Report on NIPSCO'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

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Overview

The following comments on the 2024 Integrated Resource Plan ("IRP") submitted by Northern Indiana Public Service Company ("Company" or "NIPSCO") were prepared by Chelsea Hotaling, Dan Mellinger, and Anna Sommer 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.

A major difference between the 2024 IRP and NIPSCO's 2021 IRP was the introduction of data center load. The level of load assumed by NIPSCO radically changed the resource plan outcomes in this IRP. NIPSCO indicated during a meeting with CAC[1] that data centers were considered for inclusion in its reference case load forecast if they were proposed by firms that NIPSCO felt were sufficiently capitalized to build their proposed projects. NIPSCO ultimately decided to assume 2-3 large data centers in the reference case.[2] NIPSCO did not and still has not clearly articulated the criteria it used to make these determinations or otherwise produced a robust methodology to support this load forecast. In an effort to wrestle with the question of which requests are serious and which are speculative, we see many load-serving entities ("LSEs") attempting to use criteria that have been used to weed out generators in interconnection queues or in procurement efforts. But ultimately, in our understanding, data center companies are quite insensitive to price considerations and are significantly motivated to wade through the interconnection process with as many utilities as possible, not intending to actually build all of their proposed facilities.

There is enormous uncertainty regarding data center load growth and that unquestionably makes resource planning challenging. The filing of NIPSCO's "GenCo" proposal to serve large load demands immediately after the conclusion of the IRP without any forewarning to stakeholders further upended the value of this IRP, as GenCo has not committed to using NIPSCO's IRP – including the resources that the IRP stated are needed to support new data centers – as a basis for informing the resource portfolio it would procure, and it has requested the Commission decline jurisdiction over all of its resource decisions. Moreover, it is not clear that the costs of new resources assumed by the IRP would be the same when procured or built by a sole-source developer with unregulated costs. As NIPSCO said in the IRP, "[t]he magnitude and pace of NIPSCO's load growth, however, is not certain, and NIPSCO will need to refine its resource acquisition strategy as specific customer requirements are defined."[3] The load growth assumed in the reference case and high load growth case modeling performed by NIPSCO had significant

[1] October 31, 2024 meeting.
[2] June 24, 2024 meeting, slide 22.
[3] NIPSCO 2024 IRP at 291.

implications for the level of new thermal capacity that would be needed to meet the data center load growth.

After repeated requests from stakeholders, NIPSCO did end up presenting a Preferred Portfolio that outlines two pathways: one for resource additions that are needed regardless of the data center load growth, and a second related to resource additions that will be needed once data center customers sign contracts. Throughout the IRP process, we expressed concern around the risks of NIPSCO planning to meet load that had made no firm commitment.

We have identified several areas in which to improve NIPSCO's current and future IRPs. Our review of NIPSCO's 2024 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

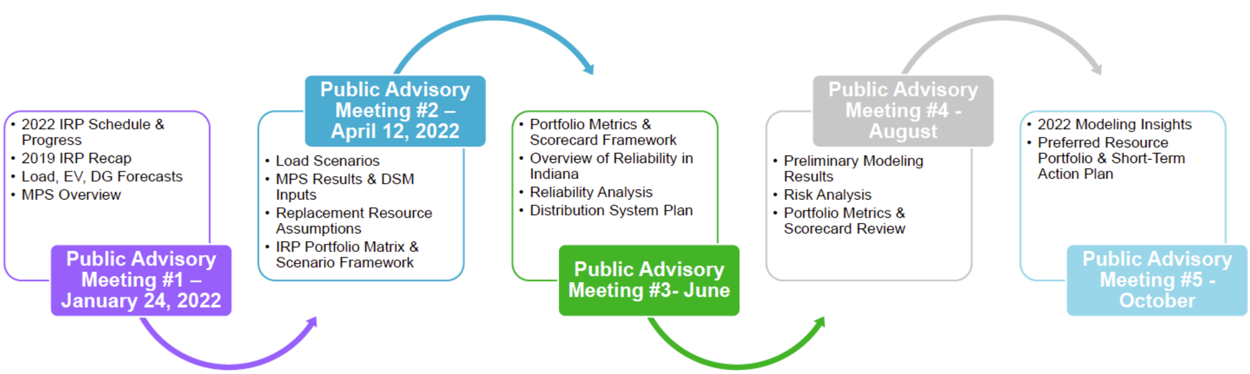
- NIPSCO lacks an adequate large load interconnection process that will protect existing customers from cost and grid reliability risks imposed by large customers;
- NIPSCO used a materially understated combined cycle and combustion turbine capital cost in its modeling;
- NIPSCO has overly optimistic assumptions on the level of new combined cycle resources that can be built in the near term; and,
- NIPSCO inadequately represented the potential for future energy efficiency savings in its IRP modeling.

We look forward to continuing to work with NIPSCO to address the issues identified here before any major resource decisions are made.

1 Stakeholder Workshops and Material Provided to Stakeholders

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 a transparent and collaborative approach for modeling inputs is an invaluable process and ensures that stakeholders can participate in a meaningful way throughout the IRP's development, rather than only being able to react to information contained in the modeling files once it is too late for feedback to be incorporated.

In the last IRP, we recommended NIPSCO incorporate a data sharing process with stakeholders similar to what AES Indiana has utilized for its last two IRPs. Most other Indiana electric investor-owned utilities have also adopted this approach. Ideally, the public stakeholder workshops would address the high-level matters, e.g., the scenarios and sensitivities developed, the major model assumptions, etc., while the technical stakeholder workshops would be where those with signed nondisclosure agreements ("NDAs") would be able to understand and offer feedback on the details of how these elements would be combined to develop the IRP. It is not possible to discuss all the consequential details of IRP modeling even in multiple public stakeholder workshops. AES Indiana has implemented an approach where technical stakeholder meetings are regularly held prior to the public meetings so that more in-depth discussions can be held on certain technical or confidential topics. AES Indiana provides data to stakeholders who have signed the NDAs in advance of these meetings pursuant to a schedule so that there can be opportunities for stakeholders to ask questions and offer feedback on the data during the meetings or shortly thereafter. The example below shows one of the schedules that AES Indiana provided to stakeholders for when data would be shared ahead of the public meetings.



For this IRP, NIPSCO was open to having technical stakeholder meetings with CAC and other parties if they were requested. While we appreciate NIPSCO's willingness to engage with stakeholders when requested, we continue to recommend that NIPSCO move to a process similar to what AES Indiana have established, and other utilities such as Duke Energy Indiana and CenterPoint have done for their IRP processes, so that there is a clear expectation of what topics will be covered and when data will be provided to stakeholders.

We appreciate that NIPSCO secured access to a project-based license to AURORA. NIPSCO's consultant, Charles River Associates, utilizes the AURORA software to perform portfolio optimization modeling for the IRP. During the last IRP in 2021, NIPSCO did not provide data from its AURORA model until the end of the stakeholder process, which made it challenging to provide meaningful feedback on modeling inputs. We asked NIPSCO to secure access to AURORA for this IRP to ensure that stakeholders had the opportunity to review modeling inputs earlier in the process. While it took an extraordinary amount of time to navigate securing the AURORA license, NIPSCO did provide data releases related to the AURORA database, and we appreciated the ability to review the modeling inputs through the project-based license to which we had access.

Prior to the last stakeholder meeting, we requested that NIPSCO turn over the exact database instead of an example database that was set up in AURORA with certain inputs and assumptions provided in an accompanying supporting workbook. It is standard practice to provide stakeholders the same database the utility is using to support the modeling presented in stakeholder meetings and, ultimately, the IRP filing to ensure consistency and transparency. We understand that, throughout an ongoing stakeholder process where several different versions of a database may be provided, there will be some draft or changing assumptions, but stakeholders should have the same database used by the utility.

Finally, it took several months for NIPSCO to set up a meeting to discuss concerns related to its transmission planning for large loads. This meeting raised critical concerns about NIPSCO's large load interconnection study process that were flagged too late in the process to be adequately addressed. We remain concerned about NIPSCO's lack of transmission planning in light of the megaload customers NIPSCO is anticipating.

2 Load Forecast

2.1 NIPSCO's Assumptions for New Data Center Customers

Assumptions around the level of new load growth, in particular from data centers, have a significant impact on the results of NIPSCO's portfolio modeling and, as NIPSCO's modeling for this IRP has determined, the need for significant spending on new gas combined-cycle resources. In NIPSCO's first stakeholder meeting in April 2024, it presented a reference case load forecast showing relatively flat demand growth for the IRP period, especially through 2030. During the second stakeholder meeting in June 2024, NIPSCO reported that the Company observed a significant increase in the potential for new loads from hyperscaler data centers, and, as a result of that, the Reference Case load forecast would assume two to three data center projects, or up to 2,600 MW of new load, would come to NIPSCO's system.[4] NIPSCO also developed an emerging high load sensitivity to incorporate up to six potential data center projects for a total of 8,600 MW.[5] Table 1 shows the additions of new load to the Reference Case and Emerging Load Sensitivity by 2028, 2030, and 2035. As NIPSCO stated in the IRP, "Such load additions are <u>not</u> attributable to a specific customer(s) but represent NIPSCO's attempt to reasonable [*sic*] estimate total load additions that may come to fruition under various future states of the world."[6]

Table 1. NIPSCO's Projected New Large Load Additions[7]

	2028	2030	2035
IRP Peak Load – Original Reference Case	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	*600 MW*	*1,600 MW*	*2,600 MW*
IRP Peak Load – New Reference Case	**2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*2,600 MW*	*4,500 MW*	*6,000 MW*
Total IRP Peak Load with Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

Under these assumptions, the New Reference Case assumes the NIPSCO system peak will increase by a factor of approximately 1.7 by 2030 and 2 by 2035. Under the New Emerging Load Sensitivity, NIPSCO's system peak will increase by a factor of approximately 2.4 by 2028, 3.7 by 2030, and 4.4 by 2035. These forecasts are problematic for several reasons. First, these are enormous increases for the NIPSCO system and introduce significant uncertainty when potential

[4] NIPSCO 2024 IRP at 16.
[5] NIPSCO 2024 IRP at 16.
[6] NIPSCO 2024 IRP, Footnote 3 at 16.
[7] NIPSCO 2024 IRP, Figure 3-42 at 81.

customers without signed commitments are included in the forecast. As NIPSCO said in the IRP, "NIPSCO acknowledges that final data center growth trajectories remain uncertain, and thus, NIPSCO will need to be flexible in its resource procurement activities based on the range of outcomes studied in the 2024 IRP."[8] Putting a highly uncertain *doubling* of existing peak load into the Reference Case load forecast without being able to articulate the exact methodology used to determine this amount and its timing and without a single signed contract with a data center – even now, nearly 10 months after NIPSCO's second IRP meeting – is not a reasonable input for an IRP. Second, this unprecedented load growth projection has cascading implications for NIPSCO, its customers, and MISO Zone 6. For example, the 8,600 MW of load growth by 2035 used in the Emerging Load Sensitivity case would require approximately 71.6 TWh per year, assuming a 95% load factor,[9] which is equivalent to 72% of the total retail electric sales in the State of Indiana in 2024 (99.8 TWh).[10] This is obviously not a realistic scenario, and NIPSCO has certainly not demonstrated how it would be remotely feasible. These implications include upward pressure on capacity and energy market prices, upward retail rate pressure, and implications for the ability to reliably serve NIPSCO's existing customers.

