Indiana Office of Utility Consumer Counselor Comments on
CenterPoint Energy Indiana South 2023 Integrated Resource Plan
September 27, 2023

Introduction

The Indiana Office of Utility Consumer Counselor (OUCC) offers its comments and recommendations on CenterPoint Energy Indiana South's (CEI South) 2023 Integrated Resource Plan (IRP) Submission. CEI South held a series of IRP stakeholder meetings in 2022 and the OUCC appreciates the opportunity to participate in them. OUCC staff also participated in separate technical meetings. However, the ultimate modeling decisions and choice of preferred resource plan are CEI South's alone and not determined by stakeholders, as is the case with each of Indiana's investor-owned electric utilities.

CEI South has continued to make some progress responding to questions and comments raised in the IURC Director's reports and OUCC submissions. The purpose of these comments is to improve CEI South's IRP process and preferred portfolio development for the benefit of Indiana's consumers. House Enrolled Act 1007 (2023) establishes reliability, affordability, resiliency, stability, and environmental sustainability as the Five Pillars of electric utility service in Indiana. The OUCC has reviewed CEI South's IRP Submission with the Five Pillars in mind.

The fact that the OUCC does not address or criticize specific items, assumptions, or portfolios does not suggest that it supports those processes and practices. Rather, constraints and the natural complexities of IRP exercises have not permitted the OUCC the opportunity to address every issue or every potential opportunity for improvement.

Summary

The OUCC offers observations, recommendations, and comments on multiple sections of CEI South's IRP below in an effort to provide a path that continuously improves CEI South's planning and future generation portfolios for the benefit of its consumers. The OUCC recognizes CEI South put significant effort into portfolio development and modeling while attempting to respond to stakeholder input. It also attempted to incorporate the moving dynamics of MISO changes to seasonal accreditation while evaluating portfolios on multiple metrics. Those metrics include not only capacity and energy production, but also affordability, cost risk, environmental sustainability, reliability, market risk minimization, and execution.

Another important aspect of the IRP in addition to defining a preferred portfolio based on these metrics is the resulting short-term plan that bridges the gap between the current portfolio and the preferred portfolio. CEI South's short-term plan does not address the capacity shortfall in 2024 for any of the portfolios, which is the entire point of a short-term action plan. This is mainly due to the gap between the A. B. Brown Generating Station ceasing operations in October 2023 and the planned in-service date for the new gas-fired combustion turbines at the Brown site. Addressing this concern is very important for CEI South's customers. The OUCC urges CEI South to incorporate a robust short-term plan analysis that leads to the preferred generation portfolio. Without it, timelines and costs can be dramatically affected.

With the exception of the least cost option, resource portfolio results are too close to each other to distinguish the best option. Portfolio scoring would better differentiate options that include a robust short-term plan and implementation of the OUCC's recommendations. The OUCC specifically recommends CEI South:

- Include a discussion of decommissioning, risk, and contingency as well as owner's costs in the IRP to inform stakeholders of the potential costs. These considerations can materially affect portfolio success. For example, including decommissioning costs for one type of generation but not for other types does not produce a reasonable and reliable comparison.
- Consider more moderate scenarios where carbon taxes would begin in a later year and provide its model inputs for NOx and SO_2.
- Fully explain the reason for the wide difference between the estimate it relied on in Attachment 6.6, and its assumed ACE Rule Compliance costs.
- Include a comprehensive discussion and analysis of its transmission and distribution system in future CEI South IRPs. Changes in locations of generating assets driven by renewable projects will undoubtedly impact reliability and affordability.
- Test the current MISO accreditation assumptions and inform stakeholders of the impacts on future capacity requirements and energy costs.
- Define critical DSM baseline parameters and identify treatment in each portfolio scenario. The finalist portfolios should then be tested with changes in critical parameters.
- Include more information, going forward, explaining how regional or national forecasts are adjusted to reflect CEI South's service territory demographics in forecasting electric vehicle (EV) adoption and distributed energy resource (DER) penetration.
- Include quantitative and qualitative comparison of tax impacts in future IRPs and in subsequent CPCN filings. Additions or removals of tax incentives are an important factor for consideration.

