INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR COMMENTS ON NORTHERN INDIANA PUBLIC SERVICE COMPANY'S 2024 INTEGRATED RESOURCE PLAN

APRIL 17, 2025

INTRODUCTION

The Indiana Office of Utility Consumer Counselor ("OUCC") offers its comments and recommendations on Northern Indiana Public Service Company LLC's ("NIPSCO") December 2024 Integrated Resource Plan ("IRP") submission.

NIPSCO held a series of IRP stakeholder meetings from April 2024 through October 2024, and the OUCC appreciated the opportunity to participate in these. OUCC staff also participated in separate technical meetings. However, as with all Indiana investor-owned electric utilities, the ultimate preferred resource portfolio and action plan decisions are NIPSCO's alone and are not determined by participating stakeholders.

NIPSCO has continued to respond to questions from stakeholder meetings and comments raised in prior Indiana Utility Regulatory Commission ("IURC") Research, Policy, and Planning Division Director ("Director") reports and OUCC submissions. The purpose of our comments is to recommend improvements to NIPSCO's IRP processes and Preferred Portfolio development as well as make suggestions to the IURC for the benefit of Indiana's consumers.

The fact that the OUCC does not address specific items, assumptions, or portfolios should not be interpreted as support on those matters. It is impractical to weigh in on every single issue given the amount of information and level of depth in these plans.

The OUCC offers the following general observations and recommendations:

- NIPSCO does not thoroughly discuss how the IRP preferred portfolio provides a basis for making decisions concerning its electric generation resource mix. Its discussions of the Five Pillars of Electric Utility Service need additional support to justify the portfolio selection.

- NIPSCO should provide more cost estimate details and review more cost benchmarks for its resource options. The chosen costs underestimate the investment required to implement the generating technologies considered. The OUCC's analysis of comparable levelized cost of energy ("LCOE") calculations, explained in these comments, shows the extent of NIPSCO's understated costs with respect to reasonable benchmarks. Six of the nine scorecard metrics are cost-based measures. Therefore, the accuracy and thoroughness of cost estimates are critical if the resulting metrics will be relied upon to make an informed portfolio decision. This diminishes stakeholders' ability to evaluate affordability.

- The OUCC's LCOE analysis, explained in these comments, demonstrates NIPSCO should evaluate the potential of converting the Michigan City Generating Station to natural gas.

- NIPSCO's Distributed Energy Resource ("DER") projections appear reasonable while the Electric Vehicle ("EV") forecast overstates EV adoption. NIPSCO does not adequately address infrastructure planning to efficiently integrate the forecasted load impacts of EVs or DERs.

- The OUCC recommends NIPSCO model sensitivities regarding natural gas availability during cold weather events in its reliability modeling to better address resiliency and stability among the portfolios.

- NIPSCO focused its environmental sustainability analysis on carbon intensity. The OUCC disagrees with NIPSCO's assessment that other issues like the impact of the Coal Combustion Residuals ("CCR") Rule on the redevelopment of Michigan City generation may not significantly impact the portfolio options and evaluations.[1]

- NIPSCO should be more critical of the viability of carbon capture, utilization, and storage.

- NIPSCO's portfolio evaluation methods improved from the previous IRP with added sensitivity and stochastic analysis, although its review of those results needs to be more robust. The OUCC recommends several deficiencies be addressed, including the following:

    - NIPSCO revised its resource portfolio scorecard from the 2021 IRP Scorecard. Two of these changes are concerning: 1) a reduction in the reliability metrics, and 2) the change

[1] Northern Indiana Public Service Company LLC, 2025 Integrated Resource Plan, December 9, 2024; p. 204, Section 7.3.1 Solid Waste Management.

from cumulative tons of carbon emissions to tons per megawatt-hour ("MWh"). Additionally, with increasing industrial and data center water demands, electric utilities should consider water use as a future metric when considering added resources and proposed portfolios.

NIPSCO's 2021 IRP focused primarily on its near-to-medium term plans, adding up to 1,201 MW of capacity through 2027. The 2024 IRP proposes five times more resource additions. NIPSCO improved its 2024 IRP with better detail for long-term generation needs and other necessary activities, including future evaluation of decarbonization options.

- NIPSCO's 2024 IRP did not reference the 2023 portfolio analysis NIPSCO prepared and utilized as supporting evidence for its significant investment in the new Schahfer Gas Peaking Resource approved in Cause No. 45947.[2] The gas peaker was significantly more costly than the 2021 IRP resource cost assumptions and, without a review of the 2023 portfolio analysis, the 2024 baseline is not well supported.

- Except for the reference flat load portfolios, all of NIPSCO's portfolios and evaluation of alternatives included more than 800 MW of storage, 2.5 GW of renewable generation, and 2.3 GW of thermal resources. In the 2021 IRP, NIPSCO reviewed an all renewable plus storage portfolio (no thermal generation), and a thermal power purchase agreement ("PPA") portfolio; however, none of these portfolios were considered in 2024. The lack of resource variety across modeled portfolios creates capital intensive and high operating cost solutions that could burden customers with higher electricity rates.

- NIPSCO should better support its assumption of 2,600 MW of large load customers in all portfolios, including discussion of the competitive marketplace to secure megaload customers. NIPSCO should evaluate more portfolios without the addition of data center loads. Although NIPSCO modeled higher levels of data center load, it did not provide

[2] NIPSCO's Verified Rebuttal Testimony of Patrick N. Augustine; p.4 ll.1-11.

a comprehensive review of its analyses or adequately provide a full picture of the risks and benefits of large load customers. A full analysis is needed in order to understand how the megaload needs affect the portfolio options.

NIPSCO reviewed very few portfolio options containing significant PPA-sourced energy and capacity resources; consequently, the preferred portfolio, its resource additions, and the resulting short- and long-term action plan do not represent NIPSCO's energy sourcing strategy to isolate megaload customers in a new generation company ("GenCo"). Because development of the proposed GenCo structure and work on NIPSCO's IRP occurred in parallel, it is reasonable to expect that NIPSCO's GenCo efforts would inform the IRP. As a result, the OUCC recommends NIPSCO update this IRP to reflect its current sourcing strategy.

