Report on CenterPoint Energy's 2022/2023 Integrated Resource Plan

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On behalf of Citizens Action Coalition, Earthjustice, Solar United Neighbors, and Vote Solar

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Overview

The following comments on the 2022/2023 Integrated Resource Plan ("IRP") submitted by Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Company" or "CenterPoint") were prepared by Chelsea Hotaling, Anna Sommer, and Dan Mellinger of Energy Futures Group ("EFG") and Scott Reeves and Eli Font of Cadeo Group. These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Earthjustice, Solar United Neighbors, and Vote Solar ("Joint Commenters") pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7.

We appreciated the collaborative environment that CenterPoint created, and we look forward to continuing to work with CenterPoint in this manner. We have identified several issues to address in advance of any resource filing and to improve CenterPoint's next IRP.

Our review of CenterPoint's 2022/2023 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- The Market Potential Study ("MPS") did not consider the avoided cost of carbon regulation when evaluating cost effectiveness;
- The translation of energy efficiency savings from the meter to the generator did not appropriately apply the line loss factor application;
- The C&I Enhanced Bundle only modestly increased savings, even though additional incentives could have been included;
- Emerging technologies were not sufficiently accounted for in the MPS;
- IRA funding and effects were not accounted for in the MPS;
- Unclear information on the capital and pipeline costs for the F.B. Culley 3 conversion to natural gas;
- Inclusion of capital costs as a stochastic variable and only applying stochastic capital costs to renewable and battery storage resources;
- Did not evaluate the potential to repower existing wind projects; and
- Achievable savings for demand response (DR) potential is underrepresented, due to several factors. These include modeling a limited set of DR products that underrepresents full resource potential (notably interruptible rates); lack of accounting of interactions with energy efficiency, such as increased deployment of DR-capable technologies and opportunities for co-deployment; omission of winter season DR potential.

Recognizing that CenterPoint is likely to request a Certificate of Public Convenience and Necessity ("CPCN"), we also make the following recommendations to CenterPoint for that proceeding:

- Seek detailed cost estimates for conversion of F.B. Culley to gas. Typically, such estimates would be developed through the process of securing an agreement with an

engineering, procurement, and construction ("EPC") contractor and conducting a design study.
- Evaluate the potential for F.B. Culley 3 to be replaced with renewables and battery storage based on updated pricing from future Requests for Proposals ("RFPs") that CenterPoint intends to issue.

We would also like to offer the following recommendations to CenterPoint for its next IRP and 3 year DSM filing:

- Work with stakeholders to outline a schedule for when modeling data inputs and outputs will be released;
- Incorporate the avoided cost of carbon regulation when evaluating cost effectiveness in the MPS;
- Appropriately apply the line loss factor in the translation of energy efficiency savings from the meter to the generator;
- Incorporate savings from emerging technologies into the MPS;
- Account for IRA funding and effects in the MPS;
- Provide more detailed cost information (capital and pipeline) for the F.B. Culley 3 conversion to gas;
- Remove capital costs as a stochastic variable;
- Model lithium-ion battery storage at longer levels of duration (i.e. 8 or 10 hours) along with modeling a multiday storage resource as candidate resource options;
- Consider the potential to repower CenterPoint's existing wind projects before the end of the project life;
- Include an equity metric in the portfolio scorecard;
- Provide more information on results of sensitivities modeled;
- Evaluate the potential for storage and battery storage projects to qualify for the Energy Community Bonus adder;
- Evaluate the potential for surplus renewable energy projects;
- Work with stakeholders to incorporate decarbonization strategies for industrial customers;
- Expand the list of DR products included in resource potential modeling;
- Improve accounting for interactivity and co-deployment opportunities between DR and energy efficiency resources in the MPS;
- Update participation assumptions for specific DR products, such as considering opt-out designs for peak time rebates or behavioral demand response; and
- Expand modeling of DR resources to consider estimates of seasonal potential beyond the current focus on summer season resources.

1 Stakeholder Workshops and Material Provided to Stakeholders

First, we acknowledge and express appreciation for improvements to CenterPoint's IRP process. One of CAC's main concerns in the last IRP process was around transparency and the inability to review modeling files throughout the IRP process. By the time that stakeholders could see and review any modeling files, it was too late for any stakeholder feedback to be incorporated into the IRP. CAC made recommendations about alternative software models and incorporation of a data sharing process with stakeholders like what AES Indiana has utilized for its last two IRP processes.

We appreciate that CenterPoint acknowledged the concerns around the process for its last IRP and took steps to implement changes for this IRP. As CenterPoint stated in its 2022/2023 IRP:

> *CEI South listened to concerns of stakeholders around the black box nature of Aurora modeling software and took action to evaluate alternatives. Encompass was recommended by Citizens Action Coalition as a tool that provides more transparency, allowing for better participation throughout the process. CEI South agreed with stakeholders that EnCompass could help improve the collaborative process. Additionally, CEI South also introduced tech-to-tech calls between formal public stakeholder meetings and shared draft modeling results throughout the process, seeking feedback along the way. This process, which was suggested by stakeholders, helped to provide a forum for more meaningful, consistent dialogue. CEI South benefited from these conversations, which helped to clarify differences of opinion and concerns in a timely manner. Ultimately, the process was strengthened. CEI South worked hard to be transparent throughout.*[1]

We agree with CenterPoint that the stakeholder process was significantly improved for this IRP. A transparent and collaborative environment is the foundation to a robust stakeholder process for an IRP. Without transparency on modeling inputs, outputs, and supporting data as well as understanding the Company's decision-making process, the opportunities for learning are limited and the feedback that stakeholders can offer is, in turn, limited.

CenterPoint's movement to the EnCompass model for this IRP alleviated the concern around model transparency because EnCompass modeling files are easily provisioned and shared through Microsoft Excel. CenterPoint also took steps to engage in a technical stakeholder process where stakeholders willing to sign a nondisclosure agreement ("NDA") with CenterPoint were able to receive access to the modeling inputs and supporting data. Utilizing this approach for sharing modeling inputs is an invaluable process and ensures that stakeholders can participate in a collaborative way throughout the process, rather than only being able to react to information contained in the modeling files once it is too late for feedback to be incorporated into the modeling or in some cases after the IRP has been filed.

[1] CenterPoint Energy's 2022/2023 Integrated Resource Plan, Volume 1, Sec. 10.2.8, at 284 ("CenterPoint 2022/2023 IRP").

The process change that CenterPoint instituted for this IRP also allowed for more meaningful collaboration between CenterPoint and stakeholders. Being able to engage in dialogue around modeling inputs and allowing for more stakeholder recommendations allows for stakeholders to feel as though they are being taken seriously. In addition, it helps fulfill the purposes of the IRP process, which includes reducing areas of disagreement between stakeholders and the utility. It also simply increases trust between the parties.

In many cases, CenterPoint did incorporate the feedback provided by stakeholders into the IRP rather than reacting defensively. As CenterPoint identified in a table in its IRP, there were several inputs that were changed in response to feedback from stakeholders, which is reproduced below in Table 1.

Table 1. Stakeholder Requests[2]

Request	Response
Allow All-Source Request for Proposals ("RFP") respondents to update their proposals to account for the IRA	RFP respondents were given the opportunity to update their bids (updated results were incorporated into the IRP)
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	Cumulative CO_2 equivalent (stack emissions) were added to the scorecard along with CO_2 intensity
Add a fuel cost risk measure and objective to the scorecard	Cost Risk metric was included in the scorecard, including both fuel risk and 95% percentile cost risk
CenterPoint should include demand response using the same methodology as AES. Implement residential rate programs (critical peak pricing, TOU, etc.) soon	CenterPoint has adopted the AES methodology and DR is aligned with peers to incorporate indicative TOU pilots. CEI South is planning to evaluate a TOU rate in the future through a pilot[3]
In the summer of 2022, the reference case forecasts for coal and natural gas prices showed a decline in the near term and do not reflect current pricing	Gas and coal price forecasts were updated as new forecasts became available in late fall of 2022

[2] CenterPoint 2022/2023 IRP, pages 53–55.
[3] CAC takes issue with CenterPoint's characterization of its response to CAC's request regarding demand response, as described in detail below. In short, CenterPoint did not project demand response potential like AES did. Rather, CenterPoint used stale current participation levels which rely on the current demand response programs and tariffs. This faulty input led to an overall underestimation of demand response in the IRP.

Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	CEI South found it plausible that coal prices could be higher in a high regulatory scenario and updated the price path to be higher than reference case in the high regulatory scenario
Revise the wind profiles being used in the model to differentiate between the output of northern Indiana and southern Indiana wind	The output profiles for wind resources were updated (increased) to better align with the information received from wind resources in the All-Source RFP
Explore alternative retirement dates for Culley 3	Culley 3 will be evaluated in scenarios with a potential retirement date of 2029 (pulled forward from 2030). Also included an alternative that converts F.B. Culley 3 to natural gas by 2027
Update modeling to reflect ITC storage year one	CEI South modeled the ITC benefit for storage in year one
Include full monetization of ITC for hydro resources	Included
Request for continued on-going dialogue following the December public stakeholder meeting	Held a tech-to-tech meeting on February 28, 2023 to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment
Include site-specific assumptions for the energy community bonus for PTC and ITC associated with the IRA	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions
Evaluate a portfolio with hydroelectric	Hydroelectric was not selected as a least cost resource within modeling. Several portfolios with hydro were evaluated, but they were higher cost and not included in the risk analysis
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

We recognize that not all stakeholder feedback will be incorporated into the IRP and that there will be items where there are differing opinions between the utility and stakeholders. In these instances, it is important for both sides to feel like their concerns have been shared with and considered by the other side.

We recognize the significant changes that CenterPoint made and implemented for this IRP. We appreciate that our feedback was often acknowledged and in some cases implemented. The additional feedback we can offer to CenterPoint on the stakeholder process for its IRP is that there can be a smoother exchange of information with stakeholders surrounding modeling inputs with a schedule for what data will be released and when. After experiencing two IRPs with AES Indiana that included this process for sharing information, we believe this is one recommendation that will further enhance the process that CenterPoint implemented for this IRP. For instance, at the beginning of the IRP process, AES Indiana set a schedule for what and when data would be released. The data shared with stakeholders included: load forecast inputs, Demand Side Management ("DSM") inputs, commodity curves, capacity accreditation for resources, new resource costs, capital expenditure and fixed O&M, the EnCompass modeling input and output files, and the stochastic modeling files. One example of what a schedule might look like is shown below for illustrative purposes:

Meeting	**Date**	**Information Released**
Stakeholder Meeting #1	January	Load Forecast MPS Data
Stakeholder Meeting #2	April	New Resource Costs Capacity Accreditation Commodity Price Assumptions
Stakeholder Meeting #3	July	Portfolio Scorecard
Stakeholder Meeting #4	September	Preliminary PVRR results

Implementing a schedule like this at the beginning of the process will further enhance CenterPoint's IRP process.