<u>Resource Options</u>

Now that CEI South has received Commission approval to acquire and own several renewable projects, it should include actual costs of these renewable projects in future IRPs. It is very concerning that CEI South is understating the costs of renewable generation in its model inputs. CEI South's assumed "high" renewable costs are lower than the costs to construct solar and wind projects it has recently requested from the Commission.[1] Examples include CEI South's recent proposals to acquire an out of state wind facility and to acquire the Posey County Solar Project, both of which received IURC approval in recent dockets (Cause Nos. 45836 & 45847). Cost differential data in both cases, which have been redacted and deemed confidential in the respective causes, demonstrate these concerns.

The difference between recently approved renewable project costs and CEI South's assumed IRP costs for solar and wind generation could be due to the inclusion of owner's costs and contingency in the estimates for Commission-approved renewable projects. However, the IRP included owner's

[1] CEI South 2023 IRP, Vol. 1, p. 228.

costs and contingency for the cost of new gas, coal, and nuclear generation.[2] Therefore, to evenly compare renewable generation to traditional generation sources, it is reasonable to consider owner's and contingency costs in all generation estimates in the model.

The OUCC also recommends CEI South include a discussion of risk and contingency as well as owner's costs in the IRP. This would make it clear to stakeholders what types of projects align best with CEI South employees' expertise and would inform stakeholders of the associated potential costs. Project risk may drive added contingency, oversight and staffing in owner's costs. Its impact can materially affect the potential success and affordability of a particular portfolio of generating assets.

<u>Environmental Considerations</u>

The only environmental commodity model input CEI South provides in the IRP body or exhibits are CO_2 allowance prices. While CEI South states air emission allowance costs are accounted for within the IRP modeling when describing costs to continue operating its existing coal units,[3] it did not provide its model inputs for NOx and SO_2 allowance prices for all fossil-fuel fired generation analyzed. This was expected in previous IRPs, annual NOx and seasonal NOx allowances will continue to be necessary for understanding future gas generation operational costs. NOx seasonal allowance price inputs are particularly important, as they have risen significantly over the last year and are likely to remain at an elevated level compared to previous years.[4] Additionally, if CEI South has only considered and added these costs to coal-fired generation, and not gas-fired generation, it could artificially depress the operational costs for gas generation and skew the model toward displaying portfolios with higher gas generation as lower cost options.

Regarding CEI South's CO_2 price assumptions, the OUCC agrees no CO_2 prices should be assumed in the reference case, and the assumption that any CO_2 regulations implemented in the short term will occur at the national level based on the Affordable Clean Energy (ACE) Rule.[5] In *West Virginia v. EPA*, the Supreme Court ruled the EPA cannot implement a cap-and-trade program for CO_2 under Section 111(d) of the Clean Air Act. Any CO_2 cap-and-trade program or carbon tax would need to be passed by Congress. Therefore, it is more reasonable to assume implementation of a command-and-control policy, as this is what the Supreme Court indicated the EPA is allowed to execute under the Clean Air Act. The only two scenarios CEI South included CO_2 prices for were the High Regulatory and the Decarbonization/Electrification scenarios, which each assume a carbon tax beginning in 2024 and 2026, respectively.[6] Both of these scenarios are highly unlikely, as Congressional action would be necessary to implement a carbon tax. Even if Congress were to

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[2] *Id*.
[3] CEI South 2023 IRP, Vol. 1, p. 204.
[4] After the EPA released its proposed Good Neighbor Rule, which significantly restricts Seasonal NOx emissions, the Seasonal NOx allowance market price skyrocketed to almost $50,000/ton in July 2022. Seasonal NOx emissions have since stabilized to around $10,000/ton; however, this is still much higher than 2021 historical prices around $2,500/ton. (Source: S&P Capital IQ, Environmental Markets).
[5] CEI South 2023 IRP, Vol. 1, p. 212.
[6] *Id.*, pp. 216-217.

pass legislation for a carbon tax within the next six months, it would be unlikely to be implemented in 2024. The OUCC understands the possible usefulness in showing how a carbon tax could influence short-term resource decisions. The OUCC is also aware that other stakeholder groups have voiced support for including carbon prices immediately. However, CEI South should also consider a more moderate scenario where carbon taxes would begin in a future year that is much later (such as 2030, for example).

