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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	**)**	**CAUSE NO. 45253**

<u>REPLY BRIEF OF DUKE ENERGY INDIANA, LLC</u>

Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company"), by counsel, hereby submits its reply brief to the Indiana Utility Regulatory Commission ("Commission") responding to the proposed orders and post hearing briefs filed by the Indiana Office of Utility Consumer Counselor ("OUCC") and intervenors in this Cause.

I. <u>Introduction</u>.

Duke Energy Indiana filed a comprehensive proposed order in this proceeding on March 3, 2020 and will not reiterate the points made in that filing. However, several parties raised new issues or arguments in their proposed orders and supporting briefs; Duke Energy Indiana responds to those issues in this Reply Brief. To the extent an issue is not addressed in this filing, it should not be interpreted as Duke Energy Indiana accepting arguments that are contrary to its various filings in this proceeding.

II. <u>Edwardsport IGCC Plant.</u>

Several parties recommend a variety of disallowances associated with the Edwardsport IGCC Plant ("Edwardsport"). Duke Energy Indiana reiterates its position in its proposed order that all Edwardsport costs are reasonable and necessary to safely, reliably, and economically operate the plant for the benefit of customers. Edwardsport has been the subject of many proceedings before the Commission and the Commission has previously found operating the plant primarily on syngas and committing it to MISO was reasonable, and it continues to be so today.

Duke Energy Indiana and the OUCC generally agree that Edwardsport should continue to operate on coal, the actual major outage costs should be deferred and recovered over a seven-year period, and there should be no disallowance associated with how the plant has been dispatched in the past, which would constitute retroactive ratemaking. There remain two points of disagreement between Duke Energy Indiana and the OUCC: (1) the appropriate amount of non-outage related operating and maintenance ("O&M") expense that should be built into base rates, and (2) whether the plant rate base balance should continue to be included in a rider.

The OUCC's proposals to reduce the annual O&M cost by $20 million is arbitrary and not supported by the record. Duke Energy Indiana presented persuasive evidence that the costs to operate the plant have been declining as Duke Energy Indiana works to improve reliability and reduce costs. Duke Energy Indiana also explained the budgeted costs included in its 2020 financial forecast are the best estimate of the actual costs to run the plant. Under cost of service ratemaking, base rates are to be set at an annual level that is representative of the actual costs to operate the utility in a safe and reliable manner. As such, Duke Energy Indiana's forecasted O&M to operate Edwardsport should be included in base rates.

As to the OUCC's proposal to continue to track only the declining base rate impact associated with Edwardsport, the Commission should find such a proposal as one-sided and unreasonable. Under the OUCC's proposal, only decreases in costs would be included in the Credit Rider (Rider 67), when there could very well be offsetting increases in other costs, such as maintenance capital. The OUCC argues that the Company has proposed to continue to track the Edwardsport tax benefits through its Credit Rider and therefore should also track the declining rate base balance. The OUCC, however, failed to consider that prior Commission orders require Duke Energy Indiana to provide the benefits of the tax credits to customers, and the use of a rider is the only option to ensure that the credits are fully refunded and to do so in a transparent way. There is no such prior Commission order that requires providing customers the benefit of declining rate base after an asset has been found to be used and useful and included in base rates, as Edwardsport will be here. In fact, quite the opposite – the settling parties in prior Edwardsport settlements, including the OUCC, agreed that the plant would *not* continue to be included in a rider after the base rate case. The OUCC's proposal is indeed contrary to traditional ratemaking and precedent in Indiana, which provides that capital tracker items be removed from the tracker and included in rate base upon the next subsequent base rate case, such as with respect to qualified pollution control property in Duke Energy Indiana's last base rate case in Cause No. 42359. As such, the Commission should reject the OUCC's one-sided proposal.

The Industrial Group continues to propose that a hypothetical O&M amount (what it represents it might possibly cost to run Edwardsport on natural gas) be included as the base rate ongoing O&M level, regardless of how the Company actually operates the plant. Under the Industrial Group's proposal, Duke Energy Indiana may continue to operate the plant on coal, with all the benefits that would inure to economic development in the state, the coal industry, fuel diversity, and reliability, but the Company may not recover the costs of doing so. The Industrial Group's effort to have it both ways should be rejected. Not only is this proposal unreasonable on its face, it is contrary to cost of service ratemaking, which provides for a utility's recovery of reasonable costs to operate the utility in a safe and reliable manner.

The Industrial Group claims that Duke Energy Indiana did not meet its burden of proof regarding the costs of running Edwardsport. However, under cost of service ratemaking, the utility's burden is to demonstrate what it costs to operate the utility, and only once a party has made a credible claim of imprudence does the Company need to rebut such claims.[1] Contrary to claims by the Industrial Group, as well as Joint Intervenors and Sierra Club, Duke Energy Indiana is under no affirmative obligation to investigate or study whether operating the plant on natural gas only or retiring the plant completely are preferable to current operations. Rather, the Company's obligation is to demonstrate that its current operations are reasonable, which the Company has done by demonstrating the benefits of operating the plant primarily on coal and the risks of running it solely on natural gas.

Regarding analysis performed in the Company's IRP, the Industrial Group claims Duke Energy Indiana had an obligation to study running Edwardsport on natural gas or retiring the unit, notwithstanding that the plant had only been operating for five years at that time. Again, the Industrial Group's claim has no basis under the law. Rather, Duke Energy Indiana was transparent in its IRP stakeholder meetings and presentation slides regarding how it was modeling retirements, including that it did not plan to model retirement of Edwardsport given it was so early in its operating life and its projected retirement date was outside the IRP's 20 year review window. Duke Energy Indiana also provided all stakeholders the opportunity to propose or develop their own portfolios, which Duke Energy Indiana would have modeled in the various scenarios. However, no party offered alternate portfolios, which could have included the retirement or operation on natural gas of Edwardsport as of a certain date. As such, the Industrial Group's claims that Duke Energy Indiana has not been forthcoming or transparent is belied by the evidence.

Next, the Industrial Group makes much of a privileged and confidential analysis that was prepared at request of counsel over two years prior to the base rate case, which, in compliance with the Company's record retention policies, was not retained in the normal course of business. The Industrial Group opines that such analysis would be relevant to this rate case and that it would be detrimental to Duke Energy Indiana's position, which of course it cannot know. Such

[1] Industrial Group argues the Company failed to meet the burden of proving its case on this issue, incorrectly alleging the Company is relying on a presumption in the face of "the absence of evidence." *See* Industrial Group Exceptions, p. 40. The Company is relying on no such presumption, and it clearly has established these expenses with sufficient evidence. In actuality, it is the Industrial Group that is ignoring Indiana law on presumptions. *See Re Ind. Mich. Power Co.,* Cause No. 39314 (IURC, 11/12/1993)("[o]nce [Petitioner] has presented a *prima facie* case for rate relief, opponents of the rate increase request such as OUCC have the burden of going forward with their evidence…. In sum, while [Petitioner] has a burden of proof to present evidence of its ordinary and necessary level of business expenses, [Petitioner] is not required to overcome any presumption that its expenditures are 'unnecessary and wasteful' until proven otherwise. On the contrary, at least a rebuttable presumption exists that such expenditures are legitimate.") (citing *W. Ohio Gas Co. v. Pub. Utilities Comm'n of Ohio*, 294 U.S. 63, 71 (1935)).

unsupported allegation should be rejected by the Commission. This argument is a red herring intended to denigrate the Company unfairly for doing nothing more than performing legal analysis in a prior proceeding and complying with its own record retention policies. In fact, Industrial Group attempts to use this (and other unsubstantiated claims) to have the Commission "send a message" to Duke Energy Indiana's management by setting a punitive return on equity ("ROE"). The Commission should reject any such suggestion as hyperbole and contrary to the evidence of record.