IRPs are required to ensure reliable and economical power supply planning by addressing the statutory Five Pillars of Electric Utility Service, providing an analysis and the resulting generation resource forecast with action plans to achieve it. NIPSCO's IRP falls short in this area. As a result, the IRP does not provide sufficient support for future filings for resource additions, Certificates of Public Convenience and Necessity ("CPCN"), or Demand Side Management plans. This support is required by 170 IAC 4-7-2.5. The OUCC recommends the Director ask NIPSCO to update its IRP to reflect the GenCo energy and capacity sourcing strategy and address this submission's other shortcomings before filing any additional PPA or CPCN requests. Without it, resource actions will not be consistent with the most recently submitted IRP.

Furthermore, Executive Order 25-50 ("EO 25-50"), which Governor Mike Braun signed on April 10, 2025, acknowledges the National Energy Emergency declared by the Trump Administration on January 20, 2025. As the Commission re-evaluates the state's coal-fired generation units and completes additional directives in EO 25-50, it behooves NIPSCO and additional investor-owned electric utilities to modify their IRPs accordingly and continue the healthy dialogue through the stakeholder processes.

Executive Orders 25-48 ("EO 25-48") and 25-49 ("EO 25-49"), also signed by the Governor on April 10, 2025, should also be considered by utilities and stakeholders in future IRP discussions and development.

A. MODELING

NIPSCO developed six resource generation addition portfolios in its modeling. These included two reference portfolios: one assuming flat load and a second flat load utilizing MISO's proposed direct loss of load ("DLOL") accreditation method. Evaluation of these portfolios under five different scenarios with added sensitivity analyses on specific variables added insight for comparing NIPSCO's proposed addition options.

1) Congestion: Congestion was simulated as a random factor in the Moment Simulation Energy Price model but not as a known problem. This means the model was not sensitive to congestion costs, except as random shocks. Persistent congestion is missing from the model, with no mention of when congestion costs might be too high for dispatch. The OUCC recommends NIPSCO consider persistent congestion alongside random shocks and analyze when congestion becomes too high for dispatch.

2) Data Centers: The IRP reference case assumes 2,600 MW of hyperscaler load based on two or three projects. The high-load sensitivity case incorporates six projects of up to 8,600 MW.[3] The only source of new load growth is data centers. NIPSCO provided a review of 21,000 MW nameplate[4] capacity added generation assets and 935 MW of combined cycle gas turbine ("CCGT") and thermal PPAs to serve large load customers. Although NIPSCO provided a single slide of Key Observations,[5] there was no presentation of scorecard metrics and no discussion of risks or benefits of a high load portfolio plan. In Cause No. 46183, GenCo, a wholly owned subsidiary of NIPSCO Holdings II LLC (the parent company of NIPSCO), requests jurisdiction declinations for GenCo to support data center loads. This is not mentioned in the IRP. In the same, pending cause, GenCo claims its separate structure will reduce risk associated with hyperscalers, but NIPSCO includes

[3] NIPSCO IRP, Section 2.3.1.1, p. 16.
[4] 2024 NIPSCO IRP, Fifth Stakeholder Advisory Meeting, October 28, 2024; p. 65.
[5] 2024 NIPSCO IRP, Fifth Stakeholder Advisory Meeting, October 28, 2024; p. 70.

no analysis quantifying this change or a comparison of portfolios with or without GenCo's existence.

3) Commody Price Forecasts: Charles River Associates ("CRA") was the only producer of commodity price forecasts across several models. No second opinion was offered. CRA used its Natural Gas Fundamentals Market Mode ("NGF") model to forecast North American gas production and prices, but the inputs and assumptions of this model are not mentioned. NIPSCO should consider more scenarios including low, medium, and high gas price scenarios.

B. GENERATION COST COMPARISONS AND MICHIGAN CITY RETIREMENT

NIPSCO understates the cost of a natural gas peaker in its IRP analysis. In its Cause No. 45947 petition filed in late 2023, NIPSCO estimated the direct cost to construct its Schahfer natural gas peaker plant as approximately $1,440/kW.[6] However, according to NIPSCO, "In 2024 dollars, a new peaking resource was estimated at $1,284/kW based on NIPSCO's ongoing actual project experience."[7] At a minimum, the OUCC recommends consistency among the estimated price of NIPSCO's gas peaker prices used in stakeholder meetings, CPCN requests, and its IRP. Additionally, NIPSCO states, "for other costs, including electric interconnection, gas interconnections, water interconnection, owner's cost, and project contingency, NIPSCO escalated costs from an earlier IRP study at the historical inflation rate and projected inflation rate assumptions. This led to a total cost of $1,225/kW in 2024 dollars."[8] It appears NIPSCO's interconnection and owner's costs assumptions actually *decrease* the total cost of a gas peaking project, which is counterintuitive and may distort the resource selection modeling.

Using NIPSCO's estimates for the 650 MW 2x1 combined cycle ("CC") generator selected in its preferred portfolio, the OUCC calculated a 35-year LCOE to compare with adjusted 35-year Lazard LCOEs and with recent benchmarks. Lazard is a well-known financial advisory and asset management firm. The LCOE is the net present value ("NPV") divided by the total energy output over the expected plant life. The NPV is calculated using annual spending forecasts of overnight

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[6] Cause No. 45947, Augustine Direct, p. 39, ll. 11-13.
[7] NIPSCO IRP, p. 130.
[8] *Id*.

capital cost, fuel cost, operations and maintenance cost using a discount rate based on the mix of debt and equity financing. Table OUCC-1 below provides the parameters of the analysis.