As stated earlier, the OUCC agrees with CEI South's assumption that any near-term CO_2 standards would be based on the ACE Rule, which requires heat rate improvements for existing coal-fired generating units. CEI South assumed $34 million (2023) for Culley Unit 3's compliance with the ACE Rule[7] and provides some support for this assumption in Attachment 6.6.[8] However, the maximum capital cost estimate presented for Culley Unit 3 to comply with the ACE Rule was significantly different than what CEI assumed in its IRP.[9] While inflation could account for the difference in these estimates, as the study was completed in 2020, it does not explain the entire discrepancy between CEI South's assumed cost input and the estimate presented in Attachment 6.6. CEI South should fully explain the reason for the wide difference between the estimate it relied on in Attachment 6.6 and its assumed ACE Rule Compliance costs.

In March 2023, the EPA proposed new GHG standards for new and existing fossil-fueled electric generating units (EGUs) that will significantly impact utility planning, if implemented. This proposal was issued recently, so the OUCC understands why CEI South would be unable to incorporate it into its modeling. However, since the final rule will substantially impact utility operations, the OUCC evaluated CEI South's assumed future costs for new and existing coal and gas-fired units. This was done to determine how well CEI South's modeling would capture new greenhouse gas (GHG) standards if fully adopted and implemented.

For new coal units, CEI South assumed carbon capture and sequestration (CCS), which would be consistent with the proposed GHG standards.[10] However, it assumed CCS additions for only one type of CT/CCGT unit. This class of CCGT (G/H Class) would not be subject to the proposed standards because its nameplate capacity is less than 300 MW. However, J Class CTs and CCGTs will be large enough to possibly trigger the proposed CO_2 standards.[11] Under these standards, a J Class CT operating at or above a 20% annual capacity factor would be expected to install CCS or co-fire with zero-emitting or "green" hydrogen. Since CEI South only considered an F-Class CT in the portfolios it analyzed, this does not appear to impact the results of this IRP. However, it is possible that including CCS for the G/H Class CT could lead to it being screened out of the optimized portfolio selection process.

[7] *Id.*, p. 219.
[8] CEI South 2023 IRP, Vol. 2 (Confidential), Attachment 6.6: ACE Rule Heat Rate Study.
[9] *Id*., Table ES-4, p. ES-7. This number was obtained by adding all capital costs presented in Table ES-4.
[10] CEI South 2023 IRP, Vol. 2, Attachment 1.2: CEI South Technology Assessment Summary Table.
[11] *Id*.

CEI South's assumed CCS costs for coal and gas units are consistent with publicly available data for other CCS projects. However, CEI South assumes that it would pipe CO_2 to locations within 50 miles,[12] which could increase costs if CEI South is required to own the injection site. Exploration costs for storage sites may also cost more. If CCS becomes the technology standard for new coal and gas generation, CEI South should continue to identify all potential costs associated with the CCS and incorporate reasonable estimates in future IRPs.

Also, CEI South excluded decommissioning costs for new gas CTs, CCGTs, and Reciprocating Internal Combustion Engines (RICE).[13] It is unclear if new nuclear and coal unit costs have decommissioning estimates in the model, as there are no specific footnotes indicating these costs are included for new generation. It is also unclear if decommissioning costs are included for new solar, wind, or battery storage. It is unreasonable to include decommissioning costs for one type of generation but exclude them for other types of generation. This would unfairly bias the analysis in favor of a specific resource. Decommissioning costs need to be included for all new resources as they are an important cost consideration over the life of a resource. A resource may seem attractive at first. But if its potential decommissioning costs are excessive, selecting another resource may be preferred when considering long-term costs.

