Report on Duke Energy Indiana's 2024 Integrated Resource Plan

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Confidential Information Redacted

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On behalf of Citizens Action Coalition, Earthjustice,
Solar United Neighbors, and Vote Solar ("Joint Commenters")

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Overview

The following comments on the 2024 Integrated Resource Plan ("IRP") submitted by Duke Energy Indiana ("Company" or "Duke") were prepared by Chelsea Hotaling, Anna Sommer, Dan Mellinger, and Scott Reeves of Energy Futures Group ("EFG"). 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 Duke created, and we look forward to continuing to work with Duke in this manner. We have identified several issues to address to improve Duke's current and future IRPs.

Our review of Duke's 2024 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- Duke used a materially understated combined cycle capital cost in its modeling which may have led to the selection of more of that resource than is optimal;
- Duke used flawed assumptions with respect to the capital costs of small modular reactors ("SMRs");
    - Even using these flawed small modular reactor costs, Duke's model did not select SMRs
- Duke's modeling continues to support the conversion of Edwardsport from coal to gas, an action that we urge Duke to quickly take for the best interests of ratepayers;
- Duke used overly constrained build limits for storage;
- Duke failed to consider the option of repowering and extending the power purchase agreements ("PPAs") for an existing wind project in its portfolio;
- Duke should undertake improvements to its SERVM model so that it better reflects the manner in which Duke's system interacts with MISO as well as the risks its own system faces;
- Duke's market potential study ("MPS"), while improved from its prior study, still suffers from major deficiencies that likely limited the overall potential identified in the study:
    - The achievable potential, a key output of the MPS, was not available to EFG and CAC until very late in the development of the MPS;
    - Duke's MPS contractor, Resource Innovations ("RI"), did not respond to feedback on the study's achievable and technical potential;
    - Similarly, feedback on the demand response portion of the market potential study was ignored;
    - Duke did not include emerging technologies in its study, which leads to an overly constrained potential;
    - Duke did not seek input on how it bundled energy efficiency in its IRP model;
    - Duke's MPS does not include peak time rebates or time of use pricing;
    - Duke's use of participation rates to constrain achievable potential is poorly justified.

1 Stakeholder Workshops and Material Provided to Stakeholders

First, we acknowledge and express appreciation for improvements to Duke's IRP process. [Importantly, this portion of our comments do not apply to the demand-side management market potential study.] Duke made significant changes to its stakeholder process. The concerns that we raised in the last IRP include a lack of two-way exchange of information during the stakeholder process, stakeholders not having important information, including modeling files, until after the IRP was filed, and Duke's disagreement with stakeholder recommendations to improve the modeling approach or inputs. In order to rectify concerns with the 2021 IRP stakeholder process, we made recommendations to incorporate a data sharing process with stakeholders similar to that AES Indiana has utilized for its last two IRPs.

A transparent and collaborative environment is the foundation for 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. 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 after the IRP has been filed.

Duke's process change for this IRP allowed for more meaningful collaboration with stakeholders. Engaging in dialogue around modeling inputs and allowing for more recommendations allows stakeholders to feel as though they are being taken seriously. 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. We recognize that not all stakeholder feedback will be incorporated into the IRP and that there will be items with differing opinions between the utility and stakeholders. In these instances, it is important for both sides to feel like their perspectives have been shared with and considered by the other side. We appreciate that our feedback was often acknowledged and, in some cases, implemented.

While we are appreciative of the significant improvement from the last IRP, there are still areas where the stakeholder process should be further improved. For example, during one of the 2024 stakeholder meetings, EFG asked if Duke would be able to provide the supporting workbooks for its firm gas transportation costs. Duke said that this could not be provided to stakeholders, even under a non-disclosure agreement ("NDA"), as it contained confidential details around potential gas supply. Not being able to access supporting information related to an important modeling input is concerning, especially given Duke's modeling of supply side resource options including new combined cycle gas ("CC"), dual fuel operations, or conversions to operate 100% on gas. We requested this information to help understand the extent that this input would impact the costs of these supply side resource options, including whether or not additional costs, such as lateral pipeline costs, were included. It was unclear why this information would be excluded from review by stakeholders who have signed NDAs. Similarly, Duke acknowledged that there were legitimate concerns about the learning rate applied to its SMR capital cost, but did not end up making any changes to its cost assumptions.

2 EnCompass Modeling

2.1 Combined Cycle Capital Cost

One of the supply side resources evaluated as part of Duke's 2024 IRP included a 1x1 combined cycle. Based on EFG's review, the cost assumptions used by Duke are unreasonably low and inconsistent with the current market for such facilities.

EFG works in jurisdictions across the country, and we have increasingly seen gas turbine original equipment manufacturers demand reservation fees for turbines. EFG has also increasingly seen a widening gap between the generic costs for new CCs modeled in an IRP and the costs that utilities report when a Certificate for Public Convenience and Necessity ("CPCN") is filed. Duke reported $1,450-$1,550 (2024 $) per kW for the capital cost modeled for a new 1x1 CC.[1] However, this is the starting capital cost, not when the resource is selected in the model, which is important to evaluate when accounting for any technology curves applied. In the case of the 1x1 CC, Duke's model EnCompass could not select a new CC until 2030,[2] which is actually a capital cost of $[redacted]/kW.[3]

Kentucky Utilities and Louisville Gas and Electric ("KU/LG&E") recently filed its 2024 IRP which assumed a new 1x1 CC was $2,121/kW in 2030 dollars.[4] This capital cost is significantly higher than what Duke modeled for this IRP. It is important to note that KU/LG&E recently (prior to filing their 2024 Joint IRP) underwent a CPCN application for a new 1x1 CC so they are familiar with the current market conditions and costs for constructing new CC units.

2.2 Combined Cycle Capital Cost Sensitivity

As part of the modeling runs conducted for this IRP, Duke did evaluate a capital cost sensitivity where CC and combustion turbine ("CT") resources were modeled with a 60% higher capital cost compared to the base forecast.[5] Table 1 below shows the impact that the increased capital cost for new CC resources has on the amount of new CCs selected by 2035 from the reference case. Using more realistic cost assumptions for a new CC resource results in the model selecting *half* as much capacity from new CCs under Blend 2 (the basis of Duke's Preferred Plan), demonstrating that Duke's overly optimistic cost assumptions played a significant role in driving gas additions.

In addition, Duke's Preferred Plan includes the retirement of Cayuga Units 1 and 2 by the beginning of 2030 and 2031 with CC replacements.[6] Upon review of the EnCompass modeling

[1] Duke Energy Indiana 2024 IRP, Table 3-24 at 93.
[2] Duke Energy Indiana 2024 IRP, Table C-21, page 239.
[3] Duke provided workbook named "CONFIDENTIAL_IRP Generic Unit Summary Midwest".
[4] KU/LG&E 2024 Joint IRP Volume III (Oct. 18, 2024), Technology Update, Table 1 at 4. Kentucky PSC Case No. 2024-00326.
[5] Duke Energy Indiana 2024 IRP at 141.
[6] Duke Energy Indiana 2024 IRP at 151.

files, however, it does not appear that Duke tested the CC replacement at the Cayuga site under this capital cost sensitivity since the Cayuga CC Units were assumed to be included in the plan. Duke should have re-optimized the plan around the increased capital cost assumption to test the CC replacement at Cayuga.

Table 1. Combined Cycle Additions by 2035 (MW)[7]

Strategy	Reference Case	High CC Cost	Change from Ref.
Convert/Co-fire	-	-	-
Retire Coal	3,595	2,876	(719)
Blend 1	2,876	1,438	(1,438)
Blend 2	2,876	1,438	(1,438)
Blend 4	1,438	-	(1,438)
Exit Earlier (Stakeholder)	2,157	1,438	(719)

2.3 Small Modular Reactor ("SMR") Capital Cost

Duke allowed four SMRs, sized at 300 MW each, to be selected in 2037 and each year thereafter.[8] While the generation strategies that Duke evaluated did not economically select any SMRs unless the SMRs were forced into the model, we are nonetheless concerned that the capital cost projections Duke made for this resource are overly optimistic, and inconsistent with industry experience.