2 Demand Side Resources

2.1 Energy Efficiency

2.1.1 Market Potential Study

CenterPoint engaged GDS Associates, Inc. ("GDS"), in January 2022, to perform a "refresh" of the most recent CenterPoint Market Potential Study ("MPS"), which was completed in 2019. Due to the nature of the refresh, the opportunities for stakeholder review and input were more limited compared to a full MPS. GDS and CenterPoint provided updates on the MPS development process periodically, but infrequently, at Oversight Board ("OSB") meetings. While CenterPoint and GDS were generally receptive to feedback provided during OSB meetings, CAC would have preferred more frequent updates with opportunities for formal review and comment. The draft MPS results were shared publicly by CenterPoint at the IRP Public Stakeholder Meeting held on August 18, 2022, prior to CAC having the opportunity to review or comment on the draft findings. The final MPS report was published in May 2023.

The market potential study quantified the technical, economic, maximum achievable, realistic achievable, and program potential savings for the years 2025 through 2042. Each of these scenarios is described within the MPS as follows:

- **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.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective, based on screening with the utility cost test ("UCT") as compared to conventional supply-side energy resources.[4]
- **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 willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:

[4] CenterPoint indicated within the 2022/2023 Integrated Resource Plan, Vol. 1, that the Total Resource Cost ("TRC") was used for economic screening. We believe this is an incorrect statement. The MPS economic screening was performed using the UCT, as indicated on page 13 within the final MPS report dated May 22, 2023.

- **Maximum Achievable Potential** ("MAP") estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.
- **Realistic Achievable Potential** ("RAP") estimates achievable potential with AES Indiana 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.

2.1.2 MPS Cost-Effectiveness Screening

The MPS economic potential cost-effectiveness screening was performed as described below by GDS:

> *[T]he 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, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness. 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.*

A notable inconsistency between the IRP and the MPS is that the MPS does not consider the avoided cost of carbon regulation. Multiple IRP scenarios, including the Reference Case, include carbon regulation.[5]. Had the MPS included a similar assumption for future carbon regulation, the UCT scores for all measures would have improved, thereby enabling additional measures to be considered cost-effective. In doing so, the gap between Technical and Economic potential, shown below in Table 2 by sector, would have been reduced. In advance of CenterPoint's 3-year DSM plan filing, CenterPoint should make that change and add measures and savings that were previously excluded.

[5] In May 2023, the EPA proposed new carbon pollution standards for coal- and gas-fired power plants.

Table 2. Residential and C&I Energy Efficiency Potential

TABLE 3-7: RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2025	2026	2027	2030	2042
MWh					
Technical	74,412	71,635	70,211	67,063	63,281
Economic	62,782	61,518	60,346	57,963	55,469

TABLE 3-13: C&I INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2025	2026	2027	2030	2042
MWh					
Technical	52,423	57,427	61,147	58,432	77,954
Economic	51,828	56,628	59,842	66,062	70,675

2.1.3 Adjustments Made to MPS Measures

CenterPoint applied two adjustments to the gross savings predicted by the MPS:

First, the Company applied a net-to-gross adjustment to model net energy efficiency impacts. CAC agrees with this adjustment. Second, the Company converted meter-level savings to the generator by applying a system line loss rate. While CAC agrees with this second adjustment in principle, we have concerns about the process. CAC has previously recommended the use of *marginal* line loss rates when performing this conversion, which CenterPoint acknowledged on page 121 of its IRP Volume 1 in saying that it "[c]aptured avoided T&D line losses at marginal level instead of system average." However, in describing the adjustment to generator-level savings on page 199, CenterPoint contradicts itself in saying, "Sector savings were adjusted based on average system line loss rate of 6% to convert savings from the meter level up to the generator level." It is therefore unclear whether 6% reflects an average or marginal line loss rate.

Furthermore, the calculation of savings at the generator incorrectly applied the line loss rate as follows:

$$Energy\ Savings\ at\ Generator = Energy\ Savings\ at\ Meter\ \times\ (1 + Line\ Loss\ Factor)$$

This application of the line loss factor was incorrect since line losses are measured with respect to the generator, not the meter. Converting savings back to the generator, from the perspective of the meter, requires the following calculation:

$$Energy\ Savings\ at\ Generator = Energy\ Savings\ at\ Meter\ \div\ (1 - Line\ Loss\ Factor)$$

As a result of the misapplication of the line loss factor, the energy savings at the generator were modestly understated by 0.4%. We ask that CenterPoint address this in advance of the 3-year DSM filing.

2.1.4 MPS Bundles for IRP Modeling

CenterPoint and GDS developed bundles of energy efficiency grouped by sector, by program (in the case of behavior and income-qualified weatherization), and by time vintage. This approach aligns with CAC's recommendations.

In response to previous comments and requests made by CAC, CenterPoint included an "enhanced" bundle of C&I measures. This bundle was intended to reflect the same set of measures included in the MPS RAP scenario, but with incentives modeled higher than RAP (based on historical incentive amounts) and lower than MAP (typically 100%). The goal was to construct a bundle of C&I measures which represent the highest amount of achievable energy savings while still being economically competitive in the IRP model. According to CenterPoint, the Enhanced C&I bundles represented increases in savings of 7.8% from 2025-2027, 4.5% from 2028-2030, and 1.5% from 2031-2042.

CAC appreciates CenterPoint's responsiveness to this prior request; however, we believe the Enhanced C&I scenario falls short of achieving the goal. The savings potential is only modestly better than predicted by the RAP scenario, as shown in the figure below. Meanwhile, the levelized cost of the C&I Enhanced bundles were well below other bundles selected in the model, indicating there was room for additional incentive enhancements. For example, Figure 1 shows that the Enhanced C&I bundle has a levelized cost of $26.07/MWh compared to Res Tier 1, which was selected at $48.54/MWh. These issues should be addressed prior to the 3-year DSM filing.

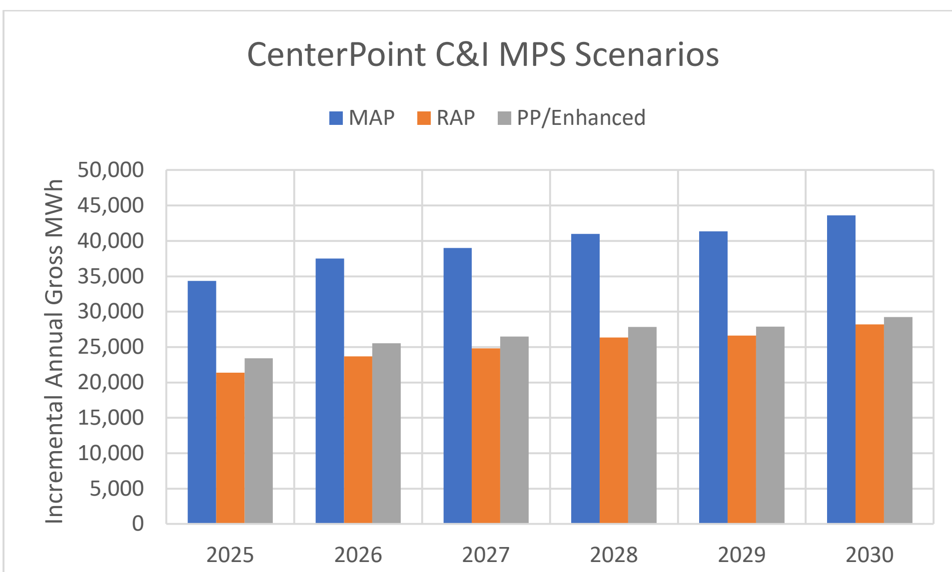


Figure 1. CenterPoint C&I MPS Scenarios

2.1.5 Emerging Technologies

The CenterPoint MPS included the following 20 residential measures and 18 C&I measures shown below in Table 3, which GDS identified as emerging technologies:

Table 3. MPS Emerging Technologies

Residential	C&I
Advanced Walls	BEIMS
Drain Water Heat Recovery	Building Benchmarking
Energy Recovery Ventilator	Building Operator Certification
Heat Pump Dryer	Business Energy Reports
Shower Timer	COM Competitions
Smart Clothes Dryer	Energy Recovery Ventilator
Smart Dishwasher	Heat Pump Water Heater
Smart LED	Lighting - Custom
Smart Lighting Switch	Ozone Commercial Laundry
Smart Outlets	Power Drive Systems
Smart Refrigerator	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor
Smart Room AC	Retro-commissioning / Building Optimization
Smart Television	Server Virtualization
Smart Vents/Sensors	Strategic Energy Management
Smart Water Heater - Tank Controls and Sensors	Switch Reluctance Motors
Smart Window Coverings	Triple Pane Windows
Smart/CEE Tier 2 Clothes Washer	Variable Refrigerant Flow Heat Pump
Thermostatic Restrictor Shower Valve	Whole Building - Custom (Other)
Thin Triple Windows	
Water Heater Timer	

CAC commends the inclusion of emerging technologies in the MPS. Unfortunately, however, the list of emerging technologies is relatively limited, and many measures on the list are well established and would not typically be classified as emerging. For example, measures such as drain water heat recovery, energy recovery ventilators, shower timers, smart televisions, thermostatic restrictor shower valves, water heater timers, building benchmarking, building operator certification, business energy reports, heat pump water heaters, Q-Sync motors, retro-commissioning, and strategic energy management are all well documented with many years of demonstrated success in multiple programs around the U.S. These measures may be new to CenterPoint, or may be newly included in the MPS, but they are not emerging technologies.

Many of the emerging technologies evaluated by GDS failed to pass the economic screening. The nature of new emerging technology is such that high initial costs tend to fall as production volume and market adoption increase. The MPS analysis makes no accommodation for any emerging technology to be included in the later years of the analysis if/when the measure becomes cost-effective. New technologies are regularly being introduced, and many utility programs contribute to the market readiness of these emerging technologies through pilot programs and incentives. Failure to account for these technologies results in an overly conservative and unrealistic view of the potential savings.

In the residential sector, the measures identified by GDS as emerging technologies account for 1.9% of RAP savings in 2025, increasing to 3.2% in 2030. Within C&I, GDS-labeled emerging technologies account for 6.8% of RAP savings in 2025, increasing to 13.8% in 2030.