Table OUCC-1

Acronyms:

OCC = Overnight Capital Cost
VOM = Variable Operations and Maintenance
FOM = Fixed Operations and Maintenance
HR = Heat Rate
ICAP = Installed Capacity
CF = Capacity Factor
NGCC = Natural Gas Combined Cycle
NGCT = Natural Gas Combustion Turbine

	Lazard Assumptions				NISPCO Assumptions	NIPSCO Reference
Financial						
Debt [%]	60%				[redacted]	1.A
Cost of Debt [%]	8%				[redacted]	1.A
Equity [%]	40%				[redacted]	1.A
Cost of Equity [%]	12%				[redacted]	1.A
Escalation [%]	2.25%				[redacted]	1.A
Lifetime [Yrs]	20[9]				[redacted]	1.A
Engineering						
	NGCT		NGCC		NGCC	
Range	Low	High	Low	High	-	
ICAP [MW]	240	50	550	550	650	2.A
OCC [$/kW]	700	1,150	850	1,300	1,225	2.B
FOM [$/kW-yr]	10.00	17.00	10.00	25.50	24.00	2.C
VOM [$/MWh]	3.50	5.00	2.75	5.00	1.32	3.A
HR [Btu/kWh]	8,000	9,800	6,750	7,500	6,704	3.B
NG Fuel Cost [$/MMBtu]	3.45	3.45	3.45	3.45	3.45	Taken from Lazard

References for Table OUCC-1:
1 NIPSCO_2024 IRP Confidential Appendix D_12092024.xlsx
1.A **TAB:** Financial Assumptions
2 NIPSCO 2024 IRP – Figure 4-15: Long-Term Natural Gas Resource Option Cost Assumptions – *NREL Annual Technology Baseline assumptions*
2.A CCGT (2x1): 2024$/kW (total cost on pg. 130)
2.B CCGT (2x1): ICAP
2.C CCGT (2x1): FOM
3 NIPSCO 2024 IRP – Figure 4-19: CCUS Costs and Operational Parameters
3.A Sugar Creek CCGT (2 x GE 7F.04) VOM
3.B Sugar Creek CCGT (2 x GE 7F.04) HR (Summer)

[9] Normalized for 35 years in subsequent analysis.

In Figure OUCC-1 below, the solid black line represents NIPSCO's LCOE based on the capacity factor or expected CC usage. As the figure reveals, the more a generator is used, the more cost the utility recovers, and the lower the LCOE. It also shows NIPSCO's IRP CC LCOE to be underestimated when compared to EIA and Lazard benchmarks and demonstrates the extreme cost impact of adding CCS, the blue line.

A CC is best used as a baseload generator. The 40% capacity factor identified in Figure OUCC-1 is, however, the maximum annual capacity for new base load CC turbines to comply with the EPA's 2032 requirement in the Clean Air Act Section 111 (b) Rule, unless retrofitted with 90% carbon capture.[10]

For comparison purposes, the OUCC utilized a 35-year adjustment to the LCOE because Duke Energy uses an expected 35-year life for two 738 MW 1x1 CCs in its proposed Cayuga project (CPCN pending under Cause No. 46193). However, as the cost of Duke's proposed CC has not been approved, the OUCC uses costs from the Florida Power & Light ("FPL") Dania Beach Clean Energy Center ("DBEC") CC that began construction in 2020. DBEC went online in 2022 with the same equipment and has reported two full years of power data. It must be noted that DBEC is the most realistic benchmark available, as the project replaced on-site retiring CCs and, therefore, had most infrastructure already in place. This will not be the case for NIPSCO. Nevertheless, the OUCC contrasts the cost per energy of FPL's DBEC utilizing fuel efficiency data and approved OCC[11] and adapting all other cost assumptions used by NIPSCO to calculate a comparable LCOE for the FPL DBEC (reference the thick red line in Figure OUCC-1).

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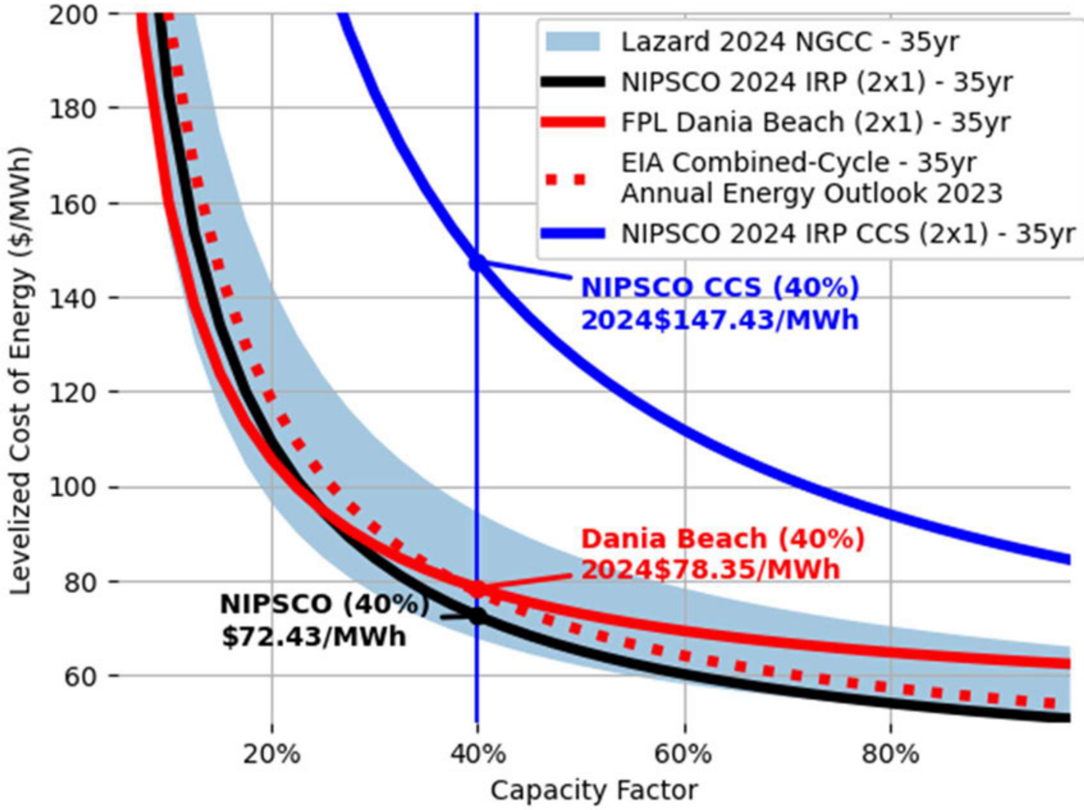
[10] https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-overview.pdf