Duke reported that the costs for the SMRs are based on Electric Power Research Institute ("EPRI") analysis and reports, information from vendors, and other engineering studies.[9] Duke's 2024 starting capital cost is $11,150/kW;[10] however, this cost sees a significant cost decline in Duke's model between 2024 and the first year in which it can be selected, 2037, because of the learning rate reduction Duke assigned to this resource. In the supporting workbooks that Duke provided for its capital cost development for supply-side resources, the learning rate reduction is applied starting in [redacted], translating into $[redacted]/kW by 2037.[11] We are concerned about the application of this learning rate because of the assumption that cost reductions happen immediately *without the benefit of actually constructing and operating these reactors first*. Not only is this nonsensical, but it does not align with the fact that history has shown that nth-of-a-kind reactors have typically cost *more* than first-of-a-kind reactors.[12]

Duke also modeled an advanced reactor ("AR") with thermal energy storage that was available for the model to select starting in 2039. For this resource, Duke assumed that a learning rate

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[7] Duke Energy Indiana 2024 IRP, Table 4-3 at 141.
[8] Duke Energy Indiana 2024 IRP at 86.
[9] Duke Energy Indiana 2024 IRP at 90.
[10] Duke Energy Indiana 2024 IRP, Table 3-19 at 91.
[11] Duke provided workbook named "CONFIDENTIAL_IRP Generic Unit Summary Midwest".
[12] See https://www.cell.com/action/showPdf?pii=S2542-4351%2820%2930458-X

would not be applied to the capital cost until [redacted].[13] It is not clear why Duke took a different approach between the SMR and the AR resources for the application of the learning rate and the cost reduction.

While Duke's Preferred Plan does not include the selection of SMR resources, Duke did include SMRs as a forced resource decision as one of the strategy variations evaluated. Including the SMR resources resulted in an increase of the Present Value of Revenue Requirements ("PVRR") by 2.9%.[14] This result is likely optimistic since it assumes the decline in the capital costs for SMR resources under Duke's assumptions. Given the identified problems with Duke's modeling inputs and the IRP results that nonetheless demonstrate that SMRs are not part of a least-cost portfolio, Duke lacks a reasonable basis or solid foundation for a proposal to develop SMRs in Indiana or recover their costs from captive consumers.

2.4 Edwardsport Conversion

In six of the seven generation strategies that Duke evaluated, Edwardsport was assumed to be converted to gas-only operations on January 1, 2030. [15] In one generation strategy, Duke evaluated a later conversion on January 1, 2035, and in one of the generation strategy variations, Duke modeled an Edwardsport conversion on January 1, 2028. Confidential Table 2 shows the comparison of the total revenue requirements Duke modeled for the three different Edwardsport conversion dates. As can be seen, there is a significant difference in cost if Edwardsport is not converted by 2030. **Based on these costs as well as prior analyses showing similar, significant benefit to customers from conversion, we urge Duke to convert Edwardsport to gas-only operations by 2028 or as soon as is practically feasible**.

Confidential Table 2. Edwardsport Total Revenue Requirements ($000)[16]

Year	Convert 2028	Convert 2030	Convert 2035
2025	[redacted]	[redacted]	[redacted]
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
NPV			

[13] Duke provided workbook named "CONFIDENTIAL_IRP Generic Unit Summary Midwest".
[14] Duke Energy Indiana 2024 IRP, Table 5-2 at 155.
[15] Duke Energy Indiana 2024 IRP, Figure 7 at 10.
[16] Duke file named "Confidential – 111 Generation Strategies and No 111 – Ongoing CAPEX – FOM".

The 2024 IRP continues to show that Duke and its ratepayers could realize significant savings by operating Edwardsport IGCC on natural gas rather than synthesized gas. Commenters request that the Director ask Duke to rectify the biases toward dual-fuel Edwardsport in its IRP and against switching the plant to natural gas operation.

Regarding Edwardsport IGCC, Duke stated in the summary portion of its IRP:

> "Given the substantial uncertainty around the future timing and extent of greenhouse gas regulations, including EPA's new CAA Section 111(d) rule, as well as future fuel prices, the cost of new resources and the pace at which they can be added to the system, and accelerating load growth driven by economic development, Duke Energy Indiana remains confident in the value of the flexibility and optionality provided by the Edwardsport IGCC."[17]

Duke repeated its claim about the "value of the flexibility and optionality" of the dual-fuel IGCC plant later in its IRP.[18] Yet both here and in its Executive Summary, Duke has once again made no effort to quantify the value of this alleged flexibility. In fact, that value is highly questionable, since in Duke's recent electric base rate case (Cause No. 46038), Duke's expert witness, Mr. William C. Luke (Vice President of Midwest Generation for a Duke affiliate), admitted that when Edwardsport's gasifiers are turned off, turning them on again takes 14 days.[19] Additionally, John A. Verderame (Vice President of Fuels and Systems Optimization for a Duke affiliate), divulged at the recent rate case evidentiary hearing that the flexibility of Edwardsport to switch to gas from coal is "limited in scope" in terms of "how big a problem we can really solve."[20]

In contrast to its unsubstantiated claims of flexibility and optionality benefits, Duke's IRP modeling shows that ratepayers would experience significant savings by converting Edwardsport to natural gas. In particular, based on such modeling, Duke concedes that "converting Edwardsport to natural gas by 2028 [] shows potential savings [], offering a PVRR reduction of approximately 0.6%."[21] 2028 is a critical decision point due to the major outage planned for Edwardsport. Given a total PVRR of $24.3 billion, that 0.6% amounts to approximately $145 million in savings from converting Edwardsport to natural gas two years earlier than the 2030 conversion that Duke assumes for Rule 111 compliance. There is every reason to think that even earlier conversion to natural gas would save ratepayers even more money. Conversely, delaying conversion to 2035, as Duke suggests it would do in a scenario without the 111 Rule,[22] would further compound the losses that ratepayers continue to incur from Edwardsport's operation on synthetic gas.

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[17] Duke Energy Indiana 2024 IRP at 18.
[18] Duke Energy Indiana 2024 IRP at 155.
[19] Cause No. 46038, Tr. D-58.
[20] Cause No. 46038, Tr. E-77.
[21] IRP at 155.
[22] IRP at 10, Figure 7.

It is no surprise that an earlier conversion to gas would save customers money. Evidence in the recent rate case established that Edwardsport has been uneconomic (that is, its production costs exceeded its market revenues) when running on coal in certain recent periods. For example, in [redacted], while when Duke had to operate the plant on only natural gas due to a gasifier outage in 2023, the Company [redacted] relative to what it would have paid to operate the unit on coal.[23] Further, Duke expert John D. Swez (Managing Director of Trading and Dispatch for a Duke affiliate) admitted that Duke offers Edwardsport into the MISO energy market as a must-run unit nearly all the time – "very, very high … generally always" -- when it runs on syngas.[24] And, as Duke admitted, running Edwardsport only on natural gas would allow Duke to potentially offer Edwardsport into the MISO energy market for economic commitment, instead of offering it on a must-run basis.[25]

Information advanced in Cause No. 46038 showed that according to FERC Form 1 data, the 5-year average non-fuel production cost for Edwardsport is $154.29 per kW of capacity, which is over ten times more expensive than the $14.80 average cost of other similarly-situated natural gas combined cycle plants, and more than five times more expensive than the next-highest natural gas plant.[26] Additionally, the average annual non-fuel operating and maintenance cost for Edwardsport on syngas over 2021 through 2023 was almost $87 million, whereas Duke projected $22.2 million of the same non-fuel O&M cost in the scenario where it converted Edwardsport to run only on natural gas in 2025.[27]

