



Comments on the CenterPoint 2025 Integrated Resource Plan

Citizens Action Coalition, Solar United Neighbors, Vote Solar

Prepared by Energy Futures Group (EFG)

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INTRODUCTION

We appreciate the opportunity to participate in CenterPoint Energy Indiana South's (CEI South) 2025 Integrated Resource Planning (IRP) process. In particular, we appreciate that CEI South ran a thoughtful stakeholder engagement process, and that this IRP shows careful consideration of, and analysis based on, stakeholder feedback. That effort led to a plan that better reflects the dynamics in this IRP cycle.

In these comments, we outline several areas for continued improvement, particularly related to large load analyses, scenario evaluation, transmission planning, and demand response and energy efficiency approaches. CEI South's rescission of its previous decision on converting F.B. Culley 3 and refusal to commit to a decision now paired with major inconsistencies in its large load assessments lead us to doubt whether this plan's findings will substantively influence the utility's actual path forward. Our recommendations, outlined below and detailed in the following sections, propose measures to align the IRP process to actual utility action.

RECOMMENDATIONS

Section 1: Portfolios & Forecasting

- When considering approval of the proposed A.B. Brown conversion, continued operation of F.B. Culley 3 for an undetermined period, or the F.B. Culley 2 storage project, the Commission must recognize that these portfolios are determined based on sensitivities around generic, unverified assumptions of future large load. At the time of application, any specific generation project should be critically reexamined, along with alternative resource options, once actual customer load is verified.
- The Commission should scrutinize CEI South's proposed Short-Term Action Plan, particularly without a commitment to the 2035 retirement of F.B. Culley 3 in its selected Preferred Portfolio.

Section 2: Modeling Assumptions

- In future IRPs, we recommend that CEI South either (1) reflect its willingness to take on some market risk in its scorecard or (2) adjust its assumptions related to capacity market purchases to reflect a lower willingness to take on capacity shortage penalties.
- CEI South should continue to work with stakeholders to consider additional distributed solar generation programs, including incentives, given the cost difference found was relatively low.

Section 3: Transmission Planning

- CEI South should not move forward with prospective large load customers, including Project Raider, until the specific scale and location of that load is studied and transmission or generation mitigations are identified that can be brought online before the expected project in-service date.
- CEI South should not move forward with prospective large load customers for which it cannot secure new capacity on the same timeline as the customer would be placed in service.
- CEI South should prepare comprehensive interconnection studies associated with actual and expected large load levels and dynamic behavior, including but not limited to short-circuit analysis, voltage and thermal analysis, and VAR needs. To the fullest possible extent, this should also include outage scenarios and energization schedules specific to customer load.

1. KEY DRIVERS: LARGE LOAD FORECASTS, F.B. CULLEY 3

1.1 Large Load Sensitivity Forecasting

Overall, the econometric load forecast provided by Itron represents a rigorous, standard build-up approach, aligned with best practices across the industry.¹ Itron also provided three large load forecasts in addition to its econometric based projections. Our understanding of these forecasts is that they are akin to bookends to consider rather than indicative of any specific load requests. Each assumes additional industrial or data center load beginning in 2030 with immediate operation at full capacity and a utilization factor of 90 percent. CEI South did not provide any evidence that these assumptions are reasonable. Typically, industrial customers do not operate at 90% utilization factors, whereas large data centers could. Further, data center customers typically see some ramp up to full operation from their initial in-service date. CEI South should provide more specificity on what commercial or industrial load growth is being considered to ensure appropriate assumptions, particularly because these assumptions are central to decisions made in the final preferred portfolio. Indeed, CEI South identifies three key findings associated with a sensitivity analysis of these load levels:

- 1) *In all cases, the conversion of A.B. Brown from combustion turbine to combined cycle is selected by the model.*
- 2) *For load additions greater than 300 MW, the preferred F.B. Culley 3 pathway shifts to continued operation through the entire study period.*
- 3) *For load additions greater than 1,000 MW, an installed battery at the F.B. Culley 2 site is part of the least-cost portfolio.²*

Given that the A.B. Brown conversion, continued operation of F.B. Culley 3, and F.B. Culley 2 storage project are also the three major actions identified in the Preferred Portfolio, it is crucial that resource decisions be based on actual, expected load growth.³ The most information provided to stakeholders, who repeatedly requested clarification on these assumptions, was that these are “indicative of the types of speculative load consistent with [requests] CenterPoint has received.”⁴

Unfortunately, CEI South does not include any specific references or information to validate the three generic load blocks provided. Further, the assumption of immediate

¹ CEI South 2025 IRP, Volume 2, Attachment 3.1, 2025 CEIS Long-Term Electric Energy & Demand Forecast Report

² CEI South 2025 IRP, Volume 1, p. 184.

³ *Id.*, p. 186.

⁴ CEI South 2025 IRP, 2nd Stakeholder Meeting Minutes Q&A, p. 10.

operation at full capacity is out of step with forecasting approaches used by other utilities and creates the potential for a false immediate step up in capacity need.

1.2 The Alternative Reference Case

CEI South modeled an Alternative Reference case, with load growth associated with generic industrial or data center projects growing by 250 MW per year starting in 2027 or 1.5 GW total additions through 2033 above current load, more than doubling CEI South's existing peak demand. In questions submitted following two different Tech-to-Tech meetings, we requested additional information validating the actual expectation of such loads coming online, including a detailed list of questions aimed at confirming that CEI South has operational infrastructure in place to onboard such loads (e.g., study agreements, data sharing requirements, customer-specific transmission studies and load forecasting, associated reliability assessments).