In the public IRP stakeholder meetings, it was not clear to stakeholders how NIPSCO was making decisions around which prospective customers were being reflected in the load forecast assumptions. For example, we noted the following omissions of topics from any coverage or discussion during the stakeholder meetings:

- There was no explanation of how NIPSCO determines which loads to include in its forecast.
- NIPSCO did not go through its load interconnection queue process, including explaining when potential customers would be making significant financial commitments.
- NIPSCO did not explain the criteria used to decide whether to include these new loads in its forecast in both the short term and long term.
- NIPSCO did not explain what the use estimates are based on, e.g., whether all load additions are coming from specific customers who have approached NIPSCO or whether NIPSCO is making data center electric consumption per sq. ft. and total sq. ft. projections especially for later term load additions.

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[8] NIPSCO 2024 IRP at 17.

[9] 8,600 MW * 8,760 hours/year * 0.95. NIPSCO used a 95% load factor for data centers in all seasons except summer, when it assumed a 98% load factor.

[10] U.S. EIA Data Electricity Browser, Indiana total annual retail sales in 2024, https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=00008&endsec=vg&linechart=ELEC.SALES.IN-ALL.A&columnchart=ELEC.SALES.IN-ALL.A&map=ELEC.SALES.IN-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

- NIPSCO did not explain how it judges the probability of new load prospects *actually* coming to its service territory, especially given that these potential customers are likely talking to other utilities as well.
- NIPSCO did not give any indication of what, when, and how its load forecast might change again during this IRP process.

As part of the stakeholder process, comments were submitted outlining these concerns and requesting that NIPSCO run scenarios with and without the forecasted new loads from data centers to identify resources needed only if data center load growth occurs and help demonstrate cost causation. Conducting this IRP without bookending the scenarios around projected new data center load would have impeded the ability to evaluate the costs at risk for new resources becoming stranded if the new loads do not materialize. The recommendation was for NIPSCO to remove all the new load added to all IRP scenarios for data centers, except for data center load that has already executed an interconnection service agreement. To the extent included in its IRP, NIPSCO should model hyperscaler facility additions as sensitivities or as a separate scenario and clearly identify the impacts relative to the Original Reference Case so that there is a transparent and comprehensive understanding of the possible impacts of new hyperscale facilities.

Throughout the IRP process, we expressed concern about including the level of projected data center load that NIPSCO assumed in the Reference Case forecast. NIPSCO did not clearly articulate in its IRP how it arrived at its data center load forecast based on 2-3 data center additions. It is our understanding that NIPSCO included data center load in its forecast if, in its opinion, the entity requesting the load is credible, even if no firm commitments for service have been executed, but, again, no clear explanation has been provided as to how it used this information to arrive at its load forecast. Using this approach exposes existing customers to enormous risk of generation over-procurement. We more typically see utilities only include those loads once there is a signed energy services agreement, given the highly speculative nature of hyperscaler data center interconnection requests. At the second stakeholder meeting, slides were presented that said "NOTE: NIPSCO is not guaranteeing that any amount of new load (referenced in the following slides) will enter our service territory, but we are sharing our current expectations with stakeholders to allow time for feedback as we prepare to conduct our IRP analysis with this significant change."[11] When asked for more detail as to whether the forecasts are based on specific data center interconnection requests received by NIPSCO, NIPSCO said, "None of the data center potential projects that were considered when the IRP peak load forecast was built have made a formal interconnection request to-date."[12]

[11] NIPSCO Second IRP Stakeholder Meeting held on June 24, 2024, at slide 17. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2024-irp-stakeholder-advisory-meeting-2-final.pdf?sfvrsn=3131e151_6

[12] NIPSCO Response to CAC Request 1-001(c).

2.2 Large Load and Transmission

Following an October 31, 2024 meeting with NIPSCO to discuss its large load interconnection process, CAC submitted comments to NIPSCO raising a number of concerns about its process. First, with regard to NIPSCO's study process, CAC stated,

[redacted]

NIPSCO responded:

[redacted]

We appreciate that NIPSCO recognizes the importance of transient models, and we hope this means that NIPSCO will require this information from customers. But these data are so critical to ensuring reliable interconnections of new, large customers that it is not clear why NIPSCO would wait until advanced interconnection to request this information. Indeed, that would seem to require NIPSCO to spend precious ratepayer-funded staff hours studying requests that will not ultimately be interconnected simply because transient models cannot be provided. An alternative would be to require this information upon entry to NIPSCO's interconnection queue rather than waiting until the end. And, of course, this requirement has implications for which loads go into NIPSCO's load forecast and the level of generation that has to be planned whether by NIPSCO or GenCo. It also remains unclear what criteria NIPSCO would use to assess acceptable performance of these loads even if transient models are provided.

NIPSCO declined to address other concerns raised in CAC's comments including whether any limits on operations of the data centers would be imposed or how exactly it would allocate the costs of transmission facilities upgraded to serve new customers. It is a convenient notion to draw a line between the IRP and these topics, but when new customers have direct implications for generation planning, it is important to understand whether the processes and procedures to reliably integrate new customers and dissuade cross-subsidization are in place. Lack of attention to the latter begets a lack of rigor in addressing the former.

2.3 Large Load Impact on Market Prices

One of the issues we raised with NIPSCO throughout the stakeholder process is the concern around the impact that new large load customers could have on market prices, especially the hyperscaler data centers included in NIPSCO's load forecast. NIPSCO's approach for developing market prices is to model the MISO footprint and then use the resulting market prices from those runs as inputs into the NIPSCO-specific portfolio optimization modeling. For the MISO footprint, it is our understanding that NIPSCO included a 3 – 5 GW increase in the load in the Reference Case scenario. With NIPSCO's own Reference Case load forecast projecting 2,600 MW of new load by 2035, this means that a substantial portion of the modeled MISO-wide data center load increase would be attributed to the NIPSCO service territory. We expect NIPSCO's market price model is set up as a zonal model, which means it would be unable to capture the market price implications of that much load coming to NIPSCO's service territory specifically. NIPSCO settles its wholesale cost of energy to serve customers at the NIPS.NIPS node, so, as a general rule, large increases in load without similar increases in generation will create congestion near load nodes. This would be true regardless of the tariff under which NIPSCO serves new data centers. Likewise, power produced away from load centers may experience depressed prices at the point of generation due to the need to wheel power over long transmission runs, increasing the probability of redispatch and subsequent congestion. Indeed, since two of NIPSCO's thermal plants (Sugar Creek and Schahfer) are both outside the NIPSCO load pocket, there is likely to be significant power already wheeled across the NIPSCO transmission system to serve existing customers.

A power price forecast based on a zonal model is unable to adequately quantify risk or reliability given what appears to be a major need for NIPSCO to import power into its service territory in the near term to satisfy both its current native load and projected load growth. Both NIPSCO's Schahfer Generation Station and Sugar Creek Generation Station are away from NIPSCO's primary load centers. Given the nature of the data center load (near constant 24x7), it is necessary to understand potential generation resource additions based on both energy and congestion.

We do not believe that this type of power price risk can be captured through market price forecasts developed for the scenario specific evaluations included in the IRP. NIPSCO found that the Reference Case expects power prices to be relatively flat in the near-term as a result of the natural gas and power price assumptions whereas longer-term prices see a decline from an increase in renewable generation resources.[13] NIPSCO also developed different market price assumptions based on the different scenarios evaluated as part of the IRP. Figure 1 shows a comparison of the market prices across the scenarios modeled by NIPSCO. Since each of these scenarios include assumptions around commodity prices, it is likely that differences in power prices are driven by those commodity price changes and not necessarily from higher load.

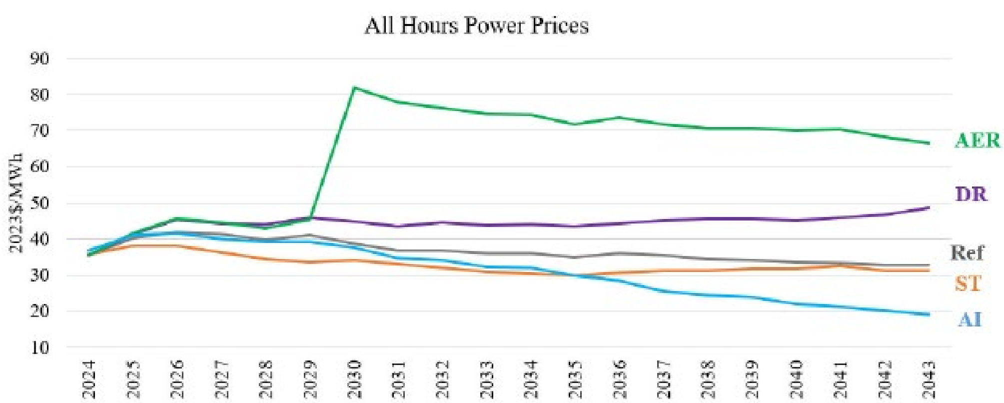

Figure 1. MISO Zone 6 ATC Power Prices across Scenarios[14]

[13] NIPSCO 2024 IRP at 218-219.
[14] NIPSCO 2024 IRP, Figure 8-20 at 221.

