: For the draft assumptions, GDS attempted to align incentives with historical offerings. For measures not historically offered, a preliminary default assumption was used. The incentive assumptions will be reviewed and updated. Note that the requested optimization is generally considered in the Enhanced RAP scenario.

6. Incentives for the enhanced RAP scenario should be optimized such that all of the following conditions are met:
    a. Incentives should be allowed to float between 10-100%
    b. Payback should be capped at one year.
    c. Levelized cost should be capped at $50/MWh. This value is a placeholder pending additional discussion among the OSB members.

RESPONSE: The requested optimization is generally considered in the Enhanced RAP scenario.

7. Heat pumps and heat pump water heaters should reflect the IRA tax credit of 30% of the full cost, up to $2,000. These tax credits are not limited by income level. https://www.irs.gov/credits-deductions/energy-efficient-home-improvement-credit.

RESPONSE: The measure database and modeling analysis has been updated to include IRA tax credits.

8. Regarding Air Source and Ductless Heat Pump measures:
    a. Please provide a reference for the EE saturation at 56%.
    b. Please provide a reference for the NTG ratios of 51% and 38%.

RESPONSE:

Part a. The EE saturation has been updated for the heat pumps to 36% to reflect ENERGY STAR Unit Shipment data. The estimate takes a long-term average of shipments in the U.S.

Part b. The NTG estimates are based on the 2025 CNP Operating Plan.

9. Regarding Heat Pump Water Heaters:
    a. Please provide a reference for the unexpectedly low savings (17.1%-18.7%) for Heat Pump Water Heater-electric resistance heat.

b. Please provide a reference for the NTG ratios of 75% and 69%.

RESPONSE:

Part a. The Heat Pump Water Heater savings are lower in homes with electric resistance heat due to the impact on electric heating. The savings estimates are based on the Illinois TRM v13. GDS will review and update this measure, if necessary.

Part b. The NTG estimates are based on the 2025 CNP Operating Plan.

10. Regarding Heat Pumps Dryers:
    a. Please provide a reference for the $900 IMC, and ensure the comparison is like-for-like. For example, heat pump dryer models that cost more due to all-in-one features should not be used when comparing costs.

RESPONSE: The measure cost assumption is from the Michigan Energy Measures Database. The measure cost assumption will be reviewed and updated if necessary.

11. The EE saturation rates are exceptionally high for many appliances with CEE tier, advanced tier, or ENERGY STAR "most efficient" performance. These appliances exceed standard ENERGY STAR performance and would not be expected to have high saturation.

End-Use	Measure Name	EE Saturation
Appliances	CEE Tier 2 Refrigerator	38.44%
Appliances	CEE Tier 3 Refrigerator	61.65%
Appliances	CEE Tier 3 Refrigerator	54.78%
Appliances	ENERGY STAR Most Efficient Dehumidifier	87.60%
Appliances	CEE Tier 2 Clothes Washer	62.50%
Appliances	CEE Advanced Tier Clothes Washer	62.50%

RESPONSE: The EE saturations for most appliance measures have been updated to reflect the most recent ENERGY STAR Unit Shipment data.

12. Regarding induction cooktops:
    a. Please provide a reference for induction cooktops at 50.2% saturation. This is still a relatively new measure.

b. Please review the IMC assumption against the Illinois TRM, which provides values for both a range and cooktop only. The measure in the MPS appears to be a cooktop.

RESPONSE:

Part a. The EE saturation has been updated to use the most recent EIA Residential Energy Consumption Survey (2020). The updated estimates are less than 5%.

Part b. GDS will review and update the IMC as necessary.

13. Please provide a reference for variable speed pool pumps at 20.2% savings. According to the DOE, variable speed pool pumps can save between 50-75%. See https://docs.nrel.gov/docs/fy12osti/54242.pdf, page 1.

RESPONSE: The pool pump measure savings are being reviewed and updated to align with the Illinois TRM.

14. The incentives for "No Program" measures appear to have been set at 50% of IMC, across the board. These incentives should be optimized in the RAP scenario, since there is not an existing program incentive to benchmark against.

RESPONSE: GDS will review and update the incentives for "No Program" measures as necessary.

15. Smart thermostats are assumed to have an EE saturation of 67%. According to data presented at the IRP workshop on May 14, only ~ 10% of households have smart thermostats.

