STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-242.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM, TO THE EXTENT NECESSARY; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	)	**CAUSE NO. 46120**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PUBLIC'S EXHIBIT NO. 8
TESTIMONY OF OUCC WITNESS ROXIE McCULLAR

Respectfully submitted,

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Table of Contents

I. <u>Introduction</u>

Q: Please state your name and business address.

A: My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois.

Q: What is your present occupation?

A: Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q: Please describe your educational and professional background.

A: I have over 25 years of experience consulting in regulatory rate cases and have addressed depreciation rate issues in numerous jurisdictions nationwide. I am a Certified Public Accountant licensed in the State of Illinois. I am a Certified Depreciation Professional through the Society of Depreciation Professionals. I received my Master of Arts degree in Accounting from the University of Illinois Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University. A summary of my qualifications and previous experience is attached to this testimony as Attachment RM-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").

II. Purpose and Summary

Q: What is the purpose of your testimony?

A: The purpose of my direct testimony is to address the depreciation rates Northern Indiana Public Service Company ("NIPSCO") proposes to use in this proceeding.

Specifically, NIPSCO introduced several new cost additives to the estimated future decommissioning costs that were not included in the studies approved in its previous rate case. NIPSCO introduced these new cost additives without providing virtually any testimonial explanation, discussion, or support for these changes. These proposed new cost additives are not necessary or supported and should be rejected by the Commission.

Q: Please describe the steps you took to prepare your testimony.

A: I took the following steps to prepare my testimony:

- Reviewed the Direct Testimony of John J. Spanos (Petitioner's Exhibit No. 12), the 2023 Depreciation Study, the 2025 Depreciation Study, and supporting workpapers filed in this proceeding.
- Examined NIPSCO's responses to data requests issued in this proceeding as they pertain to depreciation, prepared follow up data requests as appropriate, and reviewed responses to the follow up data requests.
- Considered the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act ("FERC USOA") requirements pertaining to depreciation.[1]

[1] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act, 18 C.F.R. § 101.

- Considered the accepted depreciation practices, including those contained in the Public Utility Depreciation Practices published by the National Association of Regulatory Utility Commissioners ("NARUC").[2]
- Conducted additional analyses, which are detailed in this testimony.

Q: Please summarize your recommendations.

A: The OUCC's recommended depreciation rates in Attachment RM-2 and shown in Table 1 below should be approved for NIPSCO.

Table 1: Comparison of Annual Depreciation Rates

		NIPSCO Proposed		OUCC Recommended		
Functional Category	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
A	B	C	D	E	F	G=F-D
Steam Production Plant	1,089,000,778	11.18%	121,699,275	10.48%	114,129,776	(7,569,499)
Hydraulic Production Plant	100,837,261	6.82%	6,879,602	6.70%	6,758,901	(120,701)
Solar Production Plant	1,906,215,291	4.28%	81,530,755	4.27%	81,398,107	(132,648)
Other Production Plant	297,996,293	8.94%	26,643,633	8.66%	25,802,668	(840,965)
Transmission Plant	2,342,622,107	2.03%	47,597,923	1.99%	46,653,991	(943,932)
Distribution Plant	3,887,397,528	2.41%	93,782,515	2.34%	91,039,608	(2,742,907)
General Plant	233,657,667	4.85%	11,338,172	4.85%	11,338,172	0
General Plant Reserve Amortization			(1,223,030)		(1,223,030)	0
Total Depreciable Plant	**9,857,726,925**	**3.94%**	**388,248,845**	**3.81%**	**375,898,193**	**(12,350,652)**
Common Plant	157,444,386	2.77%	4,363,908	2.77%	4,363,908	0
Common Plant Reserve Amortization			(3,339,636)		(3,339,636)	0
Total Common Plant	**157,444,386**	**0.65%**	**1,024,272**	**0.65%**	**1,024,272**	**0**

[2] NARUC, *Public Utility Depreciation Practices* (1996).

III. Definition of Depreciation

Q: Please provide the definition of depreciation you used.

A: Because this proceeding is for a regulated utility, I rely on the definition of depreciation in the FERC USOA which states:

> 12. Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

The FERC USOA definition of depreciation specifically states that depreciation is a "loss in service value." FERC USOA defines service value as "the difference between original cost and net salvage value of electric plant."[4] Determining reasonable depreciation rates is necessary to establish the loss in service value of utility cost-based plant-in-service and incorporate this into the ratemaking revenue requirement to allow for recovery of that cost.

Q: Please provide a brief discussion about the remaining life techniques for calculating depreciation rates.

A: In the calculation of depreciation rates, the remaining life technique formula is:

$$\text{Depreciation Rate} = \frac{(100\% \ - \ \text{Book Reserve}\ \% \ - \ \text{Future Net Salvage}\ \%)}{\text{Average Remaining Life}}$$

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[3] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act, 18 C.F.R. § 101, Definition 12.
[4] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act, 18 C.F.R. § 101, Definition 37.

In the formula above, the 100% represents the actual plant-in-service investment, and the book reserve percent is the actual accumulated depreciation reserve on the utility's books divided by the actual plant-in-service investment on the utility's books at the time of the depreciation study.

The depreciation study estimates the future net salvage percent and the average remaining life. These estimates are referred to as depreciation parameters. The estimated future net salvage parameter from the depreciation study estimates the future cost of removing or retiring the utility asset less any estimated future salvage. The projected average service life and retirement pattern (survivor curve) are the two parameters from the depreciation study used to calculate the average remaining life of the asset.

Q: What are some considerations when estimating the depreciation parameters used in the depreciation rate formula?

A: When estimating a depreciation parameter for an account, an initial step is to analyze the utility's actual historic life and net salvage experience data for that account. The expectations of management, any changes to current industry practices, and informed judgment are also part of the estimation process.

With respect to informed judgment, NARUC's *Public Utility Depreciation Practices* explains:

> Informed judgment is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.

> The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance.[5]

IV. Solar Projects' Life

Q: Are NIPSCO's proposed Solar Projects' depreciation rates based on a 30-year life?

A: Not entirely. NIPSCO does not consistently use a 30-year life for the Cavalry, Dunns Bridge II, Fairbanks, and Gibson solar projects ("Solar Projects") in its depreciation rate calculations. The NIPSCO 2025 Depreciation Study Table 1 indicated a 25-year life for the Solar Projects.[6] While other pages of the NIPSCO 2025 Depreciation Study indicated a 30-year life for the Solar Projects,[7] in response to discovery, NIPSCO stated:

> The previous life span for solar facilities was 25 years; however, in this study it was determined that a 30-year life span for this generation of solar farms was most appropriate. Therefore, the probable retirement date for Cavalry is 2054, Dunns Bridge II is 2055, Fairbanks is 2055 and Gibson is 2055 when these facilities are placed in service.[8]

NIPSCO's proposed depreciation rates use a 30-year life for most parts of the depreciation rate calculation, except in the calculated inflation of the estimated future decommissioning costs.[9]

Q: Is it correct that the current approved life span for the Cavalry, Dunns Bridge II, Fairbanks, and Gibson Solar Projects is 25 years?

A: No. Previous Commission Orders approved initial depreciation rates of 3.33% for all four Solar Projects based on an anticipated 30-year life, not the 25-year life referenced in

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[5] NARUC, *Public Utility Depreciation Practices*, 128 (1996), included in Attachment RM-14.
[6] Petitioner's Exhibit No. 12, Direct Testimony of John Spanos, Attachment 12-C, pp. 8, 9, and 27 of 162.
[7] Spanos Direct, Attachment 12-C, pp. 66, 72, and 76 of 162.
[8] NIPSCO Response to OUCC Request 19-001, attached as Attachment RM-3.
[9] NIPSCO Response to OUCC Request 19-001, attached as Attachment RM-3.

NIPSCO's DR response.[10] NIPSCO does not explain where the 25-year life originated or was approved.

Q: Do the OUCC's recommended depreciation rates use the 30-year life for all parts of the calculation?

A: Yes. The OUCC's recommended Solar Projects' depreciation rates shown in Attachment RM-2 consistently use the currently approved 30-year life for all parts of the calculation.

V. Estimated Future Decommissioning Costs

Q: Did you review the estimated future decommissioning costs for production plants included in NIPSCO's proposed depreciation rates?

A: Yes. The estimated future decommissioning costs for production plants included in NIPSCO's proposed depreciation rates are supported by the Decommissioning Cost Study provided as Attachment 12-D.[11]

Q: What are the estimated future decommissioning costs?

A: Estimated future decommissioning costs are estimated future costs associated with the closure of a production plant that has ceased operations. These costs are also referred to as terminal net salvage or dismantlement costs.

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[10] *Verified Joint Petition of N. Ind. Pub. Serv. Co. LLC ("NIPSCO"), Dunn's Bridge II Solar Generation LLC, and Cavalry Solar Generation LLC*, Cause No. 45936, Order at 28, Ordering Paragraph 6, January 17, 2024; *Verified Joint Petition of N. Ind. Pub. Serv. Co. LLC ("NIPSCO") and Fairbanks Solar Generation LLC*, Cause No. 46028, Order at 20, Ordering Paragraph 6, August 14, 2024; *Verified Joint Petition of N. Ind. Pub. Serv. Co. LLC ("NIPSCO") and Gibson Solar Generation LLC*, Cause No. 46032, Order at 17, Ordering Paragraph 4, August 21, 2024.

[11] Spanos Direct, Attachment 12-D.

Q: Are you proposing adjustments to NIPSCO's estimated future decommissioning costs used in calculating the depreciation rates?

A: Yes. I propose using the estimated future decommissioning costs of Bailly supported by the decommissioning study filed with the Commission in Cause No. 45772 rather than using the decommissioning study prepared at the same time but not filed in Cause No. 45772. Additionally, I recommend the Commission reject these new, unsupported cost additives included in the decommissioning cost study filed in Cause No. 46120 that differ from how NIPSCO previously conducted its decommissioning studies. Finally, I recommend the continued use of the current approved project indirect cost percentage and contingency factor.

A. Bailly Estimated Decommissioning Costs

Q: Are the estimated decommissioning costs included in NIPSCO's depreciation study supported by a decommissioning cost study filed with the Commission?

A: No. Table 4 of the NIPSCO 2023 depreciation study shows $65,828,000 uninflated estimated decommissioning costs for Bailly.[12] Since the Bailly decommissioning costs are not included in the decommissioning cost study filed in this proceeding, the OUCC issued a discovery request asking NIPSCO for the support for this $65,828,000 uninflated estimated decommissioning cost for Bailly. NIPSCO's discovery response stated the $65,828,000 uninflated estimated decommissioning cost for Bailly was from "a

[12] Spanos Direct, Attachment 12-B, p. 289.

decommissioning study prepared in anticipation of Cause No. 45772 … which was not filed with the Commission."[13]

Q: Did NIPSCO file estimated decommissioning costs for Bailly with the Commission in Cause No. 45772?

A: Yes. The estimated decommissioning cost for Bailly actually filed with the Commission in Cause No. 45772 was $60,521,000,[14] not the $65,828,000 included in the depreciation rate calculation in this proceeding. NIPSCO did not explain why it is relying on a study prepared in anticipation of Cause No. 45772 that was not filed, with a higher decommissioning cost, rather than the study that NIPSCO filed in Cause No. 45772 with the lower decommissioning cost or why the unfiled study is now more appropriate than the filed one.

Q: What estimated decommissioning costs for Bailly are included in the OUCC's recommended depreciation rates?

A: The OUCC's recommended depreciation rates include the $60,521,000 estimated decommissioning costs for Bailly that are supported by the decommissioning study actually filed with the Commission.

Q: What is your recommendation on the estimated Bailly decommissioning costs?

A: I recommend the Commission rely on the decommissioning study NIPSCO filed in Cause No. 45772, with an estimated decommissioning cost of $60,521,000. According to NIPSCO, the Bailly estimated future decommissioning costs included in the depreciation

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[13] NIPSCO Corrected and Supplemental Response to OUCC Request 14-015, attached as Attachment RM-4.
[14] Cause No. 45772, Attachment 14-B, p. 28, attached as Attachment RM-5.

rate calculation in Cause No. 46120 was prepared for Cause No. 45772, however the actually estimated decommissioning cost filed in Cause No. 45772 is a different amount. NIPSCO does not provide any explanation as to why the costs NIPSCO did not present in Cause No. 45772 should now be used instead of the costs actually filed and relied upon in Cause No. 45772. Without such justification or support for using this unfiled amount, the Commission should rely on the previously filed costs from Cause No. 45772.

B. Project Indirect Cost Additive

Q: Is NIPSCO proposing to continue using the 5% indirect cost additive used in the prior decommissioning costs study filed in Cause No. 45772?