[11] Using the inflation rate provided by the Bureau of Labor Statistics, the project cost is $1.138 billion in 2024 from the $888 million dollars approved on March 19, 2018, by the Florida Public Service Commission ("FL PSC") in Docket Number: 20170225. S&P FPL Dania Beach Clean Energy Center | Power Plant Profile reports 1447.7 MW nameplate capacity. The OCC is therefore $786/kW. The average heat rate of the CTs is 9,767 Btu/MWh, obtained from the 2023 and 2024 Form EIA 923.

Figure OUCC-1 35-year Life LCOE



A range of OCC expenditure (2024 nominal dollars per kW) should be used, anywhere between $1,200/kW (e.g., DBEC at $1,205/kW and NIPSCO at $1,225/kW) and $1,700/kW, the highest National Renewable Energy Laboratory (NREL) Annual Technology Baseline cost.[12] The Energy Information Agency (EIA) LCOE benchmark lies nearly at mid-range at $1,507/kW when inflation-adjusted to 2024.[13] Lazard's range assumes $850/kW and $1,300/kW; however, its financial returns are assumed to be much higher, resulting in a higher overall present value. By NIPSCO's financial assumptions, Lazard's upper OCC lands near $2,000/kW. NIPSCO should utilize and test a wider estimate range of OCC given the uncertainty of forecasting.

Although NIPSCO's costs begin to converge with the EIA's estimates at higher capacity factors, NIPSCO's heat rate (Btu/kWh) is likely unachievable. The EIA reports 6,431 Btu/kWh. With

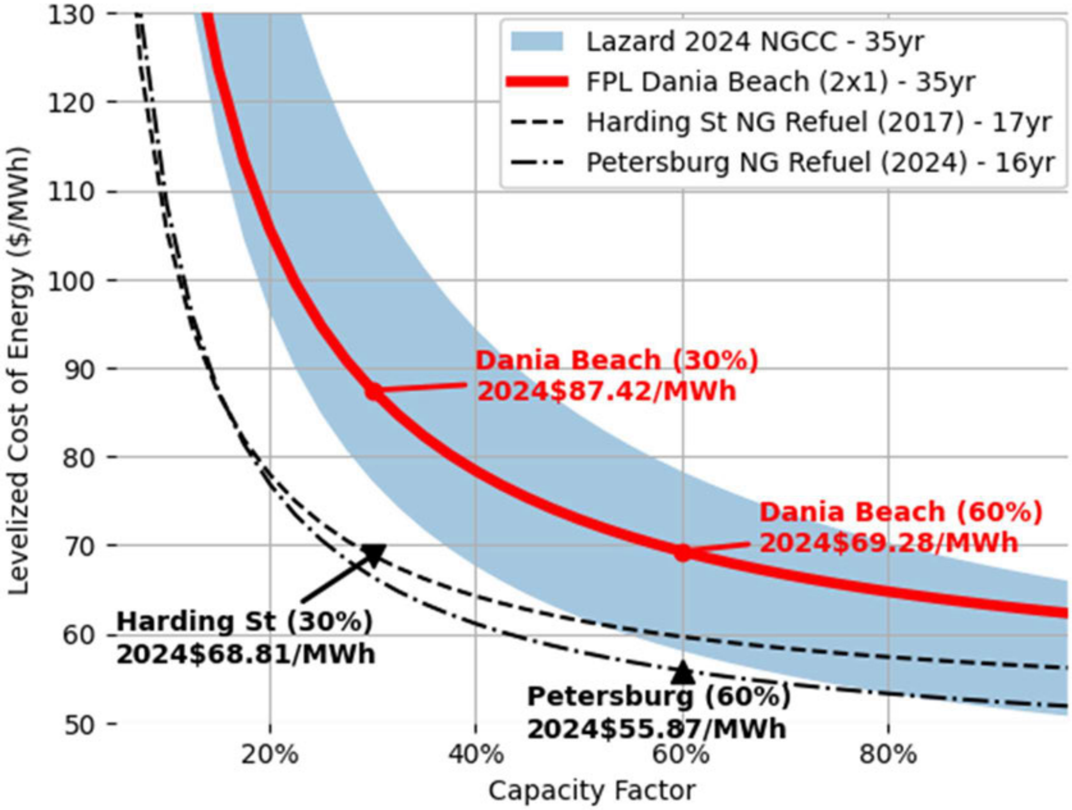
[12] NREL 2024 v2 Annual Technology Baseline, https://atb.nrel.gov/electricity/2024/data
[13] EIA's Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023, https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

carbon capture and sequestration (“CCS”), NIPSCO suggests 6,704 Btu/kWh.[14] Realistically, the heat rate modeled should be higher, leading to higher fuel costs. The DBEC illustrates this by running near 9,767 Btu/kWh for either combustion turbine, roughly at 57% and 60% capacity factors in 2023 and 2024, respectively.[15] The DBEC contains GE Vernova’s latest and most efficient combustion turbines. This was one of FPL’s arguments to justify retiring its older CCs to achieve $337 million net cost savings due to burning less natural gas.[16] Based on the reported data, these savings will be difficult to achieve.

The OUCC recommends a wider range of resource costs be used in each scenario to evaluate the best portfolio, placing greater emphasis on recent cost benchmarks, as that will more accurately predict the amount ratepayers will pay and, therefore, more accurately predict the affordability of the selection.