Rather than provide evidence of the reality of these large load customers (like measurable commitments to interconnection or a detailed internal assessment of the new customer pipeline that uses metrics of project readiness such approved permitting, sign contractual commitments, engineered site plans, and a signed connection agreement with the water utility serving the customer), CEI South gave generic explanations ("This large load profile is indicative of ongoing discussion/negotiations with prospective customers."⁵) or objected to answering these questions as "out of scope for an IRP"⁶ despite the central importance of this assumption to portfolio outcomes.

Functionally, this Alternative Reference Case served to reinforce CEI South's findings on the selected Preferred Portfolio since it included the same core generation portfolio, even though it was unverifiable with the limited information the utility provided.

We appreciate that CEI South specifically clarifies that there is no existing contract with any large load customer to-date and that related analysis will evolve as the company evaluates potential additions. We also appreciate CEI South's sentiment regarding affordability for existing customers and minimizing future cost risk in the case that such large load customers do emerge. However, these clarifications and sentiments do not justify the use of unsupported assumptions in IRP modeling.

Recommendation: When considering approval of the proposed A.B. Brown conversion, continued operation of F.B. Culley 3 for an undetermined period, or the F.B. Culley 2

⁵ CEI South 2025 IRP, Volume 1, p. 5.

⁶ Re: CenterPoint Tech to Tech Meeting #2 & Modeling Data: Questions, Citizens Action Coalition; Energy Futures Group, CEI South Response, September 22, 2025.

storage project, the Commission must recognize that these portfolios are determined based on sensitivities around generic, unverified assumptions of future large load. At the time of application, any specific generation project should be critically reexamined, along with alternative resource options, once actual customer load is verified.

Finally, neither the Itron large load sensitivities nor the Alternative Reference Case reflects the actual new large project (Project Raider) for which CEI South recently submitted a MISO Expedited Project Review request, discussed in more detail in Section 3 below.

1.3 Pathways for F.B. Culley 3

The question of F.B. Culley 3's future sits squarely at the center of this IRP's results. CEI South's last IRP selected a preferred portfolio that converted F.B. Cully 3 to gas by 2027, a process which was paused "as CEI South observed increased change and uncertainty."⁷ Ultimately, in this IRP, CEI South finds that they will reevaluate options for Culley 3 in the next IRP.⁸

This non-decision hinges on two key scenario comparisons:

1) *Reference Case vs. Delayed Reference Case*

CEI South selects the Delayed Reference Case as the Preferred Portfolio. The critical difference between it and the Reference Case is that it aligns the A.B. Brown 5 and 6 conversion into a 2x1 combined cycle plant (A.B. Brown 7) to occur in the same year as the F.B. Culley retirement (2034), rather than retiring F.B. Culley 3 at the end of 2031.⁹ According to CEI South's modeling, the continued use of coal through 2034 results in a lower NPVRR, marginally improved reliability performance, similar results on market "risk," and worse performance on environmental sustainability.¹⁰

2) *Optimized Alternative Reference Case vs. NG Conversion Cases*

In the Alternate Reference Case assessment, CEI South selects the Optimization Case as the preferred scenario over two similar cases that differ only in that they plan to convert Culley 3 to natural gas in 2030 or 2035, respectively. Given the relative equal performance of these three scenarios, the selection of the Optimization Case risks appearance of bias based on a preference to keep F.B. Culley 3 online. In the Risk Analysis Scorecard

⁷ CEI South 2025 IRP, Volume 1, p. 168.

⁸ *Id.*, p. 189.

⁹ *Id.*, p. 162.

¹⁰ *Id.*, p. 150.

associated with these scenarios, the NG conversion scenarios show similar results to the optimized case on cost and market risk, marginally worse performance on reliability, but substantially better performance on environmental sustainability.¹¹

TABLE 1. F.B. Culley Unit 3 Paths by Selected Scenarios¹²

Scenario	F.B. Culley Unit 3 Path
Reference Load Forecast + Large Load Sensitivities (100-1,000MW)	
1 – Reference Case	Retire in 2031
12 – Delayed Reference Case	Retire in 2034
Alternate Reference Load Forecast (1,500 MW)	
1 – Optimized Case	Run indefinitely
4 – FBC3 NG 2030	Converted to NG in 2030
5 – FBC3 NG 2035	Converted to NG in 2035

CEI South is choosing to delay a decision on F.B. Culley 3 as to whether it will run indefinitely, retire fully, or be converted to natural gas. But CEI South does not consider the significant risk surrounding the fact that the large load customer contract may not materialize. Particularly given the uncertainty associated with coal price forecasts as the industry continues to shrink, if CEI South puts off this decision any longer, it may face substantially higher costs and more limited options, as well as continued environmental impacts.

Furthermore, the Indiana IRP rules require the Short-Term Action Plan in each utility's IRP to include an "implementation schedule for the preferred resource portfolio."¹³ Given that CEI South's Preferred Plan dictates the retirement of F.B. Culley 3 in 2034, the utility's refusal to commit to the retirement means it is out of compliance with those requirements.

¹¹ CEI South 2025 IRP, Volume 1, p. 182.

¹² *Id.*, pp. 146, 180.

¹³ 170 Ind. Admin. Code 4-7-9.

Recommendation: The Commission should scrutinize CEI South’s proposed Short-Term Action Plan, particularly without a commitment to the 2035 retirement of F.B. Culley 3 in its selected Preferred Portfolio.