A: No, NIPSCO is proposing a 6.5% additive for "Indirect Costs" for its hydroelectric facilities.[15] This is higher than the 5% additive for "Project Indirects" used in the estimated decommissioning costs for other generation facilities and higher than the 5% "Project Indirects" used for the hydroelectric facilities in Cause No. 45772.[16] In response to discovery, NIPSCO stated: "The 5% 'Project Indirect' cost was the level used in prior decommissioning studies. Based on Gannett Fleming's experience, this continues to be reasonable and is consistent with prior studies."[17] However, for hydraulic production plants the estimated future decommissioning costs in this proceeding do not continue the use of the 5% indirect cost additive. When asked to support the increase in the indirect cost additive for hydraulic production plants, NIPSCO responded:

> As was the case for other generation assets, the indirect cost was based on levels used for prior decommissioning studies. In this case specifically, the 5% indirect cost level was increased to account for inclusion of project

[15] Spanos Direct, Attachment 12-D, pp. 18-19.
[16] Cause No. 45772, Petitioner's Exhibit No. 14, Direct Testimony of Jeffrey Kopp, Attachment 14-B, pp. 37-38.
[17] NIPSCO Response to OUCC Request 14-036, attached as Attachment RM-6.

> management costs that are unique to hydro facilities given the need to ensure continued operation of the damn [sic] and spillways.[18]

Q: Is the need to continue operation of the dam and spillways a requirement that did not exist when the 5% indirect cost additive was reasonable in the prior decommissioning study?

A: No. The continued operation of the dam and spillways is not a new requirement, and NIPSCO does not provide information that supports increasing the indirect cost additive from 5% to 6.5%.

Q: What is your recommendation regarding the project indirect cost additive for the hydroelectric facilities?

A: I recommend the continued use of the project indirect 5% cost additive in the determination of these decommissioning costs. The continued use of the dam and spillway was contemplated in the previous decommissioning study using a 5% indirect cost additive.[19] NIPSCO does not explain why it is increasing the indirect cost additive while using the same requirements for these facilities that it used in previous decommissioning studies. Without substantive support for the increased indirect cost additive, the Commission should reject the increase to 6.5% for project indirect costs for the hydroelectric facilities. The OUCC's recommended depreciation rates in Attachment RM-2 use the 5% project indirect cost additive for all production plants similar to the prior accepted decommissioning studies.

[18] NIPSCO Response to OUCC Request 14-038, attached as Attachment RM-7.
[19] Cause No. 45772, Kopp Direct, Attachment 14-B, pp. 17-18.

C. New Cost Additives in the Estimated Future Decommissioning Costs

Q: Are all the cost additives included in the estimated future decommissioning costs filed in this proceeding from previous decommissioning cost studies?

A: No. NIPSCO is proposing new cost additives in this proceeding that were not included in the previous decommissioning cost studies. These new cost additives are 15% for "Overhead" and 10% for "Profit on Subcontractors."[20] NIPSCO also included 15% for "Overhead and Profit" on two hydroelectric projects.[21] In response to discovery, NIPSCO provided the following different explanations for these new cost additives: "Overhead costs, both fixed and variable, will vary given project size. Typically, larger projects will have higher overhead rates, primarily driven by higher variable costs."[22] NIPSCO further stated: "The 15% Overhead and Profit level represents the expectation of what would be required by the General Contractor given the expected decommissioning scope and any unknown site conditions."[23]

Also, expanding on the profit cost additive:

> A rate of 10% Profit markup on Subcontractor work is reasonable when estimating a project given the scope and scale of a project. Lower rates, such as 5% would typically only be appropriate when the Contractor specifically knows the Subcontractor that is being utilized and the amount of work to be performed has a significantly high dollar value and the general contractor is trying to reduce their bid. For instance, this could occur because the general contractor is using a known subcontractor that did not provide the lowest available bid.[24]

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[20] Spanos Direct, Attachment 12-D, pp. 13-17, 20-21.
[21] Spanos Direct, Attachment 12-D, pp. 18-19.
[22] NIPSCO Response to OUCC Request 14-034, attached as Attachment RM-8.
[23] NIPSCO Response to OUCC Request 14-040, attached as Attachment RM-9.
[24] NIPSCO Response to OUCC Request 14-035, attached as Attachment RM-10.

Q: Do these descriptions of the overhead and profit cost additives support the inclusion of these new cost additives?

A: No. NIPSCO has not explained why these new cost additives should be included in the estimated future decommissioning costs. These new cost additives simply increase the estimated future decommissioning costs without identifying any actual costs that are not already included in the estimates. The response quoted above indicates these cost additive percentages could be lower if the "general contractor is trying to reduce their bid." It is unreasonable to increase the costs charged to ratepayers for some possible future profits and unidentified variable possible overheads that can be lower if the bidding process is competitive enough that the general contractor is motivated to reduce its bid.

Q: What is your recommendation regarding the new cost additives included in the decommissioning cost estimates?

A: The OUCC recommends the Commission reject these new unsupported cost additives. NIPSCO provides no substantive support for the new inclusion of these additives. As with the other issues raised, without support, NIPSCO's use of these new additives should be rejected. The OUCC's recommended depreciation rates shown in Attachment RM-2 exclude these unsubstantiated new cost additives.

D. Contingency Cost Additive

Q: Is NIPSCO proposing to continue using the 20% contingency cost additive used in the prior decommissioning cost study filed in Cause No. 45772?

A: Not for all plants. NIPSCO uses a 20% contingency cost additive for the decommissioning costs estimated for its fossil fuel and solar generation facilities but is proposing to increase the contingency cost additive to 30% for its hydroelectric facilities. In response to discovery, NIPSCO stated:

> The 20% 'contingency' cost was the level used in the decommissioning study proposed and approved in Cause No. 45772. Based on the scope of the decommissioning cost estimates as well as Gannett Fleming's experience, a contingency of at least 20% would be reasonable. The contingency captures unknown factors that will impact a project's costs, such as weather delays or incremental costs (such as environmental costs) that were not captured in the decommissioning estimates due to the level of precision in the development of these estimates.[25]

However, for hydraulic production plants the estimated future decommissioning costs in this proceeding increased the contingency cost additive to 30%.[26] When asked to support this increase in the contingency cost additive for hydraulic production plants, NIPSCO responded:

> As was the case for other generation assets, the initial contingency cost was based on levels used for prior decommissioning studies. In this case specifically, the contingency cost level was elevated to account for unknown conditions at the site and for unforeseen eventualities. As site conditions are directly observed during the decommissioning process, expected contingency costs will be better understood.[27]

Q: Do the referenced "unknown conditions" support increasing the contingency cost additives for "unknowns"?

A: No. The contingency cost additive is already included to capture "unknown costs" and already requires current ratepayers to pay additional amounts, putting the risk of future "unknowns" on the current ratepayers. However, NIPSCO provides no discussion or justification in its case-in-chief as to why hydroelectric facilities require an increase in contingency from 20% to 30% other than the vague assertion of "unknown conditions" and

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[25] NIPSCO Response to OUCC Request 14-037, attached as Attachment RM-11.
[26] Spanos Direct, Attachment 12-D, pp. 18-19.
[27] NIPSCO Response to OUCC Request 14-039, attached as Attachment RM-12.

"unforeseen eventualities." NIPSCO used, with Commission approval, a 20% contingency for these facilities in Cause No. 45772 and has neither explained nor demonstrated this additive should now be increased.[28] It is unreasonable to increase the amount of additional cost for future "unknowns" based on the type of production plant without sufficient support, which is not provided here. The increase in this cost additive for future "unknowns" is unreasonable. The addition of the contingency cost additive in the estimated future decommissioning costs inappropriately puts all the risk of the estimated future unknown unidentified costs on current ratepayers.

Q: What is your recommendation regarding NIPSCO's proposed increase in the contingency cost additive in the decommissioning estimate for hydroelectric facilities?

A: I recommend the Commission reject the increase in the contingency cost additive for future "unknowns" from 20% to 30% for the hydroelectric facilities. NIPSCO used a 20% contingency cost additive in its previous decommissioning cost estimate and provides no substantive support for why it should be increased in this proceeding. The OUCC's proposed depreciation rates in Attachment RM-2 use the current 20% contingency cost additive for future "unknown" costs for all production plants, similar to the prior approved decommissioning study.

[28] Cause No. 45772, Kopp Direct, Attachment 14-B, pp. 37-38.

VI. Estimated Future Net Salvage Percent for Mass Property Accounts

Q: Based upon your review of NIPSCO's proposed estimated future net salvage percent for mass property accounts, do you recommend a different estimated future net salvage percent for any of the mass property accounts?

A: Yes. For the accounts listed in Table 2 below, I recommend that NIPSCO's proposed increase in the estimated future net salvage percent be rejected and to continue the use of the current approved estimated future net salvage percent. As discussed in this section of my testimony, the continued use of the current approved estimated future net salvage percentages for these accounts are reasonable.

Table 2: Comparison of Proposed Estimated Future Net Salvage Percent Recommendations

Account	Current Approved	NIPSCO Proposed	OUCC Recommended
352, Structures and Improvements	-15%	-20%	-15%
354, Towers and Fixtures	-26%	-30%	-26%
355, Poles and Fixtures	-35%	-40%	-35%
356, Overhead Conductors and Devices	-40%	-45%	-40%
362, Station Equipment	-10%	-15%	-10%
365, Overhead Conductors and Devices	-60%	-70%	-60%
367, Underground Conductors and Devices	-30%	-35%	-30%
370, Customer Metering Stations and Meters	-2%	-5%	-2%

Q: Please explain what is meant by mass property accounts.

A: Transmission, distribution, and general plant accounts are considered mass property accounts since those accounts include similar assets whose retirement are not expected to occur on the same date. In contrast, production plant accounts are considered life span accounts since all of the assets at one location are expected to retire at the same time.

Q: Please explain the meaning of net salvage.

A: NARUC's *Public Utility Depreciation Practices* defines net salvage as "the gross salvage for the property retired less its cost of removal."[29] Gross salvage is defined as "the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property."[30] Cost of removal is defined as "the costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place."[31]

NARUC also explains that careful consideration should be given to the net salvage estimate stating:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate.[32]

NARUC's Public Utility Depreciation Practices later points out:

> Determining a reasonably accurate estimate of the average or future net salvage is not an easy task; estimates can be the subject of considerable discussion and controversy between regulators and utility personnel.[33]

Q: What effect does the estimated future net salvage percent have on depreciation rates?

A: All other things being equal, positive net salvage results in a lower depreciation rate since a positive net salvage percent assumes NIPSCO will receive value for the asset when it retires which reduces the total amount to be recovered over the life of the asset. Conversely, negative net salvage results in a higher depreciation rate since a negative net salvage

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[29] NARUC, *Public Utility Depreciation Practices*, 322, included in Attachment RM-14.
[30] *Id.* at 320, included in Attachment RM-14.
[31] *Id.* at 317, included in Attachment RM-14.
[32] *Id.* at 19, included in Attachment RM-14.
[33] *Id.* at 157, included in Attachment RM-14.

percent assumes NIPSCO will have expenses exceeding any possible salvage at the time of retirement, all other things being equal.

As stated in NARUC's Public Utility Depreciation Practices:

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage.[34]

The estimated future net salvage is part of the annual depreciation accrual, which is credited to the depreciation reserve to cover the estimated future net salvage costs NIPSCO may incur in the future associated with plant asset retirements.

Q: Please explain what information is included in your proposed estimated future net salvage percent analysis.

A: As discussed above, estimating the depreciation parameters includes informed judgment. My analysis included reviewing the historic net salvage data that NIPSCO provided, other relevant information provided in response to discovery, and applying my previous experience.

Q: Did the depreciation study analyze historic net salvage data?

A: Yes. NIPSCO's 2023 depreciation study included the historic net salvage data. Additionally, the 2023 depreciation study calculated historic net salvage ratios. As stated in the 2023 depreciation study:

> The estimates of net salvage by account were based in part on historical data compiled by account through 2023. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average

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[34] *Id.* at 18, included in Attachment RM-14.

> also was calculated for consideration. The net salvage estimates are expressed as a percent of the original cost of plant retired.[35]

Q: Are you aware of concerns regarding the historic net salvage ratios calculated in the depreciation study?

A: Yes. As pointed out in Wolf and Fitch's *Depreciation Systems*: "Salvage ratios are a function of inflation."[36] Additionally, Wolf and Fitch's *Depreciation Systems* points out that a historic net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator is a ratio using different units, stating:

> One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels.[37]

Calculating the historic net salvage ratio includes the impact of historic inflation rates, since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. In other words, due to inflation, the amounts in the numerator and denominator of the net salvage ratio are at different price levels.

Q: Is the fact that historic inflation is included in the net salvage ratio recognized in another authoritative depreciation text?

A: Yes. NARUC's *Public Utility Depreciation Practices*, regarding inflation states:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a

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[35] Spanos Direct, Attachment 12-B, p. 41.
[36] Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems*, p. 267, Iowa State University Press, (1994) , included in Attachment RM-15.
[37] *Id*. at 53, included in Attachment RM-15.

> tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[38]

Q: Why should inflation in the historic net salvage ratios be considered when estimating the future net salvage amounts to be collected from today's ratepayers?

A: The estimated future net salvage accruals included in the revenue requirement in this proceeding are to be collected from ratepayers in today's more valuable current dollars. Therefore, I not only reviewed the historic net salvage data as presented in the depreciation study and the underlying data provided in response to discovery. I also considered the impact of collecting the more valuable current dollars from ratepayers to pay for estimated future costs.

Q: Please explain what you mean by more valuable current dollars.

A: Due to inflation, today's dollar has more purchasing power than a future dollar.

Q: Have you reviewed the actual net salvage data included in the 2023 depreciation study?

