COMMISSION DISCUSSION AND FINDINGS

1. Standard of Review

The Commission must ensure that NIPSCO, like all regulated utilities, meets its obligation to furnish reasonably adequate service and facilities, and that its charges for that service are reasonable and just. I.C. § 8-1-2-4. Unjust and unreasonable charges are prohibited and unlawful. *Id.*

While Indiana law favors settlement, *e.g.*, *Mendenhall v. Skinner & Broadbent Co.*, 728 N.E.2d 140, 145 (Ind. 2000), the Commission cannot approve a settlement agreement unless it meets fundamental standards and serves the public interest. In the context of regulated utility ratemaking, settlement agreements are more than mere contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). "Any Settlement Agreement that is approved by the Commission 'loses its status as a strictly private contract and takes on a public interest.'" *Id.* The Commission "may not accept a Settlement Agreement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the Settlement Agreement." *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996) (citing C. Koch, *Administrative Law and Practice* § 5.81 (Supp. 1995)).

Further, any Commission decision, ruling, or order, including approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coal. v. Public Service Co.*, 582 N.E.2d 330 (Ind. 1991)). The Commission's procedural rules require that settlement be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreement, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that such agreements serve the public interest.

We find that the Settlement is not in the public interest as it has several fatal flaws. The Settlement Agreement exacerbates widespread existing residential affordability problems and provides residential customers a smaller share of the Settlement Agreement's . In particular, the Settlement fails in that:

- The Settlement would result in an average residential annual bill increase of $411, including sales tax.[1]

[1] CAC Witness Inskeep Settlement, p. 6 (($32.02 + $32.02*0.7) * 12 = $411.14). *See also* CAC Ex. 4, Stipulation of Facts in Lieu of Cross-Examination of NIPSCO Witness Whitehead, Facts 1, 2, 3.

- The Settlement provides for a modest 30.3% reduction to NIPSCO's overall revenue increase relative to the rate hike requested in its case-in-chief, but residential customers will only see a much smaller 23.6% reduction.[2]

- It is premised on the acceptance of NIPSCO's deeply flawed allocated class cost of service study ("COSS") that features a 4CP cost allocation unfairly assigning large portions of production costs to residential customers. The Settlement's proposed remedy of conducting more holistic cost allocation analyses as part of its next rate case is inadequate and a tacit admission by NIPSCO that it failed to conduct the appropriate COSS as part of this case.

- NIPSCO's misallocation of renewable energy and battery energy storage tax credits redistributes millions of dollars each year in tax credits paid for by residential customers and allocating them to non-residential customers instead.

- An unfairly large portion of the reduction in revenue requirement associated with the Settlement Agreement is going towards reducing the rates of non-residential customers, leaving little benefit and rate shock for the residential class.

- The Settlement fails to include NIPSCO's proposed multi-family rate, instead lumping this distinct rate class in with Rate 511, leading to rates that far exceed cost of service for multi-family customers based on NIPSCO's COSS.

- The Settlement transforms what had been a well-designed Low-Income Program into one that mirrors the recently failed programs of other Indiana electric utilities, with substantially fewer benefits for eligible customers and without a long-term sustainable funding mechanism.

- NIPSCO asks ratepayers to pay for $2,845,699 subsidy in amortization expense for the Economic Development Rider, which shareholders should pay instead.

- The Settlement does not provide adequate ratepayer protection with respect to significant data center load growth being actively negotiated by NIPSCO today.

[2] NIPSCO Witness Whitehead Settlement Testimony, p. 5.

2. <u>Cost Allocation Relies on an Outdated COSS and Results in Unfair Assignment of Costs to Residential Customers.</u>

A. The COSS is outdated and unreliable.

It is unclear to us when NIPSCO last did a holistic COSS "study[ing] its production, transmission, and distribution classification and allocation" as it commits to do before its next general electric rate case.[3] NIPSCO "did not deem it necessary to and did not undertake a holistic evaluation of NIPSCO's existing cost allocation methodologies in preparation for filing direct testimony in this cause",[4] even though "[a] rate case is the proper forum for a holistic evaluation of cost allocation methodologies by the Commission, as needed."[5] We are concerned about the staleness and lack of comprehensiveness of NIPSCO's current COSS.

In NIPSCO's last electric rate case, Cause No. 45772 (2023), the 4CP demand-related production deal was already done by the time NIPSCO filed its case-in-chief on September 19, 2022, seven days after reaching a settlement with industrial customers.[6] The industrial deal agreed that there would be no adjustments to the COSS that would "propose alteration of the use of the 4 CP demand related production or 12 CP demand related transmission allocation methodologies."[7] Non-industrial parties were not invited to these negotiations. The Settlement in Cause No. 46120 continues this faulty allocation of production demand-related costs using the 4CP method yet again.

Outside of just the passage of time and major changes to NIPSCO and MISO's systems, the large amount of Rate 531 load that has been allowed to exit the NIPSCO system to pursue alternative supply arrangements (Tier 2 and Tier 3 demand) means the COSS does not present results that reflect the actual cost to serve any given customer class, even assuming all the underlying cost allocation methodologies are reasonable. We share concerns that the outdated COSS does not accurately reflect cost causation and calls into question estimates about what the actual costs to serve customer classes are.

Issues of cross-subsidization cannot be accurately described and considered if the underlying COSS is not based on reasonable inputs and methods because they will produce distorted and inaccurate results. The current COSS produces absurd results, assigning the residential class a 53% rate increase if rates were set at their full cost of service and illustrating why it is not a reasonable foundation in this case. The COSS itself should be based on sound methodologies that reflect principles of cost causation. Cost of service evaluation can and should

[3] Settlement Term B(11)(b).

[4] CAC Ex. 4, Stipulation of Facts in Lieu of Cross-Examination of NIPSCO Witness Taylor, Fact No. 2.

[5] *Id.*, Fact No. 1.

[6] Cause No. 45772, Final Order, Aug. 2, 2023, p. 3; Cause No. 45772, Final Order, Attachment C, p. 1 (Stipulation and Settlement Agreement on Rate 831/531 Modification).

[7] Cause No. 45772, Final Order, Attachment C, pp. 5-6, Term B(2)(a).

evolve with changed circumstances and new or better information that renders it more accurate. It is critical that this study provide accurate information based on sound methodologies so that the Commission can have the evidence necessary to inform its decision-making.

NIPSCO's rebuttal commitment, which was memorialized in the Settlement, to do a holistic update to its COSS for the next rate case is not enough. Instead, it is an admission by the Company and the Settling Parties that this COSS is not reliable. This rate case is the proper venue and time for a holistic review of NIPSCO's cost allocation approach.[8] This Settlement term is nothing more than a commitment to again delay work on a critical issue that is more than ripe for addressing now, particularly given our concerns about residential bill affordability. Furthermore, a separate provision of the Settlement in Addendum B commits NIPSCO to prepare a 4CP COSS (but no commitment to perform a COSS based on any other methodologies). We question NIPSCO and the Settling Parties' seriousness here, particularly when NIPSCO does not commit to preparing an COSS based on any other methodologies, such as the 12CP analysis provided in the instant case.

After a reasonable, accurate COSS is completed, the Commission can *then* address its valid concerns about gradualism by applying revenue increase mitigation strategies to adjust rate impacts for each customer class.

B. No Reasonable Basis or Supporting Evidence to Continue 4CP Cost Allocation for Production Costs.

i. NIPSCO overemphasizes the FERC cost allocation test results.

There is no longer a reasonable basis for NIPSCO to continue to use the 4CP cost allocation method for production costs when a more reasonable 12CP cost allocation method should be adopted instead, especially given the fundamental flaws embedded in NIPSCO's outdated COSS and growing concerns about NIPSCO residential bill affordability. We direct NIPSCO to use a 12CP cost allocation method for production costs and make efforts to explore the range of other options presented by the parties.