CEI South discusses the current status of coal combustion refuse (CCR) cleanup at the A.B. Brown and F.B. Culley plants.[14] The cleanup and closure plans for these plants may be impacted by the May 18, 2023 US EPA proposed amendments to the federal rule on CCR disposal. This rule will end the exemption for sites that ceased receiving waste material before 2015. The proposed rule will also broaden the definition of a CCR management unit to include "any non-containerized accumulations of CCR." Any area where CCR was used as structural fill could be subject to cleanup and maintenance requirements under the CCR rule. As a result, CEI South may be subject to additional cleanup requirements. This could impact reuse of current coal power plant properties. CCR management assumptions need to be clearly stated in baseline portfolios and how they affect changes in any given portfolio option.

Transmission and Distribution System Planning

CEI South recognizes the importance of transmission in its IRP with its extensive discussion of impacts of various factors on the bulk transmission system. Included in this discussion are the Transmission Distribution Storage Improvement Charge ("TDSIC") in section 1.3.3, Distributed Generation (Section 4.4.3), MISO (Section 5.1), MISO Interconnection (Section 6.1.5), Congestion Charges (Section 6.3.1.3.4), Transmission Considerations (Section 6.4), and Transmission Appendix (Section 11.7). However, CEI South does not provide a comprehensive view of portfolio modeling, the resulting choices' effects on transmission, and the related impact on consumer rates.

[12] *Id.*
[13] *Id.*
[14] CEI South IRP Vol. 1. Section 11.2.2 Solid Waste Disposal, p. 305

Transmission and distribution affordability is driven not only by proximity of generation to load but also by the size of the generator and the location of interconnection. CEI South does recognize a need in section 6.3, Potential Future Modeling Assumptions, by stating "Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered resources and are the most difficult to estimate."

CEI South's discussion of Distributed Generation (DG) notes that high DG penetration impacts power flow on transmission lines. The concentration and location of DG resources may require the transmission system to be re-configured. However, CEI South does not develop the impact of larger distributed, utility-owned renewable resources on the grid in its portfolio evaluation.

The IRP only provides a summary mentioning the existence of the company's $446.5 million TDSIC Plan approved in 2017 and its second TDSIC Plan, filed with the IURC this year and currently pending. It does not elaborate on how its proposed projects are expected to improve reliability, resiliency, stability, and flexibility. These are significant investments that are heavily impacted by generation location and type.

Lastly, CEI South discusses in section 5.1, MISO, that the reliability impacts associated with interconnection to transmission must be studied before a new generation facility can connect. This type of study determines whether available transmission capacity or facility constraints must be resolved to accommodate interconnection of a proposed generation facility. It notes, "More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost."

The OUCC recommends a comprehensive discussion and analysis of Transmission and Distribution be included in future CEI South IRPs. This should include both quantitative and qualitative scorecard metrics of proposed generation portfolios and their effects on each of the Five Pillars as defined in House Enrolled Act 1007 (2023).

MISO Market

CEI South recognizes MISO's changing capacity accreditation for both thermal resources and renewables. It attempts to work within the new seasonal construct which provides added insight to its generation fleet and future portfolios. It also correctly identifies that the 95% accreditation afforded to battery energy storage systems (BESS) will need to decline. As a result, it recognizes costs will increase for current and proposed portfolios.

The OUCC recommends CEI South test the current accreditation assumptions and inform stakeholders of the impacts. Those impacts should be defined in how the need for additional capacity will change, what the available options will be to add capacity, and how much that capacity may cost ratepayers. It should also detail the costs or risks if capacity cannot be procured within a portfolio's required timeline resulting from the simulated tests.