As a point of comparison, the Consumers Energy 2021 Electric Energy Waste Reduction Potential Study, completed by Cadmus, evaluated over 200 emerging technology measures which were characterized and included in the model.[6] Ultimately, 170 unique measures (59 residential, 60 commercial, 51 industrial) were included in what Consumers Energy refers to as the "Transformational Scenario." The impact of this scenario was significant on the estimate of future achievable potential, as shown in the figure below.[7] In years 3 through 9, emerging technologies account for roughly 20% of the achievable potential. In the later years of the Consumers Energy study, emerging technologies account for roughly two-thirds of the achievable potential. These results plainly demonstrate the significance of emerging technologies and highlight the importance of adequately accounting for them in a market potential study.

[6] MPSC Case No. U-21090, Consumers Energy Co. Witness Garth, Exhibit A-81 available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Consumers-Energy-Electric-EWR-EE-Potential-Study-w-TransTech-Scenario-20210610.pdf

[7] Presentation by Consumers Energy, "Creating a Transformational Path to the Future of Energy Efficiency, Together!," available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Transformational-EWR-Together_CE_20220719-final.pdf

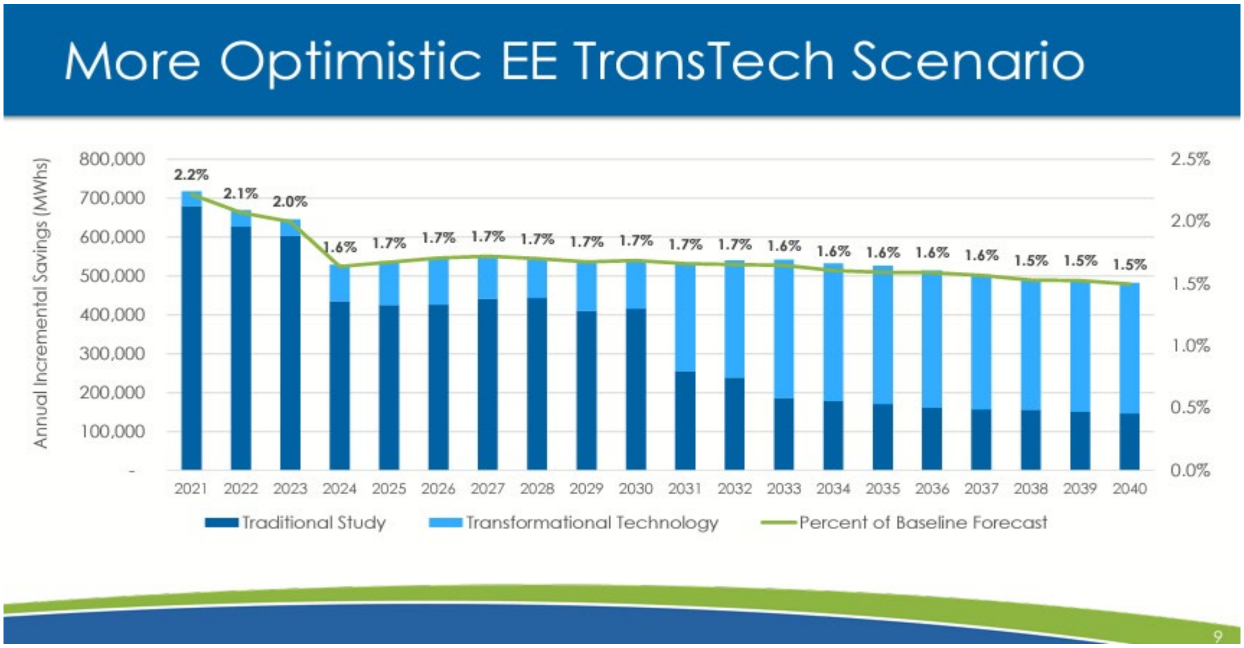


Figure 2. Consumers Energy Emerging Technology Scenario

2.1.6 Inflation Reduction Act Funding for EE

Additional funding opportunities provided by the inflation reduction act ("IRA") were not considered in the MPS since the modeling work was largely completed before the IRA was passed into law. As a result, the adoption rates and savings associated with measures supported by IRA, such as heat pumps, heat pump water heaters, and weatherization, will be significantly underestimated considering the magnitude of funding available. Therefore, we believe it is critically important that CenterPoint account for IRA funding and effects in advance of its 3-year DSM filing. Specifically, the following IRA programs are expected to stimulate the adoption of measures above and beyond what was predicted by the MPS:

a. Whole-House Rebates (HOMES)

b. High-Efficiency Electric Home Rebate Program

c. 25C Energy Efficiency Home Improvement Credit

d. 179D Energy Efficient Commercial Building Deduction

2.1.7 3-Year DSM Plan Savings Goals

Considering the issues highlighted above, we believe the level of energy efficiency savings modeled and selected in the CenterPoint IRP is inappropriately low. Inconsistencies such as the avoided cost of carbon, errors such as line loss accounting, and omissions such as IRA funding and emerging technology all contribute to an unrealistic and conservative view of energy efficiency potential. Anticipating that CenterPoint is unwilling to repeat the MPS and IRP modeling at this point, the savings targets established in the Company's next 3-year DSM plan filing should include supplemental amounts beyond what is identified in the IRP to account for the inconsistencies, errors, and omissions.

2.2 Demand Response

The GDS MPS study also included an analysis of demand response resource potential, following a similar approach in estimating technical, economic, and achievable potential. Achievable scenarios (MAP and RAP) are defined as follows (p.30 of MPS / p.764 of IRP Vo. 2), where MAP represents a "best practices" estimate of customer participation that can be achieved, while RAP represents a typical or "average" industry experience.

Table 4-1 in the GDS MPS report provides a list of DR products considered for this study, which includes the following direct load control (DLC) and rate options (nine products in total):

- ***Direct Load Control (DLC) options*** – including AC switches, AC smart thermostats, pool pumps, and water heaters.
- ***Rate Designs options*** – including Critical Peak Pricing (CPP) with and without enabling technology, Peak Time Rebates (PTR), time of use (TOU) rates, and real time pricing.

CAC commends the inclusion of additional DR products as part of its potential assessment and associated IRP bundles. However, there are several specific factors that result in unrealistic and underestimated DR potential. These include:

1. Incomplete DR products list in the MPS
2. Limited DR included in the preferred IRP bundle.
3. Underrepresented potential for Interruptible Rate programs
4. Overly conservative PTR participation assumptions
5. Unnecessary delay of time-varying rate options
6. Lack of accounting for winter season DR potential
7. Lack of accounting for increased deployment of electric, DR-capable equipment through interactions with EE and IRA programs.
8. Lack of associated co-deployment opportunities would yield increased DR program adoption.

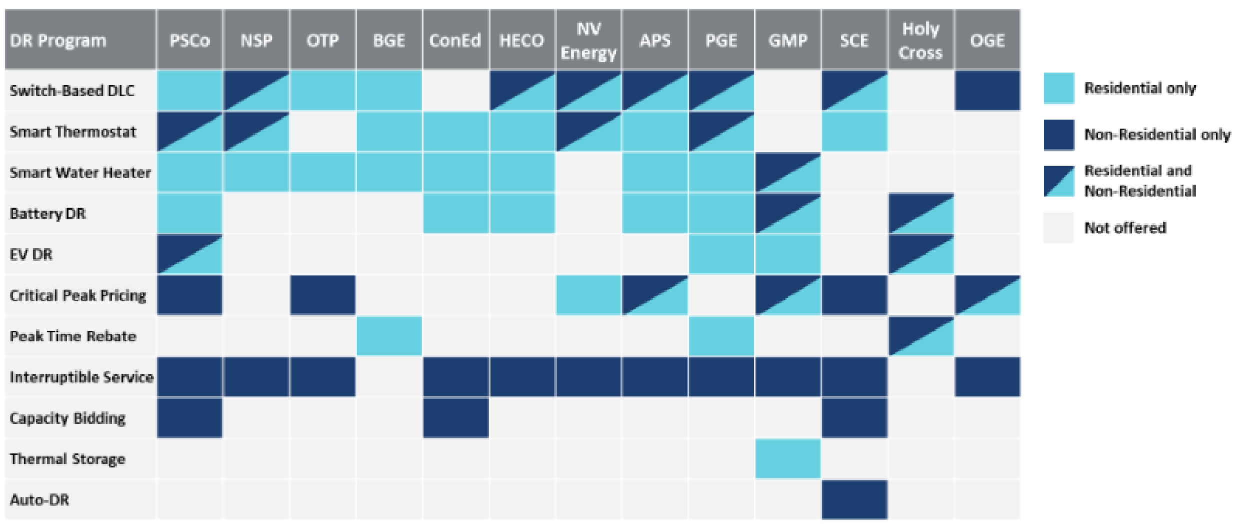
We discuss each of these items in more detail in the following sections. Note, many related points regarding CenterPoint consideration of DR resources have been raised by CAC in the past (e.g., Keeling direct testimony – Cause No. 45564).

2.2.1 Incomplete DR Products List in the MPS

The current list of DR products in the MPS is limited in scope in a few key areas.

First, it does not include resource potential for interruptible rate programs. CenterPoint did include 25 MW of industrial DR as a resource in its IRP, but this is only based on a single existing customer that used to be enrolled in its current interruptible rate offering. In this context, "potential" is analogous to the status quo and does not reflect true potential of a more robust, effective program offering that could be scaled for its non-residential sector.

Interruptible rate programs are common DR programs offered by numerous utilities and engaging variety of non-residential customer segments as participants. Figure 3 provides a summary of DR programs offered by a set of selected utilities, nearly all of which have an interruptible service offering.[8]



Notes: Based on Brattle review of utility websites and tariffs. NSP = Northern States Power, OTP = Otter Tail Power, BGE = Baltimore Gas & Electric, HECO = Hawaiian Electric Company, APS = Arizona Public Service, PGE = Portland General Electric, GMP = Green Mountain Power, SCE = Southern California Edison, OGE = Oklahoma Gas & Electric.