NIPSCO performed the FERC cost allocation tests for using a 12CP allocator. Since NIPSCO's load characteristics did not "pass" the three tests, NIPSCO reasoned that a 4CP allocator

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[8] CAC Ex. 4, Stipulation of Facts in Lieu of Cross-Examination of NIPSCO Witness Taylor, Fact No. 1.

was reasonable.[9] NIPSCO places an overemphasis on the outcome of FERC's 12CP cost allocator tests, as it has been doing since Cause No. 45159.[10]

In Cause No. 46038, we approved Duke's update from 4CP to 12CP for demand-related costs, finding that "the FERC tests are guideposts and not steadfast rules for decision making".[11] Duke also did not pass all of the FERC tests, with its expert witness explaining that the FERC tests are not determinative of the cost allocation methodology that the Commission should adopt in Indiana.[12] Likewise, FERC has also clearly stated that the FERC tests should not be viewed in black-in-white terms. In a 2019 proceeding, FERC approved Dominion Energy Virginia's change to the 12CP cost allocation method over various objections, explaining that its three tests "are not a bright line test" and that Dominion demonstrated "that its proposed 12-CP methodology is consistent with transmission planning" and consistent with cost causation.[13] Besides, FERC created these three tests in the context of ***wholesale*** electricity rate-setting under ***federal*** jurisdiction, failing to consider the unprecedented recent and ongoing changes to the electric power sector generally and to NIPSCO's operations specifically.[14]

In short, NIPSCO overemphasized the FERC test results, when it should have focused its attention on performing a holistic COSS first.

ii. Major changes at NIPSCO and at MISO require necessary changes to NIPSCO's allocation methodology.

While NIPSCO points to IURC Order in Cause No. 43839 from fifteen (15) years ago, the findings still indicate a change is necessary here. In Cause No. 43839, the Commission upheld the continued use of the 4CP method for Vectren South on the basis that one witness "provided no evidence that system operating characteristics have changed since the company's last COSS [cost

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[9] NIPSCO Witness Taylor Direct Testimony, p. 22:8-15.

[10] Cause No. 45159, Final Order, Dec. 4, 2019, p. 56 ("Dr. Gaske explained that he reviewed the system peaks for all months during the 2010 - 2017 period and applied FERC's cost allocation tests to NIPSCO's load characteristics. Those tests indicated that either a 4CP or a 12CP methodology would be appropriate for the production function. Dr. Gaske noted that after reviewing several years of data, there were ambiguous results for the FERC tests for using a 12CP allocator. He explained that the 2017 results failed one of the FERC tests and 2016 failed two of the three tests. Dr. Gaske further noted that during the past eight years, the months of June - September were almost always within 90% of the annual peak, but none of the other eight months were ever within 90% of the annual peak. Thus, it is appropriate to use a 4CP allocator for NIPSCO's demand-related production costs in this proceeding.")

[11] Cause No. 46038, Final Order, January 29, 2025, p. 94.

[12] Cause No. 46038, Duke Witness Diaz Direct Testimony.

[13] FERC, Docket Nos. ER19-1661-000 and ER19-1661-001, Order Accepting Tariff Revisions (October 17, 2019), Paragraphs 57-58.

[14] CAC Witness Inskeep Direct Testimony, p. 62.

of service study]" and that "[c]hanges in allocation methodology that significantly alter cost assignment may unreasonably disadvantage customers who have made investments in response to previous cost assignments."[15] In the cited rate case, the Commission determined that the cost allocation should remain the same because there was insufficient evidence justifying a change, such as evidence of a change in system operations. Unlike in the case cited by NIPSCO, there have been major changes to NIPSCO's operations in recent years and dramatic modifications to resource adequacy rules that fundamentally alter underlying cost causation.

The 4CP method is appropriate insofar as NIPSCO has dramatically overhauled its generation fleet, procuring and building new generation technologies, including solar, wind, battery storage, and natural gas, that produces a portfolio of resources operating significantly differently than its legacy generation portfolio of coal, which will be completely retired by 2028. For example, instead of relying principally on a few "baseload" coal plants, NIPSCO will now be using a more diverse and balanced portfolio of variable generation renewable resources complemented by flexible resources like battery storage and natural gas, as well as market purchases and sales and its demand-side management portfolio. NIPSCO witness Robles discusses these major changes in more detail in direct testimony.[16]

There have also been major changes to MISO's resource adequacy rules that fundamentally alter how utilities like NIPSCO determine its investment in production plant. NIPSCO's resource decisions are based on its IRP process, which uses the MISO resource adequacy rules and requirements as inputs into the modeling. NIPSCO's most recent IRP, submitted in December 2024, identified a number of major changes to MISO's resource adequacy construct, including changes resulting in a plan to move away from only focusing on the summer months and instead to evaluate needs throughout the entire year.[17] The record shows the progression since NIPSCO's last two rate cases, Cause Nos. 45159 (2018) and 45772 (2023), where NIPSCO's resource adequacy obligations used to be based on meeting summer peak demand, but have since evolved based on significant recent changes on the grid to ensuring sufficient accredited capacity is available to meet reserve margins in all four seasons of the year:[18]

- NIPSCO's 2018 IRP was based on meeting summer peak demand. NIPSCO stated in its 2018 IRP that "NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy.[…] This target is

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[15] NIPSCO Witness Taylor Direct Testimony, pp. 23:5-24:10 (citing the Commission's order in Cause No. 43839).

[16] NIPSCO Witness Robles Direct Testimony, pp. 10:1 through 13:24.

[17] NIPSCO 2024 IRP, p. 5, https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf

[18] CAC Witness Inskeep Settlement Testimony, pp. 14-15.

based on NIPSCO's coincident peak in MISO,"[19] which NIPSCO noted "is typically in the summer."[20]

- In its 2021 IRP, NIPSCO explained that "As a member of MISO, NIPSCO is not independently responsible for all elements of reliability, but must be prepared to meet changing market rules and standards," and it enhanced its IRP to consider both summer and winter planning reserve margins, among other enhanced reliability analyses.[21]

- In its 2024 IRP, NIPSCO moved to utilizing MISO's seasonal resource adequacy construct: "With the onset of MISO's seasonal resource adequacy construct, NIPSCO now needs to track reserve margin compliance across four seasons. In addition, as renewable resources become a greater share of the broader MISO market system, the seasonal capacity credit will likely change over time and will need to be monitored, particularly in light of MISO's recent D-LOL filing."[22]

The implication of the seasonal design and D-LOL market design is that load-serving entities, including NIPSCO, now have specific resource adequacy capacity obligations at all times of the year and must consider how different resources meet those needs throughout the year, in balance with other factors such as cost. NIPSCO witness Robles acknowledged the new seasonal construct in direct testimony.[23] Accordingly, while the 4CP may have been reasonable when MISO's resource adequacy construct was based primarily on meeting summer peak demand over four summer months, it is no longer consistent with cost causation as it relates to production costs. In contrast, the 12CP is much more reflective of MISO's current resource adequacy construct and, as a result, is more consistent with cost causation.

We consider MISO's resource adequacy construct as a factor relevant to cost allocation for generation units. We recently determined that the 12CP is more reasonable than the 4CP for allocating production costs for an investor-owned electric utility in MISO. In Duke Energy Indiana's most recent rate case (Cause No. 46038), we found that:

> **the 12CP method used for production costs** and advocated by Duke **is superior to the 4CP method** the industrial intervenors advocated in part because the 12CP method recognizes MISO's new requirements (developed after the issuance of our Order in Duke's last base rate case) moving from a summer peak to four distinct seasons (summer, fall, winter, and spring) when generation resource planning. Duke's generation fleet is planned to meet generation year-round. We also recognize that Duke's 12CP method mitigates the weather effect(s) that had been observed in the highest peak. Methodologies that account for meeting demand year-

[19] NIPSCO 2018 IRP, p. 15

[20] NIPSCO 2018 IRP, p. 48.

[21] NIPSCO 2021 IRP, p. 5.

[22] NIPSCO 2024 IRP, p. 119.

[23] NIPSCO Witness Robles Direct Testimony, pp. 4:18 through 5:3.