2. MODELING ASSUMPTIONS

2.1 Capacity Transfer Assumptions & the Incentive to Avoid Deficit

The Renewable Heavy Portfolio scores relatively lower than other portfolios across several metrics, particularly because it results in CEI South being short on capacity in the long-term – requiring substantial reliance on market imports. The same dynamic appears for the F.B. Culley 3 Gas Conversion with Renewables scenario. However, this capacity shortage is a direct result of the modeling assumptions selected by CEI South, namely the relative cost of capacity imports versus new resources.

CEI South’s results, which show capacity “shortages” in several scenarios, are less indicative of risk associated with specific portfolios and more indicative of the utility’s willingness to pay capacity-related penalties. It’s our understanding that CEI South is not a Fixed Resource Adequacy Plan (FRAP) entity, meaning that rather than using contractual or ownership rights to demonstrate sufficient resource adequacy, the utility offers its load and generators into the MISO annual planning resource auction.

Effectively, if LRZ6 ends up in a capacity shortage in any year, CEI South along with other Zone 6 utilities could pay an auction clearing price (“ACP”) equal to the Cost of New Entry (“CONE”), which is currently set at \$130,710 per MW-yr.¹⁴ This cap is not apportioned between the seasons of the Planning Resource Auction (“PRA”), but rather set as the cap for any season to “allow resources to recover their annualized going forward costs, up to CONE, in a single season.”¹⁵

The model is telling us, in scenarios with capacity deficits, that CEI South is more willing to take on increases in capacity costs than to build or purchase new capacity. Where relatively small capacity deficits are at issue, we do not see this as a particular drawback, but, as described in Section 3, CenterPoint seems to increase its load by approximately 50% in years in which it already expects to see deficits of capacity.

For example, most portfolios modeled in the IRP show capacity deficits of about 100 to 115 megawatts in the summer of 2028. If auction revenue for offered generators were fully

¹⁴ See <https://cdn.misoenergy.org/2025-10-15%20Docket%20No.%20ER26-139-000722804.pdf>

¹⁵ See <https://cdn.misoenergy.org/2024-05-13%20Docket%20No.%20ER23-2977-002632873.pdf>

credited to load, we calculate that this shortage could result in excess payments by load of \$15 million.¹⁶

$$ACP \text{ Costs Not Credited to Load} = \$130,710 \times 115 \text{ MW} = \$15 \text{ million}$$

For a scenario that only sees a capacity deficit for five years, and has an NPVRR of \$4,309M, that annual payment may be perfectly logical, from both a modeling perspective and a utility accounting perspective. In fact, this payment is so low relative to overall operating and capital cost that, particularly in the context of substantial load growth in incoming revenue, it does not provide a particularly strong incentive for a utility to avoid that deficit.

Under its “risk” category, CEI South exclusively relies on exposure to the energy and capacity markets. However, as stated above, CEI’s modeling shows that its actual exposure is modest relative to its total costs and that it is willing to bear the costs associated with a capacity shortage rather than build or purchase new capacity to avoid such market exposure.

Recommendation: In future IRPs, we recommend that CEI South either (1) reflect its willingness to take on some market risk in its scorecard or (2) adjust its assumptions related to capacity market purchases to reflect a lower willingness to take on capacity shortage penalties.

2.2 Distributed Solar Sensitivity

One of the sensitivities CenterPoint modeled for this IRP reflected higher adoption of distributed solar generation through a \$500/kW incentive.¹⁷ When CenterPoint developed a resource portfolio around the higher distributed solar forecast, the portfolio cost was approximately \$10 million higher than the Reference Case portfolio. CEI South reported that the reduced operational costs from having increased distributed solar did not offset the costs of the incentive program, and the portfolio was not evaluated under the risk metrics as a result.¹⁸

This result should not translate to an outright dismissal of the distributed solar sensitivity. First, the \$10 million cost difference to the Reference Case is within a 1% cost difference threshold, making the portfolio cost of the distributed solar sensitivity comparable to the

¹⁶ Not accounting for any capacity auction revenue that may be redistributed to LSEs.

¹⁷ CenterPoint 2025 IRP, Volume 1, p. 142. CenterPoint’s distributed solar forecast is informed by the Itron solar payback model.

¹⁸ *Id.*

Reference Case.¹⁹ We generally consider cost differences of 1% or less between plans insignificant. In the 2019/2020 IRP, CEI South used a cost threshold difference at 2%.²⁰ Second, the approach used by CEI South to develop the distributed solar forecast incorporated the \$500/kW incentive into the solar payback model, but it is not clear if this model reflected potential transmission and distributed (“T&D”) benefits associated with the adoption of distributed solar.

Recommendation: CEI South should continue to work with stakeholders to consider additional distributed solar generation programs, including incentives, given the cost difference found was relatively low.

2.3 Responsiveness on Accreditation, Build Limits, & Manual Adjustments

While we have concerns with the modeling approaches outlined above, we want to express our appreciation for three key changes CEI South made in response to feedback we provided during the technical stakeholder process.

First, we expressed concern at the first tech-to-tech meeting about CEI South’s reliance on MISO’s Regional Resource Assessment (“RRA”), which led to a substantial and sudden drop in wind and solar capacity accreditations in 2030. CEI South adjusted its accreditation methodology to reflect a more gradual transition toward those RRA values, better reflecting actual expected system operation.²¹

Second, we raised questions about CEI South’s manual adjustments of modeled scenarios in the second tech-to-tech meeting, which would have resulted in scenarios meeting different capacity requirements. We were pleased to see that CEI ultimately removed those manual modifications.²²

Finally, we were pleased to see CEI South run a sensitivity testing its annual and cumulative resource addition limits and apply an updated set of assumptions across the modeled scenarios.²³

¹⁹ See Figure 4-6 at p. 147 of CenterPoint 2025 IRP for the Reference Case PVRR of \$3,455,000 (\$000). Adding \$10 million to this PVRR would result in a difference of approximately 0.29%.