Figure 3. Matrix of DR Program Offerings at Selected Utilities

A recent 2022 potential study for Xcel Colorado by the Brattle Group estimated its interruptible program among the highest achievable resource potential of its DR portfolio, currently at 41% of its summer portfolio (194 MW) and 81% of its winter portfolio (194 MW). Furthermore, the

[8] Source: https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf

study estimated an incremental achievable savings of 17 MW summer and 11 MW winter by 2030.[9]

As another point of comparison, Consumers Energy has three tariff-based non-residential interruptible rate demand response offerings. Additionally, it has a contractual non-residential program focused on load curtailment that is not rate based. These four non-residential DR offerings provide flexibility and different options to engage its customers, currently achieving over approximately 400 MW of resource potential as of 2023, and targeting another 100 MW by 2031.[10]

While there are clearly differences between CenterPoint and other utilities (e.g., mix of non-residential customers), these are several examples of other utilities that have achieved robust interruptible rate program offerings and have continued to increase their participation over a similar time horizon.

CAC acknowledges that CenterPoint has demonstrated intent to reevaluate its interruptible rate tariff in its forthcoming rate case. We appreciate the willingness to rework and improve its existing tariff to increase its appeal for a broader array of customers. However, the omission of interruptible rates from the current MPS appears to be an oversight which neglects to account for a realistic value of its resource potential.

Furthermore, there are several other DR products that are omitted from the current MPS, which include the following. Each of these resources are fairly common measures and should be considered for a complete accounting of DR potential:

- Electric Vehicle TOU / Managed Charging
- Behind the Meter Storage
- Behavioral Demand Response (BDR)
- TOU with Enabling Technology
- Non-Residential Water Heater DLC
- Non-Residential Lighting DLC
- Non-Residential Auto-DR
- Non-Residential Time-Varying Rates (TOU, real time pricing [RTP])
- Thermal (Ice-Based) Energy Storage [11]
- Winter potential for DLC and Rate options

All these products are present in mature DR programs throughout the country. For example, there are more than 50 utilities offering some type of varying rate to manage EV charging.[12]

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[9] Source: Brattle (2022). Table 2. Winter Achievable DR Potential (2030) and Table 3. Summer Achievable DR Potential (2030). https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf

[10] Source: Direct Testimony of Emily McCraw, Director of Consumers Energy Residential Demand Response (p.661-669) https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Nib8YAAR

[11] Example: Arizona Public Service. https://www.s4btradeally.com/cool-energy-demand-with-thermal-storage/

[12] SEPA (March 2023). *Managed Charging Programs: Maximizing Customer Satisfaction and Grid Benefits*. SEPA (November 2021). *The State of Managed Charging in 2021.*

Additionally, time-varying rate (TVR) options such as BDR ensures that all customers, even those without enabling technologies, can realize bill savings while supporting peak load reduction. There are numerous BDR programs deployed at scale, including several large-scale utility, statewide, and market-wide examples being used during grid emergencies, such as California's Flex Alert program or ERCOT's Level Two Emergency Alert Service. These pricing and behavioral offerings can also easily leverage the existing infrastructure that CenterPoint has already put in place with its residential behavioral savings program. They can also be excellent methods of engaging customers in demand response and increase participation rates for firmer DR products like DLC and TOU.

For non-residential customers, TOU and RTP are among the most common TVR for this sector. Furthermore, the TVR can encourage the deployment of DERs such as behind the meter storage to reduce peak demand or demand charges.[13] These assets can ultimately participate in DR programs as well. Non-residential DLC of lighting is increasingly possible considering that 45 of the 75 networked lighting control products qualified by DesignLights Consortium are capable of DR.[14] Additionally, 29 of these lighting control systems can be integrated with BACnet to enable HVAC load control. Auto DR programs provide incentives and technical assistance customize automated DR for specific end uses like HVAC, lighting, and agricultural irrigation and pumps.[15]

2.2.2 Limited DR in IRP

While the MPS includes analysis of a suite of DR and rate programs, it appears that within the preferred scenario (F.B. Culley 3) only DLC programs are included in the IRP bundle. It is unclear why other DR bundles are not included, such as residential rate options (CPP, PTR, and TOU), non-residential BYOT, and non-residential CPP. Some DR resource bundles were modeled to only operate for a limited number of hours, largely in summer. This approach neglects the potential for some of these same DR resources (e.g., interruptible and residential rate programs) to be used beyond a limited application during the summer season.

Specifically for the residential rate program bundles (including CPP, PTR, and TOU), these were shown to only dispatch for July and August. Included in this bundle, the event-based resources (CPP and PTR) can be dispatched during all seasons, and TOU rates can be designed annually as a continuous or default load management strategy. Furthermore, the MPS has underestimated resources like PTR, which can be offered as an opt-out design, are low risk for customers, and are easily scalable. Each of these rate options should be agnostic to equipment and reflect resource potential that can be available during any season.

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[13] https://www.epa.gov/system/files/documents/2022-08/Customer%20Rates%20and%20Data%20Access_508.pdf
[14] https://qpl.designlights.org/qpl/networked-lighting-controls
[15] Example: Pacific Gas & Electric. https://www.pge.com/pge_global/common/pdfs/save-energy-money/energy-management-programs/demand-response-programs/automated-demand-response-incentive/adr-program-manual.pdf

As noted below, we encourage CenterPoint to include estimation of seasonal DR resources beyond summer-only applications in future planning studies to more accurately estimate associated resource potential.

2.2.3 Interruptible Rate Program Potential

As noted, CenterPoint included 25 MW of industrial DR as a resource, but this is only based on the existence of one customer that was enrolled and participated in CEI's interruptible offering, which is not representative of the real potential that can be achieved with good offerings in place. Given that the last MPS is considered a "refresh" and does not include any new primary market research, we suggest conducting a new potential study to determine a more realistic estimate of potential of interruptible load from commercial and industrial customers. CAC has requested in the past to include flexibility on interruptible tariffs to cater to a wider range of customers in these sectors. CAC is aware that CenterPoint has engaged a DR aggregator (who bid into its All-Source RFP) to explore the DR potential based on customer load and industry demographics. We want to reiterate the importance of conducting an extensive study to determine the real possibilities for non-residential DR in CenterPoint territory. As noted in Mr. Keeling's testimony, the industrial sector represents approximately 44% of CenterPoint electric sales, of which top segments are comprised of manufacturing loads, refrigerated warehouses, and municipal pumping, which are all typically prime targets for interruptible tariffs.

A more comprehensive discussion of factors impacting DR acquisition through interruptible rates that would inform a favorable assessment of its potential is included in CAC witness Josh Keeling's direct testimony (Cause No. 45564). Improvements include:[16]

- Reducing its minimum curtailment bid requirement (from 250 kW to 100 kW, consistent w/ other utilities like Duke and I&M) to promote participation of a larger number of commercial and industrial customers.
- Promoting aggregator participation to increase the customer base participating in these programs, including bundling smaller individual accounts (e.g., 25 kW) to meet the minimum requirement.
- Allowing for more optionality around notification time (from under an hour to 6-10 hour advance) to reduce customer deterrent to enroll in the program due to high probability of non-compliance for shorter periods.
- Right-sizing penalty amounts to avoid unintended deterrent to enrollment.

2.2.4 PTR Participation Assumptions

The MPS appears to model potential for residential PTR based on an opt-in program design. We believe programs like PTR (and BDR, which was not included) that are equal-opportunity, no-risk options for participants should be offered as opt-out options. As noted in Mr. Keeling's

[16] Source: Keeling testimony (pp. 22-24).

testimony (p. 22), an opt-out PTR offering scaled to CenterPoint's territory could reflect an additional 30-40 MW of additional demand reduction potential.

First, PTR is an equal opportunity program, meaning customers are not required to have central air conditioning or other specific equipment for eligibility. Second, it is a callable resource, similar to how DLC can be dispatched, in that customers can be notified the day before or day of an event and asked to reduce or shift energy consumption to hours outside of peak period events. Third, while it is a form of behavioral demand response, where customers are asked to reduce energy consumption by taking actions and are paid an incentive per kWh reduced over the event period, these programs have been successfully deployed across the country, including opt-out designs, which lends itself to the ability to quickly scale to achieve the full load impact potential. Fourth, since PTR is not restricted to specific equipment, like central air conditioning, it is a resource that can be used across summer, winter, and shoulder seasons. This flexibility largely reflects the full year capacity needs anticipated with increased electric load growth and reflected in the MISO seasonal capacity construct.

Finally, PTR can be used as a platform or gateway to introduce customers to demand response and then encourage migration to firmer DR, such as through DLC. In a recent evaluation of Portland General Electric's Smart Grid Test Bed project, customers who were auto-enrolled into PTR were more than twice as likely to enroll in smart thermostat DLC compared to a matched comparison group.[17]

The MPS underestimates the achievable potential of this resource and CenterPoint should reevaluate PTR as an opt-out design.

2.2.5 Delay of Time-Varying Rate Option Rollout

There is no reason to delay the deployment of TVR. CPP, PTR and TOU are well established programs across the country and CEI has a significant rollout of AMI to enable these offerings. Furthermore, PTR could enhance DR potential as an opt-out program given there is no risk for the customer.

As noted in Mr. Keeling's testimony, CenterPoint should pursue price-based programs immediately, with a focus on opt-in rate programs (such as TOU and CPP) and no-risk opt-out offerings (such as PTR and BDR). These programs are well established across the country and, given their AMI deployment, there is no reason not to aggressively pursue these in CenterPoint's service territory. Estimates of achievable potential show no savings in 2025 and a slow ramp up to 2030.

2.2.6 Winter Season DR Potential

The MPS is missing quantification of winter season DR potential, including opportunities to leverage some of the suite of existing EE (and DR) programs with DR-capable technologies with contributions to winter season peak loads. This includes existing customers with electric heating

[17] https://edocs.puc.state.or.us/efdocs/HAD/um1976had1636.pdf

and water heating, which some of them may already be enrolled in CenterPoint's DLC programs through their space cooling system. Additionally, this could include existing and new installations of heat pumps and heat pump water heaters that will add to winter (and summer) peak loads and are DR-capable.

In anticipation of the MISO seasonal construct where resource adequacy reserve margins will be required by season, there is value in differentiating potential beyond summer. Furthermore, as we anticipate increased electric loads through adoption of heat pump technology for space and water heating, encouraged at the federal level through IRA, as well as increased electric vehicle adoption, there is value in considering DR winter resource potential in advance of this anticipated load growth.

We encourage CenterPoint to include estimation of winter season DR resources in future planning studies to more accurately estimate associated resource potential.

2.2.7 EE and IRA Program Interactions

It remains unclear whether the achievable potential estimates account for interactions with other energy programs, including EE initiatives, in increasing the eligible equipment for electric demand response. As noted above, the MPS does not currently account for the impact of IRA funding. Accounting for these interactions will impact measure co-deployment, with increased recruitment and adoption potential for demand response products, and increase delivery of electric equipment (including water heating and heating measures) and yield higher estimates of demand response potential that are not captured in the estimation of achievable potential.