[14] NIPSCO IRP, Figure 4-19: CCUS Costs and Operational Parameters, p. 142.
[15] Average heat rate [Btu/kWh] from 2023 and 2024 EIA 923 filings – Page 1 Generation and Fuel Data, https://www.eia.gov/electricity/data/eia923/
[16] Petition for Determination of Need for Dania Beach Clean Energy Center Unit 7, https://www.psc.state.fl.us/clerks-office-dockets-level2?DocketNo=20170225

Figure OUCC-2 35-Year Life LCOE vs Refueling



The OUCC also evaluated the LCOEs of conversion costs of AES Indiana's Harding Street Station ($106.88 million in IPL's 2016 Semi-Annual Update[17] for Units 5 & 6 in Cause No. 44339 and Unit 7 in Cause No. 44540) and the Petersburg Generating Station conversion ($293.3 million approved in Cause No. 46022[18]). The levelized cost of conversion provides a benchmark for the Michigan City LCOE whose life could be extended by conversion to natural gas. The OUCC calculated an average annual capacity factor over 6 years of approximately 30% for Harding Street and assumed continuation of approximately 60% for Petersburg once converted[19] (the LCOEs marked in Figure OUCC-2 by downward- and upward-pointing arrows, respectively). The OUCC

[17] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/22126f8a-9184-e611-8107-1458d04fc108/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=jpeabody_ipl%27s%20submission%20of%20may%202016%20semi-annual%20report%20(44339)_5_31_20164-27-09pm.pdf
[18] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/b11526ad-5b9c-ef11-8a6a-001dd80bd98a/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_46022_110624.pdf
[19] Capacity factor derived from S&P Capital IQ annual unit operation, of which the data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings.

anticipates the costs to be recovered in the expected lifetime of 17 years for Harding Street and 16 years for Petersburg, as reported in AES's 2025 IRP Stakeholder Meeting #1 presentation.[20] The OUCC derives the cost for operation and maintenance, both fixed and variable, for pulverized coal to natural gas conversion from the EIA's 2016 Capital Cost report.[21]

Figure OUCC-2 demonstrates NIPSCO should have evaluated the option of converting its Michigan City facility to natural gas rather than retiring it altogether. However, this LCOE comparison does not directly include the ease of construction or other benefits NIPSCO could obtain from converting Michigan City, which can be achieved in a shorter timeframe than a completely new construction and full retirement of Michigan City. A conversion or delay in retirement of the existing coal-fired units could address the shortfall due to NIPSCO retiring coal-fired supply and may offset market prices from PPAs. NIPSCO failed to include analysis or discussion of Michigan City conversion as a viable option.

C. DEMAND SIDE MANAGEMENT ("DSM") AND DISTRIBUTED ENERGY RESOURCES ("DER")

NIPSCO's IRP projects between 0.8% and 3.6% of its residential customers will install solar DERs by 2045. This equates to approximately 3,320 to 15,000 residential installations. These projections appear reasonable based on current trends but require further validation of the underlying assumptions. Similarly, for commercial customers, DER adoption is estimated to range between 0.7% and 1.7% by 2045.[22] Unlike EV penetration, which follows a sigmoid adoption curve, the projected increase in DER adoption appears to follow a more linear trend. This suggests a steadier, incremental expansion rather than an exponential growth phase. While NIPSCO discusses customer-owned DERs in its IRP, including the excess distributed generation tariff that compensates excess generation at a rate equal to 125% of the utility's marginal energy cost, effectively a premium over the wholesale rate, it does not explicitly state whether all DER adopters are assumed to be grid-connected. To clarify this, NISPCO should specify what percentage of

[20] https://www.aesindiana.com/sites/aesvault.com/files/2025-01/IRP-Public-Advisory-Meeting-1-2025-AES-Indiana.pdf
[21] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf
[22] NIPSCO IRP, p. 78.

projected DER installations are expected to participate in the excess distributed generation tariff or other compensation measures and consider alternative scenarios where a portion of customers remain off-grid.

The IRP primarily focuses on solar photovoltaics as DERs with limited discussion of other DER technologies such as battery storage or demand response. While solar is dominant, broader DER integration could impact overall forecasts and require added investment to maintain network reliability.

The IRP integrates the National Renewable Energy Laboratory's ("NREL") 2023 Annual Technology Baseline cost projections and assumes continued benefits from the Investment Tax Credit. However, future federal tax credit policies are uncertain. If they expire or change, customer adoption may be lower than NIPSCO's projection, affecting long-term planning.

D. ELECTRIC VEHICLES

NIPSCO's IRP assumes private entities will develop EV charging infrastructure conservatively. This could lead to gaps in availability, particularly in rural areas. Additionally, there is a lack of clarity regarding how corridor charging will affect demand forecasts, which introduces uncertainty in infrastructure planning. NIPSCO also does not specify whether time-of-use rates or managed charging programs will be implemented to mitigate peak demand, making it unclear how the utility plans to effectively integrate EV load growth. The IRP does not address whether NIPSCO has considered a specific EV rate structure to encourage off-peak charging, leaving uncertainty about how the utility plans to manage EV-related demand growth.

Further, while the IRP relies on a sigmoid growth model for EV adoption, NIPSCO does not adequately address how external factors such as supply chain issues or policy shifts could influence EV forecasts. A sensitivity analysis should be conducted to better capture these uncertainties. Recent and anticipated near-term developments in federal policy also complicate the outlook. In February 2025, the Federal Highway Administration (”FHWA") issued a directive instructing states to suspend their National Electric Vehicle Infrastructure (”NEVI") Deployment Plans for all fiscal years, potentially affecting the $100 million allocated to Indiana.[23] Given these factors, NIPSCO's low-case scenario shown in Figure 3-10 assumes that EV adoption will reach 50% of light-duty vehicle ("LDV") sales by 2045, translating to approximately 250,000 registered EVs.[24] However, the number of registered EVs remains low, with only 2,152 LDV EVs recorded in counties served by NIPSCO in 2023.[25] In light of these dynamics, a more comprehensive analysis of EV adoption trends, infrastructure gaps, and policy risks is necessary to refine NIPSCO's long-term planning.