²⁰ CenterPoint 2019/2020 IRP, Volume 1, p. 251

²¹ CEI South 2025 IRP, Executive Summary, p. 28.

²² *Id.*, p. 25.

²³ *Id.*, p. 29.

3. TRANSMISSION PLANNING

3.1 Large Load Integration

CEI South's IRP introduces an Alternate Reference Case that represents 1.5 GW of new large customer load, as discussed above. The utility provides relatively little detail about the specifics of this case, but it did provide a confidential transmission study.

The study examines [REDACTED]
[REDACTED] Generally, the study finds that [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]²⁴

Project Raider & Posey Line

In October 2025, CEI South submitted an Expedited Project Review (EPR) request to MISO. Project Raider was submitted because CEI South said it was necessary to serve a 600 MW load along the Posey-Gibson line with an in-service date of June 2027. The Raider request includes the construction of a new 345kV breaker-and-a-half substation on the existing Posey-Gibson line. [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Most importantly, CEI South's own large load study finds that [REDACTED]
[REDACTED]²⁵ [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

²⁴The study modeled a scenario in which LTRP Tranche 2.1 projects are assumed to be online. These projects have already been studied and selected by MISO, i.e., [REDACTED] and, even so, are not expected to be in service until 2032.

²⁵ CEI South 2025 IRP, Confidential Attachment 6.2.

East Side Load

On the East side of the CEI South system, the analysis finds [REDACTED]

[REDACTED]²⁶

Generation vs. Transmission Resources

A reference email included in Confidential Attachment 6.2 states that [REDACTED]

Further, the project cost quoted in this study, [REDACTED]

[REDACTED]²⁷

While the analysis indicates that [REDACTED]

[REDACTED]. As additional large loads are introduced in different areas, [REDACTED]

Study Approach & Incorporated Elements

The large load study only evaluated [REDACTED]. It did not incorporate [REDACTED]

[REDACTED]. CEI South also noted in discovery responses that [REDACTED]

[REDACTED]. Similarly, CEI South's discovery responses indicated that [REDACTED]

[REDACTED]²⁸ It would be helpful to clarify whether alternative solutions were evaluated.

For example, were non-wires alternatives or other innovative approaches considered as

²⁶ CEI South 2025 IRP, Volume 1, p. 184.

²⁷ CONFIDENTIAL – 2025 CEI South IRP Resource Capital Costs, Updated 09.22.2025.xlsx

²⁸ CEI South Response to CAC Discovery Questions (Dec. 4, 2025), Provided December 24, 2025.

part of the analysis? Such alternatives could help mitigate the identified [REDACTED]
[REDACTED]

MISO may begin requiring such studies from load-serving entities (“LSEs”) and/or transmission owners (“TOs”) seeking to interconnect new large loads.²⁹ In addition to getting ahead of already identified reliability problems, CEI South should be anticipating changing MISO and/or NERC requirements for a more comprehensive study of large load customers going forward.

Recommendations:

- CEI South should not move forward with prospective large load customers, including Project Raider, until a study assessing the specific scale and location of that load is studied and transmission or generation mitigations are identified that can be brought online before the expected project in-service date.
- CEI South should not move forward with prospective large load customers for which it cannot secure new capacity on the same timeline as the customer would be placed in service.
- CEI South should prepare comprehensive interconnection studies associated with actual and expected large load levels and dynamic behavior, including, but not limited, to short-circuit analysis, voltage and thermal analysis, and VAR needs. To the fullest possible extent, this should also include outage scenarios and energization schedules specific to customer load.

4. DEMAND SIDE RESOURCES

4.1 Market Potential Study

CenterPoint’s 2025 IRP relies on the Demand-Side Management (DSM) Market Potential Study (MPS), prepared by GDS, to quantify energy efficiency (EE) and demand response (DR) potential. Because the MPS is a key input for the IRP’s demand-side resource screening and modeling, its methods, assumptions, and translation into IRP inputs must be transparent and aligned with how DSM is expected to be planned and delivered in practice.

²⁹ See this MISO presentation:
<https://cdn.misoenergy.org/20260130%20Large%20Load%20Workshop%20Presentation738349.pdf>

4.1.1 Stakeholder Process and Collaboration

We appreciate that CenterPoint facilitated a structured stakeholder engagement process during MPS development. Between December 2024 to June 2025, CenterPoint held six meetings with GDS and the MPS stakeholder group to share updates and gather feedback on key methodological issues.

Recommendation: Future MPS stakeholder meetings should continue to be held with a frequency of at least one per month.

4.1.2 MPS Scenarios

The CenterPoint MPS provided Technical, Economic, Maximum Achievable (“MAP”), and Realistic Achievable Potential (“RAP”) estimates. Additionally, at the request of stakeholders, GDS developed an Enhanced Realistic Achievable Potential (“E-RAP”) scenario. The E-RAP scenario adjusts incentive levels to increase participation beyond RAP levels, while still accounting for cost-effectiveness.

We support the inclusion of an enhanced scenario. It more accurately reflects real-world program planning, where administrators can increase savings through higher incentives, targeted delivery, and expanded trade ally engagement, especially in the C&I sector, provided it remains cost-effective.

Recommendation: Future MPS development should continue the use of enhanced scenarios, based on stakeholder input.