With the IRA becoming law in August 2022, there is an influx of funds to increase efficiency, reduce GHG emissions and improve local air quality in the building sector. The High Efficiency Electric Home Rebate (HEEHR) provides up to $14,000 per household in building electrification incentives targeting low to moderate income households that replace existing non-electric equipment with heat pumps, HPWH, electric ranges or cooktops, and electric clothes dryers.[18] A second program, the Home Energy Performance-Based, Whole-House Rebate (referred to as the HOMES program) program will support state energy offices in providing rebates for market rate and low- or moderate-income customers for retrofits conducive to energy savings, these retrofits include heat pumps and HPWHs among others. Additionally, the IRA offers tax credits for qualified energy efficient improvements (including heat pump installations) in the residential and commercial buildings sector.[19]

According to the Department of Energy, Indiana will receive around $182 million that will be allocated almost evenly between the HOMES and the HEEHR programs.[20] It is expected that

[18] Public Act 117-169 (Inflation Reduction Act), § 50222 (https://www.congress.gov/117/plaws/publ169/PLAW-117publ169.pdf).
[19] *Id.*, § 50121.
[20] https://www.energy.gov/articles/biden-harris-administration-announces-state-and-tribe-allocations-home-energy-rebate

some portion of this funding will be allocated to the CenterPoint's service area. IRA funds will allow the utility rebates to stretch further and reach more customers, especially in the low- and moderate-income sector.

The IRA funds will have an impact not only from an economic perspective but also from a market development perspective. These funds will drive market transformation accelerating familiarity of customers and contractors with the heat pump and heat pump water heater technologies, increasing word-of-mouth communication that will end up accelerating deployment of these measures.

In turn, these are DR-capable measures that will be adding to peak load through increased electric consumption during daily and seasonal peak periods. Omission of these interactions and anticipated increase in deployment of heat pumps and heat pump water heaters will set an artificially low estimation of the actual achievable potential of DR.

2.2.8 Co-Deployment Opportunities.

Not only is there increased potential of electric loads that can be curtailed through DR as a function of deployment of EE and IRA programs, but there are also opportunities to bundle or co-deploy these efficiency measures with DR offerings, reducing program costs (e.g., marketing, on-site installation) and increasing the adoption probability of customer enrollments in DR programs.

Co-deployment refers to the ability to leverage existing products, programs, and systems that encourage a combined deployment of resources, yielding benefits of measure interactivity 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 smart thermostat DLC reduces separate marketing/recruitment efforts, increases likelihood of demand response enrollment (lowering incremental marketing costs), and increases both customer and power system benefits (combining conservation effects and peak load impacts). Leveraging energy efficiency installations (of products like thermostats, electric HVAC and water heating equipment, and non-residential networked lighting controls) and program pathways (like in-home audits or low-income weatherization) can be opportunities to increase adoption of eligible measures, increase enrollment probability, and reduce standalone costs of unbundled offerings. It is clear that bundling demand response with other energy efficiency initiatives is an opportunity that can leverage energy efficiency deployment, increase conversion rates, decrease standalone delivery costs, and potentially increase the per-unit capacity savings of demand response products (e.g., such as installing weatherization that increases thermal storage and associated ride through for thermostat-based DR events).

It is unclear whether CenterPoint's estimates of achievable potential embed participation assumptions accounting for co-deployment of DR products across a range of EE measures, such as smart thermostats, heat pumps, and HPWHs. This would impact the potential associated with DLC programs (increasing saturation of controllable devices and increase the adoption probability of enrollment in DR) as well as rate programs. For example, technologies like smart thermostats, EV chargers, and some HPWH controls can be optimized around TOU rates to maximize usage shifting to off-peak pricing.

We encourage future assessments to more carefully explore these potential for interactions between EE and DR measures. As an example of its relevance, in the Pacific Northwest, the 2021 Northwest Power Plan is explicit about these opportunities: "As organizations and utilities develop demand response capability, they should do so by leveraging existing energy efficiency infrastructure and considering them together as part of an integrated demand-side management approach to optimize delivery of both resources holistically and equitably."[21]

[21] 2021 Northwest Power Plan (p.47) https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf

3 EnCompass Modeling

We appreciate the challenges that CenterPoint faced to incorporate the most up to date modeling inputs for this IRP. These challenges included the change to a seasonal rather than annual resource adequacy construct in MISO, supply and inflationary pressures for new resources, and the passage of the Inflation Reduction Act ("IRA"). We recognize the effort that CenterPoint put into modeling the MISO seasonal construct with the information it had available at the time the IRP modeling inputs were being developed. However, since that time, MISO has indicated that it is likely to materially change its resource adequacy construct and accreditation practices, and this additional information should be incorporated in future IRPs (and prior to any resource proceedings like a CPCN). We also appreciate that CenterPoint asked the bidders that responded to its Request for Proposals ("RFP") to refresh bids to reflect the IRA.

3.1 The Reference Case

CenterPoint's Reference Case in this IRP includes the conversion of the new A.B. Brown Combustion Turbines ("CTs") to a Combined Cycle ("CC") in 2027. In the IRP, CenterPoint stated:

> *The Reference case portfolio, which converts CEI South's two F-class combustion turbines into a large, combined cycle, was found to be the least cost portfolio by a wide margin across multiple potential future states; however, CEI South does not plan to convert either or both CTs to a combined cycle in the absence of a large load addition. The reference case, generated by computer modeling, is overbuilt for CEI South customer needs and relies on vastly more market energy sales to lower the NPVRR well below all other portfolios. The Indiana Commission instructed that this is a risky proposition for a company of this size in Cause No. 45052. CEI South's preferred portfolio complies with this view.*[22]

We agree with CenterPoint that the conversion of the CTs to a CC as modeled in the Reference Case relies on market energy sales to lower the net present value of revenue requirements ("NPVRR") and is too risky of a portfolio to continue to explore. We do not recommend that CenterPoint continue to explore this pathway, regardless of whether there is a load addition in the service territory, because of the significant cost risk and regulatory risk this option presents.

3.2 CenterPoint's Preferred Plan

CenterPoint's Preferred Plan identified in this IRP process is to convert F.B. Culley 3 to natural gas in 2027, with wind and solar additions in 2030, and additional wind in 2032 and 2033. We have several concerns and questions around the seasonal accreditation for the conversion, the cost of the conversion, the ability to secure firm gas transportation, and the projections on how

[22] CenterPoint 2022/2023 IRP, page 263.

often the unit will operate. We discuss each of these items in more detail in the following sections.

3.2.1 F.B. Culley 3 Conversion Seasonal Accreditation

CenterPoint modeled the F.B. Culley 3 conversion with seasonal accreditation, as recently adopted by MISO starting with the 2023/2024 planning year. CenterPoint's modeling assumes that the conversion will receive accreditation of 100% accreditation in the spring, summer, and fall, and receive 94.21% in the winter. However, it is our understanding that under the MISO seasonal construct, F.B. Culley 3 would be given the accreditation of the "Fleetwide Schedule 53 ISAC/ICAP" as shown in Table 4 below. The fleetwide schedule 53 ISAC/ICAP would then be adjusted by the UCAP/ISAC conversion ratio for each season as shown in Table 5.

Table 4. MISO Schedule 53 Class Averages for 2023-2024 Planning Year[23]

Row Labels	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP	Count of Units
Combined Cycle	89.5%	83.8%	83.9%	81.2%	108
Combustion Turbine 0-20MW	83.3%	82.9%	76.8%	79.8%	40
Combustion Turbine 20-50MW	89.2%	86.0%	82.3%	85.1%	115
Combustion Turbine 50+MW	92.2%	84.8%	81.9%	86.9%	174
Diesels	89.9%	86.9%	84.5%	86.8%	70
Fluidized Bed Combustion	[redacted]	[redacted]	[redacted]	[redacted]	8
Fossil Steam 0-100MW	82.0%	81.2%	78.0%	76.2%	54
Fossil Steam 100-200MW	[redacted]	[redacted]	[redacted]	[redacted]	28
Fossil Steam 200-400MW	84.6%	79.7%	77.1%	76.9%	33
Fossil Steam 400-600MW	81.2%	78.1%	81.1%	77.5%	31
Fossil Steam 600-800MW	[redacted]	[redacted]	[redacted]	[redacted]	24
Fossil Steam 800+MW	[redacted]	[redacted]	[redacted]	[redacted]	6
Hydro 0-30MW	[redacted]	[redacted]	[redacted]	[redacted]	14
Hydro 30+MW	[redacted]	[redacted]	[redacted]	[redacted]	8
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	17
FleetWide Schedule 53 ISAC/ICAP	87.4%	83.2%	81.3%	82.2%	730

Table 5. UCAP/ISAC conversion ratio for the 2023-2024 Planning Year[24]

Season	Calculated Ratio	ISAC/ICAP	Ratio x ISAC/ICAP
Summer	1.049	87.4%	91.68%
Fall	1.078	83.2%	89.69%
Winter	1.059	81.3%	86.10%
Spring	1.087	82.2%	89.35%

[23] Retrieved from https://cdn.misoenergy.org/20230328%20Schedule%2053%20Class%20Average_Posted627347.pdf
[24] Retrieved from https://cdn.misoenergy.org/20230406%20UCAP%20ISAC%20Ratio%20for%20PY23-24628473.pdf

Table 6 shows the accreditation assumptions that CenterPoint modeled for F.B. Culley 3 and what the accreditation would look like if the F.B. Culley 3 conversion had been assigned seasonal values as published by MISO for the 2023-2024 Planning Year. This shows that CenterPoint assigned accreditation values in their IRP modeling that were higher than such a facility would actually be likely to receive based on MISO's current resource adequacy rules.

Table 6. Accreditation for the F.B. Culley 3 Conversion

	Summer	Fall	Spring	Winter
CenterPoint	100%	100%	100%	94.21%
MISO Fleetwide Average	91.68%	89.69%	89.35%	86.10%
CenterPoint (MW)	270	270	270	254
MISO Fleetwide Average (MW)	248	242	241	232
Difference	8%	10%	11%	9%

3.2.2 Project Costs for the Conversion

CenterPoint included a feasibility study[25] for the conversion of F.B. Culley 3 to gas as an attachment to the IRP. Table 7 below shows the project cost information for the conversion that CenterPoint provided in the IRP.