In the rate case, Duke witness Luke objected to the use of the 2025 projection for non-fuel O&M cost, because it originated in Duke's 2021 IRP and the figures were not "rate case quality."[28] Mr. Luke averred that the Company has not studied in detail the potential operating costs for operating Edwardsport on gas only, because it has not yet made any decision to cease coal gasification, and "high-level planning quality estimates will suffice for directional purposes in the IRP."[29] He further admitted that if he saw "evidence of a recommended retirement date of said asset [the gasifiers][,] [t]hat would prompt me to determine if it was the right time to perform such a study."[30]

Duke cannot evade meaningful Commission review by using only "high-level planning quality" figures in the IRP and then resisting further scrutiny by declining to produce "rate case quality" data. In fact, in the recent Final Order in Duke's 2024 base rate case, the Commission

[23] Cause No. 46038, Direct Testimony of Glick (CAC Ex. 4) at 26.
[24] Cause No. 46038, Tr. G-63.
[25] Cause No. 46038, IG Ex. 1 at 25.
[26] Cause No. 46038, Direct Testimony of Gorman (IG Ex. 1) at 19. What's more, FERC Form 1 data also showed that annual capital improvement costs at Edwardsport over 2022 and 2023 were over four times those costs at similarly-situated natural gas combined cycle plants. *Id.* at 24.
[27] Cause No. 46038, Direct Testimony of Comings (Sierra Club Ex. 1) at 26.
[28] Cause No. 46038, Rebuttal Testimony of Luke (Duke Ex. 40) at 29.
[29] *Id.* at 30.
[30] Cause No. 46038, Tr. D-69.

"emphasize[d] the importance of Duke continuing to improve the robustness of its analysis and discussion of the qualitative considerations in its IRP (and relevant docketed proceedings) with respect to the various operating options available at Edwardsport."[31] To the extent that Duke believes that the data it used in analyzing Edwardsport is of insufficient quality, the Company should remedy that shortcoming now in this IRP process, rather than using its own data inadequacies as an excuse to continue incurring substantial losses operating the plant on synthetic gas.

In the recent base rate case Order, the Commission declined to determine that there should be a permanent fuel switch at Edwardsport in part because "the Company is currently in the middle of its 2024 IRP process and is considering these same issues in the context of that process. As such, it would be premature for the Company or the Commission to make any determinations in this proceeding regarding a permanent fuel switch at Edwardsport until that process has had an opportunity to play out."[32] This IRP is now the best forum for a careful consideration of the best evidence on how Edwardsport should be operated to minimize customer cost burdens. Commenters respectfully encourage the Director to emphasize this imperative in a final Report on this IRP because the IRP data shows that Duke should convert Edwardsport to gas-only operations by 2028 (which is a critical decision point due to the planned major outage for Edwardsport that year) or as soon as is practically feasible.

2.5 Resource Availability

The first year in which a resource can be selected in a capacity expansion model and any build limits applied to new resources are important, as they impact when the model can start selecting resources and how much of each resource can be added in any given year over the study period. It is not atypical to model annual build limits on resources in capacity expansion modeling. However, those limits merit scrutiny when they become binding, meaning that the model selects the maximum amount of a resource available in any given year. This tends to mean that if those limits are relaxed, the model may want an even higher amount of that particular resource because it finds it cost-effective to add more of the resource sooner rather than deferring building the resource or adding a less cost-effective option.

Table 3 shows the annual resource build limits that Duke modeled for solar, solar paired with storage, standalone battery storage, and wind resources. Throughout the stakeholder process, CAC submitted comments asking for Duke to consider relaxing the build limits. Based on the feedback, Duke did slightly relax the solar and wind build limits starting in 2032. While we appreciate the consideration of the feedback and slight modification to the resource builds, it would be helpful to understand how that might impact builds prior to 2032. In Duke's Preferred Plan, 300 MW of standalone storage is selected in 2028,[33] which makes the battery storage build limit binding in that year. In the IRP stakeholder process, CAC had recommended relaxing the

[31] Order, Cause No. 46038, Jan. 29, 2025, at ___.
[32] Order, Cause No. 46038, Jan. 29, 2025, at 21.
[33] Workbook named "DEIN 24 IRP 111 Blend 2 – CAY 1x1s PC".

build limits for battery storage to account for the ability to site storage at existing sites of Duke-related renewable projects and at the sites of power plants that are being evaluated for retirement. In addition, the 2023/2024 request for proposals ("RFP") that Duke released resulted in bids totaling around 2,000 MW of battery storage capacity.[34]

Table 3. Annual Resource Build Limits (MW) for Reference Case[35]

Resource	2027	2028	2029	2030-2031	2032
Solar	300	1,150	1,400	1,600	1,800
Storage with Solar	0	575	700	800	900
Standalone Storage	0	300	300	700	700
Wind	0	200	200	300	400

2.6 Wind Repowering for Benton County Wind

One of the assumptions that Duke made consistent across all modeling runs is that the 100 MW power purchase agreement ("PPA") for the Benton County wind farm expires and is removed from all portfolios as of January 1, 2028.[36] It is not clear if Duke evaluated the potential to repower this project. Repowering can involve increasing rotor length or increasing rotor length and hub height. Repowering can increase the capacity factor, can be PTC-eligible, would increase nameplate capacity, and could be more cost-effective than building a new wind project. We understand that Duke does not own these farms, but if their lives are extended, an offtaker will still be needed and Duke, 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.

[34] Duke Energy Indiana 2024 IRP, Table G-10 at 435.
[35] Duke Energy Indiana 2024 IRP, Table 3-9 at 85-86.
[36] Duke Energy Indiana 2024 IRP at 54.

As an example of this, in its most recent IRP, Ottertail Power ("OTP") evaluated the repowering of some its wind projects and concluded it would move forward with repowering those facilities in 2024 and 2025. For OTP, the repowering of its wind projects provided higher energy, capacity, and the ability to capture PTC benefits from the projects. Table 4 below shows the additional energy generation OTP will be able to obtain from the four wind resources they are planning to repower.

Table 4. OTP Wind Repowering[37]

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

2.7 Market Interaction

As part of the modeling performed in EnCompass, the model is allowed to engage in economic purchases or sales with a representation of the MISO energy market through interaction with an hourly market price forecast in the model. For the capacity expansion modeling, Duke included a constraint that required resource portfolios to be able to supply at least 75% of the annual customer energy, which was enforced in the capacity expansion model starting in 2030.[38] Duke then relaxed this constraint for the production cost modeling step.

Figure 1 shows the energy mix for the different generation strategies in the Reference Scenario. When the market constraint is removed from the production cost modeling step, there is a significant reliance on economic market purchases in 2035 for all generation strategies with the exception of the "No 111" strategy. This proportion of economic purchases in 2035 significantly decreases by 2044, when those purchases are offset by solar and wind energy. While we understand that Duke has a significant number of modeling runs to manage for an IRP, it would be helpful and informative for additional testing on this result, whether that be through adding a constraint into the production cost modeling step, adding a hurdle rate to the market price, or accelerating renewable resources.

[37] OTP Supplemental Resource Plan (March 31, 2023), Table 4-4, page 25. Minnesota PUC Docket No. E017/RP-21-339.
[38] Duke Energy Indiana 2024 IRP at 69.