NIPSCO assumes 100% of EV owners will have some form of home charging access, but workplace and public charging infrastructure needs remain uncertain. This assumption does not fully account for customers who may not have home charging access,[26] particularly renters and low-income households that may lack the ability to install home chargers due to rental restrictions, lack of dedicated parking, or financial constraints. To address this, NIPSCO needs to refine its EV adoption modeling to reflect a diverse range of EV charging behaviors to account for all customers not having access to home charging. The modeling should include assumptions based on regional housing data, income level, and rental versus homeowner statistics.

Regarding heavy-duty vehicles, the IRP estimates 43 charging station locations[27] along major traffic corridors within NIPSCO's territory. While corridor charging could create a significant impact on peak demand, the IRP does not fully address how these loads will be managed to avoid grid congestion.

The IRP forecasts EV charging demand will be a major driver of future electricity load, mostly from medium-duty and heavy-duty vehicles. However, without managed charging strategies and updated rate designs, EV adoption could create significant challenges during peak load periods, ultimately negatively impacting system reliability and costs.[28] Additionally, automakers announced ambitious EV targets but are now struggling with production challenges, battery supply

[23] https://www.fhwa.dot.gov/environment/nevi/resources/state-plan-approval-suspension.pdf
[24] NIPSCO IRP, Figure 3-10, p. 44.
[25] NIPSCO IRP, Table 3-3, p.41.
[26] NIPSCO IRP, pp. 46-49.
[27] NIPSCO IRP, p. 58.
[28] NIPSCO IRP, pp. 64-66.

chain issues, and fluctuating customer demand. Several automakers, including GM and Ford, have already started scaling back their EV rollout plans. In July 2024, GM reduced its 2024 EV production forecast, lowering the upper estimate from 300,000 to 250,000 units. Toyota also announced it is postponing its plans to build EVs in the United States from 2025 to 2026 and lowering its manufacturing goal by 500,000 EVs.[29] Ultimately, NIPSCO should conduct sensitivity analyses modeling how delays in EV infrastructure funding, combined with the federal incentive changes and vehicle supply constraints, could impact EV adoption rates within NIPSCO's service territory to provide more realistic EV adoption rate scenarios.

Overall, the IRP modeling contains low, medium, and high-growth predictions for EV adoption. However, all of NIPSCO's predictions are higher than recent trends show EV adoption to be. The medium prediction should be the high-growth prediction, and the low prediction should be the medium-growth prediction, with a near-zero growth in EVs as the new low-growth prediction. The OUCC recommends using the low prediction instead of the medium prediction, which reduces adoption rates by one-third by 2040.

E. SCORECARD, PREFERRED PORTFOLIO

NIPSCO's 2024 IRP Scorecard uses five cost-based metrics in an attempt to address affordability. However, the evaluated portfolios are similar in content of high-cost resources, contain no PPAs, and utilize underestimated gas CCGT costs. These portfolio biases adversely influence the metrics so that consumer energy cost differences among portfolios cannot be used to define a least-cost or best-cost solution to generation needs. The OUCC recommends the cost metrics be modified or a sensitivity analysis performed with results plotted against each other to enhance the understanding of affordability. The differences between the five metrics presented are not sufficient to define a preferred portfolio.

[29] 12 Automakers that pushed back EV goals and plans in 2024: https://www.foxbusiness.com/markets/automakers pushed-back-ev-goals-plans-2024.

The Local Economy metric is informative as it explains how generation siting will positively affect selected communities where new generation is sited; however, NIPSCO's IRP failed to note that property taxes will be five times more costly than the 2021 IRP portfolio forecasts.[30]

With considerable load growth predicted in the years ahead, the OUCC recommends electric utilities measure water use and water table impact with future metrics when evaluating generation technology alternatives. Retiring coal generation will reduce water usage when replaced with renewable and natural gas generation.[31] But if generation demand driven by megaload consumers materializes, the addition of multiple combined cycle natural gas plants may require much of the water saved by coal plant retirements. It should be noted that megaload consumers also come with high water demands as do many other potential economic development projects.[32]

F. ANALYSIS OF THE FIVE PILLARS

The OUCC reviewed how the attributes of each of the Five Pillars of Electric Utility Service are addressed in NIPSCO's IRP due to the Commission approving General Administrative Order 2023-04 acknowledging House Enrolled Act 1007 (2023), Ind. Code § 8-1-8.5-3.3. For IRPs submitted after June 30, 2023, the Commission's Research, Policy, and Planning Division Director must evaluate whether an IRP's preferred portfolio takes the Five Pillars into account. Indiana Code § 8-1-8.5-4(b) now requires the IURC to consider, when evaluating a CPCN request, whether the construction of the proposed facility will result in electric service consistent with the attributes of the Five Pillars. as defined in Ind. Code § 8-1-2-0.6.

Decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs need to be considered in the context of each Pillar. NIPSCO needs to demonstrate more clearly how the final portfolio selection and the timing of retirements,

[30] NIPSCO uses a Local Economy metric in both its 2021 and 2024 IRPs. This is a comparison of that metric from Figure 9-42 in the 2021 IRP and the Scorecard in the 2024 IRP Stakeholder Advisory Meeting 5, p. 76.
[31] U.S. Energy Information Administration, U.S. electric power sector continues water efficiency gains; June 14, 2023.
[32] Indiana Economic Development Corporation, IndianaLEAP.com, LEAP LEBANON Frequently asked questions.; A Senate bill, SB 4, aims to address concerns over large water transfers like those planned to serve the controversial LEAP industrial district in Lebanon. https://www.wfyi.org/news/articles/bill-aims-to-ensure-long-water-pipelines-dont-threaten-supply-exempts-part-of-leap-project .

capacity additions, and other activities build an IRP that is reinforced by the attributes of the Five Pillars.