A: Yes. NIPSCO provided the database containing the historical data used in the depreciation study. Estimating the depreciation parameters includes informed judgment. Relevant information, in addition to the historic data, that has been presented in the depreciation study and workpapers can properly be considered. The interests of NIPSCO and the interests of its ratepayers should be considered.

[38] NARUC, *Public Utility Depreciation Practices*, 19, included in Attachment RM-14.

Q: Does your recommended estimated future net salvage percentage result in an under-recovery of the estimated future costs?

A: No. Just because my recommended estimated future net salvage percentages are lower than those NIPSCO proposed, does not indicate my recommended depreciation rates will result in an under-recovery of the estimated future costs.

As a reasonableness check on the estimated future net salvage accrual amount to be included in NIPSCO's revenue requirement, which is collected from ratepayers in today's dollars, I compared the estimated future net salvage costs included in NIPSCO's proposed depreciation accrual to the actual net salvage costs NIPSCO incurred on average over the recent five-year period of 2019 through 2023. This comparison is shown in Table 3.

As shown in Table 3, my recommendation results in an annual accrual that is many times the average annual amount NIPSCO has actually incurred for net salvage; therefore, my recommendation provides recovery of the estimated cost of removal expected to be incurred in the near future and builds the reserve for estimated future cost of removal associated with future retirements.

Table 3: Comparison of NIPSCO and OUCC Proposed Net Cost of Removal Accrual and Average Net Cost of Removal Actually Incurred

Account	Five-Year Average Annual Net Salvage Actually Incurred	Net Salvage Recovery Included in NIPSCO's Proposed Depr Rates	NIPSCO Proposed / Actually Incurred	Net Salvage Recovery Included in OUCC's Recommended Depr Rates	OUCC Recommended / Actually Incurred
	A	B	C=B/A	D	E=D/A
352, Structures and Improvements	31,569	235,323	7.5	173,252	5.5
354, Towers and Fixtures	114,021	587,972	5.2	498,082	4.4
355, Poles and Fixtures	853,535	2,043,330	2.4	1,772,732	2.1
356, Overhead Conductors and Devices	459,297	1,419,167	3.1	1,236,291	2.7
362, Station Equipment	504,401	1,446,646	2.9	952,535	1.9
365, Overhead Conductors and Devices	1,148,030	3,528,575	3.1	2,931,361	2.6
367, Underground Conductors and Devices	671,244	3,684,207	5.5	3,114,004	4.6
370, Customer Metering Stations and Meters	28,220	125,707	4.5	49,424	1.8

Table 3 is shown in Attachment RM-13.

In my judgment, my recommended estimated future net salvage accrual is a good balance between the depreciation expense charged to current customers and building the book reserve to cover any future net salvage costs associated with the retirement of an asset.

Q: Please explain what you mean by building a reserve for any estimated future net salvage costs.

A: Using Account 365, Overhead Conductors and Devices as an example for discussion, as shown in Table 3 above, NIPSCO actually incurred $1,148,030 net salvage costs on average in the recent five-year period included in the 2023 Depreciation Study.[39] The OUCC recommends collection of a $2,931,361 net salvage annual accrual from current

[39] Spanos Direct, Attachment 12-B, p. 366 of 538.

ratepayers, which is 2.6 times the average cost actually incurred. The 2.6 times indicates the amount recovered from ratepayers will not only cover the expected net salvage costs in the near future, but also build the reserve to cover future net salvages costs associated with future retirements.

Q: Are your recommended estimated future net salvage percentages based only upon the comparison shown in Table 3 and Attachment RM-13?

A: No, as evidenced by the fact that my estimated future net salvage accrual amounts are not equal to the average annual historical amount shown in Attachment RM-13.[40]

As discussed above, estimating the depreciation parameters includes informed judgment. My analysis included reviewing the historic net salvage data provided in the depreciation study and the relevant information NIPSCO provided in response to discovery.

Attachment RM-13 is a reasonableness check on the estimated future net salvage accrual amount to be included in the revenue requirement.

Q: What is your recommendation regarding the estimated future net salvage percentage for some mass property accounts?

A: For the mass property accounts listed in Table 2 above, I recommend the estimated future net salvage percent remain at the level approved in NIPSCO's previous rate case. The net salvage percents I recommend adequately allow NIPSCO to recover the amounts that

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[40] If my proposed estimated future net salvage accrual amounts were equal to the average historical amounts shown in Table 3, the ratio in column E would be 1.0.

NIPSCO has actually incurred on average for net salvage. The Commission should not adopt NIPSCO's recommended increase to the estimated future net salvage percent.

VII. <u>Conclusion</u>

Q: Please summarize your recommendations.

A: For the issues addressed in my testimony, NIPSCO consistently failed to provide sufficient support for its recommended changes or demonstrate the propriety of these changes. For the reasons stated above, I recommend the Commission reject NIPSCO's proposals and approve the OUCC's recommended depreciation rates shown on Attachment RM-2.

Q: Does this conclude your direct testimony?

A: Yes.

Roxie McCullar, CPA, CDP
8625 Farmington Cemetery Road
Pleasant Plains, IL

Roxie McCullar is a regulatory consultant, licensed Certified Public Accountant in the state of Illinois, and a Certified Depreciation Professional through the Society of Depreciation Professionals. She is a member of the American Institute of Certified Public Accountants, the Illinois CPA Society, and the Society of Depreciation Professionals. Ms. McCullar has received her Master of Arts degree in Accounting from the University of Illinois-Springfield as well as her Bachelor of Science degree in Mathematics from Illinois State University. Ms. McCullar has 25 years of experience as a regulatory consultant for William Dunkel and Associates. In that time, she has filed testimony in over 50 state regulatory proceedings on depreciation issues and cost allocation for universal service and has assisted Mr. Dunkel in numerous other proceedings.

Education

Master of Arts in Accounting from the University of Illinois-Springfield, Springfield, Illinois

12 hours of Business and Management classes at Benedictine University-Springfield College in Illinois, Springfield, Illinois

27 hours of Graduate Studies in Mathematics at Illinois State University, Normal, Illinois

Completed Depreciation Fundamentals training course offered by the Society of Depreciation Professionals

Relevant Coursework:

- Calculus	- Discrete Mathematics
- Number Theory	- Mathematical Statistics
- Linear Programming	- Differential Equations
- Finite Sampling	- Statistics for Business and Economics
- Introduction to Micro Economics	- Introduction to Macro Economics
- Principles of MIS	- Introduction to Financial Accounting
- Introduction to Managerial Accounting	- Intermediate Managerial Accounting
- Intermediate Financial Accounting I	- Intermediate Financial Accounting II
- Advanced Financial Accounting	- Auditing Concepts/Responsibilities
- Accounting Information Systems	- Federal Income Tax
- Fraud Forensic Accounting	- Accounting for Government & Non-Profit
- Commercial Law	- Advanced Utilities Regulation
- Advanced Auditing	- Advanced Corp & Partnership Taxation

Current Position: Consultant at William Dunkel and Associates

Participation in the proceedings below included some or all of the following:

> Developing analyses, preparing data requests, analyzing issues, writing draft testimony, preparing data responses, preparing draft questions for cross examination, drafting briefs, and developing various quantitative models.

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2024	Kansas	Kansas Corporation Commission	24-GIMT-459-GIT	Generic Telephone	RLEC Depreciation Rates	Kansas Corporation Commission Staff
2024	North Carolina	North Carolina Utilities Commission	E-22, Sub 694	Dominion Energy North Carolina	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2024	North Carolina	North Carolina Utilities Commission	G-9, Sub 837	Piedmont Natural Gas, LLC	Natural Gas Depreciation Issues	Public Staff - North Carolina Utilities Commission
2024	Kansas	Kansas Corporation Commission	24-KGSG-610-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2024	Arizona	Arizona Corporation Commission	T-03214A-23-0250	Citizens Telecommunications of the White Mountains, Inc.	Arizona Universal Service Fund	The Utilities Division Staff Arizona Corporation Commission
2024	Delaware	Delaware Public Service Commission	23-0601	Artesian Water Company	Water Depreciation Issues	Delaware Public Service Commission
2024	Kansas	Kansas Corporation Commission	24-TTHT-343-KSF	Totah Communications, Inc.	Non-Regulated Allocations, State Allocations, Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2023	Kansas	Kansas Corporation Commission	24-SCNT-131-KSF	South Central Telephone Association	Non-Regulated Allocations, State Allocations, Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2023	Kansas	Kansas Corporation Commission	23-EKCE-775-RTS	Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc.	Electric Depreciation Issues	Kansas Corporation Commission Staff
2023	North Carolina	North Carolina Utilities Commission	E-7, SUB 1276	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2023	North Carolina	North Carolina Utilities Commission	E-2, SUB 1300	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2023	Kansas	Kansas Corporation Commission	23-ATMG-359-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2022	Alaska	Regulatory Commission of Alaska (RCA)	U-22-034	Chugach Electric Association, Inc.	Electric Depreciation Issues	Attorney General's Regulatory Affairs and Public Advocacy Section (RAPA)
2022	Kansas	Kansas Corporation Commission	22-COST-546-KSF	Columbus Communications Services, LLC	Non-Regulated Allocations, State Allocations, Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2022	Washington	Washington Utilities & Transportation Commission	UE-220066 & UG-220067	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Regulatory Staff - Washington Utilities & Transportation Commission Public
2022	North Carolina	North Carolina Utilities Commission	G-39, SUBS 46 and 47	Cardinal Pipeline Company, LLC	Natural Gas Depreciation Issues	Public Staff - North Carolina Utilities Commission
2022	Alaska	Regulatory Commission of Alaska (RCA)	U-21-070/U-21-071	Golden Heart Utilities and College Utilities Corporation	Water and Wastewater Depreciation Issues	Attorney General's Regulatory Affairs and Public Advocacy Section (RAPA)
2021	Kansas	Kansas Corporation Commission	22-CRKT-087-KSF	Craw-Kan Telephone Cooperative, Inc.	Non-Regulated Allocations, State Allocations, Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2021	North Carolina	North Carolina Utilities Commission	G-5, SUB 632	Public Service Company of North Carolina	Natural Gas Depreciation Issues	Public Staff - North Carolina Utilities Commission
2021	Kansas	Kansas Corporation Commission	21-BHCG-418-RTS	Black Hills Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2021	Florida	Florida Public Service Commission	20210015-EI	Florida Power & Light Company	Electric Depreciation Issues	Office of Public Counsel
2020	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Natural Gas Depreciation Issues	District of Columbia Public Service Commission

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2020	DC	District of Columbia Public Service Commission	FC1156	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2020	North Carolina	North Carolina Utilities Commission	E-2, SUB 1219	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2020	Kansas	Kansas Corporation Commission	20-BLVT-218-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2020	Utah	Public Service Commission of Utah	18-035-36	Rocket Mountain Power	Electric Depreciation Issues	Division of Public Utilities
2020	North Carolina	North Carolina Utilities Commission	E-7, SUB 1214	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Kansas	Kansas Corporation Commission	20-UTAT-032-KSF	United Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-ATMG-525-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-GNBT-505-KSF	Golden Belt Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	E-01933A-19-0028	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2019	North Carolina	North Carolina Utilities Commission	E-22, SUB 562	Dominion Energy North Carolina	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Utah	Public Service Commission of Utah	19-057-03	Dominion Energy Utah	Natural Gas Depreciation Issues	Division of Public Utilities
2019	Kansas	Kansas Corporation Commission	19-EPDE-223-RTS	Empire District Electric Company	Electric Depreciation Issues	Kansas Corporation Commission Staff

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2019	Arizona	Arizona Corporation Commission	T-03214A-17-0305	Citizens Telecommunications Company	Arizona Universal Service Fund	The Utilities Division Staff Arizona Corporation Commission
2018	Kansas	Kansas Corporation Commission	18-KGSG-560-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2018	Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4800	SUEZ Water	Water Depreciation Issues	Division of Public Utilities and Carriers
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4770	Narragansett Electric Company	Electric & Natural Gas Depreciation Issues	Division of Public Utilities and Carriers
2018	North Carolina	North Carolina Utilities Commission	E-7, SUB 1146	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	DC	District of Columbia Public Service Commission	FC1150	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2017	Kansas	Kansas Corporation Commission	17-RNBT-555-KSF	Rainbow Telecommunications Association, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2017	North Carolina	North Carolina Utilities Commission	E-2, SUB 1142	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	Washington	Washington Utilities & Transportation Commission	UE-170033 & UG-170034	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Washington State Office of the Attorney General, Public Counsel Unit
2017	Florida	Florida Public Service Commission	160186-EI & 160170-EI	Gulf Power Company	Electric Depreciation Issues	The Citizens of the State of Florida
2016	Kansas	Kansas Corporation Commission	16-KGSG-491-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2016	DC	District of Columbia Public Service Commission	FC1139	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2016	Arizona	Arizona Corporation Commission	E-01933A-15-0239 & E-01933A-15-0322	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2016	Georgia	Georgia Public Service Commission	40161	Georgia Power Company	Addressed Depreciation Issues	Georgia Public Service Commission Public Interest Advocacy Staff
2016	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2015	Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-TWVT-213-AUD	Twin Valley Telephone, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-MRGT-097-AUD	Moundridge Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-S&TT-525-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-WTCT-142-KSF	Wamego Telecommunications Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-PLTT-678-KSF	Peoples Telecommunications, LLC	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	New Jersey	State of New Jersey Board of Public Utilities	BPU ER12121071	Atlantic City Electric Company	Electric Depreciation Issues	New Jersey Rate Counsel