> round, as Duke's system is designed to do, have the added benefit of likely rate stability from test period to test period.[24]

(Emphasis added.) We went on to note that "the FERC tests are guideposts and not steadfast rules for decision making".[25] Therefore, NIPSCO's summer peak does not mean that the 4CP cost allocation remains reasonable. To the contrary, "There are numerous reasons why the 12CP methodology is appropriate now," we explained in Duke's rate case, confirming that "operational changes, including the wholesale market and how MISO establishes capacity requirements guide how costs should be allocated."[26] We provided further justification for moving to the 12CP for both production and transmission costs, stating:

> The Commission finds it is reasonable to recognize that MISO now establishes capacity requirements for its member utilities based on peak demand and reserve criteria. MISO stated in its Renewable Integration Impact Assessment Summary Report – February 2021 that it is extremely important to note that grid planning is changing. MISO has studied the impact of renewable resources and has concluded that the stress on the transmission system, besides the stress caused by peak demand, is impacted by the shoulder seasons of spring and fall due to renewable resources generating energy in these seasons. This is why we give weight to the fact that MISO allocates network transmission charges to its load serving market participants using a 12CP allocation.
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> By averaging the 12 monthly peaks, the 12CP method mitigates the weather effect that was observed in the highest peak more so than a 4CP method containing the highest peak. Averaging 12 monthly peaks also increases the likelihood of rate stability from test period to test period. Further, 12CP does not require complex models to weather-normalize demand prior to use in cost allocation.[27]

The same applies to NIPSCO, and NIPSCO should be moving from 4CP to 12CP at this time. An accurate cost allocation methodology must consider the multitude of factors that drive investment decisions, which requires consideration of time-varying loads throughout the day and year, resource adequacy requirements, and how different resources are actually used to meet those needs.

NIPSCO attempts to minimize the importance of the changes at MISO with respect to the resource adequacy requirements driving NIPSCO's investment and procurement decisions in generation by claiming NIPSCO "has always" had to consider resource adequacy in all months and throughout the entire year.[28] That not only misses the point, but provides further support for

[24] Cause No. 46038, Final Order, January 29, 2025, p. 94.

[25] *Id*.

[26] *Id*.

[27] *Id*. at 95.

[28] NIPSCO Witness Taylor Rebuttal, pp. 19:4-5, 12:6-9.

our directive to move to 12CP cost allocation. It is that MISO's resource adequacy requirements are the primary drivers of NIPSCO's decisions regarding when and how much generation capacity it should acquire from what resources.

We would note the cost allocation approved in the recent CenterPoint rate case order in Cause No. 45990, where we approved a non-unanimous settlement agreement in that case that included 4CP cost allocation for production costs. In that case, the OUCC and CAC had proposed alternative cost allocation methodologies to 4CP that assigned a portion of production costs based on energy instead of demand.[29] The IURC declined to adopt such an approach in both the Duke and CenterPoint rate cases. Here, CAC recommends that the Commission direct NIPSCO to move from 4CP to 12CP cost allocation for production costs if the Commission declines to adopt an energy-weighted method.[30]

The choice between 4CP and 12CP is extremely consequential, as not only does it impact rates in this case, but going forward in riders or trackers to the extent they have a production demand component. It is also important to use the 12CP in the ACOSS to be able to more accurately contextualize existing class subsidies and how they are being impacted by the Settlement. This cost allocation selection is also critical for ensuring that Rate 531, which has rates set equal to its cost to serve, is assigned the appropriate revenues. For example, in direct testimony, witness Taylor found that using a 12CP instead of the 4CP would result in a $16.9 million additional cost-based revenue increase to Rate 531, which is revenue that could be used to help mitigate rate increases for other customer classes. The 12CP would also result in a reduction in the calculated cost of service for Rate 511 (excluding multi-family customers on Rate 515) by a whopping $89.6 million (9.4%).[31] While these results will be somewhat lessened under the Settlement revenue requirement, they are still substantial.

iii. Conclusion on 4CP versus 12CP for Demand-Related Production Costs

Accordingly, this rate case is the appropriate time to reflect the dramatic changes in NIPSCO's resource portfolio and MISO rules by updating the allocation methodology used for demand-related production costs so that they remain consistent with cost causation. We hereby direct NIPSCO to adopt 12CP demand-related production as it offers a better cost allocation method than the 4CP. The 12CP recognizes that NIPSCO has an obligation to provide reliable service in all 12 months of the year, not merely in the four summer months, and allocates costs according to customer class peak usage in each of the 12 months.

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[29] Cause No. 45990, Final Order, Feb. 3, 2025, p. 112.

[30] CAC Witness Inskeep Direct, p. 69:3-7; CAC Witness Inskeep Settlement, p. 13.

[31] NIPSCO Taylor Direct, p. 48:12-13 and Table 4. *See also* CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of OUCC Witness Deupree, Fact #3.

C. Allocation of Benefits from Federal Tax Credits Must Mirror Allocation of those Costs.

NIPSCO is proposing to reduce base cost of fuel by about $33 million to reflect an estimate of the production tax credit ("PTC") that will be generated in 2025 by the solar assets at Cavalry, Dunn's Bridge II, Gibson, and Fairbanks, as well as investment tax credit ("ITC") values from the battery storage facilities at Cavalry and Dunn's Bridge II, with the FAC truing up any differences.[32] These are tax credits associated with new solar and solar-plus-storage resources that are wholly-owned by NIPSCO (i.e., not power purchase agreements). NIPSCO proposed allocating ITC/PTC credits in the same manner that fuel costs are allocated using an energy allocator, which the Settlement adopts. CAC argued that the proposal is not reflective of cost causation and would under-allocate benefits to the residential class. While CAC "objected to the Settlement Agreement's cost allocation of ITC and PTC proceeds, [it] did not oppose the Settlement Agreement's acceptance of NIPSCO's proposal to reflect a portion of these tax credit proceeds in base rates with the remaining portion flowing back to customers through the FAC."[33] CAC "proposed modifications to NIPSCO's FAC tariff to effectuate [the] recommended cost allocation approach with respect to the portion of tax credit proceeds that will be returned to ratepayers via the FAC under the Settlement Agreement."

Consider, for example, the residential class Rate 511. Under NIPSCO's cost of service study, Rate 511 is allocated 47.14% of generation costs using the 4CP. In contrast, Rate 511 is allocated only 29.25% of fuel expense using NIPSCO's fuel allocator.[34] If NIPSCO allocates the benefits of the ITC and PTC using the fuel allocator, it would result in residential customers receiving only 29.25% of the benefit of these tax credits, even though they are allocated 47.14% of the costs of building the solar and solar-plus-storage facilities. This is inconsistent with cost causation, and produces unjust and unreasonable rates for residential customers.

We find that the allocation of tax credit benefits associated with generation and battery storage facility investments must mirror the allocation ultimately adopted by the Commission in this proceeding for allocating the *costs* of generation and battery storage facilities. For example, if the Commission approves 4CP cost allocation for production *costs*, it should also approve 4CP allocation for returning the associated *benefits* of the same facilities to each customer class. The same follows with 12CP. In contrast, NIPSCO proposed and the Settlement maintains allocating ITC/PTC credits in the same manner that fuel costs are allocated using an energy allocator, which we find is not reflective of cost causation and would under-allocate benefits to the residential class.

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[32] NIPSCO Witness Bass Direct Testimony, p. 22:1-10. *See also* CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of NIPSCO Witness Taylor, Fact #5 ("The Settlement Agreement includes a portion of the forecasted tax credit benefits included in base rates, with a true-up then occurring in the FAC to credit or charge ratepayers for the difference between the amount included in base rates and the actual tax credit proceeds.")

[33] CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of NIPSCO Witness Taylor, Fact #3.

[34] NIPSCO Electric External Allocators 2024 Workpapers, tab "External Allocators".

i. ITC benefits must be credited using the same allocators approved in this proceeding for demand-related production plant.

NIPSCO appears to agree with CAC's conclusion about the proper basis for allocating ITC benefits, recognizing that "ITCs are not based on production; instead, it is based on the investment and existence of the plants regardless of kWh output."[35] Despite this admission, NIPSCO did not correct the ACOSS to appropriately allocate ITC benefits. NIPSCO provided two explanations for this decision: (1) that NIPSCO is committing to a full review of cost allocation in the future (but stopping short of actually committing to fixing the ITC allocation in the future); and (2) asserting that, "For the purposes of this case, it is better for customers to have ITCs flow back through the FAC and customers immediately begin receiving benefits."[36]

But NIPSCO's commitment to review cost allocation at an unclear future point in time – potentially many years from now, as NIPSCO is under no obligation to file another rate case by a date certain – is irrelevant. We have an obligation to establish rates that are just and reasonable *in this proceeding*. A promise by NIPSCO to think about this issue more at some later date is cold comfort for the residential customers paying the highest electric bills in the State of Indiana *now* who will also face an additional enormous bill increase under the Settlement that could otherwise be mitigated by simply correcting this cost allocation error.