It does appear that NIPSCO recognizes this potential risk, as it says in the IRP that:

> *NIPSCO will again continue to perform project-specific analyses for any new loads and resources that may enter the portfolio to evaluate items such as congestion and nodal price risk, energy deliverability, and other reliability topics. This may include detailed nodal and power flow modeling and other local transmission and distribution system analyses*.[15]

It is not clear what analysis NIPSCO might already do around new load additions, but we recommend that, before any major resource decisions are made or in future IRPs, NIPSCO perform an analysis that includes nodal modeling to evaluate the impact that new large load additions may have on the market price forecasts that will be used for developing portfolios.

[15] NIPSCO 2024 IRP at 292.

3 Thermal Resource Costs and Availability

As part of the IRP, NIPSCO evaluated thermal resources that bid into the RFP in addition to new Combined Cycle ("CC" or "CCGT") and Combustion Turbine ("CT") resources. The thermal resources that responded to NIPSCO's RFP are shown below in Figure 2. NIPSCO allowed these resources, in addition to generic new CC and CT resources, to be selectable within the AURORA capacity expansion model.

	Installed Capacity (MW)	In-Service Year[1]	Comments	PPA Term (Years)
Thermal PPA 1	600	2028	New Gas CC	20
Thermal PPA 2-4	150	2026	Various contractual options (heat rate call or blocks)	5
Thermal PPA 5	150	2027	Coal-based energy and capacity	2
Thermal Sale 1	18	2027	Existing gas peaker	*N/A*
ZRC 1-4	200	2025/26 – 2029/30	PJM external resource delivered to MISO border	Multiple options
ZRC 5-7	600	2025/26 – 2026/27	LRZ 4 delivery	Multiple options

Notes:
Each tranche listed represents a group of mutually exclusive projects. Cost data is not provided, given the fact that these tranches align to individual bids.
1: In-service year may be in the middle of the reported year.

Figure 2. Thermal and ZRC RFP Tranches[16]

While NIPSCO did model these bids in the IRP, based upon our review of Appendix D to the IRP, the majority of CC capacity builds come from the generic new thermal resources.[17] The cost and first year available assumptions NIPSCO modeled for new CC and CT resources are out of line with the current market and high demand for gas turbines. The following subsections will discuss this in more detail.

3.1 Generic CC Costs

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. NIPSCO reported $1,225/kW for the capital cost modeled for a new 2x1 CC in 2024 dollars.[18] However, this is the starting capital cost, not when the resource is actually selected in

[16] NIPSCO IRP, Figure 4-11 at 128.
[17] NIPSCO workbook "NIPSCO_2024 IRP_Confidential Appendix D_12092024". Portfolios C and D have a Gas PPA added in 2028.
[18] NIPSCO 2024 IRP at 130.

the model, which is important to evaluate when accounting for any technology curves applied. In one of the confidential attachments NIPSCO provided with the IRP filing, the cost for a new CC was modeled at $1,363/kW in 2028, $1,381/kW in 2029, and $1,399/kW in 2030.[19] NIPSCO reported that its cost estimate for the CC was based on a "high-level estimate provided by an external engineering consulting firm" [20] and that other costs for electric interconnection, gas interconnection, water interconnection, owner's cost, and project contingency were developed from an earlier IRP study with inflation applied to escalate the costs.[21] NIPSCO also reported a capital cost of $1,284/kW in 2024 dollars for new peaking or CT resources.[22] The nominal CT costs are $1,371/kW in 2028, $1,400/kW in 2029, and $1,419/kW in 2030.[23]

Kentucky Utilities and Louisville Gas and Electric ("KU/LG&E") filed its 2024 IRP in October 2024, which assumed a new 1x1 CC was $2,121/kW in 2030 dollars.[24] 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, and they have also submitted a pending CPCN application for two additional CC units, so they are familiar with the current market conditions and costs for constructing new CC units. Table 2 shows a comparison between the capital cost for CC and CT resources that KU/LG&E modeled as part of its portfolio evaluation for the 2022 CPCN proceeding and the capital cost assumed for the 2024 IRP. The 1x1 CC configuration modeled by KU/LG&E was for a unit with a size of 645 MW summer and 660 MW winter capacity.[25] NIPSCO reported that the estimates provided by the external engineering consulting firm were for a 650 MW of 1,300 MW unit.[26] In the fourth stakeholder meeting, NIPSCO noted, "The 650 MW blocks evaluated were modeled generally under a 2x1 configuration. That may change as needs dictate; however the block size was modeled at 650 MW for planning purposes."[27] While KU/LG&E modeled a 1x1 CC and not a 2x1 CC, cost pressures and escalation in costs also apply to any new CC project, regardless of configuration.

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[19] NIPSCO workbook "NIPSCO 2024 IRP Confidential Appendix D 12092024". NIPSCO confirmed this is public.
[20] NIPSCO 2024 IRP at 130.
[21] NIPSCO 2024 IRP at 130.
[22] NIPSCO 2024 IRP at 130.
[23] NIPSCO workbook "NIPSCO 2024 IRP Confidential Appendix D 12092024". NIPSCO confirmed this is public.
[24] KU/LG&E 2024 Joint IRP Volume III (Oct. 18, 2024), Technology Update, Table 1 at 4. Kentucky PSC Case No. 2024-00326.
[25] KU/LG&E 2024 Joint IRP Volume III (Oct. 18, 2024), Technology Update, Table 1 at 4. Kentucky PSC Case No. 2024-00326.
[26] NIPSCO 2024 IRP at 130.
[27] NIPSCO Fifth Stakeholder Meeting held on October 28, 2024, at slide 15. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/meetings/2024-irp-stakeholder-advisory-meeting-5.pdf

Table 2. KU/LG&E Capital Cost ($/kW) Assumptions for New CC and CT Resources[28]

	2022 CPCN (2026/2027 $)	2024 IRP (2030 $)
CT	$679	$1,636
CC	$1,048	$2,121

As part of the Short-Term Action Plan, NIPSCO said one of the items is to "[p]erform additional diligence on the costs, feasible locations, and operational characteristics of new natural gas combined cycle and peaking additions necessary to meet new data center load."[29] We expect that when NIPSCO further explores the costs of new CCs and CTs, they will receive information indicating the costs modeled as part of this IRP were too low. For example, KU/LG&E recently filed with the Kentucky Public Service Commission for approval of two 1x1 CCGTs with estimated costs between $2,144 and $2,194 per kW for each 645 MW unit.[30]

In Indiana, Duke Energy Indiana recently requested a certificate of public convenience and necessity for two 1x1 CCGTs in Cause No. 46193. At a total cost of approximately $3.33 billion for 1,476 MW, it is equivalent to $2,256 per kW.

3.2 Carbon Capture Utilization and Sequestration ("CCUS") and Hydrogen Assumptions

For the scenarios including constraints around emissions, NIPSCO had assumptions around generic CCs with CCUS and hydrogen capability. NIPSCO reported that the costs for CCUS were developed from a range of public sources, including the National Renewable Energy Laboratory ("NREL") and the Environmental Protection Agency ("EPA"), since they did not receive any bids related to CCUS in response to the RFP.[31] NIPSCO reported that it assumed an installed capital expenditure of $3,325/kW in 2024 dollars for a new CC with CCUS.[32] NIPSCO's modeled cost for a new CC in 2024 was $1,225/kW, which results in the CC with CCUS being almost three times more expensive on a $/kW basis. If NIPSCO's costs were modified to reflect the current market conditions for new CC resources, the cost for a CC with CCUS would also be higher. It is likely that the costs NIPSCO modeled for the CC with CCUS are also understated.

NIPSCO also developed costs for achieving hydrogen blending. NIPSCO reported that these costs are from "bidder data from past RFPs and information gathered from Original Equipment

[28] KU/LG&E 2024 Joint IRP Volume III (Oct. 18, 2024), Technology Update, Table 4 at 7. Kentucky PSC Case No. 2024-00326.
[29] NIPSCO 2024 IRP at 293.
[30] Testimony of Lonnie E. Bellar in Case No. 2025-00045 before the Kentucky Public Service Commission.
[31] NIPSCO 2024 IRP at 136.
[32] NIPSCO 2024 IRP, Figure 4-19 at 142.

Manufacturers".[33] NIPSCO reported that plants with retrofits or built to accommodate close to 100% hydrogen "were assumed to require approximately 30% of the original plant capex and operating costs, or about $400/kW in real 2024$."[34] For the Sugar Creek retrofit modeled, it seems like the cost may be understated if NIPSCO is assuming a percentage of the original plant capex, given the rise in materials and labor prices since the plant was built that are above and beyond inflation that can be captured through escalating prices. NIPSCO should perform additional sensitivity around the decision to retrofit Sugar Creek with sensitivities on the cost for retrofitting the unit.