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2013	Kansas	Kansas Corporation Commission	13-JBNT-437-KSF	J.B.N. Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-ZENT-065-AUD	Zenda Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2013	DC	District of Columbia Public Service Commission	FC1103	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2012	Kansas	Kansas Corporation Commission	12-LHPT-875-AUD	LaHarpe Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-GRHT-633-KSF	Gorham Telephone Company	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-S&TT-234-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2011	DC	District of Columbia Public Service Commission	FC1093	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2011	Kansas	Kansas Corporation Commission	11-CNHT-659-KSF	Cunningham Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2011	Kansas	Kansas Corporation Commission	11-PNRT-315-KSF	Pioneer Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2010	Kansas	Kansas Corporation Commission	10-HVDT-288-KSF	Haviland Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	Kansas	Kansas Corporation Commission	09-BLVT-913-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2009	DC	District of Columbia Public Service Commission	FC1076	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2008	Kansas	Kansas Corporation Commission	09-MTLT-091-KSF	Mutual Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	08-MRGT-221-KSF	Moundridge Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-PLTT-1289-AUD	Peoples Telecommunications, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-MDTT-195-AUD	Madison Telephone, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	06-RNBT-1322-AUD	Rainbow Telecommunications Assn., Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-WCTC-1020-AUD	Wamego Telecommunications Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-H&BT-1007-AUD	H&B Communications, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-ELKT-365-AUD	Elkhart Telephone Company, Inc.	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-SCNT-1048-AUD	South Central Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Utah	Public Service Commission of Utah	05-2302-01	Carbon/Emery Telecom, Inc.	Cost Study Issues & Depreciation Issues	Utah Committee of Consumer Services
2005	Kansas	Kansas Corporation Commission	05-TTHT-895-AUD	Totah Communications, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Maine	Public Utilities Commission of the State of Maine	2005-155	Verizon	Depreciation Issues	Office of Public Advocate

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2005	Kansas	Kansas Corporation Commission	05-TRCT-607-KSF	Tri-County Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-CNHT-020-AUD	Cunningham Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-KOKT-060-AUD	KanOkla Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-UTAT-690-AUD	United Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-CGTT-679-RTS	Council Grove Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-GNBT-130-AUD	Golden Belt Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	03-TWVT-1031-AUD	Twin Valley Telephone, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-HVDT-664-RTS	Haviland Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-WHST-503-AUD	Wheat State Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-S&AT-160-AUD	S&A Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-JBNT-846-AUD	JBN Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-S&TT-390-AUD	S&T Telephone Cooperative Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff

Previous Experience of Roxie McCullar

Year	State	Commission	Docket	Company	Description	On Behalf of
2002	Kansas	Kansas Corporation Commission	02-BLVT-377-AUD	Blue Valley Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-PNRT-929-AUD	Pioneer Telephone Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-BSST-878-AUD	Bluestem Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SFLT-879-AUD	Sunflower Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-CRKT-713-AUD	Craw-Kan Telephone Cooperative, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RNBT-608-KSF	Rainbow Telecommunications Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SNKT-544-AUD	Southern Kansas Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RRLT-518-KSF	Rural Telephone Service Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2000	Illinois	Illinois Commerce Commission	98-0252	Ameritech	Cost Study Issues	Government and Consumer Intervenors

Northern Indiana Public Service Company
Table 1: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

		NIPSCO Proposed		OUCC Proposed		
Functional Category	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
A	B	C	D	E	F	G
Steam Production Plant	1,089,000,778	11.18%	121,699,275	10.48%	114,129,776	(7,569,499)
Hydraulic Production Plant	100,837,261	6.82%	6,879,602	6.70%	6,758,901	(120,701)
Solar Production Plant	1,906,215,291	4.28%	81,530,755	4.27%	81,398,107	(132,648)
Other Production Plant	297,996,293	8.94%	26,643,633	8.66%	25,802,668	(840,965)
Transmission Plant	2,342,622,107	2.03%	47,597,923	1.99%	46,653,991	(943,932)
Distribution Plant	3,887,397,528	2.41%	93,782,515	2.34%	91,039,608	(2,742,907)
General Plant	233,657,667	4.85%	11,338,172	4.85%	11,338,172	0
General Plant Reserve Amortization			(1,223,030)		(1,223,030)	0
Total Depreciable Plant	**9,857,726,925**	**3.94%**	**388,248,845**	**3.81%**	**375,898,193**	**(12,350,652)**
Common Plant	157,444,386	2.77%	4,363,908	2.77%	4,363,908	0
Common Plant Reserve Amortization			(3,339,636)		(3,339,636)	0
Total Common Plant	**157,444,386**	**0.65%**	**1,024,272**	**0.65%**	**1,024,272**	**0**

Northern Indiana Public Service Company
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

		NIPSCO Proposed		OUCC Proposed		
Plant	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
A	B	C	D	E	F	G
Steam Production						
Michigan City Generating Station	181,460,343	11.80%	21,419,089	11.00%	19,955,058	(1,464,031)
Michigan City - Unit 12	736,377,345	13.14%	96,740,989	12.32%	90,686,092	(6,054,897)
Michigan City	*917,837,688*	*12.87%*	*118,160,078*	*12.05%*	*110,641,150*	*(7,518,928)*
Sugar Creek	171,163,090	2.07%	3,539,197	2.04%	3,488,625	(50,572)
Total Steam Production	**1,089,000,778**	**11.18%**	**121,699,275**	**10.48%**	**114,129,776**	**(7,569,499)**
Hydro Production Plant						
Norway Generating Station	48,987,690	6.98%	3,418,059	6.81%	3,336,385	(81,674)
Oakdale Generating Station	51,849,572	6.68%	3,461,543	6.60%	3,422,516	(39,027)
Total Hydro Production	**100,837,261**	**6.82%**	**6,879,602**	**6.70%**	**6,758,901**	**(120,701)**
Solar Production Plant						
Solar-Other	1,288,824	3.99%	51,449	3.99%	51,449	0
Cavalry	370,732,860	4.39%	16,281,490	4.39%	16,279,613	(1,877)
Dunns Bridge II	723,507,963	4.12%	29,819,550	4.12%	29,835,878	16,328
Fairbanks	444,586,105	4.31%	19,171,891	4.31%	19,165,472	(6,419)
Gibson	366,099,539	4.43%	16,206,375	4.39%	16,065,695	(140,680)
Total Solar Production	**1,906,215,291**	**4.28%**	**81,530,755**	**4.27%**	**81,398,107**	**(132,648)**
Other Production Plant						
R M Schahfer - Units 16A and 16B	33,405,537	46.51%	15,538,030	45.52%	15,204,553	(333,477)
R M Schahfer - Unit 16A	22,470,212	11.44%	2,569,510	10.43%	2,344,734	(224,776)
R M Schahfer - Unit 16B	26,705,241	5.32%	1,419,776	4.31%	1,151,857	(267,919)
R M Schahfer	*82,580,989*	*23.65%*	*19,527,316*	*22.65%*	*18,701,144*	*(826,172)*
Sugar Creek	215,415,304	3.30%	7,116,317	3.30%	7,101,524	(14,793)
Total Other Production	**297,996,293**	**8.94%**	**26,643,633**	**8.66%**	**25,802,668**	**(840,965)**
Total Production	**3,394,049,622**	**6.98%**	**236,753,265**	**6.72%**	**228,089,452**	**(8,663,813)**

Northern Indiana Public Service Company
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

			NIPSCO Proposed		OUCC Proposed		
Account	Description	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
	A	B	C	D	E	F	G
	Steam Production Plant						
311.00	Structures and Improvements						
	Michigan City Generating Station	46,027,142	14.74%	6,782,404	13.91%	6,402,375	(380,029)
	Michigan City - Unit 12	105,391,567	13.90%	14,646,475	13.07%	13,774,678	(871,797)
	Sugar Creek	8,084,108	1.88%	152,043	1.86%	150,364	(1,679)
	Total Account 311.00	*159,502,818*	*13.53%*	*21,580,922*	*12.74%*	*20,327,418*	*(1,253,504)*
312.10	Boiler Plant Equipment						
	Michigan City Generating Station	90,788,707	11.78%	10,697,444	10.96%	9,950,442	(747,002)
	Michigan City - Unit 12	261,925,850	12.18%	31,899,258	11.36%	29,754,777	(2,144,481)
	Sugar Creek	96,801,494	1.98%	1,914,475	1.95%	1,887,629	(26,846)
	Total Account 312.10	*449,516,051*	*9.90%*	*44,511,177*	*9.25%*	*41,592,848*	*(2,918,329)*
312.20	Boiler Plant Equipment - Mobile Fuel Handling and Storage						
	Michigan City Generating Station	8,502,659	8.08%	687,433	7.26%	617,293	(70,140)
	Michigan City - Unit 12	796,689	7.45%	59,331	6.62%	52,741	(6,590)
	Total Account 312.20	*9,299,348*	*8.03%*	*746,764*	*7.21%*	*670,034*	*(76,730)*
312.30	Boiler Plant Equipment - Unit Train Coal Cars						
	Michigan City Generating Station	2,841,744	0.37%	10,384	0.37%	10,384	0
	Total Account 312.30	*2,841,744*	*0.37%*	*10,384*	*0.37%*	*10,384*	*0*
312.40	Boiler Plant Equipment - SO2 Plant Equipment						
	Michigan City - Unit 12	230,108,219	14.37%	33,070,519	13.55%	31,179,664	(1,890,855)
	Total Account 312.40	*230,108,219*	*14.37%*	*33,070,519*	*13.55%*	*31,179,664*	*(1,890,855)*
312.50	Boiler Plant Equipment - Coal Pile Base						
	Michigan City Generating Station	717,113	0.00%	0	0.00%	0	0
	Total Account 312.50	*717,113*	*0.00%*	*0*	*0.00%*	*0*	*0*
314.00	Turbogenerator Units						
	Michigan City Generating Station	4,843,912	17.92%	868,065	17.10%	828,309	(39,756)
	Michigan City - Unit 12	97,485,935	14.21%	13,849,772	13.38%	13,043,618	(806,154)
	Sugar Creek	57,816,549	2.23%	1,291,945	2.20%	1,271,964	(19,981)
	Total Account 314.00	*160,146,396*	*10.00%*	*16,009,782*	*9.46%*	*15,143,891*	*(865,891)*
315.00	Accessory Electric Equipment						
	Michigan City Generating Station	23,807,801	6.97%	1,659,074	6.15%	1,464,180	(194,894)
	Michigan City - Unit 12	35,227,102	6.30%	2,220,718	5.48%	1,930,445	(290,273)
	Sugar Creek	4,897,315	1.82%	89,263	1.80%	88,152	(1,111)
	Total Account 315.00	*63,932,218*	*6.21%*	*3,969,055*	*5.45%*	*3,482,777*	*(486,278)*
316.00	Miscellaneous Power Plant Equipment						
	Michigan City Generating Station	3,931,265	18.17%	714,285	17.35%	682,074	(32,211)
	Michigan City - Unit 12	5,441,983	18.28%	994,916	17.46%	950,170	(44,746)
	Sugar Creek	3,563,623	2.57%	91,471	2.54%	90,516	(955)
	Total Account 316.00	*12,936,871*	*13.92%*	*1,800,672*	*13.32%*	*1,722,761*	*(77,911)*
	Total Steam Production Plant	**1,089,000,778**	**11.18%**	**121,699,275**	**10.48%**	**114,129,776**	**(7,569,499)**
	Hydarulic Production Plant						

Northern Indiana Public Service Company
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