And NIPSCO's assertion that it cannot correct its ITC cost allocation error now because it wants to timely provide the benefits to customers is a non sequitur. Rectifying the pass back of the benefits after correcting the error does not in any way impact the timing of when the tax credit benefits would flow back to customers. "The Commission orders in Cause Nos. 45936, 46028, and 46032 cited by Mr. Taylor approved ITC/PTC proceeds returned to ratepayers through the FAC or a successor mechanism. Those orders do not contain language that prohibits the cost allocation methodology from changing in a future regulatory proceeding."[37]

Furthermore, tariff modifications to the FAC can be adopted in this proceeding to create a new provision that outlined a separate component to the FAC to flow back the ITC credits, but modified so that these credits are allocated to customer classes based on the production cost allocators approved in this proceeding.[38] For example, this is easily achieved similar to how CenterPoint recently created a separate demand-related component of its FAC to recover demand-

[35] NIPSCO Witness Taylor Rebuttal, p. 20:7-9.

[36] *Id.*, p. 20:11-13.

[37] CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of NIPSCO Witness Taylor, Fact #6.

[38] *Id.*, Fact #4 ("Cost allocation methodologies used in electric utility trackers such as the FAC may change from time to time, subject to Commission approval.")

related costs related to a natural gas pipeline serving its new A.B. Brown gas plant, while still maintaining existing allocation methods for separate energy-related costs in the FAC.[39]

NIPSCO is directed to make modifications to the ACOSS (or even possibly as a separate mitigation step when distributing the revenue increase to customer classes), providing immediate benefits to ratepayers through a similar base rate adjustment as proposed by NIPSCO, with the remaining balance of ITC benefits returned to customers through the FAC as proposed by NIPSCO.

ii. PTC benefits must be credited using the same allocators approved in this proceeding for demand-related production plant.

It is appropriate to allocate the PTC in the same manner that the underlying generation or storage resource is allocated. NIPSCO witness Taylor responded to the proposal for passing back the PTC tax credits as "an attempt to change the well-known fact that PTCs are energy based."[40] NIPSCO's point appears to be that the PTC is earned as a $ per kWh of production tax credit for the first 10 years of an eligible system's operation. While true, this superficial examination of the mechanics of the tax credit is also largely irrelevant to determining the appropriate way to allocate the PTC benefits to specific customer classes.

The principle of cost causation underlying the selection of cost allocation methodology demands instead a focus on how rate classes played different roles in driving, or "causing," the underlying production plant investment that will subsequently create tax credit benefits. After all, it is the decision to build the solar facilities – driven to different extents by each customer class's capacity needs based on NIPSCO's resource adequacy requirements in MISO – that is now leading to the PTC benefits accruing to NIPSCO over time and being flowed back to ratepayers. From this perspective, it is clear that the PTC *benefits* that NIPSCO earns as a result of the solar investments should be returned to customer classes in the same proportion as each customer class is contributing to the *cost* recovery of the same solar facilities.

Consider a utility that builds *x* MW of solar that then receives approximately *y* value in PTC benefits each year. Although there will be modest fluctuations in generation from year to year (e.g., based on the weather), the *y* value should stay approximately the same from year to year.[6] If the utility had instead decided to double the investment and build *2x* MW of solar at the same approximate location, it would expect to generate approximately *2y* value in tax credits to help offset the costs of that investment. The PTC is meant to encourage the initial investment in solar (or other eligible resources) by helping to offset those upfront investment costs. In other words, the overall investment in the production plant is the relevant driver in determining the amount of tax credit benefits that will accrue because the solar facilities that earn PTCs will generally operate

[39] Cause No. 45564 S1. *See also* CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of NIPSCO Witness Taylor, Fact #8 ("The Commission has previously authorized CenterPoint Energy Indiana South to modify its fuel adjustment clause such that certain costs are allocated on the basis of energy and other costs are allocated on the basis of demand.")

[40] NIPSCO Witness Taylor Rebuttal, p. 20:1-6.

at their maximum output, constrained primarily by the availability of the sun. A customer class using more or less electricity does not impact the creation of more or less PTC benefits, as the PTC benefits are more closely related to the initial investment in the solar facility that was driven by MISO resource adequacy requirements.

In contrast, fuel costs are allocated on the basis of energy because it is not the size of the plant investment that determines how much fuel is used, but rather how often and at what level of output the plant is operating. It is logical that customer classes that use more electricity and, therefore, cause NIPSCO to purchase more fuel should pay proportionately more in fuel charges.

iii. Applying the wrong allocators to the ITC and PTC benefits matters.

The estimated annual benefits in 2026 that would flow to residential customers (Rate 511 and 515 combined) under base rates and the FAC, respectively, matters. Making CAC's requested correction to the allocation of both PTC and ITC benefits would result in an approximate $5.0 million reduction to residential customer base rates, plus an additional estimated $5.0 million reduction in FAC rates.[41]

Under the Settlement, residential customers would receive an approximate $102.4 (14.75%) million rate increase. Correcting the allocation of the ITC/PTC benefits would reduce the rate increase for the residential class to approximately $97.4 million (14.04%) (not including the additional $5 million in estimated annual benefits that would flow to residential customers via the FAC), which is approximately the overall system average rate increase under the Settlement. In other words, this has a material impact on rates, and correcting this now will provide critical affordability benefits to residential customers consistent with cost causation.

An example helps illustrate the issue. Rate 550 (Street Lighting) and Rate 560 (Dawn-to-Dusk) are allocated 0% of production costs by NIPSCO in its ACOSS, presumably because these classes are only using electricity when it is dark outside and not during NIPSCO's four summer peak hours occurring on summer afternoons, which is the basis for 4CP cost allocation. In contrast, both of these rate classes are allocated a portion of fuel costs (0.30% and 0.13%, respectively). Under NIPSCO's proposed allocation of ITC and PTC benefits, Rate 550 and 560 would pay *nothing* towards the fixed production costs of the solar facilities, yet they would still be allocated a portion of the PTC benefits associated with these investments. It does not make sense that customers who do not use any solar energy and do not pay for any portion of the solar investments are allocated solar tax credit benefits that reduce their rates. This further highlights why the

[41] CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of NIPSCO Witness Taylor, Fact #9 (agreeing that if CAC Witness Inskeep's proposal were adopted to create a new provision that outlined a separate component to the FAC to flow back the ITC credits, but modified so that these credits are allocated to customer classes based on the production cost allocators approved in this proceeding, "residential customer FAC rates would be reduced going forward, including during the Test Year, to the extent there are PTC/ITC proceeds to return to customers in the applicable FAC period, relative to the Settlement Agreement.")

Settlement's resolution of cost allocation issues fails to result in just and reasonable rates and necessitates Commission intervention.

iv. *NIPSCO shall allocate the benefits of the ITC and PTC to rate classes using the same allocators approved in this proceeding for demand-related production plant.*

The Commission agrees with the concerns raised about this proposal. The ITC and PTC benefits are directly associated with the generation plant investment, yet they are allocated across customer classes using an inconsistent cost allocation. Whereas NIPSCO has proposed a 4CP cost allocation for generation costs, it uses an energy allocator for fuel costs (or benefits). In other words, these tax credit *benefits* are not being allocated to customer classes in proportion to the amount each customer class contributes towards the *costs* of these projects.

We hereby deny the proposal to provide the ITC and PTC benefits to ratepayers through a reduction to the base fuel cost, with a true-up in the FAC. Instead, we direct NIPSCO to allocate the benefits of the ITC and PTC to rate classes using the same allocators approved in this proceeding for demand-related production plant.[42]

3. <u>Revenue Distribution Primarily Benefits NIPSCO's Non-Residential Customers.</u>

The Settlement apportions the revenue reduction to customer classes as follows:

1. Rate 631 was set at cost of service based on 162.061 MW of allocated Tier 1 demand;
2. No revenue change to Rate 642 and 643;
3. Credit $575,000 to each Rate 623 and 626;
4. Allocate 25% of the remaining revenue decrease to alleged "subsidizing" classes in proportion to their excess revenues;
5. Allocate the remaining amount on an across-the-board basis in proportion to the case-in-chief proposed revenues.