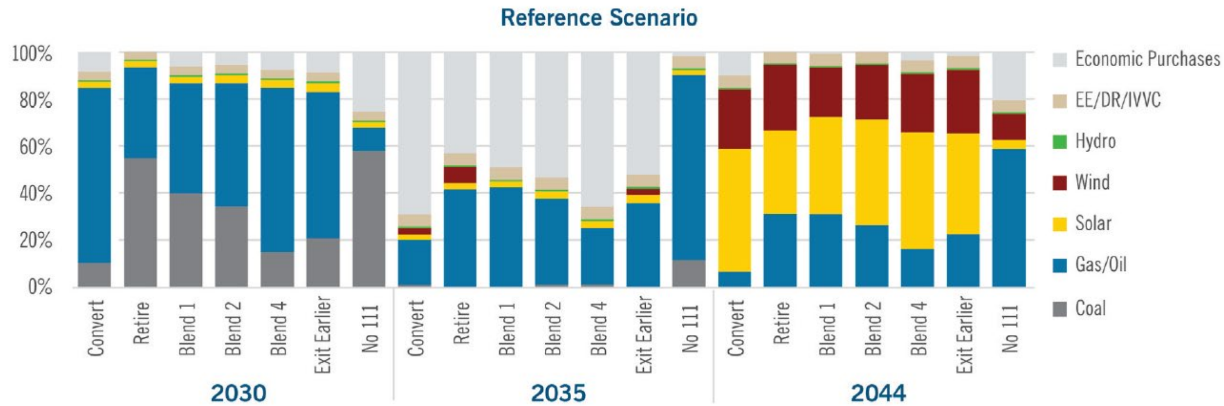

Figure 1. Duke Reference Scenario[39]

[39] Duke Energy Indiana 2024 IRP, Figure 4-3 at 108.

3 Portfolio Scorecard Metrics

3.1 Execution Risk

Duke also included an Execution Risk metric that was calculated as the cumulative resource additions through 2030 and 2035, as a total MW and a percent of MW capacity. [40] We expressed concern about this metric in the stakeholder process because calculating this as a cumulative addition of total additions places all technologies together into one bucket, which does not capture execution risk and construction timeframes that may be unique to each technology type. Duke's Preferred Plan includes 2,876 MW of CCs, 499 MW of solar, and 400 MW of battery storage in the short-term action window.[41] Since the resource build is heavily weighted by CC capacity additions, any risks unique to a CC build versus solar or storage would not be captured under this approach. It would be helpful if Duke replaced the single metric approach with a timeline that illustrates when pre-construction activities such as design would have to start, when contracting and then construction is likely to commence, and when the project would come online. This would provide a sense of how important deciding on any particular resource would be and also to what degree sequencing risks the projected online date.

3.2 Resiliency Metrics

3.2.1 Resource Diversity

One of the Resiliency metrics that Duke evaluated included Resource Diversity, which Duke calculated based on the Herfindahl-Hirschman Index ("HHI") of the capacity resources by technology type, measured on a firm capacity basis in 2035.[42] Lower values for the HHI indicate greater diversification. We recommend that Duke consider alternative metric calculations for trying to capture resource and fuel diversity. For example, Duke could base this calculation on the number of unique generators or the number of different fuel types.

3.2.2 SERVM Modeling for Enhanced Reliability Evaluation

One of the new modeling tools that Duke utilized for the 2024 IRP is the Strategic Energy and Risk Valuation Model ("SERVM") from Astrapé Consulting. SERVM evaluates several areas of risk – weather, economic forecast error, load uncertainty, and unit performance – to evaluate reliability events for an electric system. For weather and load-related risk, SERVM uses historical weather patterns to develop load profiles for each weather year to predict how loads would respond if the weather experienced in that particular year were to repeat. SERVM then applies load forecast error multipliers with their associated probabilities to capture the potential for uncertainty in economic forecasts. Since economic variables are typically one of the key variable inputs into the development of a load forecast, the load forecast error multipliers simulate the expected probability that the peak demand would be higher or lower because of an error in the economic indicator forecast. The weather years included in the model also reflect the

[40] Duke Energy Indiana 2024 IRP at 47.
[41] Duke Energy Indiana 2024 IRP, Table 6-1 at 168.
[42] Duke Energy Indiana 2024 IRP at 46.

uncertainty around renewable resources, as the profiles for each resource will reflect the expected availability for that resource based on the historical weather profiles. SERVM models the uncertainty around generator unit availability through the simulation of random unit outage draws.

For this IRP, Duke's SERVM model evaluated the dispatch of the Duke system, assuming that it was an island and could not have any interaction with neighboring utilities. The first step in this modeling was to evaluate the changes in the likelihood of market reliance from 2028 to 2035 across the generation strategies.[43] Market reliance was calculated by evaluating the resulting expected unserved energy ("EUE") reported in the SERVM modeling. For the Resiliency Metric, Duke used the SERVM modeling results to calculate the EUE in the 95th percentile of cold weather.

Since this was a new step for Duke's IRP, there was not time for stakeholders to review the SERVM database and modeling input and output files in time to provide Duke with feedback that could be incorporated into the analysis. It is our understanding that Duke will plan to account for this timeline for review in future IRPs. We do have several suggested modeling changes that we ask that Duke incorporate for any future SERVM analysis. Each of these recommendations is discussed in more detail below.

3.2.2.1 Load Shapes in SERVM

The SERVM model uses historical weather patterns to develop load profiles for each weather year to predict how loads would respond if the weather experienced in that particular year were to repeat. As Duke reported, "Astrapé Consulting uses a combination of neural network and linear regression models to project future hourly loads based on the Company's historical load history. To maintain consistency with the broader IRP, these hourly modeled loads are scaled to ensure that the median simulation in SERVM matches the 50/50 peak load and 50/50 annual energy of the load forecast used in the EnCompass model."[44]

This means that the forecasted peak load and energy for 2035 is input into SERVM, and then SERVM will scale the historical load so that the median of those weather years results in the forecasted peak load and energy for 2035. We have concerns about this approach because the 2035 forecast will include assumptions around electric vehicles ("EV") and new large load customers (such as data centers or EV manufacturers) into the load that will be scaled. The result is that the scaling could overestimate load related to EVs and new customers.

We recommend that Duke remove EV and new large load customers from the projected forecast and model EVs with a profile for each weather year that can incorporate weather and assumptions around charging. For new large load customers with a flat or consistent load factor, those can be modeled as a negative generating unit that has the same shape across each weather year.

Assumptions around the charging patterns for EVs may impact the risk hours for EUE in the SERVM model. We think it's important to represent these loads explicitly to help derive the value of different scenarios of managed charging, but this can only be accomplished if EV load is not

[43] Duke Energy Indiana 2024 IRP at 148.
[44] Duke Energy Indiana 2024 IRP at 318.

baked into the load forecast. For example, the following are charging load profiles for Seattle City Light but, based on our experience, are generally representative for other regions as well. Figure 2 represents a shape of unmanaged charging with most residential customers beginning charging upon arriving at home. Figure 3 represents a scenario in which charging largely occurs at home but is managed so that charging occurs in the early morning hours.

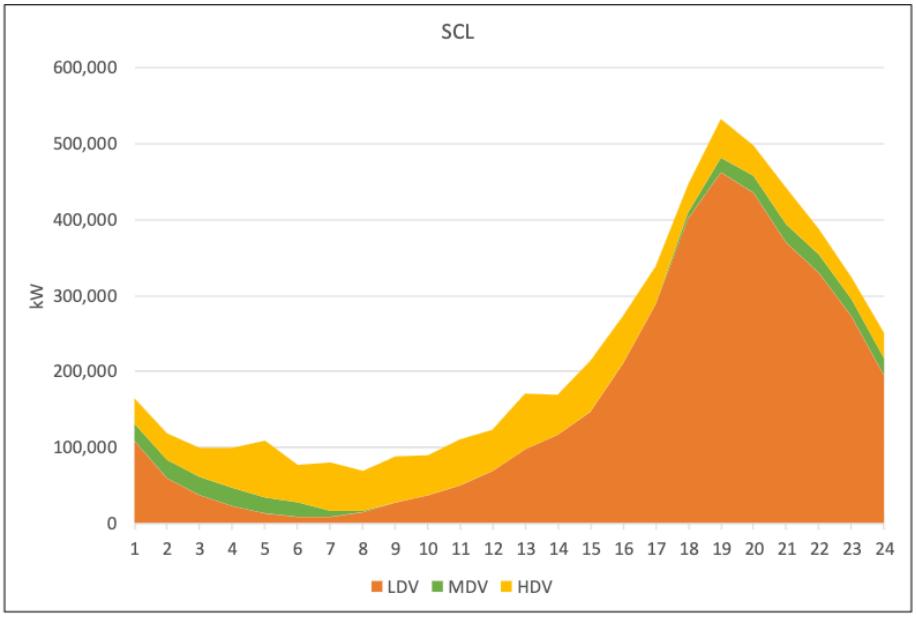

Figure 2. Unmanaged charging with significant charging at home[45]