Table 7. F.B. Culley 3 Gas Conversion Project Costs[26]

Operating Characteristics and Estimated Costs	F. B. Culley 3 Gas Conversion
Base Load Net Output (MW)	270 / 0 incremental
Base Load Net Heat Rate (HHV Btu/kWh)	10,544
Base Project Costs (2022$/kW)[48]	$196
Fixed O&M Costs ($/kW-year)[49]	$39.16

When discussing the costs of the conversion in the IRP, CenterPoint stated:

> *CEI South will seek approval from the Commission to convert F.B. Culley 3 to natural gas by 2027, consistent with the preferred portfolio. CEI South worked with 1898 to study the design conversion of F.B. Culley 3 from coal to natural gas firing to provide cost estimates consistent with AACE Class IV estimates. These planning estimates need to be refined. CEI South plans to work with boiler equipment manufacturers, consulting engineers, and construction companies to provide construction level estimates and schedules. Refining the planning typically takes 36*

[25] CenterPoint 2022/2023 IRP Attachment 6.5.
[26] CenterPoint 2022/2023 IRP, Figure 6-9, page 186.

> *months to complete preliminary engineering, material procurement, contract negotiations and execution, fabrication, installation and commissioning. CEI South will work with nearby pipelines for a firm service contract to supply the plant with natural gas. Converting FB Culley 3 to natural gas may trigger air permitting modifications. CEI South will work our consultants and IDEM to determine the appropriate permitting requirements*.[27]

In EFG's work in other jurisdictions related to the construction of natural gas facilities, we are starting to see the impact of inflationary and supply chain pressures, along with increased demand, on the costs for thermal assets. In addition, many of the Producer Price Indices for certain inputs that would be needed for the conversion also suggest that inflation is a serious risk. As shown in Figure 4, indices for Cement and Concrete, Metal Products, Construction Machinery, Hot Rolled Steel, and General Freight Trucking have increase materially at rates higher than inflation for over a year now.

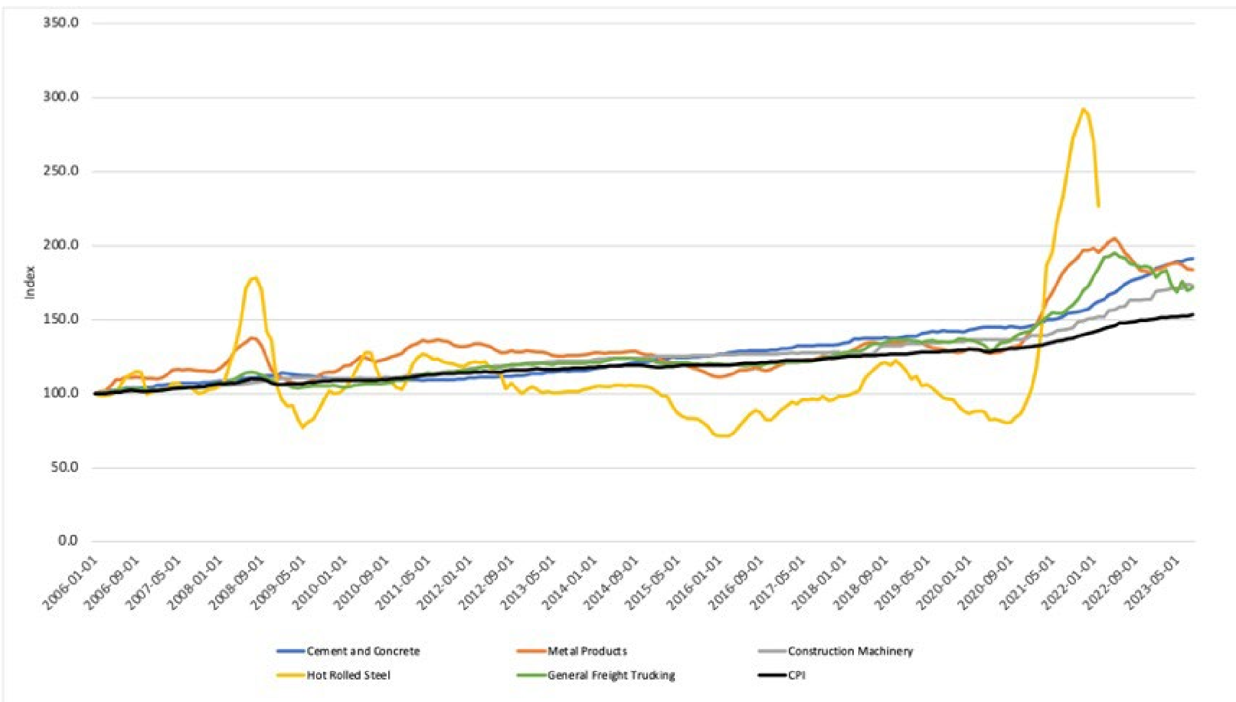

Figure 4. Producer Price Indices for Key Inputs to CCs Compared to CPI[28]

The conversion of FB Culley 3 has some benefit over a combustion turbine in the sense that it does not require a new turbine, but the balance of plant components would be exposed to these cost pressures.

[27] CenterPoint 2022/2023 IRP, page 283.
[28] FRED, 2023.

3.2.3 Pipeline Costs and Firm Gas Transportation

In the FB Culley Coal to Gas Conversion Feasibility Study, some information was provided on the natural gas pipeline locations that could potentially supply F.B. Culley 3 once it is converted:

> *Presently Units 2 & 3 both start-up with natural gas and operate with a variety of regional bituminous coals. Potential gas supply pipelines in the area are by Texas Gas Transmission Co. and by ANR Pipeline Co. Texas Gas Transmission Co. has two lines in the area, one about 6 miles to the northwest, and another about 9 miles due north. ANR Pipeline Co. has one line about 9 miles to the southeast (straight down river).*[29]

However, the report also says, "Costs regarding bringing gas to the site are outside of the scope of this report."[30] It does appear that CenterPoint is making some assumptions around F.B. Culley 3 receiving firm gas transportation once it is converted, as the IRP says, "Dispatchable generation with firm gas service at F.B. Culley will allow this resource to be available to meet peak conditions during long duration weather events."[31]

It is not clear if costs around natural gas pipelines and firm gas transportation are included in the $196/kW project cost, or the fixed O&M shown in Table 5 above. If these costs were excluded from the cost to convert F.B. Culley 3 it is possible that it would have impacted the capacity expansion plans, and the present value of revenue requirements ("PVRR") for portfolios with the conversion. We recommend that CenterPoint be clear and explicit in its IRP and any future filings about how its cost assumptions were derived and whether certain cost categories were excluded from its analysis. It is also not clear whether CenterPoint has confirmed that sufficient firm, unsubscribed capacity is available on any of these natural gas pipelines. If sufficient firm, unsubscribed capacity is not available, then the converted unit will be subject to interruptions in gas service especially during periods of high demand or it may need to incur significant cost to expand firm transmission capacity on the pipeline serving it.

It also does not appear that CenterPoint subjected the cost of the conversion to any sensitivities or under the scenarios evaluated so the risk of changes in the cost of the conversion would not be reflected in the IRP analysis. Sensitivity analysis is a critical component of a robust IRP, especially given the unprecedented uncertainty in the industry with respect to price, supply chains, changing wholesale market rules, new federal legislation, proposed federal environmental regulations, and repeated natural gas power plant underperformance and unplanned correlated outages during times of grid stress.

[29] CenterPoint 2022/2023 IRP, Attachment 6.5, page 2-1.
[30] CenterPoint 2022/2023 IRP, Attachment 6.5, page 3-15 to 3-16.
[31] CenterPoint 2022/2023 IRP, page 261.

3.2.4 Operations

When discussing how the Preferred Portfolio performs across the potential scenarios modeled, CenterPoint stated:

> *Natural gas forecast in the High Regulatory and the Inflation and Supply Chain Issues Scenarios increase by an average of 78% and 29% respectively. This could signal that a natural gas conversion would not be economic. Under the conversion to peaking generation, the unit operates roughly 1% of the time, which greatly improves the carbon output of the portfolio and limits exposure to these costs.*[32]

Operations of the unit at a 1% capacity factor are lower than what we would expect for a converted unit, and would understate the costs and emissions associated with operating the unit if the capacity factor ends up being in the range of 10-15%.

CenterPoint should reevaluate any plans to convert F.B. Culley 3 to natural gas in 2027 and address the concerns above with stakeholders before making any final decisions. As noted throughout these comments, other resource options are available and should be more thoroughly considered, e.g., additional demand response and energy efficiency, as well as repowering wind projects.

3.3 Alternative Portfolios

CenterPoint also evaluated alternate candidate portfolios that evaluated the replacement of F.B. Culley 3 with a combination of renewable resources and/or battery storage. The one major difference between these portfolios and CenterPoint's Preferred Plan is that when F.B. Culley 3 is not retired and converted in 2027, it operates until its retirement in 2029. Table 8 through Table 11 below show the comparison of the Diversified Renewables Portfolio against the Preferred Portfolio across the different metrics presented in the Scorecard. It is important to note that CenterPoint's portfolios with replacement of F.B. Culley 3 with renewables and storage resources were limited to retiring F.B. Culley 3 in 2029. With the way that the portfolios were constructed differently around retirement of F.B. Culley and replacement with renewables and storage as compared to converting F. B. Culley earlier in 2027, it only allows for an analysis that considers an earlier retirement if the unit is going to be converted to gas.

While the Diversified Renewables Portfolio has a higher 20 Year NPVRR, this NPVRR reflects the stochastic modeling of capital costs for renewables and battery storage whereas the cost for the conversion of F.B. Culley 3 is not varied. The Diversified Renewables portfolio has slightly less exposure to coal and gas markets and a comparable CO_2 intensity to the Preferred Portfolio. The CO_2 equivalent emissions are higher in the Diversified Renewables Portfolio due to the operation of F.B. Culley 3 on coal until 2029, but this portfolio does not include any new thermal

[32] CenterPoint 2022/2023 IRP, page 253.

resources that will persist through the planning period as CenterPoint modeled the F.B. Culley 3 conversion throughout the entire planning period.

Table 8. Affordability/ Cost Risk Metrics[33]

Portfolio	20 Year NPVRR	Delta from Reference	Proportion of Energy Generated by Resources with Exposure to Coal and Gas Markets (%)	95% Value of NPVRR
Preferred	$4,503	6.8%	27%	$5,316
Diversified Renewables	$4,583	8.8%	25%	$5,313

Table 9. Environmental Sustainability Metrics[34]

	CO_2 Intensity (Tons CO_2/kWh)	CO_2 Equivalent Emissions (Stack Emissions in Tons CO_2)
Preferred	0.00015	15,506,174
Diversified Renewables	0.00015	15,763,426

For the Reliability metrics, the Diversified Renewables Portfolio has a larger amount of fast start capability, but a lower total level of spinning reserve capability. For Market Risk Minimization, across the different metrics, the Diversified Renewables Portfolio relies less on energy market purchases on an average basis and for the near and long term maximum level of purchases. Both Portfolios score similarly on the energy market sales metrics, with the Diversified Renewables Portfolio having slightly lower average across the planning period.