Steps 4 and 5 do not apply to Rates 631, 642, and 643.

[42] CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of OUCC Witness Deupree, Fact #4 ("Witness Deupree is not currently aware of a Commission order or regulation that prohibits the Commission from modifying the allocation of ITC/PTC proceeds as Witness Inskeep recommended."); CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of NIPSCO Witness Taylor, Fact #7 ("Although NIPSCO's FAC is currently based on energy, Mr. Taylor is not aware of any Commission order or regulation that would prohibit the Commission from approving modifications to the FAC that would result in certain costs allocated based on energy and other costs based on demand.").

These mitigation steps differ from what NIPSCO proposed in its case-in-chief. The mitigation steps in the Settlement primarily benefit NIPSCO's non-residential customers, prioritizing the revenue reduction in the Settlement for commercial and industrial customers.

Three illustrations help highlight the issue here. First, NIPSCO initially proposed setting Rate 515 (Residential Multi-Family) equal to its cost of service. The Settlement eliminates the separate Rate 515 altogether, resulting in residential multi-family customers receiving a revenue responsibility that is above their cost of service. Second, NIPSCO initially proposed that Rate 511 (Residential Single-Family) would have a revenue increase set equal to the overall system increase. The Settlement eliminates this important residential ratepayer consideration, resulting in Rate 511 being assigned a revenue increase that is above the system average increase. Third, NIPSCO initially proposed that Rate 531 would be set at its cost of service based on 164 MW of Tier 1 demand. The Settlement reduces that to about 162 MW of Tier 1 demand, further benefiting Rate 531 and shifting costs onto other classes.

The Settlement's mitigated revenue increase for customer classes is not reasonable. While the Settlement provides for a 30.3% reduction to revenue requirement, residential customers specifically will experience only a 23.6% reduction to their revenue requirement relative to NIPSCO's case-in-chief as a result of the unbalanced Settlement mitigation that benefits non-residential customers.

Previously, the Commission has expressed a preference for mitigating class cross-subsidization in base rate cases, while also taking into consideration gradualism. The issue here is that by failing to conduct the holistic review of cost allocation prior to this rate case – despite many of the same issues and challenges being addressed at length and in detail by parties to NIPSCO's last rate case – NIPSCO's ACOSS now lacks credibility and fails to provide a reasonable basis for determining which customer classes are subsidizing / being subsidized and by how much. In other words, subsidy mitigation cannot be achieved if the subsidies themselves cannot be reasonably identified and estimated.

Instead, the Commission hereby orders NIPSCO to assign the same percentage increase to each existing customer class, i.e., equal to the system average increase. This aligns well with NIPSCO's past practice.[43] Prior to NIPSCO's next rate case, it can conduct a holistic examination of these critical issues, which is necessary to more accurately identify existing cross-subsidization occurring in rates. In its next rate case, NIPSCO can propose the appropriate cost allocation modifications and mitigation steps to address any identified cross-subsidies, while taking into consideration gradualism and other important public policy objectives.

[43] Cause No. 45159, Final Order, Dec. 4, 2019, pp. 72, 158 (NIPSCO Witness "Dr. Gaske assigned any remaining overall increase in the revenue requirement to classes on an equal percentage basis.") (After addressing Rate 831, "NIPSCO then allocated the additional revenue requirement over all customer classes equally.")

4. <u>Multi-Family Customers Will Pay More than Their Cost to Serve and Experience an Increase from the Settlement</u>.

The Settlement withdraws NIPSCO's Residential Multi-Family Rate 515 proposal with revenues set equal to its cost of service, resulting in a rate increase that is below that of Rate 511. While this approach would be reasonable if the underlying COSS were reasonable, the fundamental flaws in NIPSCO's COSS call into question whether this approach is adequate for setting rates that are just and reasonable, as the COSS will produce a cost to serve Rate 515 that is in excess of their actual cost to serve due to the cross-subsidies being provided to Rate 531.

NIPSCO originally proposed to separate the residential class into Single-Family and Multi-Family classes for cost allocation and rate design. NIPSCO presented data and analysis demonstrating that multi-family customers have distinct usage patterns compared to other residential customers resulting in a lower cost to serve them based on traditional cost causation principles. NIPSCO witness Taylor provided compelling evidence demonstrating that a Multi-Family rate is reasonable and should be approved.

The Settlement rescinds NIPSCO's proposed Multi-Family Rate in recognition of the OUCC's opposition.[44] In other words, tens of thousands of residential customers who NIPSCO had identified as residing in a multi-family dwelling and having a substantially lower cost to serve than other residential customers will be forced to take service under rates that are significantly higher than what NIPSCO claims is their cost of service. NIPSCO will collect additional data to further identify multi-family customers and further analyze cost differentials between single- and multi-family residential customers. NIPSCO may request a new multi-family rate in a future base rate case, but is not required to do so.

This is not a reasonable resolution to this issue. In NIPSCO's last rate case settlement, NIPSCO agreed to collect data and analyze cost differential between multi-family and single-family residential customers. NIPSCO fulfilled its obligation by completing a robust analysis and finding that, consistent with CAC's testimony in Cause No. 45772, multi-family customers have a lower cost to serve, and accordingly proposed a cost-based rate to serve these customers. It is not fair to multi-family customers to have to wait years more for yet another study to be completed while they continue to pay excessive rates.

This term leaves NIPSCO's approximately 68,000 multi-family residential customers[45] significantly *worse off* under the Settlement relative to NIPSCO's case-in-chief, even after taking

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[44] The OUCC's main objection to the development of a multi-family rate rests in its belief that the sample size underlying the multi-family study was inadequate. However, while "Witness Deupree opined that NIPSCO's load research sample of 127 out of 431,840 (0.03%) residential customers was inadequate from which to create a new Rate 515 rate class, but he did not identify a sample size that would be adequate." CAC Exhibit 4, Stipulation of Facts in Lieu of Cross-Examination of OUCC Witness Deupree, Fact #5.

[45] NIPSCO Witness Taylor Direct, Attachment 16-H (showing 815,471 annual bills for Rate 515, which after being divided by 12 results in 67,956 customers).

into consideration the reduction in the overall revenue requirement increase.[46] In NIPSCO's case-in-chief, it proposed a 12.5% rate increase for Rate 515 (Multi-Family) based on setting rates at its cost of service.[47] Under the Settlement, multi-family customers would be forced to instead take service under Rate 511, which provides for a 14.75% rate increase – significantly higher than NIPSCO proposed in its case-in-chief for such customers. In general, the Commission is deeply skeptical of a non-unanimous settlement agreement that would make a large group of residential customers materially worse off than what the utility originally proposed in its case-in-chief.

The Commission has repeatedly emphasized the importance of all customers benefiting under rate case settlement agreements it approves. For example, in its recent order in CenterPoint's rate case (Cause No. 45990) approving a contested settlement agreement, the Commission stated:

> While the Commission appreciates that affordability will remain a concern for CEI South's customers, this is not a reason to entirely reject the Settlement Agreement which substantially reduces the impacts of CEI South's requested relief for <u>*all customers*</u>.

(Emphasis added.) In AES Indiana's most recent rate case, the Commission approved a unanimous settlement agreement, finding "[a]ll customers benefit," "[a]ll customer classes benefit from the Settlement Agreement," and "the underlying cost allocation was aimed at balancing increases among classes."[48] And in I&M's most recent rate case, the Commission approved a unanimous settlement agreement, finding "The record reflects that all customer classes are expected to reasonably benefit from the negotiated revenue decrease."[49]

Unlike these cases, the Settlement here does not substantially reduce the impacts of NIPSCO's requested relief for all customers – in fact, it significantly *increases* the impacts of NIPSCO's requested relief for multi-family customers to provide greater rate reductions for other rate classes.

While the Commission has stated that its role in addressing affordability cannot be "to reach a conclusion as to whether the rates approved herein are 'affordable' for each and every customer",[50] the Commission's obligation under the Five Pillars is to consider affordability across the customer classes. In the context of the Settlement, such consideration will necessarily entail an examination as to whether the Settlement provides a balanced resolution when considering the various interests of the customer classes. To the extent the Settlement unduly and unreasonably

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[46] CAC Exhibit 4, Stipulation of Facts in Lieu of Cross-Examination of OUCC Witness Deupree, Facts #1, 2.