[45] See pdf page 47 of https://www.pnnl.gov/sites/default/files/media/file/EV-AT-SCALE_1_IMPACTS_final.pdf

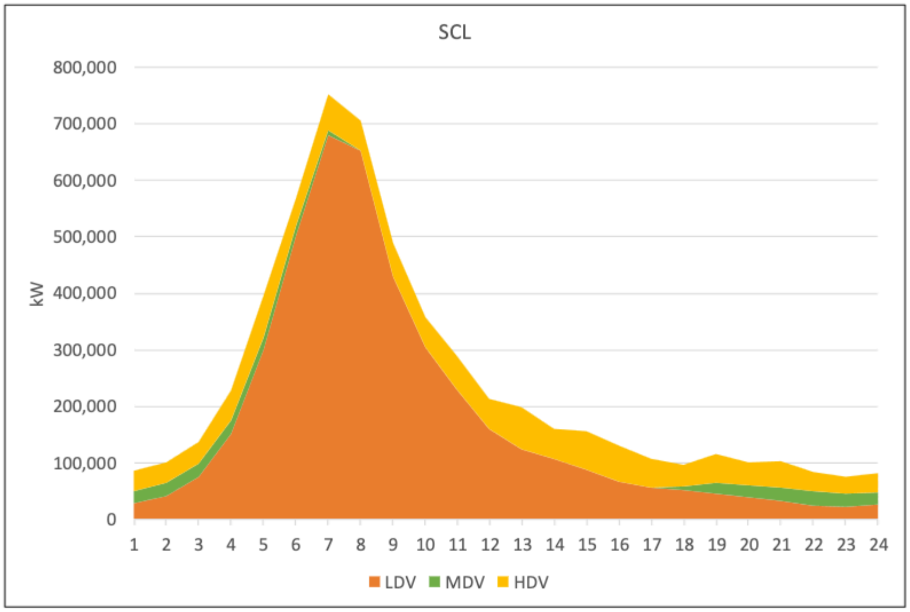

Figure 3. Managed charging with significant charging at home[46]

For new large load customers such as data centers, Duke can utilize data from those customers on the expected usage (if they are a new customer to the system) or experienced load (if the customer has been connected to the system). If Duke removes these customers from the forecast input into SERVM and models them like a negative generating unit with its own shape, then intra-day and seasonal variations can still be captured but will more accurately reflect the load since there will be some variation as a result of cooling needs. Figure 4 shows an example of data center load that changes by month and Figure 5 shows an example of data center load on an hourly basis.

[46] See pdf page 47 of https://www.pnnl.gov/sites/default/files/media/file/EV-AT-SCALE_1_IMPACTS_final.pdf

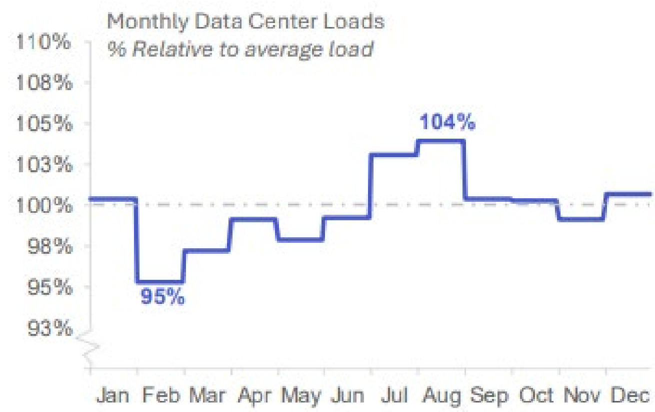

Figure 4. Monthly Data Center Loads[47]

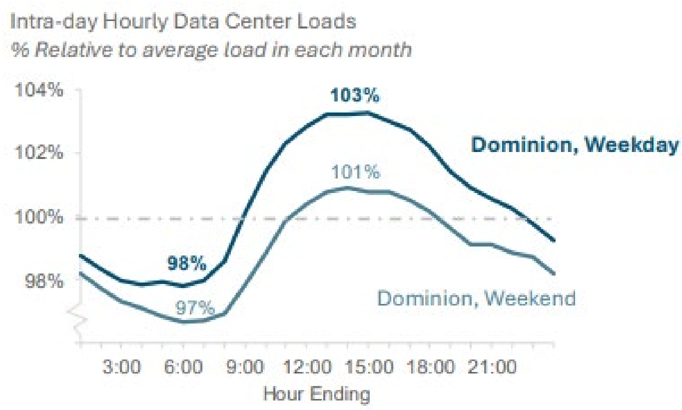

Figure 5. Intra-day Hourly Data Center Loads[48]

[47] Virginia Data Center Study. (December 2024). Energy+Environmental Economics. Slide 130. Retrieved from https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

[48] Virginia Data Center Study. (December 2024). Energy+Environmental Economics. Slide 130. Retrieved from https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

3.2.2.2 Modeling Duke as an Island in SERVM

For the modeling that Duke performed in SERVM, it was assumed that Duke would be unable to interact with the MISO market. Instead of relying on the assumption that the market would not be available for Duke, we recommend that Duke model a representation of market availability similar to how MISO models import capability from external regions in its own modeling. MISO utilizes the SERVM model for its Loss of Load Expectation ("LOLE") study that establishes the seasonal planning reserve margins ("PRMs"). As part of the modeling that MISO performs in SERVM, assumptions are made around the availability of non-firm imports from external connections to MISO based on historical data. Table 5 below shows the import distribution that MISO modeled for its 2024/2025 LOLE Study. SERVM will capture this import distribution by modeling random draws on the limits specified for this region to represent the amount of capacity MISO would be able to import.

Table 5. Import Distribution (MW) from MISO 2024-2025 LOLE Study[49]

Percentile	Summer	Fall	Winter	Spring
P5	1,138	525	9	1,384
P10	1,440	903	288	1,626
P25	2,959	1,749	1,223	2,283
P50	4,260	2,601	3,292	3,717
P75	5,198	3,632	5,785	4,987
P90	5,921	4,935	8,097	6,221
P95	6,520	5,748	9,197	6,497

Duke could also implement this approach by developing a distribution of market imports based on historical data. This would allow SERVM to capture the risk of market access without assuming that there is no market availability by modeling Duke as an islanded system.

Modeling a distribution for market access can also help address EUE that shows in the model during periods where Duke has units out for planned or forced maintenance.

3.2.2.3 Cold Weather Outage Adder

MISO's LOLE modeling also includes assumptions around additional forced outages resulting from extreme cold temperatures in the winter. Historical GADs and weather data are used to develop a relationship between outages and temperature that can be reflected in SERVM as an incremental outage. It is our understanding that Duke has not incorporated this into its SERVM modeling based on the temperature and outage relationship observed for Zone 6. However, given the changes in the resource fleet that Duke is projecting, which includes winter firm capacity from gas increasing from 30.1% in 2023 to 71.4% in 2044, and increasing from one existing

[49] MISO Planning Year 2024-2025 Loss of Load Expectation Study Report, Table 3-5 at 32. Retrieved from https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf

CC[50] to multiple new CCs, Duke should continue to evaluate the need for the cold weather outage adder as more gas resources are added to the system.

3.2.2.4 Combined Cycle Forced Outage Rate

SERVM models the uncertainty around generator unit availability through the simulation of random unit outage draws. We are concerned about the forced outage rate that was modeled for new CC units, which Duke modeled at [redacted]%. Table 6 shows the seasonal class average forced outage rates for CC units in MISO. We recommend that Duke model an increased forced outage rates for CC units.