			NIPSCO Proposed		OUCC Proposed		
Account	Description	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
	A	B	C	D	E	F	G
331.00	Structures and Improvements						
	Norway Generating Station	4,615,793	6.12%	282,348	5.94%	274,178	(8,170)
	Oakdale Generating Station	7,173,148	5.38%	386,078	5.28%	378,742	(7,336)
	Total Account 331.00	*11,788,941*	*5.67%*	*668,426*	*5.54%*	*652,920*	*(15,506)*
332.00	Reservoirs, Dams, and Waterways						
	Norway Generating Station	33,719,832	7.32%	2,466,944	7.15%	2,410,968	(55,976)
	Oakdale Generating Station	37,145,731	7.06%	2,622,088	6.99%	2,596,487	(25,601)
	Total Account 332.00	*70,865,562*	*7.18%*	*5,089,032*	*7.07%*	*5,007,455*	*(81,577)*
333.00	Water Wheels, Turbines, and Generators						
	Norway Generating Station	7,950,789	6.62%	526,005	6.46%	513,621	(12,384)
	Oakdale Generating Station	6,429,578	6.02%	386,919	5.94%	381,917	(5,002)
	Total Account 333.00	*14,380,367*	*6.35%*	*912,924*	*6.23%*	*895,538*	*(17,386)*
334.00	Accessory Electric Equipment						
	Norway Generating Station	1,678,599	4.41%	74,032	4.22%	70,837	(3,195)
	Oakdale Generating Station	830,242	5.99%	49,769	5.89%	48,901	(868)
	Total Account 334.00	*2,508,841*	*4.93%*	*123,801*	*4.77%*	*119,738*	*(4,063)*
335.00	Miscellaneous Power Plant Equipment						
	Norway Generating Station	1,022,677	6.72%	68,730	6.53%	66,781	(1,949)
	Oakdale Generating Station	270,873	6.16%	16,689	6.08%	16,469	(220)
	Total Account 335.00	*1,293,550*	*6.60%*	*85,419*	*6.44%*	*83,250*	*(2,169)*
	Total Hydarulic Production Plant	**100,837,261**	**6.82%**	**6,879,602**	**6.70%**	**6,758,901**	**(120,701)**
	Solar Production Plant						
341.10	Structures and Improvements - Solar	49,455	2.85%	1,411	2.85%	1,411	0
341.20	Structures and Improvements - Utility-Scale Solar						
	Cavalry	54,184,033	3.98%	2,157,037	3.98%	2,156,525	(512)
	Dunns Bridge II	105,743,472	3.75%	3,963,440	3.75%	3,965,380	1,940
	Fairbanks	64,977,969	3.92%	2,548,215	3.92%	2,547,136	(1,079)
	Gibson	53,506,856	4.03%	2,154,056	3.99%	2,134,924	(19,132)
	Total Account 341.20	*278,412,330*	*3.89%*	*10,822,748*	*3.88%*	*10,803,965*	*(18,783)*
344.10	Generators - Solar	991,495	4.04%	40,046	4.04%	40,046	0
344.20	Generators - Utility-Scale Solar						
	Cavalry	277,438,547	4.49%	12,455,518	4.49%	12,456,991	1,473
	Dunns Bridge II	541,438,377	4.21%	22,783,418	4.21%	22,794,556	11,138
	Fairbanks	332,706,744	4.40%	14,648,149	4.40%	14,639,097	(9,052)
	Gibson	273,971,193	4.52%	12,382,368	4.48%	12,273,909	(108,459)
	Total Account 344.20	*1,425,554,861*	*4.37%*	*62,269,453*	*4.36%*	*62,164,553*	*(104,900)*
345.10	Accessory Electric Equipment - Solar	247,874	4.03%	9,992	4.03%	9,992	0
345.20	Accessory Electric Equipment - Utility-Scale Solar						
	Cavalry	39,110,280	4.27%	1,668,935	4.26%	1,666,098	(2,837)

Northern Indiana Public Service Company
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

			NIPSCO Proposed		OUCC Proposed		
Account	Description	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
	A	B	C	D	E	F	G
	Dunns Bridge II	76,326,115	4.03%	3,072,692	4.03%	3,075,942	3,250
	Fairbanks	46,901,391	4.21%	1,975,527	4.22%	1,979,239	3,712
	Gibson	38,621,490	4.32%	1,669,951	4.29%	1,656,862	(13,089)
	Total Account 345.20	*200,959,276*	*4.17%*	*8,387,105*	*4.17%*	*8,378,141*	*(8,964)*
	Total Solar Production Plant	**1,906,215,291**	**4.28%**	**81,530,755**	**4.27%**	**81,398,107**	**(132,648)**
	Other Production Plant						
341.00	Structures and Improvements						
	R M Schahfer - Units 16A and 16B	2,484,301	28.62%	711,108	27.62%	686,164	(24,944)
	R M Schahfer - Unit 16A	212,250	4.16%	8,830	3.16%	6,707	(2,123)
	Sugar Creek	13,149,658	1.82%	239,019	1.79%	235,379	(3,640)
	Total Account 341.00	*15,846,208*	*6.05%*	*958,957*	*5.86%*	*928,250*	*(30,707)*
342.00	Fuel Holders, Producers, and Accessories						
	R M Schahfer - Units 16A and 16B	9,106,087	31.40%	2,858,947	30.40%	2,768,250	(90,697)
	Sugar Creek	3,199,462	2.21%	70,570	2.20%	70,388	(182)
	Total Account 342.00	*12,305,548*	*23.81%*	*2,929,517*	*23.07%*	*2,838,639*	*(90,878)*
343.00	Prime Movers						
	R M Schahfer - Units 16A and 16B	3,850,661	73.23%	2,819,754	72.23%	2,781,332	(38,422)
	R M Schahfer - Unit 16A	15,109,176	10.19%	1,539,832	9.19%	1,388,533	(151,299)
	R M Schahfer - Unit 16B	23,015,176	5.25%	1,209,049	4.25%	978,145	(230,904)
	Sugar Creek	118,449,541	4.00%	4,735,768	3.99%	4,726,137	(9,631)
	Total Account 343.00	*160,424,553*	*6.42%*	*10,304,403*	*6.16%*	*9,874,147*	*(430,256)*
344.00	Generators						
	R M Schahfer - Unit 16A	5,927,994	15.94%	944,741	14.94%	885,642	(59,099)
	R M Schahfer - Unit 16B	2,723,344	5.87%	159,972	4.87%	132,627	(27,345)
	Sugar Creek	40,450,119	2.53%	1,023,195	2.53%	1,023,388	193
	Total Account 344.00	*49,101,457*	*4.33%*	*2,127,908*	*4.16%*	*2,041,657*	*(86,251)*
345.00	Accessory Electric Equipment						
	R M Schahfer - Units 16A and 16B	17,562,929	51.10%	8,974,446	50.10%	8,799,028	(175,418)
	R M Schahfer - Unit 16A	1,164,785	6.15%	71,682	5.15%	59,986	(11,696)
	R M Schahfer - Unit 16B	966,721	5.25%	50,755	4.25%	41,086	(9,669)
	Sugar Creek	34,529,128	2.56%	882,580	2.55%	880,493	(2,087)
	Total Account 345.00	*54,223,563*	*18.40%*	*9,979,463*	*18.04%*	*9,780,592*	*(198,871)*
346.00	Miscellaneous Power Plant Equipment						
	R M Schahfer - Units 16A and 16B	401,559	43.28%	173,775	42.28%	169,779	(3,996)
	R M Schahfer - Unit 16A	56,008	7.90%	4,425	6.90%	3,865	(560)
	Sugar Creek	5,637,396	2.93%	165,185	2.94%	165,739	554
	Total Account 346.00	*6,094,963*	*5.63%*	*343,385*	*5.57%*	*339,383*	*(4,002)*
	Total Other Production Plant	**297,996,293**	**8.94%**	**26,643,633**	**8.66%**	**25,802,668**	**(840,965)**
	Total Production Plant	**3,394,049,622**	**6.98%**	**236,753,265**	**6.72%**	**228,089,452**	**(8,663,813)**
	Transmission Plant						

Northern Indiana Public Service Company
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

			NIPSCO Proposed		OUCC Proposed		
Account	Description	12/31/25 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
	A	B	C	D	E	F	G
350.20	Land Rights	15,667,095	0.33%	52,355	0.33%	52,355	0
352.00	Structures and Improvements	120,006,207	1.59%	1,905,289	1.51%	1,812,094	(93,195)
353.00	Station Equipment	1,209,443,673	2.19%	26,483,027	2.19%	26,483,027	0
354.00	Towers and Fixtures	234,065,559	1.45%	3,384,642	1.38%	3,230,105	(154,537)
355.00	Poles and Fixtures	441,931,660	2.14%	9,435,800	2.04%	9,015,406	(420,394)
356.00	Overhead Conductors and Devices	316,129,902	1.98%	6,250,660	1.89%	5,974,855	(275,805)
357.00	Underground Conduit	904,995	0.51%	4,599	0.51%	4,599	0
358.00	Underground Conductors and Devices	4,441,927	1.82%	80,942	1.82%	80,942	0
359.00	Roads and Trails	31,089	1.96%	609	1.96%	609	0
	Total Transmission Plant	**2,342,622,107**	**2.03%**	**47,597,923**	**1.99%**	**46,653,991**	**(943,932)**
	Distribution Plant						
360.20	Land Rights	1,611,389	1.17%	18,800	1.17%	18,800	0
361.00	Structures and Improvements	20,834,098	1.33%	276,487	1.33%	276,487	0
362.00	Station Equipment	695,297,773	2.07%	14,371,230	1.95%	13,558,307	(812,923)
364.10	Customer Transformer Station	61,383,975	2.43%	1,491,955	2.43%	1,491,955	0
364.20	Poles, Towers, and Fixtures	809,432,021	2.99%	24,161,648	2.99%	24,161,648	0
365.00	Overhead Conductors and Devices	503,615,756	2.17%	10,911,938	1.99%	10,021,954	(889,984)
366.00	Underground Conduit	5,754,045	1.35%	77,434	1.35%	77,434	0
367.00	Underground Conductors and Devices	719,335,599	2.44%	17,533,397	2.32%	16,688,586	(844,811)
368.00	Line Transformers	438,272,677	2.00%	8,781,818	2.00%	8,781,818	0
369.10	Overhead Services	58,862,878	1.97%	1,157,585	1.97%	1,157,585	0
369.20	Underground Services	329,574,658	1.61%	5,315,742	1.61%	5,315,742	0
370.10	Customer Metering Stations	24,831,212	1.57%	390,624	1.50%	372,468	(18,156)
370.20	Meters	129,340,995	3.92%	5,066,122	3.78%	4,889,090	(177,032)
371.00	Installations on Customers' Premises	13,170,732	4.59%	604,110	4.59%	604,110	0
373.00	Street Lighting and Signal Systems	76,079,721	4.76%	3,623,625	4.76%	3,623,625	0
	Total Distribution Plant	**3,887,397,528**	**2.41%**	**93,782,515**	**2.34%**	**91,039,608**	**(2,742,907)**
	General Plant						
390.00	Structures and Improvements	80,207,587	1.79%	1,436,514	1.79%	1,436,514	0
391.10	Office Furniture and Equipment	4,503,478	5.00%	225,067	5.00%	225,067	0
391.20	Computers and Perifpheral Equipment	10,225,401	14.29%	1,461,186	14.29%	1,461,186	0
393.00	Stores Equipment	840,984	3.33%	28,043	3.33%	28,043	0
394.00	Tools, Shop, and Garage Equipment	31,219,333	4.00%	1,249,729	4.00%	1,249,729	0
395.00	Laboratory Equipment	5,386,441	5.00%	269,165	5.00%	269,165	0
397.00	Communication Equipment	96,126,114	6.67%	6,411,145	6.67%	6,411,145	0
398.00	Miscellaneous Equipment	5,148,329	5.00%	257,323	5.00%	257,323	0
	Total General Plant	**233,657,667**	**4.85%**	**11,338,172**	**4.85%**	**11,338,172**	**0**
	Reserve Adjustment for Amortization						
391.10	Office Furniture and Equipment			(41,900)		(41,900)	0
391.20	Computers and Perifpheral Equipment			(1,949,179)		(1,949,179)	0
393.00	Stores Equipment			(10,860)		(10,860)	0
394.00	Tools, Shop, and Garage Equipment			(22,027)		(22,027)	0

Northern Indiana Public Service Company
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

Account	Description	12/31/25 Investment	NIPSCO Proposed Accrual Rate	NIPSCO Proposed Accrual Amount	OUCC Proposed Accrual Rate	OUCC Proposed Accrual Amount	OUCC Proposed Difference from NIPSCO Proposed
	A	B	C	D	E	F	G
395.00	Laboratory Equipment			(204,179)		(204,179)	0
397.00	Communication Equipment			987,857		987,857	0
398.00	Miscellaneous Equipment			17,258		17,258	0
	Total Reserve Adjustment for Amortization			**(1,223,030)**		**(1,223,030)**	**0**
	Total Depreciable Plant	**9,857,726,925**	**3.94%**	**388,248,845**	**3.81%**	**375,898,193**	**(12,350,652)**

Northern Indiana Public Service Company
Table 4: Calculation of Depreciation Rates
As of December 31, 2025