Load Research, Load Forecasting and Methodology - Customer Energy Needs

The OUCC recommends CEI South include historical data to illustrate trends in load growth. Excluding DSM, the annual growth of total energy requirements and peak demand is expected to average 0.7% over the next 20 years.[15] Historical energy and demand data maintained by CEI South in an internal database are listed in the IRP as a main driver of the load forecast.[16] However, the IRP's modest level of detail provided about the historical data within the load forecasting report does not support the projected long-term growth. The report states "[d]espite moderate economics and customer growth, system energy and peak demand have been declining. Energy requirements and demand have declined 0.4% annually since 2011. Energy efficiency gains have been a big factor. COVID-19 had a significant impact resulting in an 8.0% drop in 2020 commercial sales. Since 2011, weather-normalized residential average use has declined on average 1.2% per year, resulting in 0.6% annual decline in residential sales.

"Commercial sales have also been falling; normalized sales have declined 1.3% per year, [and] this is heavily impacted by the drop in 2020 sales."[17] Historical data broken out by year for annual sales are not provided. The OUCC recommends the inclusion of such data in future IRP filings and load forecasting reports to better assess historical trends and effects from short-term disruptions such as COVID-19.

In light of CEI South's declining energy and demand requirements since 2011, the IRP should include a discussion of drivers of new growth, in addition to the comments currently provided on the sources of the load forecast.[18] Some of the drivers of new energy usage are discussed including the effects of DERs and EVs. The load forecasting report states, "[m]ost of the growth is after 2030 as electric vehicles begin to have a significant impact on load."[19] This is problematic given issues with the EV forecast described within the OUCC's comments. Historical data on energy usage and peak trends, as well as the contribution of EVs and DERs on CEI South's load, should be included in future filings to contextualize the projected long-term load growth.

Demand Side Resource Options

CEI South's IRP submission includes predicted annual energy efficiency savings (MWh) and levelized costs for its demand side management (DSM) programs, based on analyses conducted in compiling the 2022 Market Potential Study.[20] The table predicts a general increase in annual energy savings over time.

CEI South uses the 2022 Marketing Potential Study as the basis for modeling potential DSM savings. But the report does not discuss major changes in federal efficiency standards for residential lighting and HVAC systems, effective in 2023, or how CEI South will adjust to these changes. Incandescent bulbs and halogen general service lamps or screw-in bulbs accounted for

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[15] 2023 IRP, pp. 142.
[16] 2023 IRP, pp. 128.
[17] 2023 IRP Attachment 4.1, pp. 2-3.
[18] 2023 IRP, pp. 128-129.
[19] 2023 IRP, Attachment 4.1, pp. 3.
[20] CEI South 2023 IRP Vol. 1, Figure 6-22, p. 202

more than 17% of CEI South's total energy savings in its 2021-2022 DSM program, but retail sales of those bulbs are now prohibited by the U.S. Department of Energy (DOE).[21] The DOE has also raised base seasonal energy efficiency ratio (SEER) standards for HVAC systems from 13 SEER to 14 SEER in Indiana and its region.

These developments at the federal level will reduce DSM programs' potential savings. CEI South's Market Potential Study identifies lighting and HVAC as significant contributors of potential residential savings. Therefore, predicted annual savings may no longer be accurate due to these changes in federal efficiency standards. The OUCC recommends CEI South define critical baseline parameters such as these and identify treatment in each portfolio option and market scenario. The final portfolio options should then be tested to reflect changes in critical parameters.

<u>Effects of Electric Vehicles (EV) and Distributed Energy Resources (DER) on Load</u>

CEI South emphasizes the potential importance of increased EV and DER adoption by identifying possible effects on generation, transmission, and distribution. For DERs these effects include technical challenges or system upgrades associated with high voltage mitigation, power quality and harmonics mitigation, and short-term load forecasting uncertainty.[22] CEI South includes up-to-date information on the number of DERs and their average installed capacity within its service territory. The OUCC recommends CEI South use historical data related to energy the DERs generated and their coincidence with peak load, especially as these values are forecasted.