Finally, in response to the Industrial Group's (and Sierra Club's) contention that fuel diversity does not support continued operation of Edwardsport on coal, the Company disagrees. When looking at fuel diversity, Duke Energy Indiana is looking to the future and not the fuel diversity of the system as it is today. Clearly, the Company has plans to retire coal units that are much older and less environmentally efficient than Edwardsport. Edwardsport is the newest plant that is capable of operating on coal and presents the best chance to continue to utilize coal, as a part of a diverse portfolio, into the next two decades after other coal plants are retired.

Joint Intervenors and Sierra Club make several arguments similar to arguments made by the Industrial Group, so Duke Energy Indiana incorporates those responses herein.

Ultimately, Joint Intervenors recommend that the Commission order a formal investigation into the future of Edwardsport and that in the meantime, Duke Energy Indiana's IGCC-17 rates for Edwardsport collected through Rider 71[2] shall continue, subject to refund or additur, pending the outcome of a subdocket related solely to the future of Edwardsport. The basis for this suggestion is similar to the Industrial Group's argument above that Duke Energy Indiana had an affirmative duty to study the retirement of Edwardsport or operation on natural gas. Joint Intervenors also point to the manner in which Duke Energy Indiana commits Edwardsport into the MISO market. Further, Joint Intervenors point to capacity ratings, operating performance, parasitic loads, heat rate, production costs, maintenance capital, low natural gas prices, energy efficiency, and renewables as factors that justify their position. Duke Energy Indiana notes that all of these issues have been addressed in prior Commission proceedings related to Edwardsport and further notes that the Commission has previously approved the operation of Edwardsport on coal and the method it uses to commit the plant into the MISO market in those proceedings. Duke Energy Indiana asserts that Edwardsport has been subject to many prior proceedings, including this one, and that Joint Intervenors' request for yet another proceeding should be rejected.

Further, the request for rates to be maintained at current levels (rather than updated in accordance with the forecasted costs to operate the plant) and for such rates to also be subject to refund pending the outcome of such requested proceeding is even more unreasonable. The evidence demonstrates that the 2020 forecasted amounts for operating the plant are reasonable and what the Company needs to safely and reliably operate the plant. The costs recovered for Edwardsport to date, and the manner in which it commits the plant into MISO, have been approved by the Commission as reasonable. To deny recovery, based on the outcome of an

[2] Duke Energy Indiana notes that these costs are recovered through Rider 61 today and that Rider 71 is for recovery of O&M associated with environmental compliance projects.

extra, unnecessary proceeding, would constitute retroactive ratemaking, as all decisions related to how the plant is operated have been approved previously, or will be approved by the Commission in this proceeding.

Sierra Club recommends that the Commission disallow all coal-related costs associated with Edwardsport. Sierra Club's argument rests on the fact that the energy market has changed, including lower gas prices and lower prices for wind and solar compared to the costs of running Edwardsport on coal. Sierra Club's analysis on losses associated with Edwardsport operation vis a vis the MISO market fails to consider the operating characteristics of the plant and requires an inappropriate backward-looking hindsight analysis. As the OUCC recognizes, Duke Energy Indiana demonstrated that the MISO 24-hour day ahead market is an imperfect fit with longer term generation commitment decisions, particularly for units that have longer start up times, like Edwardsport, and therefore, committing units on solely a short term "Economic" basis, as recommended by the Sierra Club, would not be consistent with the objective of minimizing total customer costs. As explained above, the operation of the plant and its commitment into MISO have been reviewed and approved by the Commission and it is fundamentally unreasonable and punitive to disallow recovery associated with such operation. Even assuming, as Sierra Club does, that commitment decisions should be reviewed going forward, for instance in the FAC-123 subdocket proceeding, such analysis should not impact past or current cost recovery, which is in compliance with prior and current Commission orders; rather, it must apply only prospectively.

III. <u>Coal Inventory and Decrement.</u>

Both the Sierra Club and Joint Intervenors argue that Petitioner has imprudently acquired more coal than it needs and should be required to submit all future coal contracts for review and approval. Further, Joint Intervenors argue that "Duke should be responsible for the costs of its coal oversupply problem", but then want to remove the use of the decrement as one of tools that Duke Energy Indiana uses to manage its coal supply. To support this argument, Joint Intervenors argued that Duke Energy Indiana continues to purchase more coal than it needs.

The Commission should reject this proposal to have the Commission review and approve all coal contracts as it takes a short-term view of coal procurement. Furthermore, requiring all coal contracts to be reviewed and approved injects uncertainty in Duke Energy Indiana's coal procurement strategy and has the potential to increase the cost of coal. Finally, although Joint Intervenors dismiss the need for diversity of coal suppliers, it is in the best interest of all Indiana customers to have a diversity of suppliers to provide reliability of supply and apply competitive downward pressure on the cost of coal, given the industry-wide commercial pressures on coal suppliers.

Joint Intervenors seek to have the Commission review the prudence of coal purchases applying a hindsight review of prudency. This contravenes longstanding Commission precedent that in reviewing prudence the Commission does not "engage in a hindsight analysis." *Re Duke Energy Ind., Inc.*, Cause No. 38707 FAC 76 S1 at 16 (IURC, October 21, 2009). To the extent the Commission reviews the prudency of coal purchases, the Commission reviews "the circumstances as they existed considering what was known or should reasonably have been known at the time of the actions." *Re Ind. Mich. Power Co.*, Cause No. 43827 DSM 8 at 10, (IURC, May 22, 2019) (quoting *Re Duke Energy,* Cause No. 38707 FAC 76 S1 at 16).

As Mr. Phipps stated on the stand, Duke Energy Indiana's coal procurement group undertakes a detailed analysis to determine the coal it needs to procure over the coming years. For example, Mr. Phipps stated that the coal procurement group collaborates with the forecasting team "at least quarterly" to review projected coal burns over the five-year planning horizon and to determine whether there is a need for additional coal to accommodate the projected coal burn, based on existing inventory. Tr. F-32, line 7. At the hearing, Mr. Phipps testified that the decision as to whether to enter into new contracts looks at many factors. If the Company determines that it will need additional coal, it will issue an RFP (Tr. F-26, line 24), and based on the results, commence negotiations. Tr. F-26, lines 5-6. At the end of these negotiations, a contract is awarded if the parties arrive at favorable terms.

Mr. Phipps testified, "what will happen is we're making decisions on a point in time, and at that time, burn forecasts can change." Tr. F-40, lines 15-17. Therefore, if the Commission required a review and approval of coal contracts, such review and approval would need to look at the factors in place at the time of the negotiations and not at the time of Commission review or approval.

If Duke Energy Indiana is then required to present a contract to the Commission for approval through a litigated proceeding, perhaps taking six months to a year, then Duke Energy Indiana and its customers run the risk of less favorable terms as coal providers may choose to give more favorable terms to those parties who can enter into a contract in a more timely manner. Furthermore, as Mr. Phipps testified, these contracts often have reopeners as to quantity and price which further complicate any review and approval process.