Account	Description	12/31/25 Investment	12/31/25 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	G	H	I
	Steam Production Plant							
311.00	Structures and Improvements							
	Michigan City Generating Station	46,027,142	19,214,893	41.75%	-60%	8.5	13.91%	6,403,357
	Michigan City - Unit 12	105,391,567	51,508,881	48.87%	-60%	8.5	13.07%	13,778,544
	Sugar Creek	8,084,108	4,094,685	50.65%	-27%	41.1	1.86%	150,174
	Total Account 311.00	*159,502,818*	*74,818,459*	*46.91%*	*-59%*	*8.8*	*12.75%*	*20,332,075*
312.10	Boiler Plant Equipment							
	Michigan City Generating Station	90,788,707	60,688,863	66.85%	-60%	8.5	10.96%	9,949,773
	Michigan City - Unit 12	261,925,850	166,272,474	63.48%	-60%	8.5	11.36%	29,742,222
	Sugar Creek	96,801,494	58,392,780	60.32%	-27%	34.2	1.95%	1,887,284
	Total Account 312.10	*449,516,051*	*285,354,117*	*63.48%*	*-56%*	*10.0*	*9.25%*	*41,579,279*
312.20	Boiler Plant Equipment - Mobile Fuel Handling and Storage							
	Michigan City Generating Station	8,502,659	8,356,263	98.28%	-60%	8.5	7.26%	617,411
	Michigan City - Unit 12	796,689	826,154	103.70%	-60%	8.5	6.62%	52,770
	Total Account 312.20	*9,299,348*	*9,182,417*	*98.74%*	*-60%*	*8.5*	*7.21%*	*670,181*
312.30	Boiler Plant Equipment - Unit Train Coal Cars							
	Michigan City Generating Station	2,841,744	2,753,480	96.89%	0%	8.5	0.37%	10,384
	Total Account 312.30	*2,841,744*	*2,753,480*	*96.89%*	*0%*	*8.5*	*0.37%*	*10,384*
312.40	Boiler Plant Equipment - SO2 Plant Equipment							
	Michigan City - Unit 12	230,108,219	103,181,315	44.84%	-60%	8.5	13.55%	31,175,510
	Total Account 312.40	*230,108,219*	*103,181,315*	*44.84%*	*-60%*	*8.5*	*13.55%*	*31,175,510*
312.50	Boiler Plant Equipment - Coal Pile Base							
	Michigan City Generating Station	717,113	1,197,579	167.00%	-60%	0.0	0.00%	0
	Total Account 312.50	*717,113*	*1,197,579*	*167.00%*	*#DIV/0!*	*#DIV/0!*	*0.00%*	*0*
314.00	Turbogenerator Units							
	Michigan City Generating Station	4,843,912	710,782	14.67%	-60%	8.5	17.10%	828,174
	Michigan City - Unit 12	97,485,935	45,078,446	46.24%	-60%	8.5	13.38%	13,046,947
	Sugar Creek	57,816,549	27,669,122	47.86%	-27%	35.9	2.20%	1,274,593
	Total Account 314.00	*160,146,396*	*73,458,350*	*45.87%*	*-53%*	*11.3*	*9.46%*	*15,149,714*
315.00	Accessory Electric Equipment							
	Michigan City Generating Station	23,807,801	25,656,902	107.77%	-60%	8.5	6.15%	1,463,009
	Michigan City - Unit 12	35,227,102	39,953,156	113.42%	-60%	8.5	5.48%	1,930,613
	Sugar Creek	4,897,315	2,894,694	59.11%	-27%	37.8	1.80%	87,960
	Total Account 315.00	*63,932,218*	*68,504,752*	*107.15%*	*-58%*	*9.4*	*5.45%*	*3,481,582*
316.00	Miscellaneous Power Plant Equipment							
	Michigan City Generating Station	3,931,265	493,793	12.56%	-60%	8.5	17.35%	681,910
	Michigan City - Unit 12	5,441,983	631,322	11.60%	-60%	8.5	17.46%	950,100
	Sugar Creek	3,563,623	1,126,831	31.62%	-27%	37.5	2.54%	90,639
	Total Account 316.00	*12,936,871*	*2,251,946*	*17.41%*	*-56%*	*10.4*	*13.32%*	*1,722,649*
	Total Steam Production Plant	**1,089,000,778**	**620,702,415**	**57.00%**	**-57%**	**9.5**	**10.48%**	**114,121,374**
	Hydarulic Production Plant							
331.00	Structures and Improvements							
	Norway Generating Station	4,615,793	1,890,273	40.95%	-11%	11.8	5.94%	274,005

Northern Indiana Public Service Company
Table 4: Calculation of Depreciation Rates
As of December 31, 2025

Account	Description	12/31/25 Investment	12/31/25 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	G	H	I
	Oakdale Generating Station	7,173,148	3,202,088	44.64%	-7%	11.8	5.28%	379,083
	Total Account 331.00	*11,788,941*	*5,092,361*	*43.20%*	*-9%*	*11.8*	*5.54%*	*653,088*
332.00	Reservoirs, Dams, and Waterways							
	Norway Generating Station	33,719,832	8,970,126	26.60%	-11%	11.8	7.15%	2,411,770
	Oakdale Generating Station	37,145,731	9,118,796	24.55%	-7%	11.8	6.99%	2,595,520
	Total Account 332.00	*70,865,562*	*18,088,922*	*25.53%*	*-9%*	*11.8*	*7.07%*	*5,007,290*
333.00	Water Wheels, Turbines, and Generators							
	Norway Generating Station	7,950,789	3,174,832	39.93%	-11%	11.0	6.46%	513,686
	Oakdale Generating Station	6,429,578	2,452,118	38.14%	-7%	11.6	5.94%	381,684
	Total Account 333.00	*14,380,367*	*5,626,950*	*39.13%*	*-9%*	*11.3*	*6.23%*	*895,369*
334.00	Accessory Electric Equipment							
	Norway Generating Station	1,678,599	1,091,445	65.02%	-11%	10.9	4.22%	70,807
	Oakdale Generating Station	830,242	326,461	39.32%	-7%	11.5	5.89%	48,861
	Total Account 334.00	*2,508,841*	*1,417,906*	*56.52%*	*-10%*	*11.2*	*4.77%*	*119,668*
335.00	Miscellaneous Power Plant Equipment							
	Norway Generating Station	1,022,677	360,067	35.21%	-11%	11.6	6.53%	66,819
	Oakdale Generating Station	270,873	100,425	37.07%	-7%	11.5	6.08%	16,470
	Total Account 335.00	*1,293,550*	*460,492*	*35.60%*	*-10%*	*11.6*	*6.44%*	*83,290*
	Total Hydarulic Production Plant	**100,837,261**	**30,686,631**	**30.43%**	**-9%**	**11.7**	**6.70%**	**6,758,705**
	Solar Production Plant							
341.10	Structures and Improvements - Solar	49,455	3,484	7.04%	0%	32.6	2.85%	1,410
341.20	Structures and Improvements - Utility-Scale Solar							
	Cavalry	54,184,033	3,467,681	6.40%	-15%	27.3	3.98%	2,155,456
	Dunns Bridge II	105,743,472	2,116,878	2.00%	-8%	28.3	3.75%	3,960,639
	Fairbanks	64,977,969	1,361,577	2.10%	-13%	28.3	3.92%	2,546,414
	Gibson	53,506,856	1,151,239	2.15%	-15%	28.3	3.99%	2,133,627
	Total Account 341.20	*278,412,330*	*8,097,375*	*2.91%*	*-12%*	*28.1*	*3.88%*	*10,796,136*
344.10	Generators - Solar	991,495	201,025	20.27%	0%	19.7	4.05%	40,125
344.20	Generators - Utility-Scale Solar							
	Cavalry	277,438,547	17,755,358	6.40%	-15%	24.2	4.49%	12,450,371
	Dunns Bridge II	541,438,377	10,839,143	2.00%	-8%	25.2	4.21%	22,774,377
	Fairbanks	332,706,744	6,971,750	2.10%	-13%	25.2	4.40%	14,642,336
	Gibson	273,971,193	5,894,743	2.15%	-15%	25.2	4.48%	12,268,735
	Total Account 344.20	*1,425,554,861*	*41,460,994*	*2.91%*	*-12%*	*25.0*	*4.36%*	*62,135,819*
345.10	Accessory Electric Equipment - Solar	247,874	50,631	20.43%	0%	19.7	4.04%	10,012
345.20	Accessory Electric Equipment - Utility-Scale Solar							
	Cavalry	39,110,280	2,502,423	6.40%	-15%	25.5	4.26%	1,665,663
	Dunns Bridge II	76,326,115	1,528,229	2.00%	-8%	26.3	4.03%	3,076,197
	Fairbanks	46,901,391	982,959	2.10%	-13%	26.3	4.22%	1,977,780
	Gibson	38,621,490	831,111	2.15%	-15%	26.3	4.29%	1,657,171
	Total Account 345.20	*200,959,276*	*5,844,722*	*2.91%*	*-12%*	*26.1*	*4.17%*	*8,376,811*
	Total Solar Production Plant	**1,906,215,291**	**55,658,231**	**2.92%**	**-12%**	**25.5**	**4.27%**	**81,360,314**

Northern Indiana Public Service Company
Table 4: Calculation of Depreciation Rates
As of December 31, 2025

Account	Description	12/31/25 Investment	12/31/25 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	G	H	I
	Other Production Plant							
341.00	Structures and Improvements							
	R M Schahfer - Units 16A and 16B	2,484,301	1,872,564	75.38%	-3%	1.0	27.62%	686,266
	R M Schahfer - Unit 16A	212,250	211,909	99.84%	-3%	1.0	3.16%	6,708
	Sugar Creek	13,149,658	6,912,218	52.57%	-16%	35.4	1.79%	235,632
	Total Account 341.00	*15,846,208*	*8,996,691*	*56.78%*	*-9%*	*9.0*	*5.86%*	*928,606*
342.00	Fuel Holders, Producers, and Accessories							
	R M Schahfer - Units 16A and 16B	9,106,087	6,611,384	72.60%	-3%	1.0	30.40%	2,767,885
	Sugar Creek	3,199,462	2,257,626	70.56%	-17%	21.1	2.20%	70,414
	Total Account 342.00	*12,305,548*	*8,869,010*	*72.07%*	*-5%*	*1.4*	*23.07%*	*2,838,300*
343.00	Prime Movers							
	R M Schahfer - Units 16A and 16B	3,850,661	1,184,933	30.77%	-3%	1.0	72.23%	2,781,248
	R M Schahfer - Unit 16A	15,109,176	14,173,710	93.81%	-3%	1.0	9.19%	1,388,741
	R M Schahfer - Unit 16B	23,015,176	22,726,733	98.75%	-3%	1.0	4.25%	978,898
	Sugar Creek	118,449,541	41,169,623	34.76%	-17%	20.6	3.99%	4,728,949
	Total Account 343.00	*160,424,553*	*79,254,999*	*49.40%*	*-10%*	*9.8*	*6.16%*	*9,877,835*
344.00	Generators							
	R M Schahfer - Unit 16A	5,927,994	5,220,374	88.06%	-3%	1.0	14.94%	885,460
	R M Schahfer - Unit 16B	2,723,344	2,672,305	98.13%	-3%	1.0	4.87%	132,739
	Sugar Creek	40,450,119	25,423,352	62.85%	-17%	21.4	2.53%	1,023,518
	Total Account 344.00	*49,101,457*	*33,316,031*	*67.85%*	*-12%*	*10.6*	*4.16%*	*2,041,717*
345.00	Accessory Electric Equipment							
	R M Schahfer - Units 16A and 16B	17,562,929	9,291,000	52.90%	-3%	1.0	50.10%	8,798,817
	R M Schahfer - Unit 16A	1,164,785	1,139,694	97.85%	-3%	1.0	5.15%	60,034
	R M Schahfer - Unit 16B	966,721	954,635	98.75%	-3%	1.0	4.25%	41,088
	Sugar Creek	34,529,128	22,844,101	66.16%	-17%	19.9	2.55%	882,160
	Total Account 345.00	*54,223,563*	*34,229,430*	*63.13%*	*-9%*	*2.5*	*18.04%*	*9,782,099*
346.00	Miscellaneous Power Plant Equipment							
	R M Schahfer - Units 16A and 16B	401,559	243,846	60.72%	-3%	1.0	42.28%	169,760
	R M Schahfer - Unit 16A	56,008	53,824	96.10%	-3%	1.0	6.90%	3,864
	Sugar Creek	5,637,396	3,119,781	55.34%	-17%	21.0	2.94%	165,523
	Total Account 346.00	*6,094,963*	*3,417,451*	*56.07%*	*-12%*	*10.1*	*5.56%*	*339,146*
	Total Other Production Plant	**297,996,293**	**168,083,612**	**56.40%**	**-9%**	**6.0**	**8.66%**	**25,807,703**
	Total Production Plant	**3,394,049,622**	**875,130,889**	**25.78%**	**-32%**	**15.8**	**6.72%**	**228,048,096**
	Transmission Plant							
350.20	Land Rights	15,667,095	11,598,910	74.03%	0%	77.7	0.33%	52,358
352.00	Structures and Improvements	120,006,207	27,822,792	23.18%	-15%	61.0	1.51%	1,806,301
353.00	Station Equipment	1,209,443,673	274,868,958	22.73%	-15%	42.1	2.19%	26,508,106
354.00	Towers and Fixtures	234,065,559	92,070,828	39.34%	-26%	62.7	1.38%	3,235,276
355.00	Poles and Fixtures	441,931,660	111,011,176	25.12%	-35%	53.8	2.04%	9,025,958
356.00	Overhead Conductors and Devices	316,129,902	121,826,202	38.54%	-40%	53.8	1.89%	5,962,001
357.00	Underground Conduit	904,995	701,583	77.52%	-5%	54.1	0.51%	4,596
358.00	Underground Conductors and Devices	4,441,927	1,276,270	28.73%	-5%	41.9	1.82%	80,853
359.00	Roads and Trails	31,089	15,016	48.30%	0%	26.4	1.96%	609

Northern Indiana Public Service Company
Table 4: Calculation of Depreciation Rates
As of December 31, 2025