[47] NIPSCO Witness Taylor Direct, Table 3.

[48] Cause No. 45911, Final Order, April 17, 2024, p. 31.

[49] Cause No. 45933, Final Order, May 8, 2024, p. 28.

[50] Cause No. 45870, Final Order, February 14, 2024, p. 105; *see also* Cause No. 45990, Final Order (citing to Cause No. 45870).

harms affordability of one customer class to the benefit of other customer classes, it should be found inconsistent with the public interest.

The elimination of the Multi-Family Rate creates particular concerns with respect to lower-income customers, especially in conjunction with the elimination of the low income proposal. Witness Taylor found that a greater portion of multi-family residential customers have lower incomes in NIPSCO's service territory.[51] Witness Taylor noted that the multi-family rate would "ease the energy burden of low income customers who are also MF [multi-family] customers."[52] In other words, not only does this term contradict NIPSCO's robust empirical analysis, which demonstrates that a separate multi-family rate is just and reasonable, it also has a regressive impact, disproportionately harming lower-income Hoosiers.

The Settlement's failure to adopt NIPSCO's Multi-Family Rate will significantly harm multi-family customers and produce rates that are unjust and unreasonable and well in excess of what NIPSCO considered to be the cost to serve such customers, even prior to the reduction in revenue requirement included in the Settlement. The Settlement's pronounced negative impacts to multi-family customers provide strong evidence demonstrating that the Settlement does not reflect a balanced outcome and is not in the public interest.

5. <u>The Settlement's Low-Income Program Falls Short</u>.

The Settlement eliminates the $0.25 per month ratepayer funding mechanism for the Low-Income Program, turning it into a voluntary, opt-in program. It also increases NIPSCO's annual below the line shareholder contribution to $1,500,000. These changes dramatically reduce the funding for this program, meaning eligible customers will receive substantially smaller benefits from participating in it. The program, as originally proposed by NIPSCO, would have provided $2.7 million in annual funding for the program.[53] This amount is approximately the same as the ~$2.8 million in amortization expense included in NIPSCO's proposed rates to recover bill discounts NIPSCO has provided to *non-residential* customers under its Economic Development Rider.[54] The reduction to $1.5 million in funding under the Settlement Agreement represents a more than 44% reduction in overall funding relative to NIPSCO's case-in-chief proposal and is 47% less than the amount built into NIPSCO's rates to subsidize non-residential customers.[55]

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[51] NIPSCO Witness Taylor Direct, p. 56:1-5.

[52] *Id*. at 56:4-5.

[53] NIPSCO Witness Whitehead Direct, p. 24:5.

[54] CAC Witness Inskeep Direct, p. 56:6-19; *see also* NIPSCO Attachment 2-S-A, Sch. 4 NOI, line 90.

[55] CAC Ex. 4, Stipulation of Facts in Lieu of Cross-Examination of NIPSCO Witness Whitehead, Fact #5 ("As proposed in NIPSCO's direct case, the low income program proposal was forecasted to provide approximately $15-26 on the eligible customers' four summer month bills. The settlement reduced the overall funding for the low income program, which will likely reduce the monthly benefit to eligible customers as compared to the program proposed in NIPSCO's direct case.")

The Low Income Program is designed for customers who NIPSCO itself has characterized as its "customers most in need of bill payment assistance."[56] If these are the customers most in need, the funding for this program should *at least* match the annual funding provided to NIPSCO's non-residential bill discount program and should likewise have a ratepayer-backed funding mechanism to ensure its continued fiscal sustainability.

It is unlikely that ratepayers will make voluntary contributions to provide additional program funding in a material, sustainable way to support the program, as there have been numerous similar failed attempts in Indiana.[57] For example, I&M's opt-in low-income program previously resulted in no more than a couple hundred customers opting in to providing monthly donations, with less than $14,000 collected over an eight-month period.[58] There is no reason to think NIPSCO's similar opt-in design will elicit a significantly different outcome.

NIPSCO Witness Whitehead claimed that "denying or modifying the Settlement based on the modified design of this bill assistance program would serve only to harm the eligible low income customers who stand to benefit from the bill assistance that would now be available." Settlement Rebuttal at 9-10. Under the bill assistance program originally proposed by NIPSCO in its case-in-chief (at 53), as revised in NIPSCO's rebuttal testimony (at 35-36), NIPSCO would have collected approximately $1.47 million per year from customers to then be combined with an additional $1,000,000 annual shareholder contribution to assist its eligible low income customers. Under the bill assistance program agreed to in the Settlement Agreement, the only known amount available to assist NIPSCO's eligible low income customers is the $1.5 million agreed-to annual shareholder contribution.[59]

The Low Income Program as proposed by NIPSCO in its case-in-chief instead of the Settlement is more consistent with the Affordability Pillar and the public interest generally. There is robust evidence in the record demonstrating that many income-qualified NIPSCO customers are experiencing dire affordability challenges, and that NIPSCO's original proposal provides the program design and funding levels that are more reasonable than the Settlement Agreement for addressing this challenge in a manner that will ensure stable and sustainable funding into the future without creating an unreasonable burden on other ratepayers.

The Commission finds the modifications to NIPSCO's Low Income Program in Settlement weigh against finding the Settlement is in the public interest.

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[56] NIPSCO Witness Whitehead Direct, p. 24: 5-6.

[57] CAC Witness Inskeep Cross-Answering, pp. 26:15 through 28:7.

[58] CAC Witness Inskeep Cross-Answering, p. 27:19-21.

[59] CAC Ex. 4, Stipulation of Facts in Lieu of Cross-Examination of NIPSCO Witness Whitehead, Fact #6.

6. Shareholders, Not Ratepayers, Should Pay for the Economic Development Rider Subsidy

The Settlement solidifies NIPSCO's proposal to recover the cost of discounts provided to non-residential customers under its Economic Development Rider. NIPSCO asks to increase its amortization expense in the amount of $2,845,699 associated with cost recovery from its Economic Development Rider, Rider 677 (Adjustment AMTZ 10-25R-S2).[60] In other words, the purpose of this rate increase adjustment is to charge non-participating customers with the bill discounts that NIPSCO has been and will continue to provide to non-residential customers under its Economic Development Rider from 2020-2025.

NIPSCO deferred approximately $11.5 million in Rider 677 costs over the period 2020-2023, and it anticipates spending another $5.5 million over 2024-2025, resulting in a total regulatory asset that is expected to balloon to about $17.1 million by the end of the Future Test Year (Figure 13), which, amortized over six years, produces the requested adjustment of approximately $2.8 million.

NIPSCO's subsidies to non-residential customers under Rider 677 are substantial and have been growing over time. ***Rider 677 subsidies grew from $0.7 million in 2021, to $3.4 million in 2022, to more than $4.3 million in 2023. Certain non-residential customers are even receiving as much as $1.8 million in bill discounts in a single year.***[61] At least five customers will receive more than $1 million in rate subsidies under Rider 677 through 2025.[62]

Given the circumstances, Economic Development Rider subsidies should not be recovered from non-participating ratepayers. Bill subsidies provided by NIPSCO to non-residential customers as far back as 2020 do not reflect reasonable costs necessary for providing adequate or reliable service to customers in 2026 and beyond.

NIPSCO has provided no evidence that these bill discounts provided to non-residential customers are prudent, provide benefits to other ratepayers that exceed their costs, or are necessary and reasonable. Including these costs in revenue requirement would undermine the affordability of rates for all customers, including those who are ineligible to participate under the tariff. NIPSCO shareholders rather than other ratepayers should bear these costs. NIPSCO shareholders benefit from Rider 677's aim of attracting load growth because it could lead to higher revenues and opportunity to grow profit.

The Commission hereby denies NIPSCO's Adjustment AMTZ 10-25R-S2 and orders NIPSCO to remove [alternatively, the Commission could reduce the requested adjustment by 50%) the associated $2,845,699 subsidy in amortization expense from the calculation of revenue

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[60] NIPSCO Witness Weatherford Direct Testimony 64:7-15.

[61] NIPSCO Workpaper AMTZ 10-S2, tab [.3], Line No. 7.

[62] *Id.*, Line Nos. 7, 14, 15, 18, and 25.

requirement in recognition that the Economic Development Rider provides benefits to utility shareholders.