For EVs, CEI South includes several effects that may prompt system upgrades and states "If there is a substantial increase in EV adoption within the next 10 years, it is anticipated there would be a significant change in the system load profile."[23] However, CEI South has not included refreshed data relating to its service territory and EV usage. In this IRP, CEI South uses the same estimation from the 2019-2020 IRP, that there are 238 registered EVs in the counties it serves.[24] In the same section though, the IRP reads that "CEI South purchases quarterly from the BMV a list of vehicle registrations for the counties that CEI South serves."[25] Itron's load report for CEI South indicates the number of EVs in the estimated territory is the product of the number of customers multiplied by consensus forecasts for EV adoption from the Annual Energy Outlook and BloombergNEF, and then there is "A calibration step…to adjust to the know[n] number of registered EVs in CenterPoint's service territory as of 2022."[26] A general forecast with expectations for more than Indiana is then adjusted to CEI South Service territory. The Itron report also assumes in the 2022 Forecast that CEI South had 238 vehicles in its service territory.[27] Technical appendix 4.1 of Itron's

[21] Cause No. 45895, Direct Testimony of Nicholas N. Kessler, p. 9, lines 3 through 4.

[22] 2023 IRP, pp. 135-137.
[23] 2023 IRP, p. 141.
[24] 2023 IRP, p. 138 and 2020 IRP, p. 123.
[25] 2023 IRP, p. 138.
[26] 2023 IRP, Attachment 4.1 p. 41.
[27] *Id.*, p. 28.

report provides information on EVs at the national level.[28] It is unclear as to whether CEI South's information regarding the number of battery electric vehicles (BEV) and the number of plug-in hybrid vehicles (PHEV) have been updated in its current IRP. CEI South should confirm whether Itron's forecast includes the most up-to-date service territory-specific data available, and address this accordingly.

The OUCC is concerned that CEI South's forecast for EV adoption may not be realistic given that CEI South's projected rate is not a consistent trend in EV adoption. CEI South's analysis projects a 189%[29] increase in EV adoption from the time of the forecast to 2022. This may be an overestimation considering there has only been an 8.9% increase in EVs in CEI South's service territory from 2022 to 2023 so far. [30] Additionally, the projected EV kWh usage data in this IRP are identical to the data presented in the 2019-2020 IRP,[31] rendering this information stale and unreliable. CEI South should provide current data to allow for a robust and accurate comparison.

Going forward, the OUCC recommends CEI should include more information explaining how regional or national forecasts are adjusted to reflect its service territory demographics.

Tax Impact

IRP projects (especially those included in the short-term action plan) need to include their Net Present Value Revenue Requirement (NPVRR). The NPVRR needs to include the Net Present Value (NPV) of the return "on" and "of" the projected amount included in rate base and the projected NPV of the incremental operating costs that will be included in rates. The incremental operating costs need to note the amount of property tax included in the incremental operating costs and whether a property tax abatement was assumed or considered. Taxes should also be included in the NPVRR calculation. The assumed tax rate should be noted as well as any consideration of tax incentives including, but not limited to, the PTC and the ITC. Any tax incentive included in the NPVRR should include the tax incentive's estimated effect on rates and the timeframe that the tax incentive will impact rates. CEI South does not explicitly address its tax assumptions nor the tax impact on its IRP projects.

The OUCC recognizes timing of tax incentive impacts can be difficult to project when legislation or jurisdictional decisions are pending; however, NPVRR can easily be modeled. Additionally, local property taxes can be important to siting timelines. Abatements can benefit all consumers, not just those at the generator's location. The OUCC recommends both quantitative and qualitative comparison of tax impacts in future IRPs and in subsequent CPCN filings, including additions or removals of incentives.

[28] 2023 IRP, Attachment 4.1 p. 41.
[29] *Id.*p.28.
[30] https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/
[31] Cause No. 45501, Petitioner's Exhibit 4.

Conclusion

To conclude, CEI South's methodology has improved but its results fall short due to exclusion of several factors that can dramatically affect installed costs. Among other concerns, the short-term plan as noted does not address the capacity shortfall in 2024, nor tax assumptions that materially impact customer rates.

Again, the OUCC appreciates the opportunity to offer these comments on the submitted IRP.