Account	Description	12/31/25 Investment	12/31/25 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	G	H	I
	Total Transmission Plant	**2,342,622,107**	**641,191,735**	**27.37%**	**-22%**	**47.7**	**1.99%**	**46,676,058**
	Distribution Plant							
360.20	Land Rights	1,611,389	381,082	23.65%	0%	65.4	1.17%	18,812
361.00	Structures and Improvements	20,834,098	9,549,803	45.84%	-20%	55.9	1.33%	276,406
362.00	Station Equipment	695,297,773	169,278,666	24.35%	-10%	43.9	1.95%	13,566,034
364.10	Customer Transformer Station	61,383,975	35,822,062	58.36%	-55%	39.8	2.43%	1,490,530
364.20	Poles, Towers, and Fixtures	809,432,021	262,404,188	32.42%	-55%	41.1	2.98%	24,141,495
365.00	Overhead Conductors and Devices	503,615,756	225,253,840	44.73%	-60%	57.8	1.99%	10,043,795
366.00	Underground Conduit	5,754,045	2,196,817	38.18%	-5%	49.7	1.34%	77,363
367.00	Underground Conductors and Devices	719,335,599	213,843,036	29.73%	-30%	43.2	2.32%	16,696,603
368.00	Line Transformers	438,272,677	156,425,125	35.69%	-10%	37.1	2.00%	8,778,297
369.10	Overhead Services	58,862,878	42,319,943	71.90%	-50%	39.7	1.97%	1,158,045
369.20	Underground Services	329,574,658	155,332,144	47.13%	-50%	63.8	1.61%	5,313,947
370.10	Customer Metering Stations	24,831,212	10,772,610	43.38%	-2%	39.2	1.50%	371,307
370.20	Meters	129,340,995	28,225,729	21.82%	-2%	21.2	3.78%	4,891,608
371.00	Installations on Customers' Premises	13,170,732	7,189,523	54.59%	-30%	16.4	4.60%	605,636
373.00	Street Lighting and Signal Systems	76,079,721	23,336,866	30.67%	-40%	23.0	4.75%	3,616,293
	Total Distribution Plant	**3,887,397,528**	**1,342,331,434**	**34.53%**	**-33%**	**42.0**	**2.34%**	**91,046,171**
	General Plant							
390.00	Structures and Improvements	80,207,587	8,245,613	10.28%	-10%	55.7	1.79%	1,435,956
391.10	Office Furniture and Equipment	4,503,478	2,826,155	62.75%	0%	7.5	4.97%	223,643
391.20	Computers and Perifpheral Equipment	10,225,401	7,827,834	76.55%	0%	1.6	14.65%	1,498,480
393.00	Stores Equipment	840,984	461,876	54.92%	0%	13.5	3.34%	28,082
394.00	Tools, Shop, and Garage Equipment	31,219,333	11,811,607	37.83%	0%	15.5	4.01%	1,252,111
395.00	Laboratory Equipment	5,386,441	3,348,174	62.16%	0%	7.6	4.98%	268,193
397.00	Communication Equipment	96,126,114	26,077,512	27.13%	0%	10.9	6.69%	6,426,477
398.00	Miscellaneous Equipment	5,148,329	1,999,319	38.83%	0%	12.2	5.01%	258,116
	Total General Plant	**233,657,667**	**62,598,090**	**26.79%**	**-1%**	**15.3**	**4.88%**	**11,391,057**
	Reserve Adjustment for Amortization							
391.10	Office Furniture and Equipment		125,698			3.0		(41,899)
391.20	Computers and Perifpheral Equipment		5,847,536			3.0		(1,949,179)
393.00	Stores Equipment		32,579			3.0		(10,860)
394.00	Tools, Shop, and Garage Equipment		66,081			3.0		(22,027)
395.00	Laboratory Equipment		612,538			3.0		(204,179)
397.00	Communication Equipment		(2,963,573)			3.0		987,858
398.00	Miscellaneous Equipment		(51,772)			3.0		17,257
	Total Reserve Adjustment for Amortization		**3,669,087**					**(1,223,029)**
	Total Depreciable Plant	**9,857,726,925**	**2,924,921,235**	**29.67%**	**-29%**	**26.1**	**3.81%**	**375,938,354**

Northern Indiana Public Service Company
Table 5: Current and Proposed Parameters
As of December 31, 2025

		Current Approved				NIPSCO Proposed					OUCC Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Steam Production Plant														
311.00	Structures and Improvements														
	Michigan City Generating Station	12-2026	110	R2.5	-8%	12-2028	110	R2.5	8.5	-67%	12-2028	110	R2.5	8.5	-60%
	Michigan City - Unit 12	12-2026	110	R2.5	-8%	12-2028	110	R2.5	8.5	-67%	12-2028	110	R2.5	8.5	-60%
	Sugar Creek	06-2068	110	R2.5	-20%	06-2068	110	R2.5	41.1	-28%	06-2068	110	R2.5	41.1	-27%
	Total Account 311.00														
312.10	Boiler Plant Equipment														
	Michigan City Generating Station	12-2026	55	S0	-8%	12-2028	55	R1	8.5	-67%	12-2028	55	R1	8.5	-60%
	Michigan City - Unit 12	12-2026	55	S0	-8%	12-2028	55	R1	8.5	-67%	12-2028	55	R1	8.5	-60%
	Sugar Creek	06-2068	55	S0	-20%	06-2068	55	R1	34.2	-28%	06-2068	55	R1	34.2	-27%
	Total Account 312.10														
312.20	Boiler Plant Equipment - Mobile Fuel Handling and Storage														
	Michigan City Generating Station	12-2026	55	S0	-8%	12-2028	55	R1	8.5	-67%	12-2028	55	R1	8.5	-60%
	Michigan City - Unit 12	12-2026	55	S0	-8%	12-2028	55	R1	8.5	-67%	12-2028	55	R1	8.5	-60%
	Total Account 312.20														
312.30	Boiler Plant Equipment - Unit Train Coal Cars														
	Michigan City Generating Station		25	R2.5	0%		25	R2.5	8.5	0%		25	R2.5	8.5	0%
	Total Account 312.30														
312.40	Boiler Plant Equipment - SO2 Plant Equipment														
	Michigan City - Unit 12	12-2026	55	S0	-8%	12-2028	55	R1	8.5	-67%	12-2028	55	R1	8.5	-60%
	Total Account 312.40														
312.50	Boiler Plant Equipment - Coal Pile Base														
	Michigan City Generating Station	12-2026	55	S0	-8%	12-2028	55	R1	0.0	-67%	12-2028	55	R1	0.0	-60%
	Total Account 312.50														
314.00	Turbogenerator Units														
	Michigan City Generating Station	12-2026	60	R2	-8%	12-2028	60	R2	8.5	-67%	12-2028	60	R2	8.5	-60%
	Michigan City - Unit 12	12-2026	60	R2	-8%	12-2028	60	R2	8.5	-67%	12-2028	60	R2	8.5	-60%
	Sugar Creek	06-2068	60	R2	-20%	06-2068	60	R2	35.9	-28%	06-2068	60	R2	35.9	-27%
	Total Account 314.00														
315.00	Accessory Electric Equipment														
	Michigan City Generating Station	12-2026	65	R2	-8%	12-2028	70	R2	8.5	-67%	12-2028	70	R2	8.5	-60%
	Michigan City - Unit 12	12-2026	65	R2	-8%	12-2028	70	R2	8.5	-67%	12-2028	70	R2	8.5	-60%
	Sugar Creek	06-2068	65	R2	-20%	06-2068	70	R2	37.8	-28%	06-2068	70	R2	37.8	-27%
	Total Account 315.00														
316.00	Miscellaneous Power Plant Equipment														
	Michigan City Generating Station	12-2026	70	R1.5	-8%	12-2028	70	R1.5	8.5	-67%	12-2028	70	R1.5	8.5	-60%
	Michigan City - Unit 12	12-2026	70	R1.5	-8%	12-2028	70	R1.5	8.5	-67%	12-2028	70	R1.5	8.5	-60%
	Sugar Creek	06-2068	70	R1.5	-20%	06-2068	70	R1.5	37.5	-28%	06-2068	70	R1.5	37.5	-27%
	Total Account 316.00														
	Total Steam Production Plant														
	Hydarulic Production Plant														
331.00	Structures and Improvements														
	Norway Generating Station	11-2037	70	S1	-8%	11-2037	70	S1	11.8	-13%	11-2037	70	S1	11.8	-11%
	Oakdale Generating Station	11-2037	70	S1	-9%	11-2037	70	S1	11.8	-8%	11-2037	70	S1	11.8	-7%
	Total Account 331.00														
332.00	Reservoirs, Dams, and Waterways														
	Norway Generating Station	11-2037	85	R3	-6%	11-2037	85	R2.5	11.8	-13%	11-2037	85	R2.5	11.8	-11%
	Oakdale Generating Station	11-2037	85	R3	-7%	11-2037	85	R2.5	11.8	-8%	11-2037	85	R2.5	11.8	-7%
	Total Account 332.00														
333.00	Water Wheels, Turbines, and Generators														

Northern Indiana Public Service Company
Table 5: Current and Proposed Parameters
As of December 31, 2025

		Current Approved				NIPSCO Proposed					OUCC Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Norway Generating Station	11-2037	75	R2	-6%	11-2037	75	R2	11.0	-13%	11-2037	75	R2	11.0	-11%
	Oakdale Generating Station	11-2037	75	R2	-7%	11-2037	75	R2	11.6	-8%	11-2037	75	R2	11.6	-7%
	Total Account 333.00														
334.00	Accessory Electric Equipment														
	Norway Generating Station	11-2037	55	L1.5	-6%	11-2037	55	L1.5	10.9	-13%	11-2037	55	L1.5	10.9	-11%
	Oakdale Generating Station	11-2037	55	L1.5	-7%	11-2037	55	L1.5	11.5	-8%	11-2037	55	L1.5	11.5	-7%
	Total Account 334.00														
335.00	Miscellaneous Power Plant Equipment														
	Norway Generating Station	11-2037	55	S0.5	-6%	11-2037	60	S0.5	11.6	-13%	11-2037	60	S0.5	11.6	-11%
	Oakdale Generating Station	11-2037	55	S0.5	-7%	11-2037	60	S0.5	11.5	-8%	11-2037	60	S0.5	11.5	-7%
	Total Account 335.00														
	Total Hydarulic Production Plant														
	Solar Production Plant														
341.10	Structures and Improvements - Solar						33	S2.5	32.6	0%		33	S2.5	32.6	0%
341.20	Structures and Improvements - Utility-Scale Solar														
	Cavalry	06-2054				06-2054	35	R4	27.3	-15%	06-2054	35	R4	27.3	-15%
	Dunns Bridge II	06-2055				06-2055	35	R4	28.3	-8%	06-2055	35	R4	28.3	-8%
	Fairbanks	06-2055				06-2055	35	R4	28.3	-13%	06-2055	35	R4	28.3	-13%
	Gibson	06-2055				06-2055	35	R4	28.3	-16%	06-2055	35	R4	28.3	-15%
	Total Account 341.20														
344.10	Generators - Solar		20	S2.5	0%		25	S2.5	19.7	0%		25	S2.5	19.7	0%
344.20	Generators - Utility-Scale Solar														
	Cavalry	06-2054				06-2054	30	S1.5	24.2	-15%	06-2054	30	S1.5	24.2	-15%
	Dunns Bridge II	06-2055				06-2055	30	S1.5	25.2	-8%	06-2055	30	S1.5	25.2	-8%
	Fairbanks	06-2055				06-2055	30	S1.5	25.2	-13%	06-2055	30	S1.5	25.2	-13%
	Gibson	06-2055				06-2055	30	S1.5	25.2	-16%	06-2055	30	S1.5	25.2	-15%
	Total Account 344.20														
345.10	Accessory Electric Equipment - Solar		20	S2.5	0%		25	S2.5	19.7	0%		25	S2.5	19.7	0%
345.20	Accessory Electric Equipment - Utility-Scale Solar														
	Cavalry	06-2054				06-2054	40	R1.5	25.5	-15%	06-2054	40	R1.5	25.5	-15%
	Dunns Bridge II	06-2055				06-2055	40	R1.5	26.3	-8%	06-2055	40	R1.5	26.3	-8%
	Fairbanks	06-2055				06-2055	40	R1.5	26.3	-13%	06-2055	40	R1.5	26.3	-13%
	Gibson	06-2055				06-2055	40	R1.5	26.3	-16%	06-2055	40	R1.5	26.3	-15%
	Total Account 345.20														
	Total Solar Production Plant														
	Other Production Plant														
341.00	Structures and Improvements														
	R M Schahfer - Units 16A and 16B	12-2026	50	S2.5	-6%	12-2026	55	R3	1.0	-4%	12-2026	55	R3	1.0	-3%
	R M Schahfer - Unit 16A	12-2026	50	S2.5	-6%	12-2026	55	R3	1.0	-4%	12-2026	55	R3	1.0	-3%
	Sugar Creek	06-2048	50	S2.5	-7%	06-2068	55	R3	35.4	-17%	06-2068	55	R3	35.4	-16%
	Total Account 341.00														
342.00	Fuel Holders, Producers, and Accessories														
	R M Schahfer - Units 16A and 16B	12-2026	50	S2.5	-3%	12-2026	55	S2	1.0	-4%	12-2026	55	S2	1.0	-3%
	Sugar Creek	06-2048	50	S2.5	-7%	06-2048	55	S2	21.1	-17%	06-2048	55	S2	21.1	-17%
	Total Account 342.00														
343.00	Prime Movers														
	R M Schahfer - Units 16A and 16B	12-2026	50	R1	-3%	12-2026	50	R1	1.0	-4%	12-2026	50	R1	1.0	-3%
	R M Schahfer - Unit 16A	12-2026	50	R1	-3%	12-2026	50	R1	1.0	-4%	12-2026	50	R1	1.0	-3%
	R M Schahfer - Unit 16B	12-2026	50	R1	-3%	12-2026	50	R1	1.0	-4%	12-2026	50	R1	1.0	-3%