4.2 Energy Efficiency (EE)

We appreciate several improvements in how CenterPoint treated energy efficiency in the 2025 IRP, including adjustments to the load forecast to avoid double counting future EE, use of a marginal line loss factor to convert savings from the meter to the generator, netting out avoided T&D benefits from EE costs, and inclusion of residential RAP and C&I enhanced RAP inputs.

CenterPoint appears to have adjusted its sales forecast treatment so that future energy efficiency was not embedded in the SAE load forecast and then double-counted in the resource plan, consistent with Itron guidance. CenterPoint also used generator-level savings for IRP inputs, based on a “peak system line loss rate” of 8.4% to convert meter-level savings to the generator.³⁰ That is a meaningful improvement over the use of

³⁰ CenterPoint 2025 IRP, Volume 1, p. 119. The equivalent multiplier used to convert energy efficiency savings from the meter to the generator is 1.092, as noted on page 122.

average losses and is consistent with our prior recommendation that marginal rather than average losses be used for this purpose. In addition, DSM bundle costs reflected utility costs net of the present value of avoided T&D benefits.

CenterPoint used sector-based EE bundles, with residential and nonresidential EE as selectable resources, and income-qualified EE as a going-in resource. Consistent with CAC's recommendation, residential EE savings were based on the MPS RAP scenario, and C&I EE savings were based on the Enhanced RAP scenario. Three time-based vintages were included, reflecting the next DSM planning period (2028-2030) as vintage 1; the next three-year period (2031-2033) as vintage 2; and all remaining years (2034-2045) as vintage 3.

While not explicitly noted within the published IRP report, materials from CenterPoint's final IRP Public Stakeholder Meeting indicate all energy efficiency bundles were selected within the Preferred Portfolio (Delayed Reference Case) during vintage 1, 2028-2030.³¹

The changes and modeling decisions noted above represent meaningful progress. However, important concerns remain regarding residential bundle construction, the threshold used to separate Residential Tier 1 and Tier 2, and the lack of transparency regarding EE levelized cost calculations, as discussed below. Those issues matter because they affect how much EE was available for selection in the Preferred Portfolio and therefore likely understates achievable, cost-effective savings in future DSM planning.

4.2.1 Residential Bundle Construction

One area of concern is CenterPoint's decision to combine the costs and savings for Residential Tier 1 and Behavioral measures into a single bundle.³² This decision was not made clear during stakeholder meetings and is inconsistent with the planned bundles presented to stakeholders on June 30, 2025.³³

Behavioral measures differ from other residential EE measures materially in persistence and measure life. Behavioral savings are inherently different from equipment-based savings, both in expected duration and in planning value over a long-term IRP horizon.

Bundling those savings streams together obscures important distinctions that are relevant to portfolio selection. A residential equipment bundle with long-lived savings should not be treated as interchangeable with behavioral savings that may have shorter

³¹ CenterPoint IRP Public Stakeholder Meeting 4, held on October 23, 2025, slide 31.

³² CenterPoint 2025 IRP, Volume 1, p. 122.

³³ 2025 MPS Check-In Meeting, June 30, 2025, slide 11, available in Center IRP, Volume 2, PDF p. 1099.

persistence and different EM&V risks. Combining them may make the residential resource easier to manage in the model, but it reduces transparency and makes it harder for stakeholders to assess whether the plan is appropriately balancing short-lived and long-lived savings.

Although this bundling choice may not have changed the near-term selection outcome in this IRP, it still reduced transparency and obscured important distinctions that should remain visible in future IRP modeling.

Recommendation: For future IRPs, CenterPoint should model Residential Tier 1 and behavioral efficiency as separate selectable resources. That approach would better reflect their distinct characteristics, improve transparency, and allow the model to determine the appropriate amount of each resource based on cost, persistence, and system value rather than forcing them into a blended category.

4.2.2 Residential Bundle Cost Threshold

A second concern is that the levelized-cost threshold between Residential Tier 1 and Residential Tier 2 appears to have been set too low. CenterPoint used a \$70/MWh levelized cost cut-off between residential Tier 1 (low/medium cost) and Tier 2 (high cost) measures.³⁴ The resulting Tier 1 levelized cost started at only \$30.27/MWh while Tier 2 started at \$84.06/MWh in 2028.³⁵ We recommended a higher cutoff to retain more moderately cost-effective measures in Tier 1, which would have increased the Tier 1 savings potential.

The cutoff decision affected resource selection by pushing moderately cost-effective residential savings into a higher-cost bundle that was not selected in later vintages.³⁶ As a result, the IRP likely understated the amount of residential EE that could reasonably have been selected over the planning horizon.

Recommendation:

In future IRPs, CenterPoint should establish the Residential Tier 1 / Tier 2 threshold in consultation with stakeholders and should test alternative threshold values before finalizing EE bundles. If the initial threshold causes a meaningful quantity of moderately cost-effective residential measures to fall into an unselected Tier 2 bundle, CenterPoint should revise the cutoff and rerun the bundle construction.

³⁴ CenterPoint 2025 IRP, Volume 2, PDF p. 1099.

³⁵ CenterPoint 2025 IRP, Volume 1, Figure 3-38.

³⁶ Residential Tier 2 vintages 2 and 3 were not selected in the Preferred Portfolio.

4.2.3 Calculation of EE Levelized Costs

Our third concern relates to the calculation of EE bundle levelized costs and a request for increased transparency. While CenterPoint provided the results of the levelized cost calculations in its IRP report, stakeholders were not provided with information regarding the calculation of these levelized costs. As we have commented on other Indiana IRPs, levelized costs can easily be miscalculated through oversights such as using the incorrect discount rate for savings, failing to account for savings that persist beyond the planning horizon, or failing to include T&D benefits.