3.3 First Year Available Date for Generic CC and CT Resources

In addition to the concern around the costs for new generic thermal resources, we are concerned about the assumed first year build dates of 2028 for CC and CT resources. When we raised this concern and asked about the feasibility of the 2028 date, NIPSCO said, "NIPSCO appreciates the development risk. The date modeled was based on consultation with NIPSCO and NiSource internal Major Projects and Supply Chain teams. Other consideration may have to be taken into account during project execution."[35] For ongoing additions, NIPSCO may also be overoptimistic in how many resources can be brought online in any year in the near term, as NIPSCO said:

> *Based on model testing, NIPSCO identified a need for resources that provide a significant amount of energy to the portfolio and found a very limited selection of generic CT options across portfolio themes. Thus, generic CT additions were limited to one block per year for modeling purposes, with two or three blocks per year for CCGT additions based on the time period. NIPSCO's Major Projects and Supply Chain teams advised that up to two 650 MW combined cycle blocks could be reasonably brought online in a year in the near-term, with the potential for up to three over the mid-to-long-term.*[36]

NIPSCO's assumption for 2028 is in significant contrast with other jurisdictions who report delays in the ability to construct new CC and CT resources. In KU/LG&E's 2024 IRP, the companies reported 2030 as the earliest in-service year due to permitting and construction timelines, as well as lead times for electric equipment, like generator step up transformers.[37] In Duke Energy Indiana's recent IRP, Duke allowed a limited selection of CC resources in 2030 and allowed CT resources to be selected starting in 2031.[38] This is consistent with what Duke

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[33] NIPSCO 2024 IRP at 135.
[34] NIPSCO 2024 IRP at 135.
[35] NIPSCO Fifth Stakeholder Meeting held on October 28, 2024, at slide 15. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/meetings/2024-irp-stakeholder-advisory-meeting-5.pdf
[36] NIPSCO Response to CAC Request 3-012.
[37] KU/LG&E 2024 IRP Volume III, Technology Update at 4 and 6. Kentucky PSC Case No. 2024-00326.
[38] Duke Energy Indiana 2024 IRP, Table 3-9 at 85-86.

Energy Kentucky told Kentucky Commission Staff in response to a data request, where it reported that it is seeing 5+ years for long lead time equipment delivery, construction, and commission for a CC. [39] Duke Energy Kentucky estimated a total timeline need of 8+ years when considering time from project development to an in-service date.[40] In its recently submitted IRP, Indiana Michigan Power Company ("I&M") assumed that new CT resources would be available in 2030 with new CCs allowed to be selected in 2031.[41] As John Ketchum, the CEO and President of NextEra said, "When you look at gas as a solution, to get your hands on a gas turbine, and actually get a built brought to market, you're really looking at 2030 or later."[42] NIPSCO has provided no meaningful evidence to support a different timeline for new thermal plant development.

[39] Duke Energy Kentucky Response to Staff Data Request DR-01-024. Kentucky PSC Case No. 2024-00197.
[40] Duke Energy Kentucky Response to Staff Data Request DR-01-024. Kentucky PSC Case No. 2024-00197.
[41] Indiana Michigan Power Company IRP Stakeholder Workshop. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/IN_Stakeholder_Meeting_2.pdf
[42] Retrieved from https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/031025-ceraweek-renewables-ready-to-go-labor-and-parts-delays-gas-plants-nextera-ceo

4 Portfolio Analysis

NIPSCO's portfolio analysis developed portfolios assuming certain details surrounding MISO capacity accreditation and the future around greenhouse gas emission constraints. For MISO capacity accreditation, NIPSCO modeled portfolios under the current construct and then also developed portfolios assuming the Direct Loss of Load ("DLOL") accreditation methodology, which is set to take effect in planning year 2028/2029. For emissions, NIPSCO evaluated portfolios under no emission constraints, the current EPA rules which apply constraints on new CC and CT resources, and under a scenario where no new fossil fuel generators would be added without emission controls. Figure 3 below shows an illustration of NIPSCO's portfolio decision.

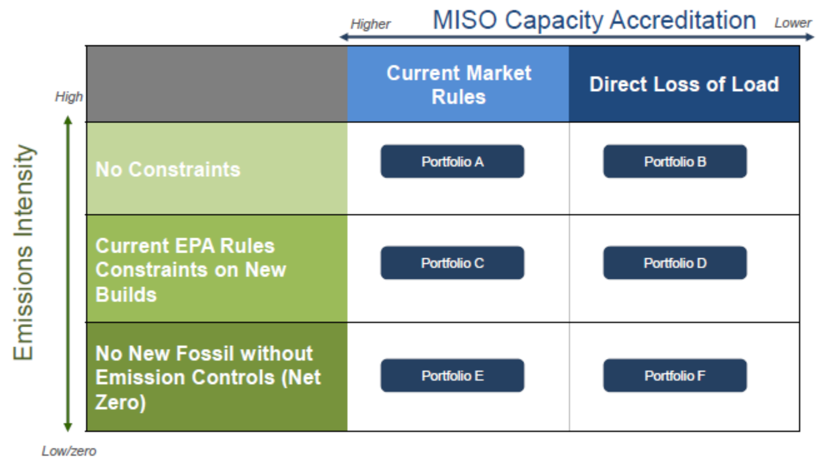

Figure 3. NIPSCO Portfolio Concept[43]

4.1 Portfolio Scorecard Metrics

Figure 4 below shows the scorecard metrics NIPSCO used to evaluate the portfolios developed for this IRP. The following subsections offer some recommendations related to: (1) providing additional information to support the development of the Forced Market Exposure metric, and (2) metrics for inclusion in future IRPs.

[43] NIPSCO 2024 IRP, Figure 9-1 at 251.

Objectives	Indicators	Metrics
Affordability	Cost to Customer	• Near-term and long-term Impact to customer bills • Metric: 10-year and 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	Cost Certainty	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: 95th%-50th% cost risk from probabilistic analysis
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: 50th%-5th% cost risk from probabilistic analysis
Environmental Sustainability	Carbon Emissions	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions / cumulative generation (2024-40 short tons/MWh of CO2)
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis • Metric: Capacity able to respond within 30 mins
Positive Social, & Economic Impacts	Local Investment in Economy	• The effect on the local economy from new projects and ongoing property taxes and targeted investment • Metric: NPV of property taxes from the entire portfolio

Figure 4. Scorecard Metrics[44]

4.1.1 Forced Market Exposure Metric

NIPSCO's Forced Market Exposure Metric assesses the frequency and magnitude of events for when NIPSCO may need to rely on the market. NIPSCO defines this as a period when NIPSCO does not have sufficient generating resources to cover its load. As NIPSCO discussed in the IRP:

> *NIPSCO operates within the MISO market and is not its own balancing authority, meaning that it does not need to produce a portfolio that meets the desired resource adequacy target ("1- Day-in-10 Years") on its own. Rather, it benefits from integration into the broader MISO market by pooling reliability risks and responsibilities toward meeting resource adequacy targets. However, NIPSCO is committed to ensuring reliable service to its customers and recognizes that it must bring its fair share of resource adequacy to the broader MISO system. Thus, as part of its stochastic analysis for the 2024 IRP, NIPSCO has performed an assessment of the frequency and magnitude of events when it might be forced to rely on the market.*

[44] NIPSCO 2024 IRP, Figure 9-13 at 260.

> *During normal operations, NIPSCO will operate the system economically and buy and sell energy on the market when it is cost-optimal to do so. However, NIPSCO may experience periods of forced market exposure when its native load is greater than its owned and contracted generating capacity, due to planned or unplanned generating outages, low renewable generation, and/or unusually high load demand. During these "pseudo-loss of load" events, NIPSO must rely on the market. This leaves NIPSCO potentially exposed to high market prices during these forced market exposure events and in extreme cases, exposed to loss of load events if these periods of NIPSCO stress align with periods of MISO-wide stress events.*[45]

In order to conduct the analysis to develop the Forced Market Exposure Metric, NIPSCO modeled itself as an island, with no market interaction, and evaluated several variables in a stochastic manner using CRA's AdequacyX probabilistic reliability analysis tool.[46] These variables that were evaluated in a stochastic manner include renewable profiles, load, and thermal unit availability. The Forced Market Exposure risk metric compares NIPSCO's resources to load across each hour of the 2030 sample study year and over 1,000 iterations of stochastic inputs.[47]

4.1.1.1 Data Center Load

One of the stochastic variables that NIPSCO is trying to capture with this analysis is the impact that weather has on demand for NIPSCO's system. NIPSCO said:

> *To capture these temperature impacts on demand, NIPSCO developed a regression model between HDD and CDD and load. Using this regression model, NIPSCO generated synthetic load shapes by "temperature shocking" a randomly selected historical hourly load shape (from years 2013 to 2022) by removing the temperature impact of historical temperature and adding back the predicted temperature impact of the synthetic temperature shape. NIPSCO also simulated changes occurring within the load shapes due to the addition of new technologies like electric vehicles, grid electrification, and data centers.*[48]

If the process NIPSCO used to develop the synthetic load profiles results in the projected data center load being influenced by temperature, this could be scaling those data center load profiles when they otherwise would not be scaled. 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 instead of being input into the load forecast. If NIPSCO removes these

[45] NIPSCO 2024 IRP at 241.
[46] NIPSCO 2024 IRP at 244.
[47] NIPSCO 2024 IRP at 267.
[48] NIPSCO 2024 IRP at 246.

customers from the synthetic load shapes 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.

4.1.1.2 Modeling NIPSCO as an Island

NIPSCO's analysis to calculate the Forced Market Exposure Metric is trying to capture the risk NIPSCO says the system could face if there are insufficient generating resources to cover load. While NIPSCO is taking the approach that NIPSCO is an island for this analysis, NIPSCO is integrated in the broader MISO market. If NIPSCO wanted to capture the risk of market exposure, NIPSCO could develop a distribution to model for market import across the simulations performed in the AdequacyX model used by CRA. In order to capture this, NIPSCO could model a representation of market availability similar to how MISO models import capability from external regions in its own modeling. MISO utilizes the Strategic Energy and Risk Valuation Model ("SERVM") 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 3 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 3. 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

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

[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

4.1.1.3 Consideration of Cold Weather Outage Adder for Thermal Availability

At the MISO system level, MISO is responsible for performing the Loss of Load Expectation ("LOLE") studies that determine the seasonal planning reserve margins. One of the assumptions MISO began incorporating into its LOLE model is around additional forced outages resulting from extreme cold temperatures in the winter. Historical NERC Generating Availability Data System ("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 not clear if NIPSCO and CRA factored this into the variables representing thermal unit availability. If it has not been incorporated, we recommend that consideration for these incremental outages be incorporated. If it has been incorporated, we recommend that NIPSCO explain how it did so.