In Cause No. 38707 FAC 96 (October 30, 2013), the Commission rejected the Industrial Group's recommendation that Duke Energy Indiana submit detailed testimony and analysis demonstrating the reasonableness of entering into any new long-term contract. At that time, the Commission found that "Duke Energy Indiana has reasonably presented detailed discussion in the past, for example its testimony filed in Cause No. 38707 FAC 80 concerning the coal contract with Bear Run mine, for significant long-term commitments. As Duke Energy Indiana is required to show the reasonableness of its actions as a working of the FAC summary proceeding, we will afford it the opportunity to do so absent a showing that it has failed to do so thus far." Joint Intervenors have not demonstrated that anything has changed significantly since that time and the Commission should reject any requirement for review and approval of coal contracts.

Sierra Club and Joint Intervenors also argue that Duke Energy Indiana should bear the costs of its oversupply of coal, but they do not specify what those costs are. As Mr. Phipps repeatedly testified at the hearing, the off-site storage of excess coal is a no cost option. *See,* Tr. F-81, line 22; Tr. F-81, line 24; Tr. F-82, line 11; Tr. F-82, line 22. Furthermore, Mr. Phipps testified to terms included in one contract that allowed the Company to negotiate more favorable terms for the benefit of Duke Energy Indiana's customers. Tr. G-7, lines 11 through 25.

Furthermore, Mr. Phipps testified that the Company's goal in negotiations is to secure as "low – the cheapest price or the lowest cost for our customer." Tr. G-11, lines 8 and 9.

Finally, Joint Intervenors argue that Duke Energy Indiana should not be allowed to use the coal decrement or otherwise be penalized for doing so. Joint Intervenors seek to prohibit Duke Energy Indiana from using a proven lowest cost method to address an excess of coal when market conditions change. The Commission should reject this punitive approach.

As stated in Mr. Swez' rebuttal testimony in this proceeding, "to the extent that the price decrement results in units being committed and dispatched that otherwise would not be, coal coming into the station is consumed, other potential costs are avoided, and customers' costs are reduced since higher cost alternatives to manage the inventory are avoided." *Swez Rebuttal*, page 27, lines 16-19. The Sierra Club loses sight of the fact that there is risk on both sides of the equation. If Duke Energy Indiana buys too much coal, it could end up with oversupply and a potential need to decrement or utilize other mitigation measures; conversely, the risk in under buying and not having enough coal when needed is that the Company may become dependent on purchasing power from the MISO market, which may have a negative impact on customer costs and/or reliability. Simply because the Company has experienced a recent trend of falling commodity prices, cheap natural gas and increasing renewable generation, resulting in lower power prices and excess coal, does not mean the market will always be that way. Duke Energy Indiana has a responsibility to ensure it has fuel to operate its plants in a reliable manner for the benefit of its customers under all circumstances.

The use of the decrement, when necessary, is an elegant solution that benefits customers. As Joint Intervenors acknowledge, the Commission has approved this approach in the past, *see:* Cause No. 38707 FAC 96, and there are no significant changes that necessitate a prohibition on applying the decrement when needed.

IV. <u>Prepaid Pension.</u>

In their proposed orders, the OUCC and Industrial Group continue to argue for the exclusion of all or most of the Company's prepaid pension asset from rates, focusing on the fact that under ERISA, companies are required to make minimum contributions to their pension plans. This focus is misguided and ignores the fact that the Company's prepaid pension asset meets the criteria for inclusion in rates, as set out by the Commission in its most recent pronouncement on the issue, *In re Indiana Michigan Power Co.*, Cause No. 45235 (IURC; 03/11/2020).

In the recent *I&M* rate order (at pp. 27-28), the Commission stated as follows:

> The Commission is persuaded by Mr. Ross that the prepaid pension asset continues to be reflected on I&M's books pursuant to GAAP. We further find, and as will be explained further in our finding on pension expense, that the prepaid pension asset continues to reduce overall pension costs, which is reflected in I&M's cost of service. It, therefore, continues to provide benefits to customers. Based on the evidence, inclusion of the prepaid pension asset is akin to including working capital and other prepayments and

> should be similarly reflected in I&M's rate base. As recognized in the 44576 Order, p. 23, materials, supplies, and fuel inventory are typically included in utility rate base, *i.e.*, used and useful utility property. As such, these items recognize capital that has been put to work for the purpose of providing utility service. While a "cash" working capital allowance is one type of "working capital", it is not the only type. 44576 Order, p. 23, fn. 4. Recognizing working capital in rate base is an appropriate method of compensating investors for the cost of capital they have advanced in the course of providing service. Finally, the Commission finds, based upon I&M's testimony-particularly Mr. Ross' rebuttal testimony upon the nature of the prepaid pension asset calculation, that the prepaid pension asset at issue was funded by investors, and customer rates have reflected the level of pension expense calculated pursuant to GAAP. I&M's prepaid pension asset was shown to be the cumulative total of cash contributions *in excess of* cumulative pension expense pursuant to GAAP and not, as Mr. Gorman testified, the result of growth in the pension fund through return on pension assets; rather, its calculation is directly from cash contributions. In other words, we find, based on Petitioner's testimony, that the prepaid pension asset reflects cash amounts contributed over and above the level of costs that have been recovered through rates and has been supplied by investor capital. Accordingly, the Commission finds the prepaid pension asset should continue to be reflected in I&M's rate base.

The above criteria outlined by the Commission are met in this case. The prepaid pension asset is reflected on the Company's books pursuant to GAAP. The prepaid pension asset reduces the Company's pension costs, and those reduced costs are reflected in the Company's cost of service. Thus, the prepaid pension asset benefits customers. The prepaid pension asset is akin to a prepayment and other forms of working capital – capital that has been put to work in the provision of utility service. The Company's prepaid pension asset was funded by investors, and customer rates have reflected the level of pension expense calculated pursuant to GAAP. The Company's prepaid pension asset was shown to be the cumulative total of cash contributions *in excess of* cumulative pension expense pursuant to GAAP; the calculation is directly from cash contributions. In sum, the evidence demonstrates that the prepaid pension asset reflects cash amounts contributed over and above the level of costs that have been recovered through rates and has been supplied by investor capital. Additionally, like I&M, Duke Energy Indiana's cumulative pension costs are greater than the cumulative minimum ERISA contributions. *See* Douglas Revised Direct Testimony, at pp. 34-35; and Setser Rebuttal Testimony, at pp. 5-18. Accordingly, the Commission should find in this case, as it did in the *I&M* case, that Duke Energy Indiana's rate base should include the prepaid pension asset.

V. **Coal Ash Basin Closure and Remediation Issues**.

In their proposed orders, the OUCC and the Industrial Group argue that Duke Energy Indiana should not be permitted to recover past expenses associated with coal ash basin closure and remediation as the Company did not seek prior Commission approval to defer the costs and that recovery of previously incurred costs constitutes impermissible retroactive ratemaking. The OUCC further argues that IDEM project costs do not meet the definition of federally mandated costs, pursuant to Indiana Code ch. 8-1-8.4.

As discussed in Duke Energy Indiana's testimony and proposed order, the Company is required by both federal and state law to engage in coal ash closure activities; such activities are directly related to the Company's provision of utility service; the Company appropriately deferred its coal ash closure-related expenses in accordance with GAAP, thus preserving such expenses for consideration by the Commission in this case; the Company's coal ash closure-related activities, and associated expenses, are reasonable and prudent; and the Commission should authorize recovery of such expenses over time either under traditional ratemaking or pursuant to the federal mandate statute.