RESPONSE: The EE saturation has been updated to 30% based on the most recent CNP Residential Energy Efficiency Baseline Study. It includes homes with smart thermostats and Wi-Fi thermostats.

16. Please provide a reference for air sealing (regular and whole building aerosol) at 91% EE saturation. According to data presented at the IRP workshop on May 14, only ~ 15% of homes are never drafty.

RESPONSE: The updated EE saturation for these measures is 73%, based on the most recent CNP Residential Energy Efficiency Baseline Study. This assumes that homes that are rarely, never, and a portion of those that are sometime drafty, would not achieve the level of savings estimated for the air sealing measure.

17. Please provide a reference for triple pain windows at 69.9% EE saturation.

RESPONSE: The EE saturations have been updated using the most recent EIA Residential Energy Consumption Survey (2020).

18. Please provide a reference for duct sealing at 91% EE saturation.

RESPONSE: The updated EE saturation for these measures is 73%, based on the most recent CNP Residential Energy Efficiency Baseline Study. This assumes that homes that are rarely, never, and a portion of those that are sometime drafty, would not achieve the level of savings estimated for the duct sealing measure.

19. Can you please describe how the modeling will work for measures that are eligible through both EE and DR, such as smart thermostats?

RESPONSE: In general, the EE analysis estimates the energy savings, and the DR analysis captures the demand savings. GDS will coordinate with CNP in allocating program costs appropriately.

C&I

1. Can you please provide the commercial and industrial electric rates that will be used to calculate the customer payback (for purposes of the adoption curve)?

   RESPONSE: GDS assumed $0.10 for commercial and $.07 for industrial based on the latest published rate schedules for small and large customers.

2. The following measures show zero savings. Can you please provide the savings?
   a. Secondary Windows
   b. Energy Recovery Ventilator
   c. GREM Controls
   d. Strip Curtains, Cooler
   e. Strip Curtains, Freezer

RESPONSE: For these measures, the IL TRM measure only provides data for select building types suggesting limited applicability in those permutations. Savings are non-zero where input assumptions were provided in the TRM.

3. The following measures have no incentive. Can you please provide the proposed incentives?
    a. Secondary Windows
    b. Energy Recovery Ventilator
    c. GREM Controls

RESPONSE: Incentives are non zero when savings are non-zero for these measures. For secondary Windows, and ERVs, the incentive is based on the custom incentive. For GREM controls, the incentive is $200.00

4. Building type is missing starting at row 366.

RESPONSE: Addressed in model.

5. Can you provide the NTG ratios for the C&I measures?

RESPONSE: Assumed 84% from DSM Operating Plan

6. Numerous emerging tech measures have very low incentives (such as less than 10% of IMC), despite having a longer payback period and apparent room to increase the incentive in terms of $ per lifetime MWh. The incentives for these measures should be optimized in RAP since there is not an existing incentive to benchmark against.

RESPONSE: We did not alter incentives for the RAP scenario, but did allow incentives to be "optimized" in the Enhanced RAP scenario. We did not increase the incentive in RAP because there is typically a prescribed incentive ($/kWh) for custom measures.

7. Numerous measures have very high incentives (greater than 75% of IMC) despite already having a short payback period. In these cases, the incentive cost is unnecessarily high for very little gain. We recommend that incentives be capped at a 1-year payback if the WTP results indicate little benefit beyond this point.

RESPONSE: Similarly, we did not alter incentives down for the RAP scenario, but did allow incentives to be "optimized" in the Enhanced RAP scenario.

8. Incentives for the enhanced RAP scenario should be optimized such that all of the following conditions are met:
    a. Incentives should be allowed to float between 10-100%
    b. Payback should be capped at one year.
    c. Levelized cost should be capped at $40/MWh. This value is a placeholder pending additional discussion among the OSB members.

RESPONSE: Done.

9. The measure life (EUL) for exterior LED dusk-to-dawn (D2D) measures is assumed to be 10 years. The Illinois/Indiana TRM assigns 16 years for dusk-to-dawn applications. Can you update this assumption to align with the Illinois/Indiana TRM?

RESPONSE: Done.

10. Several measures have a GDS-assumed EE saturation that varies considerably from the 2023 PA Non-Residential Baseline Study. GDS used this study for lighting, but not for other measures. Can you please review and provide supporting evidence for the following EE saturation levels?