The Pillars are addressed as follows in NIPSCO's 2024 IRP:

1) Reliability & Resiliency

NIPSCO's IRP uses multiple metrics to measure reliability. However, the plan does not include a quantitative reliability analysis. NIPSCO relies on MISO's six reliability attributes as initial priorities, including rapid start-up, voltage stability, fuel assurance, long duration energy at high output, availability, and ramp up capability.[33] Since its 2021 IRP, NIPSCO has made enhancements to its stochastic analysis process in the current IRP to focus on the economic and reliability metrics.[34] Additionally, NIPSCO assesses how often it must rely on external resources to meet load requirements.

NIPSCO uses two metrics to assess the reliability Pillar: 1) a loss of load expectation proxy (forced market exposure) for NIPSCO's system based on its probabilistic reliability analysis, and 2) capacity response within 30 minutes.[35] While stochastic modeling improvements are included, the IRP does not provide a clear probabilistic reliability assessment illustrating how often NIPSCO's system may fail to meet demand under stress conditions.

Resiliency can be better addressed through specific metrics such as black start capabilities, recovery time from major disturbances and/or outages, and islanding potential for critical loads.

The IRP states that it constantly reviews circuit and substation adequacy, voltage levels, and system-wide reliability metrics (Customer Average Interruption Duration Index, System Average Interruption Frequency Index, and System Average Interruption Duration Index).[36] However, in addition to not providing a detailed resilience study, NIPSCO's IRP does not provide a detailed assessment of how future load growth, DER integration, and electrification will impact these metrics or how these metrics will shift as a result of the new load growth.

Regarding long-term reliability, the IRP provides an evaluation of several resource portfolios using

[33] 2024 IRP Stakeholder Meeting 2, p. 79.
[34] 2024 IRP Stakeholder Meeting 2, p. 81.
[35] NIPSCO IRP, p. 260.
[36] NIPSCO IRP, pp. 199-200.

a range of resource costs as well as scenarios that model different possible market futures. NIPSCO includes an analysis of supply-side and demand-side resources; however, its analysis could be improved by quantifying the cost of major event days from extreme weather events, supply chain and labor disruptions, or fuel supply risks that may impact system reliability and resiliency.[37] It is recommended NIPSCO expand its modeling to perform a sensitivity analysis to assess system performance during extreme event scenarios, particularly those reflecting climate change impacts, fuel shortages, and infrastructure failures, to strengthen reliability planning.

2) Stability

Given preferred portfolios are required to be evaluated on the attributes of electric utility service set forth in Ind. Code § 8-1-2-0.6 in IRPs according to Ind. Code §8-1-8.5-3.3, stability should be addressed in NIPSCO's public IRP. Although the evaluated portfolios may be capable of maintaining a state of equilibrium during normal and abnormal conditions or disturbances, NIPSCO does not evaluate stability by comparing and contrasting stability characteristics in its portfolio analysis. Rate stability is not the intent of the stability pillar. NIPSCO's stability review needs to discuss ancilliary services, frequency or voltage consistency, and how managing energy supply characteristics can be achieved with faster response times. The objective is to provide stable energy supply with minimal variability to the design parameters of the system.

3) **Affordability**

NIPSCO's affordability analysis is constrained by its baseline portfolio proposals, generation cost assumptions, and the scorecard evaluation of them.

For example, the scorecard considers short- and long-term effects on affordability without adequate attention to the middle-term. The timelines of new generation construction impact the middle term. Policy variation due to changing Federal administrations can affect those timelines and incentives. Specifically, the scorecard looks at 10-year NPV and 30-year NPV. To address the middle-term, the OUCC recommends a 20-year NPV be tested and added to the scorecard. This would better inform portfolio decision making.

[37] NIPSCO IRP, pp. 324-325.

The 2021 IRP evaluation of a portfolio consisting of all renewable investment plus thermal PPAs scored well on 2021 affordability metrics, but NIPSCO did not evaluate a similar portfolio in 2024. A similar analysis would allow stakeholders to understand if utility-owned thermal assets compare favorably to RFP-generated PPA options. It would also provide insight into the future affordability of a GenCo strategy as a benchmark. Because GenCo is a risk mitigation strategy, leaving it and thermal PPAs out of the IRP hinders an appropriate risk analysis. Without a benchmark risk analysis, any affordability argument that supports the preferred portfolio is weakened.

Another issue with NIPSCO's analysis, as shown in the OUCC's LCOE analysis, is that NIPSCO understates its costs. Furthermore, NIPSCO did not evaluate the option to convert its Michigan City generating facility to natural gas, which the OUCC estimates has a lower LCOE. Failure to consider these issues raises additional affordability questions about NIPSCO's preferred portfolio.

Portfolio D, as the preferred portfolio, moves NIPSCO down a riskier path where the company could be forced to install carbon capture and sequestration under stringent CO_2 emissions requirements. Investing in the preferred portfolio now may not be the most prudent option. The NPVRR metric chosen to evaluate "Costs to Customer"[38] for the portfolio options is a time-sensitive measurement which can vary significantly based on investment timing and discount rates. A CCS path may be more viable and affordable in the future depending on how technology evolves.

This leads to a final shortcoming of NIPSCO's affordability analysis in the IRP: No timing evaluations were performed in the sensitivity analyses. NIPSCO could delay or accelerate retirements or investments within the constraints of emissions requirements and technological capabilities. A timing analysis may show delaying coal retirements, even for a few years, to be more prudent and give newer technologies the time needed to mature.

[38] 2024 IRP Stakeholder Advisory Meeting 5 Final is the scorecard showing the 10- and 30-year NPVRR measurement, p. 76.