To begin, the evidence is clear that under applicable accounting rules, specifically ASC 980, the Company appropriately deferred its coal ash basin closure and remediation costs. As the Company's evidence explains, an order from regulators is not required in order for a utility to defer costs. *See* Rebuttal Testimony of Duke Energy Indiana witness Abernathy.[3] Further, the OUCC's discussion of the *South Haven* case (Cause No. 41903, dated June 5, 2002) misses the point. Although the Commission denied recovery of certain of the utility's deferred expenses on the basis of immateriality, management deficiencies, and a lack of supporting evidence in *South Haven*, those problems are not present in this case. Conversely, Duke Energy Indiana cited the *South Haven* case for the proposition that a utility may defer expenses if it concludes, consistent with SFAS 71 (now ASC 980) that recovery of such expenses is probable. The Commission observed in *South Haven* that SFAS 71 provides a utility may preserve a particular cost for future consideration if it is probable that recovery will be allowed. Order at 17. Further, in *South Haven*, the Commission noted the general circumstances under which it will allow recovery of expenses deferred by the utility under SFAS 71, stating: "In those cases where the Commission has allowed the recovery of a deferred debit, the common traits are that the costs being amortized as deferred debits are infrequently incurred, involve assets with significant and long-lasting benefits, and involve significant cost, to the point that it is prudent to smooth the cost over a period of years." Order at pp. 17-18. Further, the Commission noted that "fairness dictates that deferred debits can also be used to increase a revenue requirement where certain significant expenses are incurred outside of the test year, and where the benefits of those expenses will continue in future years." Order at 18.

The OUCC attempts to make much out of the fact that the *South Haven* case involved water utility accounts, not electric utility accounts. However, , the Commission discussion about the propriety of deferring utility costs for future recovery is clearly tied to SFAS 71 (now ASC 980), the same accounting pronouncement at issue in this rate case that is applicable to water, as well as gas and electric utilities.

Duke Energy Indiana's decision to defer its coal ash basin closure and remediation expenses was consistent with accounting requirements and with Commission precedent. Further, these expenses meet the requirements for recovery over time under traditional ratemaking

[3] *See also Indiana Michigan Power*, Cause No. 45235 (March 11, 2020) ("As to the OUCC's argument that I&M should have sought authority to defer these costs as a regulatory asset, based on the accounting testimony presented, GAAP does not require such authorization. The question for recording a regulatory asset under ASC 980 is the probability of recovery…., which may come from a Commission order, but such an order is not the only means. p. 44).

concepts: the expenses are infrequently incurred; they relate to long-lived assets (generating plants); they are required to meet federal and state environmental mandates; they involve significant cost, such that it is reasonable to smooth out recovery over a number of years; and they were incurred largely outside of the test period, but will have long-lasting environmental compliance benefits.

The OUCC and the Industrial Group also argue that allowing recovery of the Company's appropriately deferred coal ash basin closure and remediation expenses would violate the rule against retroactive ratemaking. The OUCC and Industrial Group are wrong. The rule against retroactive ratemaking prohibits regulators from setting future rates to allow a utility to recoup past losses or to refund to customers excess utility profits. The fact that the Commission routinely recognizes and allows the deferral of expenses to be considered and recovered in future rate cases proves the point that this is not a retroactive ratemaking situation. *See, e.g., In re Northern Indiana Public Service Co*., Cause No. 43396-S1 (IURC; 02/18/2009). As explained in the Company's proposed order (and supported by the Commission's *South Haven* and other orders), when expenses are appropriately deferred, those expenses are not recorded as a loss; rather, they are preserved for consideration in a future proceeding. Thus, there is no recoupment of a past loss when deferred expenses are subsequently authorized for recovery.

Other state commissions have similarly recognized that the deferral and subsequent recovery of expenses does not violate the rule against retroactive ratemaking. For example, in *Business & Professional People for the Public Interest v. Illinois Comm. Comm'n*, 563 N.E.2d 877 (Ill. Ct. App. 1990), the Illinois Commission approved a utility request to defer depreciation and financing costs related to a nuclear plant. Consumer intervenors challenged this order in court on retroactive ratemaking grounds. In addition to approving the Commission's order authorizing deferral of the costs, the Illinois Court of Appeals held that in a future rate order, the Commission could allow recovery of the deferred costs, reasoning that retroactive ratemaking only applies to adjustments in past rates. Because the Commission had not taken those expenses into account in setting past rates, the Commission was free to consider the deferred expenses in setting future rates. Similarly, the Maine Supreme Court found that recovery of deferred costs relating to the expansion of basic telecommunications service was not retroactive ratemaking, because such costs had not been previously considered in setting rates. *Public Advocate v. Public Utilities Comm'n*, 718 A.2d 201 (Me. 1998).

As in these cases, Duke Energy Indiana's deferred coal ash basin closure and remediation expenses have not been considered in setting the Company's rates in the past, thus recovery of such costs in this case is not precluded by the rule against retroactive ratemaking.

Finally, although these expenses are recoverable under traditional ratemaking, they are also recoverable via the Federal Mandate statute, Indiana Code 8-1-8.4. The Company's testimony and proposed order explains in detail how both the "CCR Projects" and the "IDEM Projects" stem from federal mandates, and how the Company has met all of the requirements of the Federal Mandate statute. Further, the Company's extensive testimony and exhibits on this issue demonstrate the prudence of the Company's closure and remediation activities and associated costs. The OUCC and Industrial Group's primary argument against use of the Federal Mandate statute in these circumstances is that the Company made expenditures prior to filing for relief under the Federal Mandate statute. Their proposed orders also seem to imply that recovery of these significant environmental compliance expenses should not be allowed even under traditional ratemaking, due to the timing of the Company's request for relief under the Federal Mandate statute.

The parties base their argument on a very recent Commission decision – September 2019 in Cause No. 44367 FMCA 4. As the Company pointed out in its proposed order in this proceeding, the Commission has previously allowed recovery under the Federal Mandate statute in several cases where the request for relief came after expenditures were incurred. Further, in its order on reconsideration in Cause No. 44367 FMCA 4, the Commission stated that its holding on this issue was limited to the facts and circumstances of that particular case. The Commission also indicated that recovery of pre-petition costs had been allowed in the past and were appropriate under certain circumstances, such as for planning and development costs or when the timing of federal mandate compliance was such that the utility had to begin compliance activities to meet deadlines.[4] As the Company also emphasized in its proposed order in this proceeding, the coal ash situation is distinguishable in several ways from the situation in Cause No. 44367 FMCA 4 and meets the criteria the Commission set out for approval of pre-petition costs through the federal mandate tracker. Among other things, much of the work performed was engineering and planning necessary to develop its proposed closure plans to submit to IDEM. Further, while the Company's proposed compliance plans remain pending before IDEM, the Company could not wait to begin some of its compliance activities because it has CCR Rule-mandated compliance deadlines to meet. For all of these reasons, the Commission can reasonably conclude that recovery of the Company's previously-incurred coal ash closure and remediation expenses are fully recoverable under the Federal Mandate statute.