Table 6. MISO Combined Cycle Seasonal Class Average Forced Outage Rates for Planning Year 2024-2025[51]

Season	Class Average Forced Outage Rate (%)
Summer	5.92%
Fall	7.43%
Winter	5.38%
Spring	6.55%

[50] Duke Energy Indiana 2024 IRP, Table B-1 at 198.
[51] MISO Planning Year 2024-2025 Loss of Load Expectation Study Report, Table 3-2 at 27. Retrieved from https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf

4 Demand Side Resources

4.1 Market Potential Study

Duke Energy Indiana engaged with Resource Innovations ("RI") in 2023 and 2024 to determine the potential energy and demand savings that could be achieved by demand-side management ("DSM") programs. The resulting market potential study ("MPS") quantified technical, economic, and achievable energy efficiency ("EE") and demand response ("DR") savings for years 2025 through 2049. Achievable savings were further grouped into three scenarios as follows:

- **Base** – reflects current Duke programs and program costs, incentive rates, and utility avoided cost benefits generated by the program; includes estimated impacts from the 2022 Inflation Reduction Act ("IRA").
- **High Incentive** – doubles current incentive rates with a cap at 75% of the measure incremental cost; applies utility avoided cost benefits from the base scenario.
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates.

Duke and RI sought input from members of the Duke DSM Oversight Board ("OSB"), including CAC, during the development of the MPS until its completion in August 2024. There were several areas of concern and recommendations made by CAC and EFG which RI did not accept or incorporate. These areas of concern are discussed in sections 4.2 (Energy Efficiency) and 4.3 (Demand Response).

4.2 Energy Efficiency

4.2.1 Stakeholder Engagement

While Duke and RI were generally receptive to input during the MPS process, there were long delays between EE stakeholder meetings. For example, three months passed between the MPS kickoff meeting on 9/21/2023 and the next stakeholder meeting on 12/15/2023; three more months passed until the presentation of energy efficiency technical potential on 2/21/2024; and three more months passed until the first presentation of EE economic and achievable potential on 5/15/2024. By the time achievable potential was being presented, which is a very advanced stage of MPS development, CAC and other stakeholders had had only three opportunities to meet with and provide input to Duke and RI. In contrast, MPS development processes with other Indiana utilities have used bi-weekly or monthly stakeholder meeting schedules to allow numerous opportunities for review and input.

As the MPS development process advanced, RI stopped providing formal responses to comments. Specifically, formal responses were never provided to CAC comments on EE technical potential and achievable potential, as shown in Table 7.

Table 7. Dates of CAC EE Comments and RI Responses

MPS Topic Area	Date of CAC Comments	Date of RI Response
General Areas of Interest	10/13/2023	10/31/2023
EE Measure Algorithms	12/4/2023 (residential) 12/8/2023 (commercial) 12/18/2023 (industrial)	1/29/2024
EE Market Baseline	1/5/2024	1/29/2024
EE Technical Potential	3/8/2024	None[52]
EE Achievable Potential	5/29/2024	None[53]

4.2.2 Measure Assumptions

CAC raised concerns about numerous EE measure assumptions used in the MPS. While RI was responsive to some of the CAC input, other feedback was not addressed. These include:

- Limited visibility into influential factors such as saturation levels, applicability factors, and adoption rate. These factors are core components of the technical potential equation, shown below in Figure 6, and the adoption rate influences the achievable potential. The lack of transparency was raised at the IRP stakeholder meeting on April 29, 2024, and again at the MPS stakeholder meeting on May 15, 2024. Following this feedback, RI provided a "Data Import Template" which contained some, but not all, of these factors. Adoption rates were a notable omission. Furthermore, at this late stage of MPS development, it would have been challenging to revise key assumptions that affect technical potential. This information should have been shared months earlier when technical potential was still being developed.

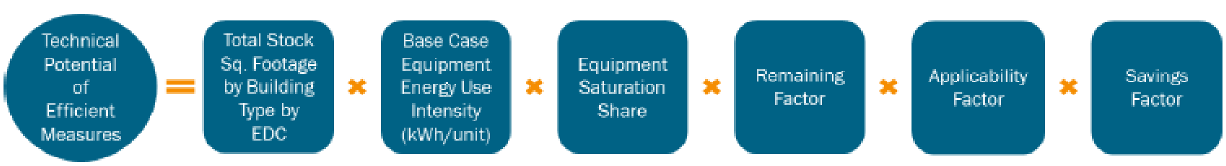

Figure 6. MPS Equation for Nonresidential Technical Potential[54]

[52] Portions of the CAC input were responded to verbally at the MPS stakeholder meeting on May 15, 2024. An email response to one of the comments was received on May 28, 20204. A full written response was not provided.
[53] Portions of the CAC input were responded to verbally at the MPS stakeholder meeting on July 16, 2024. A written response was not provided.
[54] Duke Energy Indiana 2024 Market Potential Report, Equation 5-2 at 23.

- On three separate occasions, CAC provided comments on the square feet assumption used for residential single-family homes.[55] This value is an important and influential factor given the large number of measures which rely on it as an input to the savings calculation. Of the 113 unique measures modeled within the residential sector, 46 measures (41%) use single family square footage as an input in the savings algorithm.[56] CAC recommended that the study use a single-family square footage value of 2,269 ft^2 based on the EIA Residential Energy Consumption Survey ("RECS") results for Indiana, which is 22% higher than the assumed value of 1,857 ft^2 used by RI. Our rationale is summarized below in Figure 7.

Regarding the residential sqft parameter (residential measure comments #1), RI indicated that the following values used in the study are based on RECS 2020 microdata:

1,857.1	Average single family square footage
897.2	Average multifamily square footage
1,157.7	Average mobile home square footage

The single-family home square footage does not appear to be weighted by the number of detached and attached single family homes. The following figures and resulting weighted average are based on the RECS 2020 microdata:

Home Type	Number of Homes	Total Square Feet	Avg Sq Ft
SF-Detached	1,990,016	4,585,325,390	2,304
SF-Attached	125,056	212,742,907	1,701
Total	**2,115,072**	**4,798,068,297**	
	Weighted Avg		**2,269**

CAC requests that the weighted average value of 2,269 square feet be used for single family homes.

Figure 7. CAC Comment Provided on March 8, 2024[57]

RI provided an email response to this comment on May 28, 2024, indicating that the difference in square feet is due to RI using the variable "SQFTEST" from the RECS data set, while CAC's calculations were based on TOTSQFT_EN. In that same email, RI indicated that a higher square footage value would indeed increase the savings potential identified. CAC reaffirmed our recommendation in comments submitted on May 29, 2024, shown below. A response from RI was not received.

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[55] CAC comments on residential algorithms, sent on 12/4/2023; CAC comments on technical potential, sent on 3/8/2024; and CAC comments on achievable potential, sent on 5/29/204.
[56] Per 20231129_DRAFT_DEI MPS Measure Algorithms and Impacts_Energy Efficiency.xlsx
[57] CAC comment on technical potential, submitted on March 8, 2024.

> *"CAC recommends that the residential single family square footage assumption be derived using the RECS microdata variable TOTSQFT_EN rather than SQFTEST. The TOTSQFT_EN variable is appropriate to use since it reflects the total energy-consuming area of the housing unit. According to EIA, TOTSQFT_EN includes "all main living areas; all basements; heated, cooled, or finished attics; and heating or cooled garages." Any calculation of home heating and cooling should consider all spaces within the thermal envelope. Basements are appropriate to include since they are within the thermal envelope, as defined in the 2020 Indiana Residential Code. Responded-reported square footage (SQFTEST), on the other hand, may include unconditioned spaces such as garages and may exclude spaces that should be counted within the thermal envelope (such as basements)."*[58]

4.2.3 Emerging Technologies

The MPS made 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 routinely 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 a conservative and unrealistic view of future potential savings.