7. <u>Data Center Load Must Be Addressed Now</u>.

According to NIPSCO, there are no rate schedules in NIPSCO's current or proposed tariff for which a hyperscaler data center of 100 MW or larger would qualify. NIPSCO says that such a customer could be served through a special contract, an IURC-approved future modification to a current rate schedule, or a newly proposed, IURC-approved rate schedule.[63]

"While the Settlement Agreement states certain intentions NIPSCO has with respect to new anticipated data center customer cost recovery and crediting of revenues to other customers, it does not include a commitment by NIPSCO that (1) new data center customers will not result in higher costs for NIPSCO's existing customers, or that (2) existing customers' rates will be reduced if a large load customer takes service from NIPSCO."[64]

We find this to be problematic insofar as NIPSCO is anticipating unprecedented, rapid load growth this decade, growing from 600 MW by 2028 to approximately 2,600 MW by 2035 under its 2024 IRP Reference Case.[65] Load growth could be even quicker and more extreme, however, as NIPSCO's Emerging Load sensitivity considers a whopping 3,200 MW of new hyperscaler load by 2028, soaring to 8,600 MW by 2035. Yet, despite this unprecedented near-term load growth, NIPSCO failed to provide any information in this proceeding about it and refused discovery requests asking for more information on these new facilities and their potential impacts to NIPSCO and existing customers.[66] NIPSCO also did not propose any tariff modifications to mitigate risks to existing customers and ensure that they benefit through downward pressure on rates from new large load customers. Finally, NIPSCO admitted that it does not even have a tariff in place that could serve these facilities, so it is unclear what rates would be charged to these customers based on which costs, an issue that should be addressed within the context of a COSS in a base rate case like this or at least contemplated in a new tariff so as to avoid a piecemeal, nontransparent approach like individual special contracts.

Even if new hyperscaler load growth does not begin service before the end of the Future Test Year, it is critical that a framework be developed and the necessary terms and conditions and tariff changes be addressed now. NIPSCO is already incurring costs today with respect to interconnecting large load customers, including conducting studies on behalf of potential new large load customers. NIPSCO could soon be entering into electric service agreements with certain new

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[63] CAC Witness Inskeep Direct, Attachment BI-3, NIPSCO Response to CAC DR 1-006(c).

[64] CAC Ex. 4, Stipulation of Fact in Lieu of Cross Examination of OUCC Witness Deupree, Fact #3.

[65] NIPSCO 2024 IRP, p. 5, https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf.

[66] CAC Witness Inskeep Direct, Attachment BI-3, NIPSCO Responses to CAC DRs 2-007, 2-008, and 2-009.

large load customers, therefore these issues must be addressed and resolved now so that these customers can be treated consistently and fairly, while protecting existing consumers from risks and cost shifts. It is unreasonable that NIPSCO shields stakeholders and the Commission from this information in a general rate case. It is possible that large load customers could accelerate their timelines and begin service sooner than expected. NIPSCO has refused to provide information that would allow intervenors and the Commission to independently verify the scale and the timing of data center load growth in this service territory. It is prudent to plan ahead for this potential. Even if such load growth is ultimately delayed, developing the appropriate mechanisms now will provide the market clarity and transparency that will facilitate decision-making. New large load customers present unique risks to existing customers, along with potentially large costs and benefits. These issues are best addressed openly in a docket to facilitate the development of just and reasonable rates and terms and conditions of service.

NIPSCO has suggested that it might pursue special contracts with each data center customer, which would be problematic and inadvisable for several reasons, including the significant transaction costs associated with negotiating separate deals for each customer, the lack of transparency and consistency across special contracts, and the inappropriateness of using special contracts for customers that can be served under standard tariffs that are developed based on embedded costs that are transparently identified through the class cost of service study. For example, Indiana Michigan Power Company will be serving its new large load customers under its standard Industrial Power Tariff, rather than negotiating separate special contract rates.[67]

We are concerned that the addition of data center customers in between rate cases could result in large increases in revenue to NIPSCO, but a significant lag in adjusting cost allocators that would appropriately reduce the costs allocated to existing customers as new large loads assume a share of the embedded costs. A transparent process should be developed for determining the appropriate rates for data centers and reasonable mechanisms for crediting existing customers through reduced cost of service allocations as new large load customers take service and are allocated an increasing portion of system costs. While it may be appropriate to wait the standard cadence of rate case filings for load changes that occur over time for other classes, the uniquely large loads of data centers could create uniquely large impacts that require adjustments in a timelier fashion to ensure rates are just and reasonable. In the meantime, we hereby direct NIPSCO to assign all costs of interconnecting a large load customer, including interconnection studies, network upgrades, direct connect facilities, and any additional transmission or distribution system costs, to the large load customer and not shift any of these costs onto existing customers.

The Settlement Agreement does nothing meaningful to address the issues surrounding new large load customers that was raised by U.S. Steel and CAC in direct and cross-answering testimonies. We find it necessary to open a subdocket to holistically examine these issues in a more appropriate forum for the Commission to collect and weigh the evidence and determine the appropriate path forward. Issues will include serving new large load customers, including standardized tariff terms and conditions, consumer protections and transparency, cost allocation, and rate design.

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[67] *See* Cause No. 46097.

8. Field Hearing Comments and Written Public Comments Overwhelmingly Oppose NIPSCO's Increase.

In addition to the testimony received at the public field hearings held in Gary, Hammond, and Valparaiso, a staggering 4,885 pages of written comments from the public were also submitted by the OUCC.[68] Individuals who were motivated to speak or provide public comment included city and town leaders, representatives from various school districts concerned about school budgets and their students' well-being, the American Association of Retired Persons, mothers, seniors, and more. The City of Hobart included an official action opposing NIPSCO's proposed rate increase, Resolution 2024-9.[69]

These commenters provided informed and detailed testimony from thousands of NIPSCO ratepayers and community leaders about the negative impacts of past NIPSCO rate hikes and the current unaffordability of NIPSCO's rates for residential customers. These customers described how NIPSCO's pending proposals would further harm them and their communities. Those who testified or provided written comments overwhelmingly opposed the proposed rate increase and urged the Commission to deny it.

Most commenters' primary concern was affordability. They testified to the current energy insecurity faced by NIPSCO customers and explained how NIPSCO's proposals would exacerbate unaffordability, especially for those with low or fixed incomes. Commenters noted recent previous NIPSCO rate increases, the rising cost of living, and inflation as compounding factors that amplify the hardship and reduce the capacity of a household to respond to additional increases to their utility bills.

Public hearings and comments are an essential component of the rate case process, as they allow us to hear directly from affected members of the public about how rates and programs impact them. We take these voices into consideration as representative of the public interest while making decisions in this proceeding. The Settlement Agreement does not adequately address concerns expressed by NIPSCO ratepayers at the public field hearings and through written comments in this case.

Given the unprecedented public outpouring opposing further NIPSCO increases, the need for action addressing the dire affordability challenges is clear. The Settlement Agreement's terms provide for a considerable increase in revenue requirement, unfairly allocate much of the increase onto residential customers, and fail to meaningfully address these affordability concerns expressed by many NIPSCO ratepayers, among other shortcomings. The record is devoid of probative evidence in support of the Settlement.

[68] Public Ex. No. 13.

[69] *Id*. at 4.

9. <u>Indiana Code §§ 8-1-2-0.5 and -0.6.</u>

In HEA 1007, the Indiana General Assembly declared it is the continuing policy of the State that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the five pillars of electric utility service. *See also* Ind. Code § 8-1-8.5-4(b)(4). Ind. Code § 8-1-2-0.6 codifies the five pillars of electric utility service as reliability, affordability, resiliency, stability, and environmental sustainability.

Reliability, according to the statute, includes the adequacy of electric utility service, including the ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all times, taking into account: (i) scheduled; and (ii) reasonably expected unscheduled; outages of system elements; and the operating reliability of the electric system, including the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. I.C. § 8-1-2-0.6(1). The Commission must consider NIPSCO's continued poor service reliability. Specifically, the average duration power outage experienced by a NIPSCO customer, as measured by the System Average Interruption Duration Index ("SAIDI"), excluding major event days ("MEDs"), was 58% longer than the next-worst performing Indiana electric IOU in 2023 (CAC Exhibit 1, Figure 12). Despite significant NIPSCO spending on its Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plans for 2016-2021 and 2022-2026, ratepayers continue to experience poor reliability. We find these issues weigh against NIPSCO for the Reliability Pillar.