Further, the other parties' implication that seeking recovery of previously-incurred costs should also be precluded under traditional ratemaking, due to the timing of the Company's filing for relief under the federal mandate statute, flies in the face of both traditional ratemaking concepts and the policy underlying the federal mandate statute. Under traditional ratemaking, the utility always incurs costs first, then seeks recovery of such costs. In this paradigm, the utility takes the risk of disallowance if its incurred costs are found to be unreasonable or imprudent, but there is no precedent in traditional ratemaking requiring preapproval. In this case, due to the disconnect between the federal compliance deadlines and IDEM's cautious approach to approving closure plans, the Company has been thrust into the position of incurring a risk of disallowance, whether it wants to or not. Nevertheless, in this case, the Company has demonstrated the prudence and reasonableness of its actions taken to comply with federal and state coal ash compliance requirements. Moreover, the clear purpose of the federal mandate statute is to allow timely recovery for costs incurred by utilities in complying with federally-mandated requirements. The statute recognizes both the importance of timely recovery of costs, and the inequity of not allowing a utility to recover costs that it has no choice but to incur. It would be ironic indeed if the existence of this alternative ratemaking statute allowing timely cost

[4] Duke Energy Indiana, Cause No. 44367 FMCA 4, *Order on Reconsideration* (p. 3).

recovery were used to affirmatively disallow recovery of federally-mandated environmental compliance costs under traditional ratemaking.[5]

VI. Return On Equity.

In their proposed orders, the OUCC, the Industrial Group, Steel Dynamics, Inc ("SDI"), and Federal Energy Association Department of Navy ("FEA") argue that the Commission should approve an authorized ROE of 9.0%, while Walmart argues for an authorized ROE of 9.6% Notably, the Industrial Group argues for the first time that a 9.0% authorized ROE is supported by a need to send a message to the Company about its purported "lack of transparency" in this case.

Duke Energy Indiana's testimony and proposed order explain and support a cost of equity substantially higher than the OUCC's, Industrial Group's, and other parties' recommendation of 9.0%. The full extent of the Company's explanations and support will not be repeated here, except to note that (1) even the current trend of declining authorized returns on equity does not remotely support a 9.0% return on equity, and (2) an authorized return on equity in the range of 9.0% would almost certainly create credit and other financial integrity issues for the Company. This Reply Brief addresses the Industrial Group's new argument that a low (9.0%) return on equity is justified by the Company's alleged "lack of transparency," the argument that Indiana regulatory mechanisms justify a lower return on equity, and the FEA's criticism of Duke Energy Indiana witness Hevert's testimony based on selective use of orders from other state commissions.

As to the Industrial Group's argument that Duke Energy Indiana deserves a lower authorized ROE to send a message about the Company's alleged "lack of transparency", there are three major problems with this specious argument. First, the Commission has discretion with respect to the precise return on equity it authorizes for the calculation of base rates; however, in order to meet the requirements of *Hope*, *Bluefield*, and progeny, it must authorize a return on equity that falls within a reasonable range of the utility's cost of equity. In this case, the evidence demonstrates that a reasonable range of Duke Energy Indiana's cost of equity is well above 9.0%. Indeed, the Industrial Group's new argument that a 9.0% ROE is justified because the Company should be punished exposes that a 9.0% ROE is simply not supportable under a traditional cost of equity analysis.

Second, the Industrial Group's argument that Duke Energy Indiana should be punished for an alleged "lack of transparency" is without merit. Much has been made of the format and presentation of the Company's cost of service studies in this proceeding. However, it is clear that the Company's cost of service studies were prepared and presented consistent with the Commission's requirements, and similar to how such have been prepared and presented in past Company rate cases. *See generally* Duke Energy Indiana's Response to Joint Movants' Motion to Certify for Interlocutory Appeal (filed Jan. 13, 2020); Duke Energy Indiana's Response to

[5] The Company's position that the Commission's FMCA 4 order and other precedent do not preclude recovery of coal ash-related expenses also applies to the OUCC's argument regarding the Company's properly deferred 316(a) and 316(b) compliance expenses.

Joint Movants' Appeal to the Full Commission (filed Nov. 12, 2019); Duke Energy Indiana's Response to Joint Movants' Motion to Amend Procedural Schedule (filed Oct. 22, 2019). Moreover, it is also clear that the Company took many steps above and beyond the Commission's requirements to educate the parties about the Company's cost of service studies, going so far as to replicate the entirety of the studies in Excel format for the convenience of the parties. *Id*. Additionally, as discussed elsewhere in this Reply Brief, the Industrial Group's allegations with regard to transparency of information related to Edwardsport and Utility Receipts Tax are without merit.

Third, regulatory policy supports the concept of taking into account qualitative factors related to management performance in determining the precise return on equity to authorize for rate-setting purposes:

> While exceptional management is rarely explicitly rewarded, and mediocrity infrequently penalized, it suggests more systematic and deliberate efforts on the part of regulating agencies to distinguish, somewhat as competition is presumed to do, in favor of companies under superior management and against companies with substandard management. The distinction might take the form of an explicit and publicly recognized differential in the allowed rate of return. There is ground for the conviction that the opportunity of a well-managed utility to earn a return *liberally* adequate to attract capital is in the public interest as encouraging rapid technological progress and long-run policies of operation. Objection might be raised to a substandard rate of return on the grounds that it would make bad matters worse, but one might hope that the restriction of a company, by virtue of a commission finding of inferior management, to a minimum rate of return measured, say, by a bare bones estimate of the cost of capital, could become so intolerable to the stockholders that they would enforce a change of management.

James C. Bonbright *et al*., *Principles of Public Utility Rates*, at 366-67 (2d ed. 1988). The Commission, in other cases, has used qualitative factors in determining its authorized return on equity for other utilities. *See, e.g., In re Indianapolis Power & Light Co*., Cause No. 44576 (IURC; 03/16/16). If the Commission desires to take account of qualitative factors in determining the precise return on equity to authorize for the Company, within a reasonable range of the Company's cost of equity, it should look to the quality of the service provided by the Company to its customers. The evidence in this case overwhelmingly demonstrates that the quality of service provided by Duke Energy Indiana is excellent. For example:

- Duke Energy Indiana's customer satisfaction is top quartile according to 2019 J.D. Power surveys and is 96% as measured by a Company survey of community leaders. *See* Duke witness Pinegar Revised Direct Testimony, at pp. 32-35.
- Duke Energy Indiana's generating plants are safe, reliable, and environmentally compliant. The Company's generation unit performance (equivalent forced outage rate, net capacity factor, starting reliability) is above average, while its coal units' net capacity factor has increased. *See* Duke witness Mosley Direct Testimony, at pp. 15-20.
- Duke Energy Indiana's electric grid is highly reliable, well maintained, and customers are highly satisfied with the Company's reliability. The major contributor to outages is

vegetation-related, which the Company is proposing to address as outlined in this case. *See* Duke witness Hart Direct Testimony, at pp. 7-12.

- Duke Energy Indiana is consistently recognized as a top Electric Utility Economic Development Program. *See* Duke witness Pinegar Revised Direct Testimony, at p. 41.
- Duke Energy Indiana's retail electric rates are highly competitive – the lowest average retail rate among all Indiana investor-owned utilities -- and are expected to remain so. *See* Duke witness Davey Revised Direct Testimony, at pp. 34-35.

The Industrial Group also continues to argue that Duke Energy Indiana's cost of equity is lower than the proxy group's due to the prevalence of regulatory adjustment mechanisms in Indiana. Although that may have been true 15 to 20 years ago, it is no longer true today. A review of other state regulatory mechanisms indicates that Indiana is in the mainstream today. *See* Petitioner's Ex. 11-I, "*Summary of Adjustment Clauses and Alternative Ratemaking Mechanisms*," attached to Duke witness Hevert's Direct Testimony. *See also* Mr. Hevert's Direct Testimony at pp. 43-48.