4.1.2 Environmental Sustainability Metric

NIPSCO used cumulative carbon intensity of emissions (cumulative carbon emissions divided by cumulative generation) as its sole metric evaluating Environmental Sustainability. This is a poor and unreliable metric for evaluating the environmental sustainability of NIPSCO's resource portfolio. This is clearly evidenced by NIPSCO's Figures 9-27 and 9-28, which show declining carbon intensity of emissions over the next decade even under scenarios where NIPSCO's *absolute emissions* (tons of CO_2) will significantly increase. NIPSCO's poor choice of metric thereby obscures the fact that its environmental regulatory risk is significantly increasing under its Preferred Portfolio to the extent risk is correlated with its absolute CO_2 emissions (e.g., as it would be under a carbon tax). Furthermore, non-CO_2 environmental sustainability and related environmental regulatory compliance risks are not adequately captured through a carbon intensity metric.

4.2 Metrics for Future IRPs

One metric we recommend that NIPSCO include in future IRPs is a fuel market exposure metric, which would capture the level of energy generation from thermal resources as a percentage of total fleet generation. This metric could be reported for specific periods over the planning period (i.e. 2030, 2035, 2040) and should be accompanied by a chart to show how the metric changes over time through the planning period. When NIPSCO performed its stochastic analysis of portfolios, it said, "portfolios with more natural gas-fired capacity (Portfolios A through D) exhibit higher cost risk than those with less natural gas capacity (Portfolios E and F)."[50] We recommend including a fuel market exposure metric in order to capture the level of risk across portfolios.

[50] NIPSCO 2024 IRP at 282.

4.3 Portfolio Sensitivities

For this IRP, NIPSCO looked at two sensitivities around the growth of data center load and one sensitivity around demand side management ("DSM"). Throughout the stakeholder process, we recommended that NIPSCO perform additional modeling that removed the data center load from the forecast. While we continue to dispute the inclusion of new customer load in a reference case load forecast without signed contracts, we do appreciate that NIPSCO included at least the sensitivity of excluding data center load.

4.3.1 Load Growth Sensitivities

The two sensitivities around load growth that NIPSCO performed included looking at a Flat Load sensitivity that does not include any new large load growth additions from data centers. The second sensitivity, or the Emerging High Load sensitivity, evaluated an even higher level of new data center load growth than what was included in the Reference Case forecast. Both of these sensitivities were modeled under the EPA Rules and D-LOL assumptions from Portfolio D.

As shown in Table 4, the Flat Load sensitivity results in the addition of 200 MW of natural gas peaking capacity under the Current MISO Capacity Rules, but this peaking capacity is not selected under the D-LOL MISO Capacity Rules, as that run results in a higher level of battery storage build. For both modeling runs, no new CCGT resources are selected over the planning period. This is in stark contrast to Portfolios A through F, which result in anywhere between 2,600 MW to 3,235 MW of CCGT capacity under the assumption that data center load is included in the forecast. Under the Emerging High Load sensitivity, the CCGT capacity is even larger, with 8,435 MW of CCGT capacity being added over the planning period, with 3,885 MW through 2029.

Table 4. Incremental Resource Additions across All Portfolios[51]

	Flat Load	Flat Load DLOL	A	B	C	D (all)	E	F
Data Center Load	None	None	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	CCGT<40%	CCGT<40%	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	None	None	Late 2030s	At start-up	At start-up
Wind	550	350	1,500	1,850	1,800	1,550	2,250	2,350
Solar	450		2,125	675	3,235	1,275	2,322	1,922
Storage[1]	786	1,296	1,249	1,882	811	959	1,409	2,111
Gas CCGT			2,600	2,600	2,585	3,235		
Gas Peaking	200				400	618		
Gas CCGT w/CCUS							2,340	2,340
Sugar Creek	H2 (or CCUS) Retrofit	H2 (or CCUS) Retrofit	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DSM (DR/EE)[2]	390	440	400	430	230	270	365	365
Total ICAP Additions Through 2043 (excl. DSM/DR)	1,986 MW	1,646 MW	7,474 MW	7,007 MW	8,831 MW	7,637 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer) Covered	~850 MW	~1,350 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

[1] Includes both 4-hour Lithium-ion and long-duration storage
[2] DSM additions calculated as peak capacity contribution in summer of 2043

On a cost basis, the Present Value of Revenue Requirements ("PVRR") is significantly less for the Flat Load portfolio due to the lower level of load, as Portfolio D has a PVRR of $10.7 billion over 10 years and almost $26 billion over 30 years.[52] Figure 5 shows the 10-year and 30-year PVRR comparison for the Flat Load portfolios under the Current and DLOL MISO capacity accreditation.

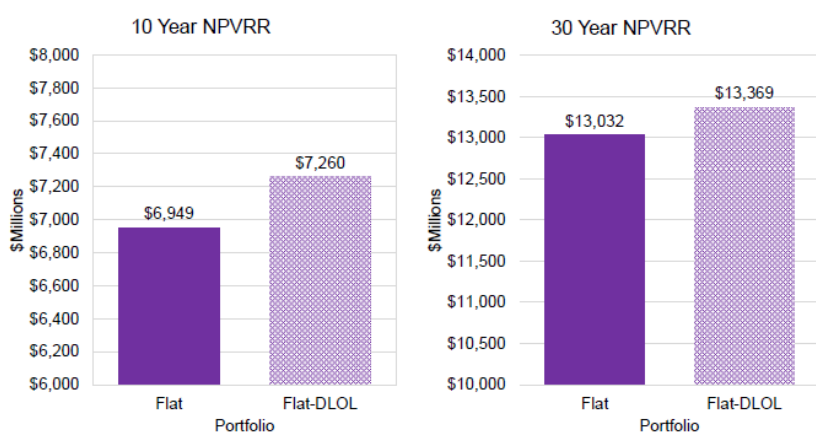

Figure 5. NPVRR for Flat Load Portfolios[53]

NIPSCO also presented the levelized cost of the portfolio PVRRs and reported that the Flat Load portfolio is higher than all other Reference Case portfolios, except for Portfolio F. As NIPSCO said, "[t]his suggests that incremental costs associated with larger levels of resource additions in

[51] NIPSCO 2024 IRP, Figure 9-32 at 277.
[52] NIPSCO reported PVRR results at 283.
[53] NIPSCO 2024 IRP, Figure 9-33 at 278.

the Reference Case load outlook can be spread over more MWh, such that the per MWh system cost goes down."[54] The result of the levelized cost for portfolios is shown in Figure 6 below.

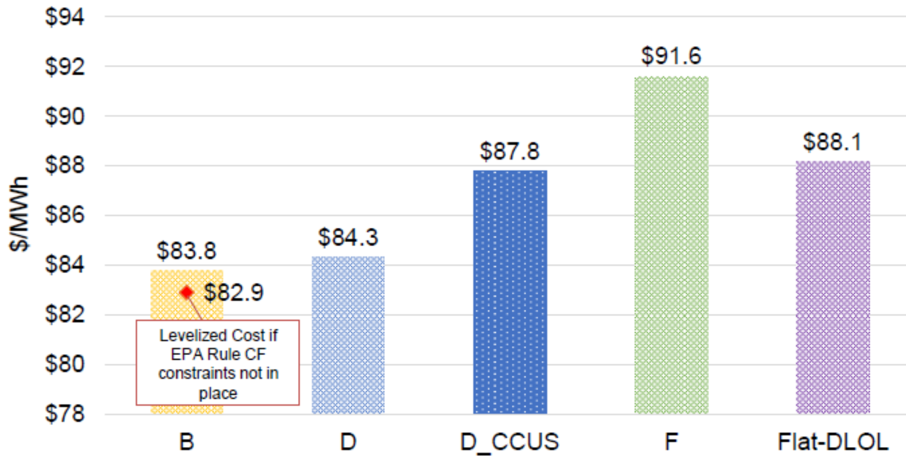

Figure 6. Levelized Portfolio Costs for Reference Case and Flat Load Portfolios under D-LOL Market Rules[55]

While this calculation does show a higher $/MWh system cost based on the AURORA modeling results, it does not represent the question of cost allocation and recovery. If the load included in the Reference Case forecast, and reflected in the calculation for Portfolios B, D, D_CCUS, and F in Figure 9 does not materialize, then this calculation would not hold, and NIPSCO's existing customers would bear the costs of the full portfolio without being "spread over more MWhs".

4.3.2 DSM Sensitivity

NIPSCO performed a sensitivity that evaluated the impact of moving from the Realistic Achievable Potential ("RAP") levels to the enhanced RAP for energy efficiency and the Maximum Achievable Potential ("MAP") level for demand response resources for Portfolio D.[56] NIPSCO modeled this sensitivity by forcing in the same energy efficiency and demand response bundles that were selected in the portfolio optimization step, but moved those resources to either the Enhanced RAP or MAP level.[57] Based on the explanation provided by NIPSCO in the IRP, it appears that portfolios were not re-optimized around this decision, but that NIPSCO identified 75 MW of future natural gas peaking capacity additions around 2030 that could be removed, and then the portfolio was re-dispatched in AURORA.[58]

[54] NIPSCO 2024 IRP at 277.
[55] NIPSCO 2024 IRP, Figure 9-34 at 278.
[56] NIPSCO 2024 IRP at 281.
[57] NIPSCO 2024 IRP at 281.
[58] NIPSCO 2024 IRP at 281.

Figure 7 shows the PVRR results for Portfolio D, which only includes the RAP level of energy efficiency and demand response, to Portfolio D_DSM, which includes the enhanced RAP level of energy efficiency and the MAP level of demand response. Including the Enhanced RAP of energy efficiency and MAP for demand response resources results in a $28 million reduction in the PVRR over a ten-year period, but a $12 million increase over the 30-year PVRR. It is possible this change in result is driven from the approach NIPSCO used, which was to defer 75 MW of peaking capacity in the 2030 timeframe, but no other deferred resources outside of that time period.