Table 10. Reliability Metrics[35]

	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)		Fast Start Capability (MW)	Dispatchable Resource with Spinning Reserve Capability (MW)
	Summer	Winter		
Preferred	60	21	469	941
Diversified Renewables	89	71	669	671

33 CenterPoint 2022/2023 IRP, Figure 8-35, page 258.
34 *Id.*
35 *Id.*

Table 11. Market Risk Minimization Metric[36]

	Energy Market Purchases			Energy Market Sales		
	Average	Near Term Max	Long Term Max	Average	Near Term Max	Long Term Max
Preferred	26%	39%	32%	19%	22%	27%
Diversified Renewables	25%	31%	30%	18%	22%	24%

The Diversified Renewables portfolio would allow CenterPoint to continue to diversity its resource fleet and would not lock the Company into additional 270 MW of gas capacity in addition to the new CTs that are projected to come online.

3.4 Stochastic Capital Costs

One of the recommendations that we made in the IRP stakeholder workshops was for CenterPoint to reconsider modeling capital costs as a stochastic variable. We expressed concern about this modeling approach since capital costs are uncertain and not volatile in the sense that they are unlikely to swing between wide decreases and increases in cost from year to year, which makes it challenging to develop an appropriate probability distribution. Our recommendation was to address capital costs through sensitivities or scenarios.

In response to that feedback, CenterPoint opted to model the capital costs in a different manner. In the IRP, CenterPoint described the process of modeling the stochastic capital costs:

> *Instead, the base, high and low renewables capital costs were treated as discreet distributions and assigned to the 200 iterations for inclusion with the other stochastically develop input variables. The low capital costs were assigned to the first 50 iterations of stochastic variables. The base, or Reference Case capital costs were assigned to the next 100 iterations. The high capital costs were assigned to the final 50 iterations. Because it is unlikely capital costs would stay high or low for every year of the study period, the order of iterations was randomly shuffled every four years prior to the 50/100/50 iteration assignments. With this approach, any one iteration would have a combination of base, high and low capital costs in four-year segments.*[37]

One of the recommendations we had made to CenterPoint was that:

> *If CenterPoint does not agree and continues to include capital costs as a stochastic variable, then we would recommend that CenterPoint include new thermal resources along with the renewable and battery storage resources. While we understand that the renewables and storage are in more portfolios, there are still*

[36] *Id.*
[37] CenterPoint 2022/2023 IRP, page 321.

> *several portfolios that include either the conversion of FB Culley 3 or new thermal resources.*[38]

Based on the information presented in the IRP and the modeling files, it appears that the stochastic capital costs were only applied to the new renewable and storage resources. This creates an asymmetry problem when trying to compare portfolios with new thermal resources, as those resources were not subjected to stochastic capital costs like renewable and battery storage resources were, despite the fact that they are also subject to significant cost uncertainty.

We recommend that CenterPoint discontinue the treatment of capital costs as a stochastic variable and evaluate capital costs through sensitivities and scenarios.

3.5 Modeling Long Duration and Multiday Energy Storage Resources

Throughout the IRP stakeholder workshops, CAC continually suggested that CenterPoint include a representation of long duration and multiday storage resources. CenterPoint acknowledged the disagreement on the modeling approach expressed by stakeholders:

> *IRP stakeholders did not agree compressed air storage was a good proxy for long duration storage and suggested CEI South either include longer duration lithium ion or utilize an upcoming technology like, iron air battery. While iron air batteries could help solve the long duration storage need, the technology is not yet in commercial operation, and CEI South did not have good cost data to model in this IRP. CEI South will continue to watch updates from Form Energy, the industry leader of this upcoming technology, and may incorporate this resource in future IRPs. Ultimately, CEI South did allow the model to select multiple four-hour blocks of lithium ion storage or an alternative 10-hour storage resource. The long-duration storage proxy was pushed out to 2032, so it could not be selected in the near term.*[39]

In future IRPs and in advance of any major resource filings, we recommend that CenterPoint include long duration and multiday storage resources as candidate resources for selection in the capacity expansion model. While we recognize that CenterPoint attempted to capture a long duration storage option by modeling compressed air as a proxy for this IRP, we do not believe this is a good proxy for long duration storage given the technology advancements and prevalence of lithium-ion battery storage resources. We look forward to the opportunity to collaborate with CenterPoint on modeling inputs around long duration and multiday storage resources in future IRPs and in advance of any major resource filings.

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[38] CAC comments submitted to CenterPoint on the EnCompass modeling files, submitted on March 17, 2023.
[39] CenterPoint 2022/2023 IRP, page 119.

3.6 Wind Repowering

CAC also continued to provide feedback to CenterPoint throughout the IRP stakeholder process about repowering two of their existing wind projects that are coming to the end of the PPA term in 2028 and 2030. In the stakeholder process, CAC submitted these comments[40] on modeling the repowering of these projects:

> *Given the long delays in the generation interconnection process in MISO, we would strongly recommend that CenterPoint evaluate the option of repowering the Benton County and Fowler Ridge wind farms rather than assuming they are rolled off the system. Repowering can involve just increasing rotor length or increasing rotor length and hub height. The former may not increase the capacity of the projects, but it can increase the capacity factor, can be PTC-eligible, and could be more cost-effective than building a new wind project while the latter would increase nameplate capacity as well. We understand that CenterPoint does not own these farms, but if their lives are extended, an offtaker will still be needed and CenterPoint, as one of the current offtakers, is an obvious candidate. Evaluating this option would be consistent with the purpose of evaluating new build options in the IRP and we would not expect that new wind builds could substitute because of the difference in cost.*

The end date for these projects is important for looking at resource needs when F.B. Culley 3 retires. Evaluating the potential repowering of these projects will be important for CenterPoint's system, especially if the projects can capture the PTC benefit from the IRA or increase the production at the sites.

For its recent IRP, Ottertail Power ("OTP") evaluated the repowering of some its wind projects and concluded to move forward with repowering those facilities in 2024 and 2025. For OTP, the repowering of the projects provided them with higher energy, capacity, and the ability to capture PTC benefits from the projects. Table 12 below shows the additional energy generation OTP will be able to obtain from the four wind resources they are planning to repower.

Table 12. OTP Wind Repowering[41]

Line No.	Wind Energy Facility	Name Plate (MW)	Current NCF	Repower NCF	Current GWh	Repower GWh	Increase GWh
1	Ashtabula	48.0	40%	50%	168	210	42
2	Langdon	40.5	40%	50%	142	178	36
3	Luverne	49.5	42%	50%	182	217	35
4	Ashtabula III	62.4	40%	50%	219	274	55
	Total				711	878	167

[40] CAC comments provided in response to the Second IRP Stakeholder Workshop.
[41] OTP Supplemental Resource Plan, Table 4-4, page 25. Docket No. E017/RP-21-339.

We recommend that CenterPoint start taking the steps now to evaluate the potential of repowering their existing wind resources.

3.7 Portfolio Scorecard Metrics

As part of the stakeholder process, CenterPoint asked for feedback on metrics that should be included in the Portfolio Scorecard to which CAC submitted a few recommendations. We appreciate that CenterPoint recognized the need to include a metric that captured fuel price risk, but we would still put forward the recommendation to include an Equity metric in the scorecard given the high proportion of low-income ratepayers in CenterPoint's service territory and the disproportionate impact of emitting industries on its service territory. CAC recommended that CenterPoint include the following metric that evaluates low-income cost burdens and emissions exposure:

> *First, a metric that measures whether emitting units in each portfolio are located in low-income and/or communities of color and how those overlap with other emitters in Southern Indiana. An example of this as it relates to peaker plants in New Mexico is given below.*

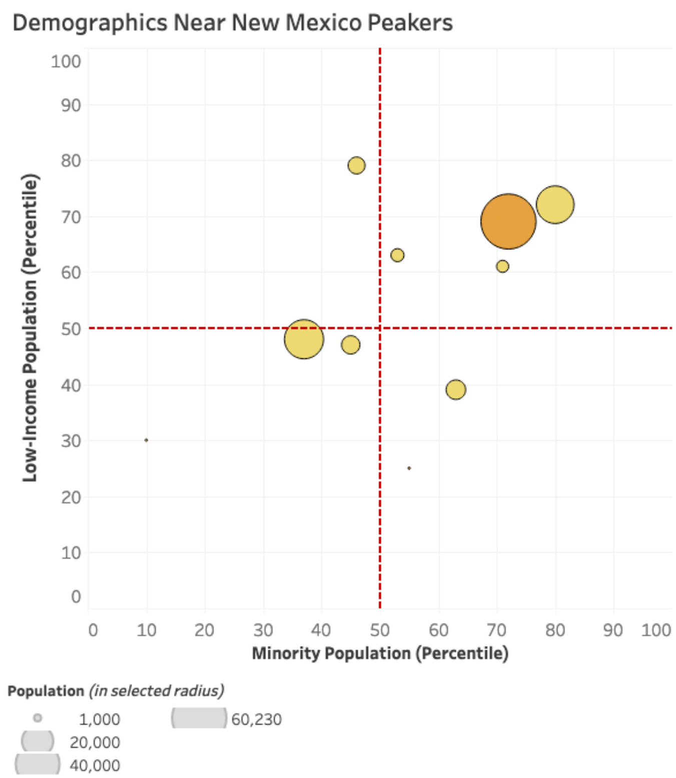

Figure 5. Demographics Near New Mexico Peaker Plants[42]

[42] https://www.psehealthyenergy.org/our-work/energy-storage-peaker-plant-replacement-project/new-mexico/

> *The circle size indicates the population within a given radius of the plant and the color, in this case, distinguishes between peakers at their own site versus those co-located with a combined cycle plant. For CenterPoint's purposes, we would recommend keeping the low-income and community of color axes, but changing the color coding to reflect the fuel burned at emitting units. We would note that a similar graph, but for all fuel types, could be used to identify some of the positive and negative impacts as well as the equity of those impacts of replacement generation once those locations are identified.*
>
> *Second, a metric that looks at the cost burden by census tract and could account for the bill impacts of community-solar projects that could be placed in those communities (since those are now eligible for a bonus Investment Tax Credit) would be very useful. An example of this is given in a report looking at energy cost burdens as a percent of median household income in the state of Colorado.*[43]

CenterPoint should work with stakeholders to include this metric in subsequent IRPs.