4.2.4 IRP Bundles

Duke grouped the energy efficiency outputs from the MPS into "bundles" to be available as selectable demand-side resource options in the 2024 IRP. Bundle 1 represents the existing approved Duke DSM programs for 2025-2026. Starting in 2027, the bundles consist of savings and costs as identified by the MPS. These bundles are shown below in Table 8. Bundles 2 through 5 represent various time vintages from the "Base" MPS scenario described above in section 4.1. Bundles 7 through 10 represent various time vintages from the "High Incentive" MPS scenario.[59]

[58] CAC comment on achievable potential, submitted on May 29, 2024.
[59] Duke Energy Indiana 2024 IRP, page 97.

Table 8. Duke EE Bundles Available for Selection in the 2024 IRP.[60]

Bundle	Type	Year Available	Max Annual Savings (GWh)	Levelized Cost ($/MWh)
Bundle 1	Base	Current	357	$28.86
Bundle 2	Base	2027	459	$32.46
Bundle 7	High	2027	552	$51.22
Bundle 3	Base	2030	667	$33.28
Bundle 8	High	2030	789	$52.72
Bundle 4	Base	2034	1,042	$27.59
Bundle 9	High	2034	1,307	$43.34
Bundle 5	Base	2042	403	$27.59
Bundle 10	High	2042	488	$42.68

The OSB had no opportunity for input on the construction of energy efficiency bundles, nor the calculation of EE levelized cost, used in the IRP. CAC made a recommendation on October 11, 2023, sent via email to RI, to create IRP bundles by sector, cost, and time vintage, and to treat income-qualified ("IQ") separately. Unfortunately, this input was not addressed. Constructing bundles with consideration to IQ eligibility, sector, and cost is important for the following reasons:

1. IQ measures should be bundled separately, since they are not subject to cost-effectiveness screening and should be modeled as a forced-in resource in the IRP.
2. Residential and commercial/industrial ("C&I") sectors should be bundled separately, given the potential that "High" bundles for C&I may be selected in the model,
3. Very high-cost residential measures should be bundled separately, if necessary, to allow for better economic performance of low- and medium-cost residential measures.

Similarly, the EE levelized costs were calculated without input from the OSB. We are unable to identify important considerations such as line loss factors to gross up savings to the generator, the treatment of savings that persist beyond the planning horizon, and the inclusion of transmission and distribution ("T&D") benefits.

[60] Duke Energy Indiana 2024 IRP, Table 3-29 at 98.

4.2.5 EE Selections within IRP Preferred Portfolio

The 2024 IRP Preferred Portfolio includes Bundles 1 through 5 for energy efficiency. These bundles reflect the current approved Duke programs for 2025-2026 (Bundle 1) and the MPS "Base" scenario for 2027 and beyond (Bundles 2 through 5).

Unfortunately, none of the "High" bundles were selected in the Preferred Portfolio, likely due to the higher levelized costs shown in the final column of Table 8. Again, the "High" bundles were based on the "High Incentive" MPS scenario, in which incentives were doubled up to a 75% incremental measure cost cap. We believe a more nuanced approach to incentives would have yielded better results in the IRP modeling. Rather than doubling all incentives, measure incentives could have been adjusted selectively based on factors including customer payback and levelized cost. Incentives do not need to be doubled on measures where the customer payback is already desirable. Similarly, it's not advisable to double incentives on measures where the levelized cost is already high. Doubling incentives across all measures unnecessarily increases costs, even when a cap is employed. The more nuanced approach described above would result in savings and costs greater than the "Base" bundles, but less than the "High" bundles. As a result, the bundles would have had an increased chance of being selected in the Preferred Portfolio.

4.3 Demand Response

4.3.1 Timing of MPS Process

Duke's demand response market potential study fell short in fostering meaningful stakeholder participation and incorporating feedback. Throughout the process, schedules were delayed, and communication was insufficient, leaving stakeholders in the dark about the progress and status of their input. Despite active engagement and detailed comments provided, it became evident that the feedback was disregarded, as the modeling was finalized without addressing or integrating stakeholder concerns. This lack of transparency and collaboration undermined trust in the process and highlighted significant gaps in stakeholder engagement practices. In short, we do not feel that stakeholders were able to provide meaningful input in this DR MPS process, and we request Duke take steps to address this now in collaboration with stakeholders.

Details related to delayed schedule for DR potential milestones:

- RI provided a schedule update on November 17, 2023, indicating that estimates of DR economic and achievable potential would be delivered on February 9, 2024, and March 15, 2024, respectively.
- However, in an update from January 24, 2024, these dates shifted to February 16, 2024, and April 5, 2024.
- On March 5, 2024, RI provided the first file of DR inputs that CAC had seen, containing its list of DR measures, segmentation, and load forecast. This did not include estimates

of economic or achievable potential, nor details on program design or structure for individual measures.

- It was not until July 16, 2024 that CAC finally received information about the estimates of economic and achievable potential through its Oversight Board meeting and draft report, approximately four to five months after the original schedule.
- On July 30, 2024, CAC provided RI with questions and comments on the DR portions of the MPS report within two weeks of receipt.
- After CAC checked in on the status of their response (email sent August 15, 2024), RI acknowledged the slow response, promising answers the following week.
- On August 30, 2024, RI provided responses to the DR comments along with what was characterized as the final MPS draft.

The timeline stated above evidences a lack of organization and timely communication that resulted in no time for further discussion, clarification, or revisions, and ultimately, failure to meaningfully consider and incorporate stakeholder feedback. Holding an engagement process and committing substantial time and resources, only to have it culminate in an inability for stakeholders to sufficiently discuss results or provide feedback fosters distrust, disempowerment, and really perverts the spirit of having an engagement process to begin with.

Ideally, MPS cycles will remain on schedule, and everyone will have clear expectations about due dates for deliverables, comments on deliverables, incorporation of comments into deliverables, and another review of the deliverable before finalizing it and moving onto the step. When scheduling delays occur, sufficient time and safeguards must be built into the process so that it is not at the expense of engagement. Additionally, we request this process give more time for discussion of results, to foster greater transparency and the opportunity to meaningfully provide and adopt feedback prior to finalization.

4.3.2 Missing Measures

CAC had requested that this study include a variety of time varying rate products, including time-of-use (TOU), peak time rebates (PTR), and critical peak pricing (CPP); only one of these (CPP) appeared in the MPS. When asked about why these other measures were omitted, RI's response was "Refer to the presentations, measures lists, memoranda where we describe dynamic pricing as a permanent load-shifting approach that does not constitute dispatchable or callable DR resources for economic or emergency use". We grant that TOU and real time pricing (RTP) rates can be permanent load shifting measures, assuming they are properly designed and fully adopted by customers. But PTR is a callable resource, typically implemented for residential and small commercial segments, that has a similar objective as CPP with a different structure. While customers will incur a higher rate under CPP events, PTR does not penalize customers for non-participation and has shown great adoption in several studies. PTR is an equal opportunity DR product, allowing customer participation that is not contingent on specific equipment or fuel types. PTR can be offered as an opt-out program and has been shown to have benefits as a platform for introducing customers to DR concepts and then to use as a steppingstone for encouraging enrollment in firming DR resources, like direct load control programs.[61]

PTR measures are common and should have been included in this potential assessment. Duke should work with its OSB to rectify this. Here are a few examples of recent studies that recognize PTR resource potential as a substantial capacity resource. In a 2022 study of DR potential for Xcel Energy Colorado, Brattle Group estimated at 2030 achievable potential for PTR of 49 MW winter and 123 MW summer (with no existing PTR program as of the study). PTR is also shown to be among the highest savings measures, at third highest savings for winter and fifth highest for summer.[62] Additionally, Portland General Electric identified PTR as a key measure contributing to its flex load capacity, by 2026 estimating PTR at 16.6 MW summer and 12.4 MW winter.[63]