Transparency is especially important here because the Tier 1 / Tier 2 split and the relative competitiveness of residential and C&I bundles depended directly on those levelized cost calculations. Without the underlying calculation, stakeholders cannot determine whether the bundle construction and the resulting resource selection were reasonable.

Recommendation: CenterPoint should provide the derivation and calculation of EE bundle levelized costs to stakeholders for the 2025 IRP, and during the next MPS and IRP development process.

4.3 Demand Response (DR)

We appreciate several improvements in how CenterPoint treated demand response in the 2025 IRP, including increasing the granularity of DR bundles (from 5 to 13) and revisions to the line loss factor used to convert savings from the meter to the generator. The following sections provide additional detail on issues related to CenterPoint's modeling of DR potential and selection in the IRP.

4.3.1 DR Products Missing from MPS

During the MPS process, the CAC team raised concerns about several DR programs that were excluded from CenterPoint's assessment of DR potential.

The intent of a potential study is to estimate the service territory's full resource potential, not to model the current state of existing pilots or programs. Consistent with this perspective, CAC provided several sets of comments encouraging CEI South to revise programmatic assumptions, add several missing DR products, and model what DR products will look like at scale, reflecting a more accurate assessment of resource

potential, not just the business-as-usual existing offerings.³⁷ Several key recommendations from CAC were either disregarded, ignored, or rejected.

CenterPoint underestimated DR potential by excluding several key DR rate programs: (1) several time-varying rate (“TVR”) offerings, including time-of-use (“TOU”) and peak time rebate (“PTR”) products, and (2) non-residential demand response offerings like interruptible rates.

Estimation of Demand Response potential differs from that of Energy Efficiency potential in that DR potential focuses on programmatic options, rather than EE’s discrete measures. For EE, customers may choose to install energy efficiency measures without utility programs, whereas DR does not exist outside utility offerings of dynamic rate designs or control-based programs. For this reason, it is important for an MPS of DR resources to include a range of products that reflect different end use loads and pathways for program participation. Limiting the set of DR products by omitting key program offerings effectively reduces the scope of the resource potential considered in this study.

Omission of Time-Varying Rates (TVRs): Time of Use (TOU) and Peak-Time Rebates (PTR)

CAC requested throughout the process that CenterPoint include a more comprehensive assessment of TVRs beyond its current CPP pilot, specifically standalone TOU rates and PTR offerings. On May 21, 2025, CAC further clarified and reiterated this request, noting that the MPS exercise should be focused on considering a range of DRs at scale, rather than modeling existing pilots (like CenterPoint’s CPP pilot) or existing programs. CenterPoint’s response did not actually respond to or otherwise address CAC’s request, instead stating:

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.³⁸

³⁷ CAC provided the following questions/comments to CenterPoint to address specific omissions and received the corresponding responses: (1) CAC DR Comments #1 (sent March 26, 2025) – CenterPoint response sent April 17, 2025 and April 25, 2025; and (2) CAC DR Comments #2 (sent May 21, 2025) – CenterPoint response sent June 4, 2025.

³⁸ From CenterPoint Response to CAC Comments dated June 4, 2025; included in CenterPoint 2025 IRP, Volume 2, pp. 1139-1140.

Despite multiple attempts by CAC to address this egregious omission of new TVRs, CenterPoint proceeded with its business as usual and current pilot assessment, resulting in an underrepresentation of DR resource potential in the MPS (and ultimately in the IRP).

Other Indiana investor-owned utilities (AES, I&M, and NIPSCO) included TOU and PTR in their recent MPSs, finding these resources largely cost-effective:

- NIPSCO: The most recent NIPSCO MPS included several TVRs, including TOU rates, CPP, and PTR, which were found to pass UCT cost-effectiveness screens for both market achievable potential (“MAP”) and realistic achievable potential (“RAP”) scenarios, reflecting nearly a third of total MW potential at 84 MW and 66 MW, respectively, in each scenario.³⁹ NIPSCO’s summer season RAP potential for CPP (19 MW) was nearly a third of the expected savings from TOU (65 MW) or PTR (66 MW).
- AES: AES’s 2025 MPS also modeled TOU and PTR, finding both cost-effective. This represented approximately 18% of total residential DR capacity potential from each MAP (at 36 MW) and RAP (at 28 MW) scenarios.⁴⁰

With the deployment of AMI meters, there is no good reason for CenterPoint to undervalue this important resource by only considering limited pathways to leverage Demand Response. The omission of TOU and PTR led to an inaccurate underestimation of CenterPoint’s DR resource potential.

Omission of Non-Residential DR

CenterPoint also underestimated the savings potential of its non-residential DR programs, relying on a single third-party aggregation bid to estimate the entirety of non-residential DR savings potential. There are several issues surrounding this omission and underestimation of non-residential DR:

1. CenterPoint conducted a Request for Proposal (“RFP”) process for a third-party aggregator of non-residential DR, but did not involve its Demand Side Management Oversight Board (“OSB”) in any stage of the solicitation process.
2. CenterPoint relied on just one bid for the entirety of the non-residential DR savings potential. CAC asked that common non-residential DR options like interruptible rates be included in the initial measure list, but CenterPoint declined to adopt this recommendation. While CAC supports third-party aggregation as

³⁹ NIPSCO 2024 IRP, pp. 176-178.