In sum, a return on equity at or near 9.0% is unreasonably low, confiscatory, and would be unsupported under both the principles of *Hope* and *Bluefield* and the current trend of authorized ROEs. Such a low return on equity is not justified by proper cost of equity analyses, nor is such a low return justified by Indiana's regulatory paradigm. The Commission may use qualitative factors in determining the precise return on equity for Duke Energy Indiana, so long as such ROE falls within a reasonable range of the Company's cost of equity. However, a 9.0% ROE is well outside of any reasonable range of cost of equity. Moreover, the Industrial Group's proposed punitive 9.0% ROE, based on arguments unsupported by the facts and evidence, should be rejected. No such lack of transparency exists. The Company's rate case filing was fully compliant with the Commission's requirements and similar to rate cases previously filed by the Company. Further, Duke Energy Indiana made numerous efforts – above and beyond Commission requirements -- to educate the parties about its rate proposals and calculations. For example, as the Presiding Officers stated and the Full Commission affirmed, the Company's invitations to the parties for on-site visits to review the Cost of Service Study Model were uniformly rejected by the parties. *See* October 28, 2019 Docket Entry, p. 2. If the Commission desires to consider qualitative factors in its determination of a return on equity for the Company, it should consider the excellent service quality provided by the Company to its customers. Based on this excellent quality of service, it would be appropriate for the Commission to authorize a return on equity in this case at the upper end of a reasonable range of the Company's cost of equity.

VII. <u>Unbilled Revenues.</u>

The OUCC argues that that the Commission should reject the Company's *pro forma* removing unbilled revenues. The OUCC further argues that the Commission should order Duke Energy Indiana to use unbilled revenues in the calculation of all tariffed rates. The OUCC did not make this recommendation in its testimony; as such, the Company has not had an opportunity to respond to this position and will do so in this Reply Brief.

Mr. Bailey explained in his rebuttal testimony that the rate design process utilized a historical billing period predicated on billing cycle data that was then used to apportion the forecast to rate schedules and ultimately calculate revenue at present rates. Further, revenue at proposed rates is also calculated on a billing cycle basis. Finally, and most importantly, customer bills are calculated by applying tariff rates to billed usage only. Including unbilled usage in the development of tariff rates would be inconsistent with the application of tariff rates to billed usage when calculating a customer bill. Therefore, the Commission should reject the OUCC's recommendation to include unbilled usage in the billing determinants used in developing tariff rates.

VIII. Depreciation.

A. ELG vs. ALG Methodology

Both the OUCC and Industrial Group argue that the Commission should adopt the Average Life Group ("ALG") methodology for purposes of calculating depreciation rates. As discussed below, this argument ignores the fact that the Commission has consistently approved the use of the Equal Life Group ("ELG") methodology for Indiana utilities, including for Duke Energy Indiana in prior proceedings approving its depreciation rates.

The Company's testimony and proposed order support the use of the ELG depreciation methodology in great detail, and therefore it will not be repeated here. However, in their proposed orders, the OUCC and Industrial Group emphasize one argument that does bear re-addressing: the mistaken idea that the ELG methodology is only appropriate if depreciation rates are updated annually.

Both the testimony of Duke Energy Indiana witness Spanos and Commission precedent make clear that this is not the case. As Mr. Spanos explained in his rebuttal testimony, given the vast amounts of utility properties and the many moving parts, there are numerous asset additions and retirements every year. As a result, even if updated every year (as Mr. Spanos noted happens in Pennsylvania), ELG depreciation rates are relatively stable and do not change much from year to year. Thus, in his expert opinion, annual updates are unnecessary.

Further, the Industrial Group's argument totally ignores the fact that the Commission has approved the use of the ELG methodology for years in Indiana, for a number of different utilities, without finding a need for annual updates to depreciation rates. *See, e.g., In re Northern Indiana Public Service Co.*, Cause No. 43526 (IURC; 08/25/10); *In re Indiana-American Water Co*., Cause No. 43081 (IURC; 11/21/06); *In re PSI Energy, Inc*., Cause No. 42359 (IURC; 05/18/04); *In re Indiana-American Water Co*., Cause No. 40704 (IURC; 12/11/97); *In re Public Service Co. of Indiana, Inc.* Cause Nos. 37414-S2 and 38809 (IURC; 04/04/90). Indeed, the Commission has found the ELG methodology – without annual updates – to be the preferred depreciation methodology, superior to the use of the ALG methodology. *In re Northern Indiana Public Service Co*., Cause No. 43526, at p. 51 (IURC; 08/25/10) ("The Commission has frequently and consistently expressed its preference for the use of the ELG procedure.")

Duke Energy Indiana itself has used the ELG methodology going back to its rate cases in the 1990s, without a requirement to update depreciation rates annually. The Commission should uphold its longstanding and consistent preference for the ELG methodology, without the need for annual updates.

B. Calculation of Decommissioning Costs

In calculating decommissioning costs to be reflected in depreciation rates, Commission precedent is clear that decommissioning costs should be escalated at an appropriate inflation rate and contingency should be included. *See, e.g.*, *In re Northern Indiana Public Service Co.*, Cause No. 43526 (IURC; 08/25/10); *In re PSI Energy, Inc*., Cause No. 42359 (IURC; 05/18/04). Duke Energy Indiana will not rehash the evidence and arguments supporting these well-defined propositions in this Reply Brief.

The Company's evidence also supports the reasonableness and need for inclusion of end-of-life materials and supplies ("M&S") inventory costs in depreciation expense. Such end-of-life inventory costs are necessary to keep plants reliably operating for the benefit of customers until they are retired, and such inventories will likely be obsolete and unable to be salvaged. *See* Rebuttal Testimony of Duke Energy Indiana witness Mosley and Duke Energy Indiana witness Kopp. However, Duke Energy Indiana recognizes that the Commission has not traditionally recognized generating plant end-of-life M&S inventories in setting depreciation rates. In recognition of the novelty of this issue for the Indiana Commission, the Company offered an alternative in its rebuttal case – authorization by the Commission to utilize a regulatory asset to capture inventory costs at the end of a plant's life, with recovery to take place over time following a future rate case. *See* Rebuttal Testimony of Duke Energy Indiana witness Douglas. Duke Energy Indiana submits it would be reasonable for the Commission to accept the Company's rebuttal position, in order to reflect the reality of end-of-life inventory costs as necessary costs incurred in order to reliably provide electric service that should be able to be recovered as a cost of service, while also mitigating the impact of such on rates set in this proceeding.

IX. URT-Related Issues and Disallowance.

The Industrial Group did not take exception with Duke Energy Indiana's proposed treatment of the Utility Receipts Tax ("URT") as a separate line item on customer bills, similar to sales tax, rather than embedding URT in its base rate revenue requirements. However, in its brief and proposed order, the Industrial Group continues to argue that Duke Energy Indiana was not transparent and timely in communicating and correcting rate and revenue requirement impacts associated with URT. The Industrial Group's description of the issues constitutes revisionist history and fails to recognize the actual order of events.