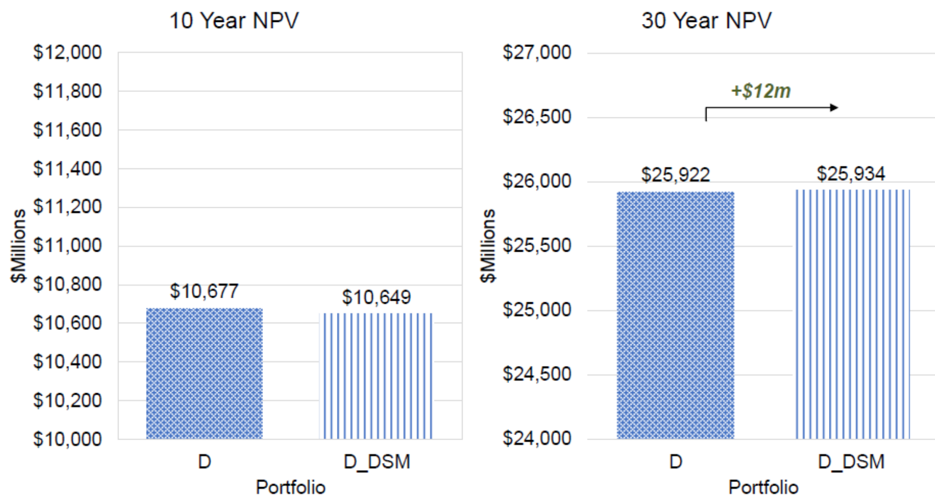

Figure 7. NPV for Enhanced RAP or MAP for Portfolio D[59]

We appreciate the DSM sensitivity that NIPSCO performed for this IRP; however, we would recommend a change for this process prior to moving forward with any major resource decisions. The enhanced RAP level of energy efficiency should be considered a resource option that can be selected in the portfolio optimization stage so the model can select between the RAP and Enhanced RAP levels. However, as discussed in the next section, there may be some further investigation of the selection around energy efficiency bundles in AURORA. In the event that Enhanced RAP levels are not selected in AURORA, we support forcing in the Enhanced level of RAP for energy efficiency bundles to be able to evaluate their impact on the PVRR.

[59] NIPSCO 2024 IRP, Figure 9-38 at 282.

5 Selection of Energy Efficiency and Demand Response across Portfolios

In the IRP, NIPSCO presented Table 5 below, showing the energy efficiency bundles selected across the different portfolios modeled in AURORA. An "X" denotes that a bundle was selected while an "O" means a bundle was not selected. For Portfolios A, B, and C, the model did not select the "Res(Low/Med)" bundle for 2027 – 2029, and the "Res(Low/Med)" bundle for 2030 – 2032 was not selected for Portfolio C, but was selected for Portfolios A and B. In addition, the "C&I" bundle for 2027 – 2029 was not selected for Portfolios A and B, but was selected across the other Portfolios. This seems like a puzzling result given the relatively low levelized costs presented in the IRP. NIPSCO reported a levelized cost of $26.56/MWh for the "Res(Low/Med)" bundle for 2027 – 2029 and $24.95/MWh for 2030 – 2032.[60] The "C&I" bundle for 2027 – 2029 is reported to have a levelized cost of $15.81/MWh.[61]

We recommend that, before any major resource decisions are made, additional modeling runs be performed to test forcing in energy efficiency bundles that have been consistently selected across other portfolios, especially if the cost of that bundle appears to be economic.

Table 5. Energy Efficiency Selection across Portfolios[62]

Program	Portfolio A			Portfolio B			Portfolio C			Portfolio D			Portfolio E			Portfolio F		
	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46
Res (Low/Med)	o	X	X	o	X	X	o	o	X	X	X	X	X	X	X	X	X	X
Res (High)	o	o	o	o	X	X	X	o	X	X	X	o	o	o	o	X	X	o
Res (Behavioral)	o	o	X	X	o	X	X	X	X	X	X	X	X	o	X	o	X	X
C&I	o	X	X	o	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQW	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQHear	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

X = Selected
o = Not Selected

Table 6 shows the demand response bundles selected across the different portfolios modeled in AURORA. However, this table does not show the results of the sensitivity runs that NIPSCO performed around Portfolio D with the Flat Load that removed data center load from the forecast. Based on the modeling files[63] provided to stakeholders in November, under the Flat Load

[60] NIPSCO 2024 IRP at 191.
[61] NIPSCO 2024 IRP at 191.
[62] NIPSCO 2024 IRP, Figure 9-10 at 258.
[63] Workbooks named "NIPSCO_Draft_Aurora_Financial_Outputs" and "Aurora Table Tracker Final Release".

modeling run, Thermostats, Behavioral, C&I, and Data Center demand response resources are included in that portfolio in 2027, and, by 2030, the Dynamic Rates resource is also included in that portfolio. Since a variant of Portfolio D was selected by NIPSCO for the Preferred Plan, we recommend that NIPSCO evaluate all of the demand response programs selected under the Flat Load modeling run in the next DSM program plan.

Table 6. Demand Response Selection Across Portfolios[64]

Program	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E	Portfolio F
RAP Thermostats	X	X	O	O	O	O
RAP Water Heaters	O	O	O	O	O	O
RAP Behavioral	X	X	X	X	X	X
RAP Dynamic Rates	X	X	O	O	X	X
RAP EV Managed Charging	O	O	O	O	O	O
RAP BTM Storage	O	O	O	O	O	O
RAP C&I	X	X	O	O	X	X
RAP Data Center	X	X	O	X	X	X

X = Selected
O = Not Selected

[64] NIPSCO 2024 IRP, Figure 9-11 at 259.

6 NIPSCO's Preferred Portfolio

NIPSCO selected the Portfolio identified as "Portfolio D_CCUS" for its Preferred Portfolio. NIPSCO has developed two different pathways for resource additions that are dependent on the hyperscaler data center load. As NIPSCO said:

> *Given the uncertainty around the timing and amount of hyperscaler data center load that may come onto NIPSCO's system, NIPSCO has a preferred plan that lays out two sets of new resource additions: The first set of resource additions will be added to the portfolio regardless of the size and timing of new hyperscaler data load on the system, and the second set of resource additions will only be added after hyperscaler data center load is contracted.*[65]

Figure 8 shows the near-term, mid-term, and long-term capacity additions for NIPSCO's Preferred Portfolio. In the near-term, the capacity additions are storage, thermal contracts, and DSM resources. However, if the base case level of data center load materializes, then the resource additions include 1,285 MW of gas CCGT capacity and 420 MW of gas peaking capacity.

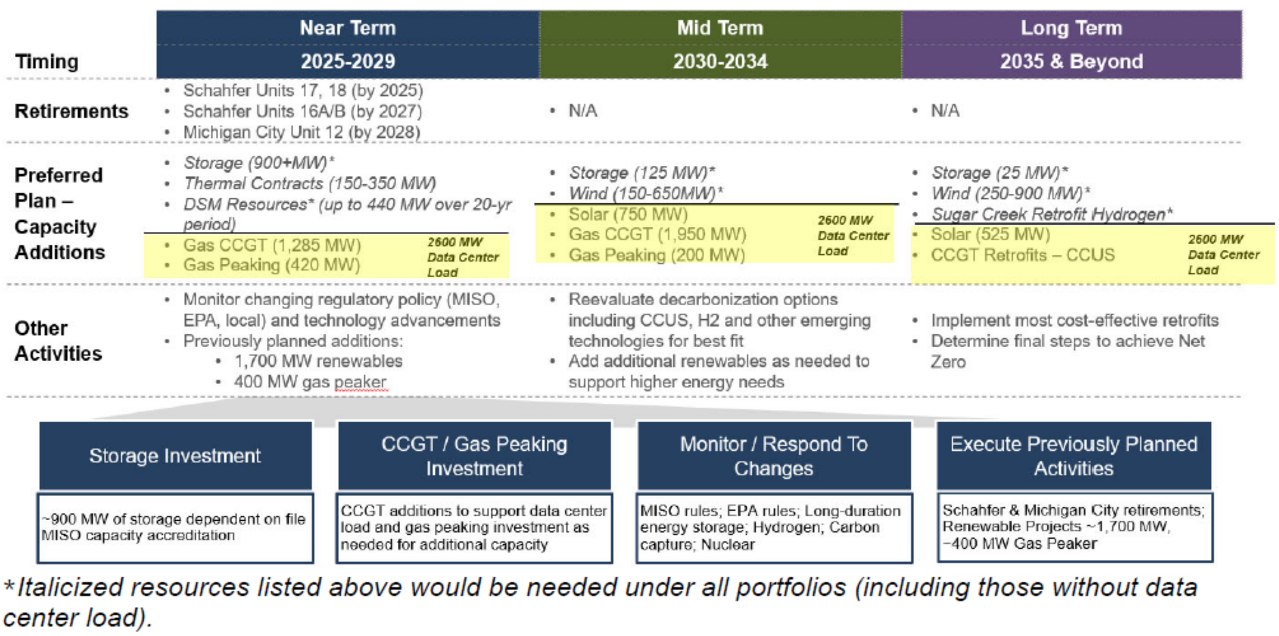

Figure 8. NIPSCO Preferred Portfolio[66]

[65] NIPSCO 2024 IRP at 9.
[66] NIPSCO 2024 IRP, Figure 9-10 at 285.

7 Demand Side Resources

7.1 Market Potential Study

NIPSCO engaged GDS Associates, Inc. ("GDS"), in September 2023 to perform a "refresh" of the most recent NIPSCO Market Potential Study ("MPS"), which was completed in 2021. The market potential study quantified technical, economic, maximum achievable, realistic achievable, and enhanced realistic achievable savings for the years 2027 through 2046. Each of these scenarios is described within the MPS as follows:

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective, based on screening with the utility cost test ("UCT") as compared to conventional supply-side energy resources.
- **Achievable Potential** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:
    - **Maximum Achievable Potential** ("MAP") estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.
    - **Realistic Achievable Potential** ("RAP") estimates achievable potential with NIPSCO paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
    - **Enhanced RAP** estimates achievable potential by adjusting incentive levels to allow for more savings than in the RAP scenario. In some cases, incentives were lowered to improve cost-effectiveness and in others, incentives were increased to boost adoption rates if this did not change measure-level cost-effectiveness screening.