Resiliency is similar to reliability, and much of our discussion above regarding reliability is applicable here. Resiliency represents the distinct concept concerned with ensuring availability of electricity under changing or extraordinary system conditions. The record showing NIPSCO's declining reliability scores shows there is no evidence to support the Settlement in this regard.

Stability is defined in the statute as the ability of the electric system to: (a) maintain a state of equilibrium during normal and abnormal conditions or disturbances and (b) deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters, consistent with industry standards. Again, much of our discussion above regarding reliability is applicable here. The record showing NIPSCO's declining reliability scores shows there is no evidence to support the Settlement in this regard.

Environmental sustainability considers both the impact of regulations and the demand from customers for power from environmentally sustainable resources, both from the utility and from customer-owned resources or options. This pillar weighs in support of NIPSCO insofar as some of the case supports NIPSCO's generation transition, which supports environmental sustainability.

Affordability is where NIPSCO falls short in a significant way. The statute does not define affordability, but it does expound that affordability includes "ratemaking constructs that result in retail electric utility service that is affordable and competitive across residential, commercial, and industrial customer classes." We are concerned about the hundreds of thousands of NIPSCO residential customers that would experience rate shock and accelerating unaffordability.

Residential bills have increased significantly over the past three years. As of March 2021, a residential customer bill based on 729 kWh per month was $114.74.[70] As of March 2024, the same usage level resulted in a $136.30 bill, reflecting a 18.8% increase over three years, or a compound annual growth rate ("CAGR") of 5.9%. The record shows this increase exceeds the rate of inflation, even though inflation rates were much higher during this period than in recent years.[71] This does not include other significant rate increases on the horizon for NIPSCO, like Cause No. 45947.

As evidenced at the public field hearings, NIPSCO ratepayers are experiencing substantial affordability challenges under current rates. The impact of NIPSCO's proposed rate increase will result in more hardship to these communities that NIPSCO serves. The public field hearing testimony is buttressed by robust empirical evidence demonstrating that NIPSCO's residential rates have increased precipitously in recent years and are no longer competitive with respect to its peers. NIPSCO recently moved to having Indiana's most expensive residential bills in 2024, surpassing CenterPoint which had the highest for the prior 16 consecutive years.[72]

Record evidence shows the number of NIPSCO accounts with 60+ days arrears and the number of accounts assessed late payments have also generally trended upward over the past several years. The most recently available data shows more than 127,000 NIPSCO residential customers in arrears (60+ days) as of June 2024, which is higher than for any other month reported by NIPSCO in Cause No. 45736, and about 12% higher than June 2023. Every month, NIPSCO assesses late fees on approximately 75,000 to 92,000 residential customers, resulting in approximately 1 *million* late payment fees assessed every year.[73] The total amount of residential late payment fees assessed by NIPSCO has also been higher in the past few years than it was pre-COVID-19 pandemic, with NIPSCO assessing $3.3 to $3.5 million per year in late payment fees in each year 2021-2023.[74]

The Settlement would result in an average residential annual bill increase of $411, including sales tax.[75] Furthermore, the Settlement discards some of the most critical residential

[70] CAC Witness Inskeep Direct, p. 9.

[71] *Id*. According to the U.S. Bureau of Labor Statistics, $100 in March 2021 had the same buying power as $117.92 in March 2024. httpsta://www.bls.gov/data/inflation_calculator.htm

[72] CAC Witness Inskeep Direct, p. 12; IURC Annual Residential Electric Bill Survey. Based on 1,000 kWh monthly usage. *See* https://secure.in.gov/iurc/energy-division/electricity-industry/electricity-residential-bill-survey/.

[73] See monthly data for 2023-2024 and annual totals for 2021-2023 in NIPSCO Response to CAC Data Request 1-8(v) (Attachment BI-3).

[74] CAC Witness Inskeep Direct, pp. 13-15.

[75] CAC Witness Inskeep Settlement, p. 6 (($32.02 + $32.02*0.7) * 12 = $411.14).

affordability protections proposed by NIPSCO in its case-in-chief, such as a ratepayer-funded income-qualified bill assistance program, a cost-based multi-family rate, and limiting the residential class rate increase to the system average increase. The modest consumer protection provisions included in the Settlement do little to mitigate the unprecedented rate shock NIPSCO residential customers will experience. Further, the undue burden being placed on residential customers, while certainly influenced by factors such as significant new investments by NIPSCO, is unnecessarily and unfairly exacerbated by unreasonable provisions included in the Settlement. This motivated the Commission to deny/make major modifications to protect the public interest, consistent with its duty and statutory obligation.

Based on the evidence of record and having considered the Five Pillars enumerated in § 8-1-2-0.6, the Commission finds the Settlement Agreement are inconsistent with and does not appropriately balance the legislative directive in this state policy statement.

10. <u>Conclusion on Settlement.</u>

The proposed Settlement fails in multiple respects. As discussed herein, the Settlement does not reflect a just and reasonable resolution of the issues in this case. It would impose extreme rate shock on the residential class, who are already experiencing dire affordability challenges paying the highest electric bills of any IURC-regulated electric utility in Indiana. It is not just or reasonable to exacerbate these affordability challenges for residential customers to benefit a handful of large industrial customers.

Based upon our review of the record as a whole and consideration of the Settlement Agreement terms in totality and the admitted testimony and exhibits, as well as the testimony heard at the field and evidentiary hearings, the Commission finds that the Settlement Agreement does not represent a just or reasonable resolution of the issues disputed in this proceeding. The Settlement Agreement is not supported by substantial or probative evidence and is not in the public interest. Accordingly, the Settlement Agreement is rejected.

See also CAC Ex. 4, Stipulation of Facts in Lieu of Cross-Examination of NIPSCO Witness Whitehead, Facts #1 ("Except for 2025, Ms. Whitehead settlement reply testimony does not dispute the accuracy of Mr. Inskeep's residential bill presentation in Figure 1 of his testimony in opposition to the Settlement Agreement with respect to all data presented for NIPSCO, which is for the period 2004 through 2026."); *id*., Fact #2 ("Ms. Whitehead settlement reply testimony does not dispute the accuracy of Mr. Inskeep's residential bill presentation in Figure 1 with respect to all data presented for non-NIPSCO utilities for all years in which data was presented, which is for the period 2004 through 2024."); *id*., Fact #3 ("Ms. Whitehead's claim that Mr. Inskeep's residential bill presentation in Figure 1 was 'an inaccurate depiction' referred exclusively to Ms. Whitehead's objection that estimated bills were not presented for non-NIPSCO utilities in years 2025 and 2026, whereas they were for NIPSCO.")

11. <u>Confidentiality</u>.

NIPSCO filed two motions for protection and nondisclosure of confidential and proprietary information on September 12, 2024 and January 29, 2025, both of which were supported by affidavits showing certain documents to be submitted to the Commission contain confidential, proprietary, competitively sensitive, and/or trade secrets as defined under Ind. Code §§ 23-2-3-2 and 5-14-3-4. A Docket Entry was issued on each motion finding such information to preliminarily be confidential, after which the information was submitted under seal. The Commission finds all such information preliminary granted confidential treatment is confidential under I.C. §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana Law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement, a copy of which is attached to this Order, is rejected [unless CAC recommendations are adopted as stated herein, including the use of 12CP cost allocation method for production costs, correcting the revenue distribution as outlined above, correcting the cost allocation of ITC and PTC proceeds, denying the Economic Development Rider request, instituting the multi-family rate and low-income program as originally proposed].

2. A subdocket is hereby opened for the purpose of developing a standard tariff and addressing other pertinent issues related to new large load customers like data centers. A docket entry will be forthcoming establishing an attorneys' conference to discuss an appropriate scope and procedural schedule.

3. NIPSCO shall assign all costs of interconnecting a large load customer, including interconnection studies, network upgrades, direct connect facilities, and any additional transmission or distribution system costs, to the large load customer and not shift any of these costs onto existing customers.

4. The information filed in this Cause pursuant to motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

5. This Order shall be effective on and after the date of its approval.

<u>HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR</u>:

APPROVED:

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco
Secretary of the Commission