First, it should be noted that this proposal by Duke Energy Indiana was intended to benefit customers. Duke Energy Indiana recognized that if the URT rate decreases in the future, as may occur under current statute, customers could easily receive the benefit without waiting for a change in base rates if it were included as a line item on the bill. In addition to timely passing the benefit of lower URT rates on to customers, at the time of its initial filing, the Company believed there would also be an attendant state income tax benefit that would result from this treatment that could be passed to customers. Income tax expense was modeled in the case-in-chief to include a lower level of income tax expense to reflect this anticipated income tax benefit.

Because of this unique change in treatment, when presenting the impact of the rate increase in its case-in-chief, Duke Energy Indiana failed to consider the impact of the URT that would still be billed to customers, but was no longer included in base rates. However, as soon as this mistake was realized, Duke Energy Indiana filed an amended petition, revised testimony, exhibits and workpapers, and provided a new notice to its customers. Contrary to the Industrial Group's contention, Duke Energy Indiana did update the rate impact and included the impact of the URT on its workpapers in that filing.[6] Duke Energy Indiana further explained that since the URT was being excluded from base rates, it was appropriate to calculate its exhibits and workpapers with just the base rate amount; although Duke Energy Indiana did indicate the URT impact in a separate column on its workpapers. The Industrial Group claims that it was evasive for Duke Energy Indiana to present the testimony this way. However, all the data needed to fully understand the impact of the URT was included in the Company's revised September 9, 2019 testimony.

Also at the time of its September 9, 2019 filing, Duke Energy Indiana had become uncertain as to whether it would be able to recognize a state income tax benefit as a result of changing the bill presentation of URT. However, the Company had not yet been able to affirmatively confirm with its tax experts whether such benefit was or was not available under its line item bill proposal.[7] When the Company filed its rebuttal testimony, after having determined that the tax benefit was not available, the Company updated its testimony and exhibits for the removal of the tax benefit by increasing state income tax expense (with a corresponding reduction in federal income tax expense). This is not a *new* revenue requirement item presented for the first time in rebuttal testimony as claimed by the Industrial Group. Rather, it was a necessary adjustment to the amount included for the state and federal income tax items based on a final determination related to the income tax treatment of URT revenues under the Company's line item billing proposal, a determination which had been previously communicated to the Industrial Group and other parties via discovery later in September. In the rebuttal filing, the income taxes were also recalculated to reflect the income tax effect of certain rate mitigations agreed to in rebuttal testimony. In fact, to ignore reflecting the appropriate treatment for URT revenues when revising income taxes for the tax impact of other items adjusted in rebuttal would have been knowingly providing inaccurate information to the Commission and the parties. This argument is another example of the Industrial Group trumping up charges of lack of transparency that falls flat.

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[6] See Davey Revised Direct Testimony, pp. 18-20 and Petitioner's Exhibit MSFR-4C (at Revised Confidential MSFR Workpaper COSS24-MTD, RevSum Tab).

[7] IG CX-23 (Duke Energy Indiana's response to Industrial Group DR 34.1). The Company did confirm toward the end of September that such tax benefit would not be realized; however, given the amount at issue ($2.3 million), the fact that parties had notice of the issue through discovery, and the fact that the Company would be updating its requested revenue requirements in rebuttal testimony, the Company determined the change was not material enough to file corrected testimony.

Duke Energy Indiana was completely transparent to the point of rushing to file its amended petition and revised testimony so the revised estimated rate impact amounts including the URT amounts not in base rates and other known corrections affecting the HLF rate codes could be quickly communicated, rather than waiting additional time before filing to fully understand whether the original tax guidance provided regarding the Company's URT line item billing proposal (that there would be state income tax benefits) was still appropriate. For all these reasons, the Industrial Group's recommended punitive treatment of disallowing the portion of test period income tax expense associated with the taxation of URT revenues by the state and imposing an unreasonable reduction in the Company's ROE because of these URT issues should be rejected by the Commission.

X. <u>Nucor Issue.</u>

For the first time in this proceeding, Nucor alleges that the Company's treatment of a large portion of Nucor's revenues is inaccurate in the Cost of Service Study. This issue, raised by Nucor for the first time in its Post-Hearing Brief Exceptions to Duke Energy Indiana's Proposed Order, is clearly not supported by the record and therefore should be rejected.

Cost of Service Studies generally employ two approaches: 1) assignment of costs based on the measurable and predictable components of a customer's service; or 2) if the nature of services and quantities are contractually categorized as non-firm, are interruptible, and exhibit variability, costs to serve are not assigned and instead a supportable level of revenues as revenue credits are established within the Cost of Service Study to offset other costs of service. The latter method was used by Duke Energy Indiana. Specifically, the other operating revenues associated with the unique interruptible, buy-through, and as available portions of the Nucor special contract were treated as a reduction to the overall revenue requirement.

Duke Energy Indiana maintains that Nucor does not comprehensively consider the Company's treatment of the non-firm revenues in light of the cost assignments made directly to Nucor for their firm load.

In the Cost of Service Study, there was no production investment or expenses allocated to Nucor for their loads above the firm level.[8] Only their firm load was used to develop Nucor's production demand and energy allocators.

It is fundamental to understand that generation costs, which Nucor depends on for firm load (and loads in excess of firm load), are included in the Cost of Service Study and all retail customers are paying for that generation. Therefore, it is appropriate that any monies received from Nucor for any contributions in excess of firm loads, such as their interruptible, buy-through, and as available services, are shared with all retail customers with firm load. This was accounted for in the Company's Cost of Service Study[9]. The revenue credits were allocated on the basis of production demand, production energy, and transmission demand, depending on the

[8] See MSFR Workpaper COSS1-MTD for the production allocators used in the Cost of Service Study.

[9] See Rebuttal Workpaper JS-8 MTD (lines 23 – lines 26) which include the aforementioned revenue credits.

nature of the non-firm revenue. These customer specific revenues were not omitted when the Company determined base rates, as alleged by Nucor. Conversely, customer specific revenues were accounted for in a manner that provided revenue credits to all retail customers, including Nucor itself who received an allocation of the revenue credits based upon its firm production load and firm and interruptible transmission load. The Company properly accounted for Nucor's special contract in its cost of service study and the there is no evidence of record for the Commission to determine otherwise.

XI. Jurisdictional Separation Study – Change in Wholesale Native Load

In its reply brief, although not based on testimony or evidence in the record, the Industrial Group shifts the characterization of its argument on this jurisdictional separation study issue to echo the rationale recently used by the Commission in its March 11, 2020 Order in Cause No. 45235 (*In re Indiana Michigan Power Co*.). Instead of arguing that the Commission should impute a hypothetical amount of wholesale native load,[10] the Industrial Group now articulates its argument in terms of excess capacity that is purportedly not used and useful, and on that basis, claims a portion of capacity should be excluded from retail rates.[11] The facts and the law support neither articulation of the Industrial Group's argument.

In Cause No. 45235, the Commission excluded a portion of I&M's capacity from its retail rate base, finding that retail customers should not bear the costs of a shift in capacity allocation resulting from the termination of certain wholesale native load customer contracts, where such freed-up capacity is not needed by retail customers. While Duke Energy Indiana believes this decision is flawed, it is also distinguishable from the case at hand in two major respects.