NIPSCO needs to address all affordability shortcomings in future IRPs. According to the IURC's 2024 Annual Report, NIPSCO had the highest 2024 residential bill for 1,000 kWh usage of any Indiana investor-owned utility ("IOU") as of July 1, 2024. This represents a 17.8% increase over 2023.[39] NIPSCO's 10-year increase of $58.85 is the highest dollar increase among the five IOUs in Indiana.[40] When Cost to Customer (NPVRR) and the Cost Certainty (scenario NPVRR range) metrics more than double for a 30-year analysis from the 2021 IRP to 2024 IRP[41], NIPSCO should be required to thoroughly justify how this rate stability is supported by the needs of all Five Pillars. The 2024 IRP fails to achieve this.

4) **Environmental Sustainability**

NIPSCO's primary metric for measuring environmental sustainability is the carbon intensity estimate for 2024-2040 of each portfolio as measured cumulative carbon emissions per MWh generated (short tons/MWh).[42] Other environmental issues and regulations were considered; however, NIPSCO did not believe regulations will impact future generation supplies to have a significant impact on the IRP modeling.[43]

NIPSCO's focus on carbon emissions is likely driven by three main factors:

- **Federal regulations on carbon emissions:** On April 25, 2024, the EPA released its final rule on carbon pollution standards for fossil fuel-fired power plants. The rule requires a 90% reduction in carbon emissions from existing coal-fired power plants and new gas-fired power plants. Existing natural gas plants or coal plants that are converted to natural gas before the compliance date of 2030 will be exempt from the 90% reduction requirement. The Section 111 Rule also requires the State of Indiana to develop a state implementation plan for regulation of

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[39] Annual Report 2024, Indiana Utility Regulatory Commission; Residential Electric Bill Survey Year to Year Comparison (Appendix F).
[40] Annual Report 2024, Indiana Utility Regulatory Commission; Residential Electric Bill 10-Year Comparison (Appendix G)
[41] NIPSCO uses Cost to Customer and Cost Certainty metrics in both its 2021 and 2024 IRPs. This is a comparison of those metrics from Figure 9-42 in the 2021 IRP and the Scorecard in the 2024 IRP Stakeholder Advisory Meeting 5, p. 76.
[42] NIPSCO IRP, Portfolio Evaluations – Scorecard Metrics, p. 260.
[43] NIPSCO IRP, Section 7. Environmental Considerations, p. 203.

carbon emissions within two years of the publication of the final Section 111 Rule. [44]

The Trump Administration is expected to, at the very least, significantly weaken the Section 111 Rule. On April 8, 2025, the Trump Administration signed an executive order aimed at promoting coal, and reducing regulatory barriers to its use. However, at the time of writing these comments, there has been no official action on the 111 rule itself.

- **NiSource's Net Zero Goal:** Before the publication of the Section 111 Rule, NIPSCO's parent company, NiSource, set an internal goal of net zero Scope 1 and Scope 2 greenhouse gas emissions by 2040.[45]

- **Customer Demand:** Indiana utilities have faced increased demand across rate classes for renewable energy and other low or no carbon sources of energy. Within the past year, CenterPoint Energy, I&M, and AES Indiana have all introduced plans to sell renewable energy credits ("RECs") to meet increasing requests for RECs to help meet sustainability goals.[46] These companies are also concerned about reducing their Scope 2 or secondary source greenhouse gas emissions. Demand could remain strong regardless of developments on federal regulations of greenhouse gases.

Carbon Emissions Assumptions

NIPSCO's selection of Portfolio D with carbon capture, utilization, and storage ("CCUS") as its preferred portfolio was made with the following carbon emissions assumptions [47]:

- **The federal emissions standards the Section 111 Rule created will be in place.** As discussed above, this assumption is likely no longer valid given the change in administration.

- **NIPSCO will be able to take full advantage of Inflation Reduction Act (IRA) tax credits, known as the 45Q credits, for geological storage of carbon dioxide of $85 per ton.** The Trump Administration's regulatory review is creating an uncertainty for such funding.

- **NIPSCO assumes no technology cost and performance risk associated with CCUS**

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[44] US EPA Fact Sheet, Carbon Pollution Standards for Fossil Fuel-Fired Power Plants Final Rule, State Plan; https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-state-plans-2024.pdf
[45] NIPSCO IRP, Plan Summary, p. 4.
[46] CenterPoint Energy (Cause No. 45990), I&M (Cause No. 45961), and AES Indiana (Cause No. 46137).
[47] NIPSCO IRP, Portfolio Evaluation – Analysis Results, p. 261.

based on its view that CCUS technology is well established[48] and can be easily retrofitted to existing NIPSCO facilities. The OUCC disagrees with this assumption. Any carbon capture unit needs to be studied and custom built for each facility, and associated geological formations to store carbon.

- **Use of CCUS and hydrogen gas for preferred portfolio D to meet NIPSCO's 2040 net zero goal will result in an additional $1.3 billion 30-year net present value revenue requirement**. Since the assumptions about tax credits, technology, and performance may be invalid, carbon control costs may be underestimated.

CCS

NIPSCO presents CCS as a low-risk well-established technology. To date, only one large scale project, the Petra Nova oil recovery project in Texas, has been operating within the United States. All others are still being developed. Even Petra Nova ceased operation for a time due to low oil prices and poor commercial viability.[49] With all other projects awaiting construction, viability has not been demonstrated to achieve 90% carbon reduction.

Site-specific geologic studies at the Sugar Creek site are needed to determine if storage is possible. Given the variability of geologic formations, viability at the Wabash Carbon Services site does not guarantee viability at other nearby sites.

NIPSCO did not receive any bids for a CCS project in its 2024 RFP.[50] The fact that no contractor was willing to bid for a CCUS project indicates CC may not be economically viable in Indiana when considering existing geological and technological uncertainties.

CONCLUSION

The OUCC appreciates the opportunity to review NIPSCO's IRP and participate throughout the stakeholder process. We trust these comments will be helpful in the Director's assessment.

[48] NIPSCO IRP, CCUS Technology Overview, pp. 137-140.
[49] NIPSCO IRP, Demonstration Projects, p. 139.
[50] NIPSCO IRP, CCUS Cost Estimate, p. 141.