7.2 Energy Efficiency

7.2.1 Stakeholder Engagement

The MPS update completed by GDS was a refresh of the 2021 study, rather than a new and complete study of market potential. As such, the opportunities for stakeholder review and input were more limited. GDS and NIPSCO provided updates to the DSM Oversight Board ("OSB") on the MPS development process at a kickoff meeting in September 2024, and then roughly monthly between March 2024 and July 2024. The final MPS was included with the IRP filing as Appendix B on December 9, 2024. NIPSCO and GDS were generally receptive to stakeholder feedback. Though, as discussed later, agreed-upon modeling approaches were not executed by NIPSCO within the IRP.

7.2.2 Measure List and Measure Assumptions

The 2024 MPS analyzed 379 unique measure types, with many more permutations to account for market segments, building types, and efficiency levels, as shown in Table 7.

Table 7. Electric Energy Efficiency Measures Modeled in the 2024 MPS[67]

	# of Measures	Total # of Measure Permutations
NIPSCO – Electric		
Residential	196	1,276
Nonresidential	183	1,435
Total	379	2,711

The types of measures included in the MPS did not substantially change from the 2021 MPS; however, the number of unique measures appears lower in 2024. The 2021 MPS analyzed 454 unique measure types, as shown in Table 8. The reduction is primarily due to the methodology used to model industrial energy savings, which relied on discrete measures in 2021 versus end-use measures in 2024. Many measure assumptions were revised in the 2024 MPS based on the recently updated Indiana Technical Resource Manual ("TRM").

[67] NIPSCO 2024 Demand Side Management Market Potential Study, Volume I Electric Energy Efficiency Potential, Table 3-2.

Table 8. Electric Energy Efficiency Measures Modeled in the 2021 MPS[68]

	# of Measures	Total # of Measure Permutations
NIPSCO – Electric		
Residential	182	739
Commercial	169	5070
Industrial	103	2060
Total	*454*	*7869*

7.2.3 IRP Bundles

The energy efficiency results from the MPS were "bundled" according to customer sector and time vintage. Within the residential sector, additional segmentation occurred by program type and cost. NIPSCO and GDS sought input from the OSB on the creation of the bundles, resulting in the groupings depicted in Table 9. These bundles were used as inputs into the IRP.

Table 9. Energy Efficiency Bundles

RAP			Enhanced RAP		
2027-2029	2030-2032	2033-2046	2027-2029	2030-2032	2033-2046
Res Low/Medium Cost			Res Low/Medium Cost		
Res High Cost			Res High Cost		
Res Behavior			Res Behavior		
Res IQW			Res IQW		
Res IQ HEAR			Res IQ HEAR		
All C&I			All C&I		

The introduction and discussion of these energy efficiency bundles within the NIPSCO IRP, in section 5.3.1 and Tables 5-15 through 5-20, is consistent with our understanding of the process. However, subsequent discussion of the EE modeling merely references the RAP bundles. Furthermore, the selection of DSM resources shown in IRP Figure 9-10, reproduced below as Figure 9, merely presents the results from the RAP scenario. **This approach is inconsistent with the agreed-upon modeling methodology.**

[68] NIPSCO 2021 Demand Side Management Market Potential Study, Volume I Electric Energy Efficiency Potential, Table 4-2.

Figure 9-10: Energy Efficiency Selection across Portfolios

Program	Portfolio A			Portfolio B			Portfolio C			Portfolio D			Portfolio E			Portfolio F		
	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46	'27-'29	'30-'32	'33-'46
Res (Low/Med)	o	x	x	o	x	x	o	o	x	x	x	x	x	x	x	x	x	x
Res (High)	o	o	o	o	x	x	x	o	x	x	x	o	o	o	o	x	x	o
Res (Behavioral)	o	o	x	x	o	x	x	x	x	x	x	x	x	o	x	o	x	x
C&I	o	x	x	o	x	x	x	x	x	x	x	x	x	x	x	x	x	x
IQW	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
IQHear	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x

X = Selected
o = Not Selected

Figure 9. Energy Efficiency Selection Results from the NIPSCO IRP[69]

At the MPS stakeholder meeting on April 18, 2024, NIPSCO agreed to model as a selectable resource both RAP and enhanced RAP for commercial and industrial, while residential would be modeled only at the RAP level. **Instead, NIPSCO modeled all RAP bundles as a selectable resource, but none of the enhanced RAP bundles.** NIPSCO only evaluated the enhanced RAP scenario as a sensitivity analysis within Portfolio D_DSM. As we discussed earlier in section 4.3.2, this sensitivity analysis bundled all enhanced RAP (residential + commercial/industrial), plus demand response MAP. Therefore, there is no way to know how the C&I enhanced RAP bundles would have performed on their own, or if they would have been selected by the model. The performance of Portfolio D_DSM as a sensitivity provides no indication of how it would have performed since C&I enhanced RAP was comingled with other DSM resources.

The impact of this approach is a **potential loss of 7% more C&I energy efficiency savings**, shown below in Figure 10. As noted by NIPSCO, the savings contained within the enhanced RAP are more expensive, though we believe the C&I enhanced RAP bundles would have been economically competitive considering the overall low costs of C&I energy efficiency.

[69] NIPSCO 2024 IRP, Figure 9-10 at 258

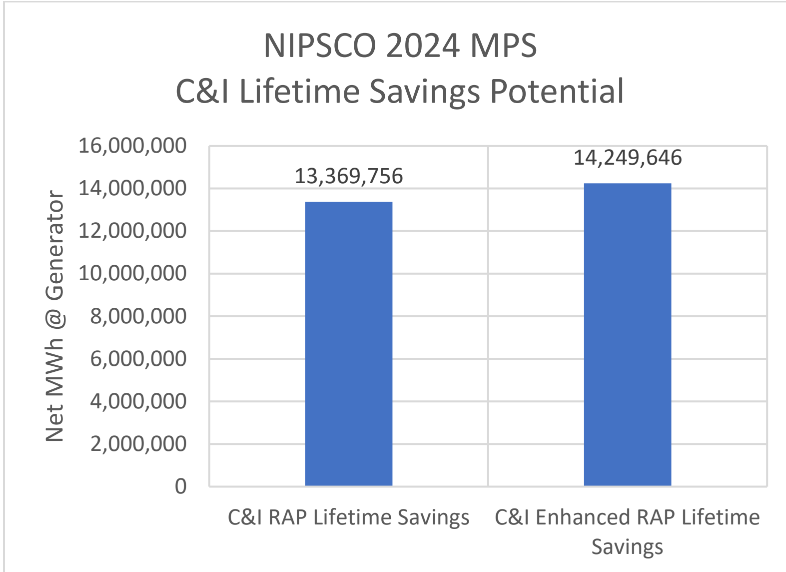

Figure 10. C&I Lifetime Energy Efficiency Savings, RAP vs. Enhanced RAP

7.2.4 EE Savings

The IRP included energy efficiency savings as quantified by the MPS, with the following adjustments:

- Gross savings were converted to net, using net-to-gross factors defined in the MPS
- Meter savings were converted to the generator with an assumed line loss factor of 7.5%
- Avoided lifetime transmission and distribution benefits were discounted from the program costs

While we agree with these adjustments, we believe that NIPSCO improperly converted MPS savings (gross savings at the customer meter) for use in the IRP (net savings at the generator) for the commercial and industrial sector. **This error further diminishes the energy efficiency savings modeled in the IRP by 3.6%**, as shown below in Table 10. The residential energy efficiency savings appear to have been properly converted for modeling within the IRP.

Table 10. Energy Efficiency Savings Conversion from MPS to IRP, Demonstrated for 2027

		C&I	Res	Notes
MPS	Gross MWh	71,173	50,575	MPS Table 5-3 (C&I) and Table 4-3 (Residential)
	Net MWh	60,829	46,512	Based on measure net-to-gross factors defined in the MPS
	Net MWh @ Gen	65,762	50,284	7.5% line losses, as defined in the MPS
IRP	Net MWh @ Gen	63,372	50,284	Table 5-15
	MWh Shortfall	2,389	0	
	% Shortfall	**3.6%**	**0.0%**	

7.2.5 EE Levelized Cost

NIPSCO calculated the levelized cost of the energy efficiency bundles for modeling within AURORA. These levelized costs are shown below in Table 11.

Table 11. NIPSCO Lifetime Levelized Costs for Energy Efficiency[70]

Bundle	Lifetime Levelized Cost ($/MWh) 2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

NIPSCO provided a worksheet showing the calculation of these levelized costs in its response to a data request.[71] In its calculation of levelized costs, NIPSCO divided the net present value ("NPV") of the cost by the NPV of the lifetime savings. The NPV calculation for both cost and savings used a nominal discount rate of 7.22%. This approach is appropriate for the costs since the MPS applied an inflation rate of 3.21% to future costs.[72] However, it is inappropriate to discount savings using a *nominal* discount rate since inflation does not apply to energy savings. Energy savings are a physical quantity that does not experience economic inflation and, therefore, must be discounted using a *real* discount rate.

In the calculation of levelized cost, the discount rate must be applied consistently to the numerator (costs) and denominator (savings). Since the savings must be discounted using a real discount rate, as mentioned above, then the costs must be treated the same. To accomplish this, the nominal costs from the MPS must first be deflated, and then the cost NPV can be calculated using the real discount rate.

[70] NIPSCO 2024 IRP at 191
[71] NIPSCO Response to CAC DR 3-008 (Attachment A).
[72] NIPSCO 2024 Demand Side Management Market Potential Study, Volume I Electric Energy Efficiency Potential, Table 4-2.

In either case, the NPV of the costs will be similar. Using a nominal discount rate on inflated costs will return the same result as using a real discount rate on uninflated costs. The NPV of the energy savings, however, will be very different, as demonstrated below in Table 12. **The levelized costs for most of the energy efficiency bundles, as calculated by NIPSCO, are roughly 25% higher than they should have been if calculated correctly.** While this discrepancy has no bearing on the preferred portfolio since all bundles were selected, it does affect the results of other portfolios in which some bundles were not selected. Perhaps more importantly, the sensitivity analysis that evaluated enhanced RAP savings may have had a different outcome with appropriate levelized costs.