⁴⁰ AES 2025 IRP, pp. 58-59.

an implementation strategy, any single bid from a DR aggregator is not a substitute for conducting a potential analysis of commercial and industry segments and, in fact, likely represents an overly conservative estimate of savings given the nature of bidding for competitive contracts.

3. CenterPoint did not ultimately develop Aggregation in the MPS and provided no underlying details about the end uses and technologies assumed in the Aggregation program modeled in the IRP. Stakeholders were completely squeezed out of the process of developing this resource in the MPS for use in the IRP. While CenterPoint initially indicated it may look in the MPS at Aggregation for EV managed charging and direct load control (“DLC”), DR battery storage, Automated DR (Lighting, HVAC), non-residential lighting DLC, HVAC DLC, irrigation DLC, and thermal energy storage,⁴¹ no details were ever provided. CenterPoint later indicated that it planned to expand its DR products to include Aggregation within its MPS;⁴² yet, as shown in the list of DR Program Options (in Table 4-1 of its MPS report)⁴³, and, in subsequent tables, there is no mention of an Aggregation program in the MPS. Instead, CenterPoint included “DR Industrial (DR Aggregation Program)” as a fixed resource bundle in the IRP, which they indicate includes 12 MW in 2026 and ramps up to 25 MW in 2027 through 2045.⁴⁴ However, no details are provided to verify and validate specific end uses or control technologies associated with these capacity savings.

For these reasons, there is no transparency into the estimate of non-residential DR savings, which was limited to just those savings from a single bid for a potential DR Aggregation program and was developed with no stakeholder involvement and no opportunity to verify assumptions related to this resource.

Recommendation: Future potential studies should include a broader range of DR product offerings to ensure a more accurate estimate of resource potential at scale, rather than limiting modeled programs to what CenterPoint currently offers or prefers. In particular, future studies should model TOU and PTR offerings. CenterPoint should also conduct a more rigorous analysis of non-residential end use loads by business and customer type to better inform resource potential estimates across a broader range of non-residential product offerings. These should include (but are not limited to) interruptible or curtailable rates, irrigation load control, thermal energy storage, and auto DR. Finally, third-party bids for DR services should be developed in conjunction with the

⁴¹ CenterPoint April 25, 2026 response to CAC DR Comments #1.

⁴² CenterPoint April 25, 2026 response to CAC DR Comments #1.

⁴³ CenterPoint 2025 IRP – Vol. 2, PDF pp. 303-304 (MPS pp. 40-41).

⁴⁴ CenterPoint 2025 IRP – Vol. 1, pp. 104, 140-141.

utility's DSM OSB, and third-party bids should not be substituted for a rigorous potential assessment. While such bids may offer useful insights, they do not necessarily provide an accurate assessment of a jurisdiction's DR resource potential.

4.3.2 Estimation of Marginal Peak Line Loss for DR

Line loss values, typically expressed as an average annual percentage, represent the energy lost as electricity travels through the transmission and distribution system. Actual losses vary significantly depending on the system load at any given time.

System-wide average losses differ from marginal line losses, which occur when additional load is added to the grid. Peak losses, which occur during periods of peak loads, represent the highest losses. DSM programs deliver savings directly at the margin, with DR typically occurring at peak times. When average line loss values are used to reflect DSM savings at the generator, DSM benefits are undervalued. This can affect measure selection within the IRP and will inflate the levelized costs of capacity within IRPs by failing to recognize the additional value of these resource savings at both margin and peak.

The National Standard Practice Manual discusses the concepts of DSM savings occurring at the margin and the exponential growth of line loss values occurring at the margin.⁴⁵ Additionally, the Regulatory Assistance Project (RAP) released a 2011 report summarizing the dynamics of line losses at average versus marginal periods.⁴⁶ Key concepts from these resources are:

- First, marginal line losses are avoided when energy efficiency measures are installed or DR programs are dispatched.
- Second, as losses increase exponentially relative to linear load growth, losses occurring at system peak will be substantially higher than losses occurring at a system average (across all hours) or an average of marginal periods of system load. The RAP study found that marginal losses are approximately 1.5 times greater than average losses, with marginal peak losses nearly 3 times greater than average losses (e.g., 7% average vs. 20% peak).

⁴⁵ National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, NESP, available at https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

⁴⁶ Valuing the Contribution of Energy Efficiency to Avoid Marginal Line Losses and Reserve Requirements, RAP, available at <https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-eeandlinelosses-2011-08-17.pdf>

Recent line loss studies and analyses for Commonwealth Edison (ComEd) and DTE Energy have confirmed similar relationships, with average marginal losses for energy efficiency exceeding 1.5 times the average.⁴⁷

During the MPS stakeholder engagement process, we raised concerns with CenterPoint about the application of line loss values for converting demand-side resource savings (of EE and DR) from the meter to the generator. In response to CAC's question regarding line loss assumptions for DR resources (originally set at 4.2%), CenterPoint indicated it has been updated to the "correct" 8.4% value.⁴⁸ We appreciate that CenterPoint developed a revised line loss factor; however, it did not address the clarification regarding whether the peak demand line loss value differs from average and marginal values. It is unclear how CenterPoint revised its prior line loss assumption, and while the revised factor appears directionally correct, we encourage future studies to estimate both average marginal and peak marginal values specifically for application with demand response.

Recommendation: CenterPoint should conduct a new line loss study (or adapt its existing study) to estimate both average marginal and peak marginal line loss values for applications for energy efficiency and demand response resources, respectively, before the next planning study or litigated DSM plan case.