3.8 Additional Recommendations for Modeling Renewable and Battery Storage Resources

3.8.1 Project Size

In the stakeholder process, we submitted feedback to CenterPoint on the resource sizes offered in the model for solar and battery storage resources along with the recommendation to allow for partial selection of battery storage resources. While CenterPoint disagreed with us, we continue to support these recommendations and would put them forward again for consideration in upcoming IRPs and in advance of any major resource filing.

CenterPoint modeled solar and battery storage resources in sizes of 10 MW, 50 MW, and 100 MW sizes. We recommended that CenterPoint select one solar and one battery storage resource size to model (i.e. 100 MW solar) instead of setting up six different resources which adds to the model problem size and run time. CenterPoint should have allowed the model to view the option for battery storage resource selection as a partial unit, which means the model could have added any size greater than 0 and less than the maximum capacity size input for the resource, i.e. 50 MW. This would have allowed the model to determine the optimal size, while reducing the model run time.

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[43] See PDF page 26 of https://www.psehealthyenergy.org/wp-content/uploads/2022/01/Colorado-Energy-Affordability-Study_Full-Report.pdf

3.8.2 Energy Community Bonus Adder

We would also recommend that CenterPoint consider the potential for renewable and battery storage resources to qualify for the additional 10% PTC and ITC bonus adder for projects that could be located in an Energy Community.[44] This is an important value stream for projects that should be captured in the modeling.

3.9 Sensitivities

CenterPoint discussed a list of sensitivities that were performed, including monetization of the ITC for storage, wind costs, carbon tax, lower capacity accreditation for battery storage resources, and 300 MW of additional load. In discussing the results of the sensitivity analysis, CenterPoint referenced relative cost impacts on the NPVRR of the portfolios but did not provide a final table or any additional information to help readers of the IRP to be able to understand the cost changes or compare portfolios to one another. For instance, with regard to modeling a carbon tax, CenterPoint stated:

> *Given the potential changes in the New Source Performance Standard 111B, nearly half (80 out of 200) of the probabilistic risk analysis simulations included a carbon tax. The introduction of a carbon tax as a proxy for potential change in legislation helps quantify the magnitude of the impact portfolios would be exposed to under more stringent emission regulations. From this sensitivity each of the 10 portfolios saw a 16% to 26% increase in NPV.*[45]

While it is helpful to see the range of the NPVRR cost increases, it would also be informative to see how the cost of each portfolio changed. We recommend that CenterPoint include more detailed information on any sensitivities performed for the IRP.

Additionally, in the last IRP, CenterPoint performed a sensitivity that evaluated including additional EE fixed into the model. CenterPoint stated, "A sensitivity was run on the Reference Case to assess 1.25% energy efficiency (EE) in the near-term as compared to the selected 0.75% EE in the near-term, which raised portfolio costs by 0.15%. As such, 1.25% was included in all portfolios for the first 3 years."[46] We appreciated that CenterPoint performed that sensitivity in the last IRP, but it is not clear if CenterPoint did so in this IRP to evaluate higher levels of EE in the near term. We would recommend that evaluating higher levels of EE in the near term is a

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[44] On April 4, 2023, the IRS issued Notice 2023-29 (https://www.irs.gov/pub/irs-drop/n-23-29.pdf) with further guidance (in advance of more formal rules to be released later) on the definition of "energy communities" and an interactive mapping tool (https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d) to identify the localities that the IRS believes at this time count as "energy communities" (excluding brownfield sites). On June 15, 2023, the IRS issued Notice 2023-45 (https://www.irs.gov/pub/irs-drop/n-23-45.pdf) and Notice 2023-47 (https://www.irs.gov/pub/irs-drop/n-23-47.pdf) with further clarifying information.

[45] CenterPoint 2022/2023 IRP, page 255.

[46] Vectren 2019/2020 IRP, page 102.

good sensitivity analysis to always include in the IRP. We request that CenterPoint further discuss this with CAC in advance of its 3-year DSM filing.

3.10 Surplus Renewable Opportunities and Reusing Injection Rights

In order to increase the progress on clean energy and reduce the exposure to volatile natural gas prices, we recommend that CenterPoint consider the potential of adding surplus interconnection projects at F.B. Culley if CenterPoint moves forward with a proposal to convert F.B. Culley 3 to gas. In other jurisdictions, we have seen utilities take advantage of using surplus interconnection for solar and wind projects at existing thermal generation sites, such as combustion turbines. Under this framework, the renewables would not receive capacity credit until the thermal resource is retired. However, the surplus interconnection would allow for the addition of more renewable resources that could operate during periods when the thermal resource is not. We have seen proposals from other utilities that would either allow for renewables at the site of the thermal plant or, through the use of a gen tie line, that could incorporate renewable projects at other locations. We recommend that. if CenterPoint moves forward with the conversion of the F.B. Culley 3, it explore this possibility as a way to incorporate more renewable energy for their system. Northern States Power in Minnesota is using a similar approach to replace energy and capacity at its Sherburne power plant site.[47]

Since CenterPoint is also putting forward the retirement of F.B. Culley 2 in 2025, it seems like there is also an opportunity to explore renewable and storage projects that could reuse those injection rights, which would be approximately 90 MW. The reuse of interconnection rights is one of the reasons CenterPoint supports the conversion of F.B. Culley 3 to natural gas in its Preferred Plan, as CenterPoint said:

> *The preferred portfolio maintains the existing 270 MW interconnection rights at F.B. Culley 3, protecting customers from untimely delays associated with a generation resource at another location, especially with the extensive MISO queue delays in recent years due to the record amount of interconnection requests submitted. In addition, it shields customers from potential transmission upgrade costs because the increase of interconnection requests is exhausting available transmission capacity. Lastly, maintaining the existing interconnection preserves the rights for replacement resources in future IRPs.*[48]

It is not clear from the IRP how the interconnection rights for F.B. Culley 2 may be reused by future projects, but we request this be considered and that language is factored into future RFPs to reflect this so CenterPoint can explore the potential for renewables or battery storage to reuse the rights for F.B. Culley 2.

[47] https://mn.my.xcelenergy.com/s/about/newsroom/press-release/xcel-energy-proposes-minnesota-energy-connection-power-line-to-replace-retiring-MCH2FCUPO3HRFWTBHJGADEMXUTY4
[48] CenterPoint 2022/2023 IRP, pages 267-268.

3.11 Industrial Load Forecast

In the last IRP, CAC expressed concerns around transparency in the industrial sales forecast and the level of growth projected. The issue persists with this IRP. In the load forecast report prepared by Itron and included as an attachment to the current IRP, it is noted that the industrial sales growth is driven by the addition of a new customer in 2023. Table 13 below shows the comparison in the industrial sales forecast for the 2022/2023 IRP compared to the 2019/2020 IRP. The 2022/2023 IRP still shows a projection for growth in the industrial sales forecast from this new customer between 2023 and 2024 (approximately 22%); however, the projected increase in sales is lower than what was forecasted in the 2019/2020 IRP.

Table 13. Industrial Forecast

Year	2022/2023 IRP Sales (MWh) [49]	2019/2020 IRP Sales (MWh)[50]
2020	-	2,347,543
2021	-	2,360,025
2022	1,854,221	2,463,638
2023	1,793,424	2,669,566
2024	2,189,424	2,682,185
2025	2,179,125	2,693,010
2026	2,178,524	2,702,706
2027	2,187,341	2,715,218
2028	2,194,083	2,730,260
2029	2,198,120	2,742,862
2030	2,200,486	2,753,258

Given this growth from a new industrial customer, and CenterPoint's comments throughout the IRP narrative about prospects and opportunities for new industrial customers, there should be more consideration around items to address industrial load growth, like targeted demand response and energy efficiency programs.

In addition, CAC would also ask that CenterPoint collaborate in future IRPs on industrial decarbonization strategies for industrial customers. For example, the Alcoa Warrick aluminum smelter and coal-fired power plant is the sixth-largest source of carbon dioxide emissions in the state of Indiana.[51] CenterPoint notes its current plan to exit the joint ownership agreement with Alcoa regarding Unit 4 in 2023. Repowering Warrick with renewable energy could be an opportunity to bring the smelter in as a CenterPoint customer, preserve jobs and economic development associated with this facility, and meaningfully reduce pollution from what currently

[49] Attachment 4.1 2022-2023 CEI South Long-Term Electric Energy and Demand Forecast Report. Table 2-3, page 16.
[50] Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report. Table 2-3, page 14.
[51] https://www.epa.gov/ghgreporting/ghgrp-state-and-tribal-fact-sheet

is one of the largest sources of air and water pollution in southwestern Indiana. However, bringing such a customer onto CenterPoint's system would take significant preparation and careful planning given it is a very large load relative to CenterPoint's current peak load.

4 Conclusion

In sum, we found the CenterPoint IRP process to be a significant improvement from the last IRP. However, there are still several unresolved issues, including the need to evaluate with stakeholders the total project costs for the F.B. Culley 3 conversion, building a lateral and securing firm gas supply for the F.B. Culley 3 conversion, the potential for repowering CenterPoint's existing wind projects, the potential to leverage surplus renewable interconnection at F.B. Culley, and the potential for additional demand response and energy efficiency.

Since there is still unknown information about the final costs for the F.B. Culley 3 conversion, we would ask CenterPoint to consider instead the potential for F.B. Culley 3 to be replaced with a combination of renewables and battery storage resources, especially as it moves forward with future RFPs. As CenterPoint stated in its IRP:

> *Given fundamental changes in the market, renewables projects now require much longer lead times than in previous IRP cycles. There will not be time to wait for the next IRP to begin pursuing suitable projects to meet the needs of CEI South customers by 2030. To fill this need, CEI South plans to pursue attractive projects from its 2022 All-Source RFP consistent with the findings in the 2022/2023 IRP, to the extent that they are still available. It is likely that CEI South will go out for another RFP over the next year to identify other projects. There is high demand for these projects in Indiana as other utilities are also working through their own generation transitions. Affordable pricing will be important.*[52]

We look forward to seeing the continued collaborative nature of this IRP process replicated in other forums with CenterPoint, including working together in advance of issuing any new RFPs, performing modeling in advance of moving forward with any major certificate of need and 3-year DSM cases, and, of course, in the next IRP cycle.

[52] CenterPoint 2022/2023 IRP, page 281.