First, in Duke Energy Indiana's case, there is no shift in capacity allocation. The evidence demonstrates that the allocation of capacity between retail and wholesale native load as represented in the Company's jurisdictional separation study is roughly the same level as existed at the time of the Company's last retail rate case – in fact, it is slightly higher on a percentage basis than the level reflected in the Company's current base rates. Importantly, this means that

[10] As for this argument, already addressed in Duke Energy Indiana's proposed order, the law is well settled that hypothetical situations cannot be the basis for ratemaking in Indiana. *See, e.g., Public Service Comm'n v. City of Indianapolis*, 131 N.E.2d 308, at 316-17 (1956) ("The statute does not permit the fixing of rates on a hypothesis or a situation never in existence.") The Commission has repeatedly upheld this proposition of law, noting in one case "[o]ne of the compelling reasons why regulatory bodies reject establishing rates based upon a hypothetical capital structure is quite simply that such ratemaking ignores reality." *In re Indianapolis Water Co*., Cause No. 37612 (IURC; 03/20/85). In another case, the Commission emphasized "[t]he Indiana Courts have made it clear that we cannot base rates on a hypothetical." *In re South County Utilities, Inc*., Cause No. 39999 (IURC; 01/18/95).

[11] It is important to understand that there are essentially two categories of lost wholesale native load at issue: (1) 100 MWs under contract in a short-term bundled energy and capacity sale through 2021; and (2) an additional 260 MWs of wholesale native load contracts that have terminated in recent years. The Industrial Group argues that both of these categories of lost wholesale native load should be disallowed for retail ratemaking purposes. As has been extensively covered in the Company's testimony and proposed order, the 100 MW contract load is quite different from a wholesale native load contract and should not be treated as such. The Company does not plan or build for this contract load, and the contract will terminate soon.

retail customers will be allocated slightly less of the overall production costs in this rate case than they were in the last rate case (*i.e*., in current rates). While the level of wholesale native load sales may fluctuate from time to time, retail customers are not being asked to pay for a greater share of production costs in this rate case compared to what they are paying in current rates per the last base rate order.

Second, contrary to the Industrial Group's contention, the evidence shows that even with its current level of wholesale native load, the Company does not have excess or unused capacity. The Company's preferred portfolio in its current IRP shows that even with its 2020 level of wholesale native load, the Company still needs to add capacity for the benefit of customers. Specifically, the Company's IRP calls for incremental capacity additions in the near-term as follows (plus incremental DSM): 50 MW of storage in 2020; 16 MW of CHP in 2021; 116 MW of solar and CHP in 2023; 216 MW of solar, wind and CHP in 2024; 200 MW of solar and wind in 2025; 216 MW of solar, wind and CHP in 2026; 200 MW of solar and wind in 2027; 1390 MW of CC, wind and solar in 2028; and 200 MW of solar and wind in each of the five following years.[12] There is simply no basis for concluding that Duke Energy Indiana's test period capacity will not be used and useful for the benefit of retail customers.

Additionally, conspicuously absent from the Industrial Group's argument is any evidence that Duke Energy Indiana's existing generating resources were imprudently added. In previous excess capacity cases, the Commission has emphasized a key factor that must be considered and addressed is the prudence of the decision to construct the plant. *In re Northern Indiana Public Service Co*., Cause No. 37458, 67 PUR4th 396, 401-02 (IURC; 06/19/85). *See also, In re Petition of Indiana-American Water Co*., Cause No. 42029, 2002 Ind. PUC LEXIS 432 (IURC; 11/06/2002); *In re Petition of Indiana-American Water Co*., Cause No. 42520, 2004 Ind. PUC LEXIS 351 (IURC; 11/18/2004). A review of previous Commission orders shows that all of the Company's existing generating resources were found to be prudently added and used and useful in previous rate cases. Further, all of the Company's major generating plants added after 1985 were preapproved, certificated, and found reasonable under Ind. Code ch. 8-1-8.5 and other certificate statutes.[13]

There are policy reasons supporting the Company's position, as well. Within the confines of the law and the evidence, the Commission should encourage electric utilities to pursue wholesale native load. Such pursuit not only reduces costs to retail customers, it also assists in the provision of adequate and reliable service to the wholesale utilities' ultimate customers – customers that are almost exclusively Indiana customers. The Industrial Group's

[12] In this proceeding, Duke Energy Indiana agreed to switch the retirement dates for Gibson Unit 4 and 5, which could slightly lower the capacity additions starting in 2024.

[13] Any finding that existing plant is not used and useful would need to take into account the cost recovery assurances included in Ind. Code ch. 8-1-8.5. Additionally, while citing the *NIPSCO Bailly* case, the Industrial Group ignores the fact that in that case, the Indiana Supreme Court explicitly distinguished new plants that have never been in service from plants that had been used and useful. *See Citizens Action Coalition, Inc. v. Northern Indiana Public Service Co*., 485 N.E.2d 610, 1985 Ind. LEXIS 1037, at **18-19 (1985). Under Indiana law, cost recovery is allowed for plants that have been used and useful and have provided service to customers for many years.

proposal for disallowance would only deter utilities from pursuing wholesale native load contracts in the first place, to the long-term detriment of the utility's retail customers and to the detriment of customers throughout Indiana.

In sum, the Industrial Group's arguments must be rejected. The Commission may not set rates based on a hypothetical situation as the Industrial Group urges. Further, the evidence shows that in this case, the Company is proposing to allocate a slightly larger portion of its production costs to the wholesale native load than it did in its last case; there is no shift in the allocation of costs to retail customers. And, there is no basis to conclude that the Duke Energy Indiana system has any excess capacity that is not used and useful to retail customers. Instead, the Company's IRP preferred portfolio shows the need for additional capacity for the foreseeable future. Finally, there is also no evidence whatsoever that the Company's previous decisions to add generating plants have been imprudent — a key requirement in any excess capacity determination. For all of these reasons, the Industrial Group's position should be rejected.

XII. Self-Scheduling of Generation.

In its Proposed Order, the OUCC asserts the Commission should reject Sierra Club's recommendation that the Company's self-commitment practices be subject to a Commission directed investigation. The OUCC rightly points out there is no basis in the record for an investigation and the Company's dispatch decisions are reviewed regularly (by the OUCC and Commission) in FAC proceedings. The Company also affirms the OUCC's determination that "committing units on solely short term 'Economic' basis would not be consistent with the objective of minimizing total customer costs". This is correct. The OUCC appropriately highlighted Company Witness John Swez' testimony that the "MISO 24-hour day ahead market is an imperfect fit." Therefore, the Company agrees with the OUCC's determination that the Commission should not only reject an investigation but reject the Sierra Club's proposal to reduce the Company's O&M expense to reflect its view of "economic dispatch losses".

The same holds true for Sierra Club's request for a specific proceeding to "assess the operational decisions" of specific Duke Energy Indiana generating units. As the OUCC asserted, with regard to self-commitment practices, unit operational decisions are continually reviewed by the Commission and the OUCC in the Company's quarterly FAC proceedings. The operational approach to Cayuga Station was previously reviewed in Cause No. 44087, when the Commission approved (and OUCC reviewed) a customer specific contract that contemplated the operation of Cayuga Station to serve the specific needs of a steam contract customer. Any additional proceedings or investigations would be redundant and garner no additional information. Therefore, the Commission should reject Sierra Club's request for the proceeding to "assess the operational decisions" of Duke Energy Indiana generating assets.

XIII. Conclusion.

For the reasons stated herein, Duke Energy Indiana respectfully requests that the Commission reject the exceptions filed by the OUCC and intervenors in their proposed orders and briefs and issue the proposed form of order submitted by Duke Energy Indiana in this proceeding.

Respectfully submitted,

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