4.3.3 Co-Deployment and Co-Enrollment

Based on our review and understanding, CenterPoint's MPS had very limited consideration of how effective co-deployment⁴⁹ and co-enrollment⁵⁰ strategies can increase adoption rates and lead to increased DR savings at a lower cost. This also reflects

⁴⁷ DTE 2019 IRP; ComEd 2018-2021 Energy Efficiency and Demand Response Plan, Case No. 17-0312, Appendix A, pages 10-11, available online at <https://www.icc.illinois.gov/docket/P2017-0312/documents/254601>

⁴⁸ CenterPoint 6/4/25 response to CAC DR Comments #2 (originally sent 5/21/25).

⁴⁹ Co-deployment refers to the ability to leverage existing products, programs, or systems that encourage a combined deployment of resources, yielding benefits of interacting and achieving more cost-effective delivery. For example, combining messaging and incentives for customers to (1) purchase/install a smart thermostat and (2) enroll in a smart thermostat DR program reduces separate marketing/recruitment efforts, increases likelihood of DR enrollment (lowering incremental marketing costs), and increases both customer and power system benefits (combining conservation effects and peak load impacts).

⁵⁰ Co-enrollment refers to the ability of a customer to participate in multiple energy programs at the same time. Co-enrollment is important, particularly for demand flexibility programs, through the ability to maximize savings through customers enrolling multiple devices and participating in multiple offerings, made more cost-effective through the interaction driving increased adoption rates.

a more conservative estimate of CenterPoint's full DR resource potential (with several examples discussed below).

As noted in 4.3.1 above, potential studies for DR are programmatically focused, rather than measure focused. An MPS should consider the implications of how co-deployment and co-enrollment strategies can be applied to MPS assumptions, like adoption rates, resulting in efficiencies that lead to increased adoption and higher savings values. A limited consideration of these effects in the MPS will likely lead to more conservative estimates of DR resource potential, particularly if the utility develops and adopts these strategies in subsequent deployment.

Since we have discussed the topics of co-deployment and co-enrollment of DR and EE programs with CenterPoint through the OSB and in DSM cases, it is long overdue for CenterPoint to develop an explicit strategy for leveraging EE and DR programs to realize increased adoption rates, savings potential, cost-effectiveness, and general engagement and satisfaction with customer participation in its DR programs. Interactions can occur through the deployment of multiple demand-side products (including EE, DR, time-varying rates, and other distributed energy resources) that can impact (1) per-unit energy savings, and (2) the likelihood of adoption and increased saturation of a given product or technology.⁵¹

Unlike EE where customers likely have a single point of contact (e.g., equipment rebate at time of replacement), customers will participate in DR programs over longer periods, including multiple events per season, and ideally over years of continued participation. Given the customer experience and longer duration of participation in DR programs, it is important to consider the customer journey and that customers may participate in different DR programs over time, as well as multiple complementary DR programs at the same time. It will be important for CenterPoint to develop a strategy for how to leverage existing programs, how the customer journey may take shape over near vs. longer term engagement, and how to structure eligibility requirements to encourage participation in multiple offerings (i.e., co-enrollment) to optimize the flexible load resource. CenterPoint will need to determine how to develop DR offerings that encourage engagement, satisfaction, and retention to ensure a sustainable and scalable resource over time.

⁵¹ Accounting for Interactivity in Resource Planning & Impacts on Demand Flexibility, Cadeo, available at <https://nwcouncil.box.com/v/FlexibilityMemo>; A Conceptual Framework to Describe Energy Efficiency and Demand Response Interactions, available at <https://emp.lbl.gov/publications/conceptual-framework-describe-energy>

Recommendation: CenterPoint should develop a robust strategy for co-deployment of its energy programs, including EE, DR, TVRs, and DERs. CenterPoint should develop a strategy specific to each EE program offering to (1) demonstrate how marketing and delivery can achieve goals of increased enablement devices and technologies, (2) embed offerings for DR/TVR/DER enrollment at optimal touch points, and (3) achieve more successful development of load flexibility programs through higher adoption rates and improved cost-effectiveness.

Additionally, we recommend that CenterPoint develop eligibility guidelines for its complementary flexible load programs to encourage co-enrollment, thereby providing the most cost-effective opportunities to scale its DR resources. CenterPoint should work with its OSB to identify a comprehensive list of complementary programs and ensure that any barriers to co-enrollment are considered and potentially addressed.

CONCLUSION

We appreciate the opportunity to provide feedback on CenterPoint's 2025 IRP and welcome further dialogue. Please refer to our compiled recommendations beginning on [page three of this document](#).

PUBLIC ATTACHMENT 1

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 or 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 report¹.

- 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.

Year	Total Sales	Total Eligible Sales (Less Opt-Out)
2024	4,721,887	3,134,265
2025	4,893,116	3,140,421
2026	4,885,598	3,133,076
2027	4,899,327	3,150,198
2028	4,919,463	3,173,983
2029	4,933,226	3,184,380
2030	4,950,711	3,196,205
2031	4,964,537	3,205,175
2032	4,979,732	3,217,501
2033	4,978,031	3,217,434
2034	4,982,137	3,222,442
2035	5,000,897	3,235,351
2036	5,036,218	3,257,997
2037	5,059,991	3,269,293
2038	5,087,475	3,284,870
2039	5,114,658	3,300,201
2040	5,149,038	3,323,953
2041	5,170,040	3,336,543
2042	5,197,409	3,356,630
2043	5,225,249	3,377,791
2044	5,260,538	3,405,681
2045	5,289,621	3,425,063
2046	5,326,346	3,451,727

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.