Bldg Type	Measure Name	EE Saturation	Saturation Source	2023 PA Study Saturation	Reference
All	Commercial Electric Convection Oven	55.0%	DOE 2015 / ES Ship	19.0%	Table 41
All	Commercial Electric Steam Cooker	45.0%	DOE 2015 / ES Ship	25.0%	Table 41
All	Dishwasher Low Temp Door (Energy Star)	61.0%	DOE 2015 / ES Ship	6.0%	Table 41
All	Dishwasher High Temp Door (Energy Star)	61.0%	DOE 2015 / ES Ship	6.0%	Table 41
All	Pre-Rinse Spray Valves - DI	85.0%	GDS / GDS	72.0%	Figure 160
All	ENERGY STAR Uninterrupted Power Supply	73.0%	GDS_AEO SEG / ES Ship	0.0%	Table 42
All	Kitchen Exhaust Hood Demand Ventilation Control System	30.0%	GDS_AEO SEG /AES MR (2024)	20.0%	Figure 161
All	Non-Refrigerated Vending Machine Controls	31.0%	GDS_AEO SEG / ES Ship	2.2%	Table 42
All	Energy Star Printer/Copier/Fax	95.0%	GDS_AEO SEG / ES Ship	12.1%	Table 42
All	Commercial Ice Marker	44.0%	DOE_Scout / ES Ship	4.6%	Table 42
All	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	80.0%	DOE_Scout / GDS	34.0%	Figure 14
All	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	80.0%	DOE_Scout / GDS	34.0%	Figure 14
All	ESTAR Refrigerated Vending Machine	31.0%	DOE_Scout / GDS	20.6%	Table 42
All	Evaporator Fan Motor Controls	50.0%	DOE_Scout / 2020 NIPSCO	34.0%	It is unlikely that the saturation of motor controls would exceed EC motors
All	Solid/Glass ENERGY STAR Freezer	55.0%	DOE_Scout / GDS_ES Ship	2.0%	Table 38
All	Solid/Glass ENERGY STAR Refrigerator	55.0%	DOE_Scout / GDS_ES Ship	55.0%	Table 38
Food Service	Pump and Fan Variable Frequency Drive Controls (Fans)	30.8%	GDS / SCOUT	11.0%	Figure 91
Assembly	Pump and Fan Variable Frequency Drive Controls (Fans)	33.0%	GDS / SCOUT	64.0%	Figure 91
Food Sales	Pump and Fan Variable Frequency Drive Controls (Fans)	33.3%	GDS / SCOUT	20.0%	Figure 91

Retail	Pump and Fan Variable Frequency Drive Controls (Fans)	42.1%	GDS / SCOUT	8.0%	Figure 91
Lodging	Pump and Fan Variable Frequency Drive Controls (Fans)	42.9%	GDS / SCOUT	10.0%	Figure 91
Education	Pump and Fan Variable Frequency Drive Controls (Fans)	47.6%	GDS / SCOUT	77.0%	Figure 91
Health	Pump and Fan Variable Frequency Drive Controls (Fans)	65.0%	GDS / SCOUT	72.0%	Figure 91
Office	Pump and Fan Variable Frequency Drive Controls (Fans)	66.9%	GDS / SCOUT	13.0%	Figure 91
Food Service	Pump and Fan Variable Frequency Drive Controls (Pumps)	30.8%	GDS / GDS	11.0%	Figure 91
Assembly	Pump and Fan Variable Frequency Drive Controls (Pumps)	33.0%	GDS / GDS	64.0%	Figure 91
Food Sales	Pump and Fan Variable Frequency Drive Controls (Pumps)	33.3%	GDS / GDS	20.0%	Figure 91
Retail	Pump and Fan Variable Frequency Drive Controls (Pumps)	42.1%	GDS / GDS	8.0%	Figure 91
Lodging	Pump and Fan Variable Frequency Drive Controls (Pumps)	42.9%	GDS / GDS	10.0%	Figure 91
Education	Pump and Fan Variable Frequency Drive Controls (Pumps)	47.6%	GDS / GDS	77.0%	Figure 91
Health	Pump and Fan Variable Frequency Drive Controls (Pumps)	65.0%	GDS / GDS	72.0%	Figure 91
Office	Pump and Fan Variable Frequency Drive Controls (Pumps)	66.9%	GDS / GDS	13.0%	Figure 91

RESPONSE: Done.