Table 12. Calculation of Energy Efficiency Levelized Costs for Time Vintage 2027-2029[73]

		Residential - Low/Medium	Residential - High	Residential - Behavior	C&I	IQW	IQ HEAR
NIPSCO Approach	NPV of costs (nominal)	$10,109,975	$6,261,160	$4,576,526	$20,424,046	$2,616,205	$2,721,459
	NPV of savings (nominal)	380,606	61,682	78,617	1,291,454	33,756	30,547
	Levelized Cost	$26.56	$101.51	$58.21	$15.81	$77.50	$89.09
Correct Approach	NPV of costs (real)	$10,434,505	$6,462,143	$4,723,433	$21,079,658	$2,700,186	$2,808,818
	NPV of savings (real)	492,570	80,433	83,695	1,624,148	45,944	39,904
	Levelized Cost	$21.18	$80.34	$56.44	$12.98	$58.77	$70.39

7.2.6 EE Summary

The modeling approach used by NIPSCO failed to adequately model the higher savings potential from C&I enhanced RAP, despite previous agreement to do so; improperly converted C&I savings from the MPS to the IRP resulting in a 4% savings shortfall; and used levelized costs for energy efficiency bundles that were 25% too high. Any one of these issues would be cause for concern, but combined they represent an egregious misrepresentation of energy efficiency potential within the IRP.

[73] MPS costs were deflated using an inflation rate of 3.21%. A real discount rate of 3.89% was used to calculate the NPV, based on the NIPSCO nominal discount rate of 7.22%. The conversion from a nominal discount rate to real is achieved using the following formula: (1+rate_nominal) / (1 + inflation) – 1. Slight differences in the NPV of costs between the two approaches may be due to the T&D costs, which were removed from the program costs after the MPS and may or may not have included inflation.

Appendix

Please also see the separately filed Excel attachment:

NIPSCO Response to CAC DR 3-008 Attachment A

Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Request 1
2024 Integrated Resource Plan

CAC Request 1-001:
Please refer to NIPSCO's IRP slides from June 24, 2024 Second Stakeholder Advisory Meeting and the "NIPSCO 2024 IRP Load Forecast Summary" data file. Regarding the load forecast for new data centers: a. Please confirm that tab "LF Reference" refers to load factors and provides the class load factor for each month of each year. b. Please describe the basis for the Load Factor percentages used in tab "Large ED Load Adjustments," columns O through R. c. Please describe in detail the process used and factors considered by NIPSCO to determine the peak load assumptions are included in NIPSCO's base load forecast for the IRP. Are these forecasts based on specific data center interconnection requests received by NIPSCO and the specific MW loads these data centers have identified, or are they based on creating a generic load profile for a generic data center and scaling that by the number of data centers assumed to interconnect with NIPSCO's system? Please explain. d. At slide 22, it identifies "2-3 projects" of "up to ~2,600 MW" included in all scenarios. Please clarify what "2-3 projects" means in the context of developing the data center load forecast. Is this an averaging of a scenario with 2 centers and a scenario with 3 data centers? If there is uncertainty about the third data center, please explain why the base forecast does not include only 2 data centers as opposed to "2-3 projects". e. Please explain why it is reasonable to include 2,600 MW of data center load growth by 2035 if no data centers have actually executed interconnection agreements with NIPSCO to date. If any data center with an anticipated load of more than 100 MW by 2035 has executed an interconnection agreement with NIPSCO, please identify the data center, the owner of the data center, and the data center's monthly load forecast through 2035 for each interconnection agreement that has been executed. f. Please explain whether NIPSCO plans to make adjustments to its data center load forecasts given the recent announcement that the Chesterton

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data center is not moving forward as initially proposed (https://www.nwitimes.com/news/local/business/chesterton-data-center-provident-realty-advisors/article_cfa2c0e8-27e4-11ef-82c9-13d5c84f02ce.html).

g. Please explain the basis for the assumption that six data center projects would use 8,600 MW by 2035.

h. Please explain in detail why NIPSCO believes it is technically and financially feasible for NIPSCO to build or contract for additional new capacity resources sufficient to meet data center load growth of 8,600 MW by 2035 given current siting, interconnection, supply chain, labor, and regulatory challenges in the power sector, and NIPSCO's commitment to retire and replace capacity at Schahfer and Michigan City generating stations.

i. Please explain why NIPSCO is not proposing to include any scenario where data center load growth is less than in its base case.

j. Please refer to slide 18. Please confirm that the referenced Amazon Web Services and Google data centers are not in NIPSCO's service territory.

k. Of the approximately 2,600 MW data center load by 2035 identified by I&M, please identify:
    i. the total load (MW) each year from 2025 through 2035 associated with the announced $1 billion Microsoft data center in LaPorte (https://iedc.in.gov/events/news/details/2024/06/04/gov-holcomb-announces-plans-for-new-1b-microsoft-data-center-in-northwest-indiana)
    ii. the total load (MW) each year from 2025 through 2035 associated with any other individual data center projects NIPSCO currently believes are highly likely to move forward with an interconnection agreement.

Objections:

NIPSCO objects to sub-part (k) of this Request on the grounds and to the extent that this Request seeks third-party information that is confidential, proprietary, and/or trade secret.

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NIPSCO further objects to this Request on the separate and independent grounds and to the extent the Request seeks information related to a different utility.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

a. Confirmed. The "LF Reference" tab contains the class-specific load factors for the class segments included in the base econometric forecast: residential, commercial, small industrial, large industrial non-531, large industrial 531 T1/2/3, railroad, street lighting, public authority, and company use. Sales and monthly peak load forecasts for other components of the load forecast, including DERs, EVs, other electrification, and large economic development (data center) loads are developed separately in the relevant tabs.

b. NIPSCO's conversations with potential new large loads suggest that demand will be close to "24x7" and around the clock. For modeling purposes, NIPSCO assumed a 95% load factor for most of the year, with a 98% load factor in the summer to account for additional load from temperature control.

c. NIPSCO's peak load forecast includes generic data center assumptions around load factor, and NIPSCO then multiplied that by the number of data center customer opportunities that NIPSCO considers to have serious potential to be added to its system between now and 2035. The opportunities in NIPSCO's pipeline are all different. None of the data center potential projects that were considered when the IRP peak load forecast was built have made a formal interconnection request to-date.

d. See CAC Request 1-001 Confidential Attachment A.

e. See CAC Request 1-001 Confidential Attachment A.

f. See CAC Request 1-001 Confidential Attachment A.

g. See CAC Request 1-001 Confidential Attachment A.

h. See CAC Request 1-001 Confidential Attachment A.

i. See CAC Request 1-001 Confidential Attachment A.

j. See CAC Request 1-001 Confidential Attachment A.

k. See NIPSCO's objections.

**Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Request 3
2024 Integrated Resource Plan**

CAC Request 3-008:
Please provide the supporting workbooks, with all formulas and links intact, used to develop the "Energy Cost" for each of the DSM resources in the AURORA Table named "Portfolio Contract".
Objections:
Response:
Please see CAC Request 3-008 Attachment A. The energy efficiency program costs are levelized over their full lifetime energy savings using NIPSCO's discount rate and are summarized in rows 35, 69, and 103 of the "DSM Annual Costs" tab. The annual costs and savings for each program bundle were developed as part of NIPSCO's DSM study performed by GDS, as documented in Stakeholder Meeting #3 and with the DSM Oversight Board.

**Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Request 3
2024 Integrated Resource Plan**

CAC Request 3-012:
Please refer to the AURORA Table named "Portfolio Optimization" and the columns named "Upper Bound" and "Lower Bound". a. Please confirm that these two columns set the build constraints for each resource in the table. b. Please explain the difference in the annual "Upper Bound" between the generic CC and the generic CT.
Objections:
Response:
a. Yes, these set the upper and lower limit for the number of allowed additions for the specified new resource option. b. Based on model testing, NIPSCO identified a need for resources that provide a significant amount of energy to the portfolio and found a very limited selection of generic CT options across portfolio themes. Thus, generic CT additions were limited to one block per year for modeling purposes, with two or three blocks per year for CCGT additions based on the time period. NIPSCO's Major Projects and Supply Chain teams advised that up to two 650 MW combined cycle blocks could be reasonably brought online in a year in the near-term, with the potential for up to three over the mid-to-long-term.

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-024

REQUEST:

Refer to Duke Kentucky's 2024 Integrated Resource Plan (IRP), page 63, regarding the effects of Kentucky Senate Bills 4 and 349 and page 61, Figure 7.1.

a. State how much lead time Duke Kentucky needs from filing of notice with the Commission under Senate Bill 349 to completion of projects included in the preferred portfolios and provide an estimated timeline.

b. State whether this lead time was factored into the timing of modeling of new generation construction or conversion generation resources.

c. State what PJM interconnection queue lead time was factored into the timing of modeling of new generation construction or conversion generation resources and explain how that lead time was determined.

d. State whether the 50 MW of solar to be added in 2029 is intended to reflect power purchase agreements, purchase of existing or planned facilities, or self-built facilities.

RESPONSE:

a. The EPIC commission under KY SB349 requires 180 days and the PSC has 8 months to approve a CPCN following its acceptance (KRS 278.019). After receiving the CPCN order, it is currently taking 5+ years for long lead time equipment deliver and construction and commissioning of a CC. Prior to filing the

CPCN there is approximately 2-3 years of development activities required. Total timeline then from the time project development starts to unit in service is 8+ years.

b. This timeline was factored into the construction of new resources that may replace East Bend at some point in the future.

c. The Company assumed that conversion of East Bend to DFO would not require the Company entering into the PJM interconnection queue as this project is not adding incremental capacity to the site. When East Bend retires in 2038, the Company would need to enter the PJM interconnection queue for any incremental generation at that time (in this case, 64 MW). It is the Company's assumption that there is adequate time to enter the PJM queue and complete any necessary transmission network upgrades prior to executing the retirement and replacement of East Bend in 2038. For incremental solar resources online in 2029, the Company assumed that there would be resources available with completed interconnection agreements for an in-service date of 2029.

d. Duke Energy Kentucky modeled a generic solar resource for purposes of the IRP. The Company is evaluating next steps for sourcing this resource need.

PERSON RESPONSIBLE: Matthew Kalemba