Furthermore, we disagree with the assertion that dynamic pricing products like TOU and RTP that may yield a permanent load shift should be excluded from consideration of a robust assessment of potential. Dynamic pricing products like TOU have been shown to achieve savings of 5-20% of peak, dependent on design parameters, enabling technologies, and education. Figure 8 provides a comparison of peak savings potential for different dynamic pricing treatments with and without enabling technologies (e.g., smart thermostats), showing rates with on-peak to off-peak pricing ratios between 2.5 and 5 achieve between approximately 5% to 20% of peak.[64]

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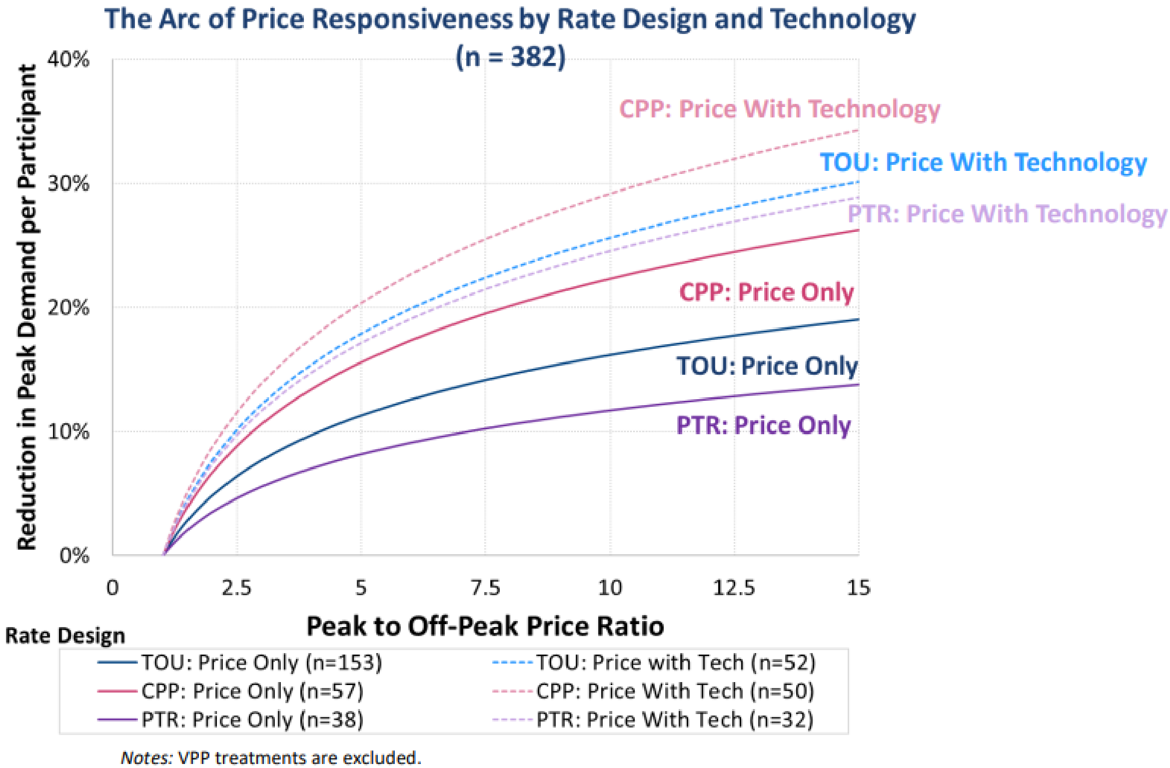
[61] Cadmus 2021. *Portland General Electric Smart Grid Test Bed Evaluation.* Link: https://edocs.puc.state.or.us/efdocs/HAD/um1976had164616.pdf

[62] Brattle Group 2022. *Xcel Energy Colorado Demand Response Study; Opportunities in 2023.* Link: https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf

[63] PGE 2024. Flexible Load Multi-Year Plan (2025-2026). Link: https://edocs.puc.state.or.us/efdocs/HAQ/um2141haq332220025.pdf

[64] Brattle Group. 2023. *Do Customers Response to Time-Varying Rates: A Preview of Arcturus 3.0.* Link: https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf

Figure 8. Comparison of Peak Reduction by Dynamic Pricing Treatment



Moreover, dynamic rates are proven program strategies that yield savings through a mix of conservation and load shifting, regardless of whether they are defined as demand response, and are regularly included in DR potential studies. The 2022 Xcel Colorado DR Potential Study, for example, categorizes demand response resources into two groups: low-frequency resources (such as direct load control and interruptible programs) and high-frequency resources (such as TOU and continuous load management for water heating or lighting). This categorization is based on whether the resource is used more or less than 75 hours annually. Notably, Colorado projects that high-frequency demand response programs will contribute 61% (167 MW) of its incremental achievable potential by 2030.

By excluding these resources from its analysis, Duke's assessment significantly underestimates the true capacity savings potential. We recommend that future potential assessments incorporate all dynamic rate opportunities to provide a more accurate and comprehensive evaluation.

4.3.3 MPS Transparency and Disconnection Between Economic and Achievable Potential

While the schedule did not permit additional feedback, we feel that the MPS report and proposed methodology for DR lacks clarity and transparency, in particular with regard to the reduction in potential from economic to achievable. **Across sectors and seasons, DR potential is reduced by approximately 86-96% between estimates of economic and achievable.**

The MPS report provides some context for how achievable potential is estimated that involves running participation models to estimate participation rates, which can be a function of incentives and marketing. The report states that it uses a bottom-up approach through this modeling method, rather than a top-down approach of benchmarking against enrollment rates of mature programs, as the latter top-down approach does not "provide enough detail to calibrate achievable program potential." We recognize that different jurisdictions may have various factors driving participation; however, we still find this current study's approach to be opaque and result in a more extreme reduction in economic potential than anticipated.

As a point of comparison, Xcel Energy Colorado's 2022 DR potential study assumed participation rates of eligible customers that are quite a bit higher than the current study. For example, residential smart thermostats assume 45% participation rate for eligible customers, compared to the base participation level of 31.5% for the Duke study (combining BYOT [20.9%] and utility installed [10.5%] offerings). Additionally, residential water heaters assume a 30% participation rate for Xcel compared to 1.6% for Duke.[65]

Beyond some unjustified issues with assumed participation rates, CAC still does not feel that the current report adequately explains the reduction between achievable and economic. CAC asked about this shift and more context for why this is occurring, specifically noting **Large C&I going from 2,514 MW economic potential to 370 MW achievable potential**. The MPS vendor, RI, responded that achievable potential is incremental to existing participants, while its estimate of economic potential included existing participants. This appears one time in the final report on p.71 in reference to large C&I: "LCI achievable potential excludes the current (as of 2024) 235 MW 'at generator,' or 219 MW 'at-meter' enrolled capacity." Nevertheless, subtracting enrolled capacity leaves economic potential with 2,279 MW, which reflects an **84% reduction for achievable potential**.

Furthermore, there are some consistency issues that make it difficult to compare potential throughout the report. While large C&I economic potential is shown per season (Figure 6-8), achievable potential (Figure 7-9) is shown by customer size (kW), which is inconsistent, lacks clarity as to how to compare results, and does not explain what is driving this reduction from economic potential.

Note, it is also not clear whether residential or small C&I categories similarly include existing enrolled capacity in their economic potential and are treated similarly, as this is not addressed.

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[65] Brattle Group 2022. *Xcel Energy Colorado Demand Response Study; Opportunities in 2023.* Link: https://www.brattle.com/wp-content/uploads/2022/09/Xcel-Energy-Colorado-Demand-Response-Study-Opportunities-in-2030.pdf

However, one may assume there is some level of existing enrolled capacity based on Table 7-1 on p. 54 showing a list of Duke DR programs. As such, the report does not clarify for a reader how much of the economic potential is associated with enrolled capacity, nor adequately explain the key drivers that result in the reduction shown in the estimates of achievable potential.