Northern Indiana Public Service Company
Table 5: Current and Proposed Parameters
As of December 31, 2025

		Current Approved				NIPSCO Proposed					OUCC Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Sugar Creek	06-2048	50	R1	-7%	06-2048	50	R1	20.6	-17%	06-2048	50	R1	20.6	-17%
	Total Account 343.00														
344.00	Generators														
	R M Schahfer - Unit 16A	12-2026	55	R3	-3%	12-2026	55	R3	1.0	-4%	12-2026	55	R3	1.0	-3%
	R M Schahfer - Unit 16B	12-2026	55	R3	-3%	12-2026	55	R3	1.0	-4%	12-2026	55	R3	1.0	-3%
	Sugar Creek	06-2048	55	R3	-7%	06-2048	55	R3	21.4	-17%	06-2048	55	R3	21.4	-17%
	Total Account 344.00														
345.00	Accessory Electric Equipment														
	R M Schahfer - Units 16A and 16B	12-2026	50	S1	-3%	12-2026	50	S1	1.0	-4%	12-2026	50	S1	1.0	-3%
	R M Schahfer - Unit 16A	12-2026	50	S1	-3%	12-2026	50	S1	1.0	-4%	12-2026	50	S1	1.0	-3%
	R M Schahfer - Unit 16B	12-2026	50	S1	-3%	12-2026	50	S1	1.0	-4%	12-2026	50	S1	1.0	-3%
	Sugar Creek	06-2048	50	S1	-7%	06-2048	50	S1	19.9	-17%	06-2048	50	S1	19.9	-17%
	Total Account 345.00														
346.00	Miscellaneous Power Plant Equipment														
	R M Schahfer - Units 16A and 16B	12-2026	55	R2.5	-3%	12-2026	55	R2.5	1.0	-4%	12-2026	55	R2.5	1.0	-3%
	R M Schahfer - Unit 16A	12-2026	55	R2.5	-3%	12-2026	55	R2.5	1.0	-4%	12-2026	55	R2.5	1.0	-3%
	Sugar Creek	06-2048	55	R2.5	-7%	06-2048	55	R2.5	21.0	-17%	06-2048	55	R2.5	21.0	-17%
	Total Account 346.00														
	Total Other Production Plant														
	Total Production Plant														
	Transmission Plant														
350.20	Land Rights		75	R4	0%		80	R4	77.7	0%		80	R4	77.7	0%
352.00	Structures and Improvements		65	R1.5	-15%		70	R1.5	61.0	-20%		70	R1.5	61.0	-15%
353.00	Station Equipment		52	S0	-10%		50	S0	42.1	-15%		50	S0	42.1	-15%
354.00	Towers and Fixtures		75	R4	-26%		75	R3	62.7	-30%		75	R3	62.7	-26%
355.00	Poles and Fixtures		62	R1	-35%		60	R1	53.8	-40%		60	R1	53.8	-35%
356.00	Overhead Conductors and Devices		68	R2	-40%		65	R2	53.8	-45%		65	R2	53.8	-40%
357.00	Underground Conduit		65	S4	-5%		70	S4	54.1	-5%		70	S4	54.1	-5%
358.00	Underground Conductors and Devices		50	R1.5	-5%		50	R1.5	41.9	-5%		50	R1.5	41.9	-5%
359.00	Roads and Trails		70	R4	0%		65	R4	26.4	0%		65	R4	26.4	0%
	Total Transmission Plant														
	Distribution Plant														
360.20	Land Rights		75	R4	0%		80	R4	65.4	0%		80	R4	65.4	0%
361.00	Structures and Improvements		65	R1.5	-15%		70	R1.5	55.9	-20%		70	R1.5	55.9	-20%
362.00	Station Equipment		50	R1.5	-10%		52	S0	43.9	-15%		52	S0	43.9	-10%
364.10	Customer Transformer Station		50	S0	-53%		49	S0	39.8	-55%		49	S0	39.8	-55%
364.20	Poles, Towers, and Fixtures		47	R1	-53%		48	R1	41.1	-55%		48	R1	41.1	-55%
365.00	Overhead Conductors and Devices		65	R1	-60%		65	R1	57.8	-70%		65	R1	57.8	-60%
366.00	Underground Conduit		70	S2.5	-5%		70	S2.5	49.7	-5%		70	S2.5	49.7	-5%
367.00	Underground Conductors and Devices		52	R2	-30%		53	S2.5	43.2	-35%		53	S2.5	43.2	-30%
368.00	Line Transformers		47	S0	-8%		47	S0	37.1	-10%		47	S0	37.1	-10%
369.10	Overhead Services		47	R1	-32%		48	R1	39.7	-50%		48	R1	39.7	-50%
369.20	Underground Services		70	R3	-32%		75	R3	63.8	-50%		75	R3	63.8	-50%
370.10	Customer Metering Stations		50	R2	-2%		50	R2	39.2	-5%		50	R2	39.2	-2%
370.20	Meters		24	L0	-2%		25	L0	21.2	-5%		25	L0	21.2	-2%
371.00	Installations on Customers' Premises		20	O1	-25%		20	O1	16.4	-30%		20	O1	16.4	-30%
373.00	Street Lighting and Signal Systems		31	L0	-30%		30	L0	23.0	-40%		30	L0	23.0	-40%
	Total Distribution Plant														
	General Plant														
390.00	Structures and Improvements		55	R1.5	-10%		60	R1.5	55.7	-10%		60	R1.5	55.7	-10%
391.10	Office Furniture and Equipment		20	SQ	0%		20	SQ	7.5	0%		20	SQ	7.5	0%

Northern Indiana Public Service Company
Table 5: Current and Proposed Parameters
As of December 31, 2025

		Current Approved				NIPSCO Proposed					OUCC Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
391.20	Computers and Perifpheral Equipment		7	SQ	0%		7	SQ	1.6	0%		7	SQ	1.6	0%
393.00	Stores Equipment		30	SQ	0%		30	SQ	13.5	0%		30	SQ	13.5	0%
394.00	Tools, Shop, and Garage Equipment		25	SQ	0%		25	SQ	15.5	0%		25	SQ	15.5	0%
395.00	Laboratory Equipment		20	SQ	0%		20	SQ	7.6	0%		20	SQ	7.6	0%
397.00	Communication Equipment		15	SQ	0%		15	SQ	10.9	0%		15	SQ	10.9	0%
398.00	Miscellaneous Equipment		20	SQ	0%		20	SQ	12.2	0%		20	SQ	12.2	0%
	Total General Plant														

Northern Indiana Public Service Company
Table 6: Calculation of Weighted Net Salvage Percent for Generation Plant
As of December 31, 2025

	Terminal				Interim						
Location	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Retirements ($)	Net Salvage ($)	Percent of Total Retire	Net Salvage (%)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
A	B	C	D = C/K	E = C/B	F	G = F*I	H = F/K	I	J = C+G	K = B+F	L = J/K
Steam Production											
Bailly											
Michigan City	834,866,280	(508,231,554)	97.14%	-61%	24,559,095	(9,578,047)	2.86%	-39%	(517,809,601)	859,425,375	-60%
R.M. Schahfer											
Sugar Creek	94,683,301	(17,382,976)	57.49%	-18%	70,016,056	(27,306,262)	42.51%	-39%	(44,689,238)	164,699,357	-27%
Total Steam Production	**929,549,581**	**(525,614,530)**	**90.77%**	**-57%**	**94,575,151**	**(36,884,309)**	**9.23%**	**-39%**	**(562,498,839)**	**1,024,124,732**	**-55%**
Hydro Production Plant											
Norway	43,763,097	(3,579,259)	94.43%	-8%	2,579,233	(1,650,709)	5.57%	-64%	(5,229,968)	46,342,330	-11%
Oakdale	48,380,224	(2,479,797)	97.02%	-5%	1,488,218	(952,459)	2.98%	-64%	(3,432,256)	49,868,442	-7%
Total Hydro Production	**92,143,322**	**(6,059,056)**	**95.77%**	**-7%**	**4,067,451**	**(2,603,168)**	**4.23%**	**-64%**	**(8,662,224)**	**96,210,772**	**-9%**
Solar Production											
Cavalry	211,283,629	(48,995,737)	56.99%	-23%	159,449,231	(4,783,477)	43.01%	-3%	(53,779,214)	370,732,860	-15%
Dunns Bridge II	411,911,097	(50,220,631)	56.93%	-12%	311,596,866	(9,347,906)	43.07%	-3%	(59,568,537)	723,507,963	-8%
Fairbanks	253,113,939	(50,220,631)	56.93%	-20%	191,472,166	(5,744,165)	43.07%	-3%	(55,964,796)	444,586,105	-13%
Gibson	208,429,583	(50,220,631)	56.93%	-24%	157,669,956	(4,730,099)	43.07%	-3%	(54,950,730)	366,099,539	-15%
Total Solar Production	**1,084,738,248**	**(199,657,630)**	**56.94%**	**-18%**	**820,188,219**	**(24,605,647)**	**43.06%**	**-3%**	**(224,263,277)**	**1,904,926,467**	**-12%**
Other Production Plant											
R.M. Schahfer	75,086,746	(1,883,309)	97.27%	-3%	2,106,373	(568,721)	2.73%	-27%	(2,452,030)	77,193,119	-3%
Sugar Creek	165,979,646	(21,245,859)	80.08%	-13%	41,286,276	(11,147,294)	19.92%	-27%	(32,393,153)	207,265,921	-16%
Total Other Production	**241,066,392**	**(23,129,168)**	**84.75%**	**-10%**	**43,392,649**	**(11,716,015)**	**15.25%**	**-27%**	**(34,845,183)**	**284,459,041**	**-12%**
Total Production	**2,347,497,542**	**(754,460,384)**	**70.93%**	**-32%**	**962,223,470**	**(75,809,139)**	**29.07%**	**-8%**	**(830,269,523)**	**3,309,721,012**	**-25%**

Source:
Spanos Attachment 12-C

Northern Indiana Public Service Company
Table 7: Calculation of Terminal Net Salvage Percent
As of December 31, 2025

Plant	Estimated Total Decommissioning Cost (Current Year $)	Current Dollar Year	Retirement Year	2.50% Escalated Decommissioning Cost (Rate Year $)
A	B	C	D	E=B*(1+2.5%)^[D-C]
Steam Production				
Bailly	60,521,000	2023	2028	68,473,956
Michigan City	129,367,063	2023	2028	146,366,957
R.M. Schahfer	259,314,576	2023	2028	293,390,641
Sugar Creek	5,722,031	2023	2068	17,382,976
Total Steam Production	**454,924,670**			**525,614,530**
Hydro Production Plant				
Norway	2,533,139	2023	2037	3,579,259
Oakdale	1,755,020	2023	2037	2,479,797
Total Hydro Production	**4,288,159**			**6,059,056**
Solar Production				
Cavalry	22,788,643	2023	2054	48,995,737
Dunns Bridge II	22,788,643	2023	2055	50,220,631
Fairbanks	22,788,643	2023	2055	50,220,631
Gibson	22,788,643	2023	2055	50,220,631
Total Solar Production	**91,154,573**			**199,657,630**
Other Production Plant				
R.M. Schahfer	1,748,840	2023	2026	1,883,309
Sugar Creek	6,993,593	2023	2068	21,245,859
Total Other Production	**8,742,433**			**23,129,168**
Total Production	**559,109,834**			**754,460,384**

Source:
Spanos Attachment 12-B

Northern Indiana Public Service Company
Table 8: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2025

			NIPSCO Proposed		OUCC Proposed		
Account	Description	12/31/23 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from NIPSCO Proposed
	A	B	C	D	E	F	G
	General Plant						
390.00	Structures and Improvements	119,186,170	1.76%	2,094,082	1.76%	2,094,082	0
391.10	Office Furniture and Equipment	6,400,112	5.00%	319,979	5.00%	319,979	0
391.20	Computers and Perifpheral Equipment	3,435,861	14.29%	490,951	14.29%	490,951	0
393.00	Stores Equipment	2,740,544	3.33%	91,323	3.33%	91,323	0
394.00	Tools, Shop, and Garage Equipment	9,143,195	4.00%	365,645	4.00%	365,645	0
395.00	Laboratory Equipment	2,298,862	5.00%	114,882	5.00%	114,882	0
397.00	Communication Equipment	10,512,400	6.67%	700,781	6.67%	700,781	0
398.00	Miscellaneous Equipment	3,727,242	5.00%	186,265	5.00%	186,265	0
	Total General Plant	**157,444,386**	**2.77%**	**4,363,908**	**2.77%**	**4,363,908**	**0**
	Reserve Adjustment for Amortization						
391.10	Office Furniture and Equipment			(2,009,776)		(2,009,776)	0
391.20	Computers and Perifpheral Equipment			390,829		390,829	0
393.00	Stores Equipment			18,225		18,225	0
394.00	Tools, Shop, and Garage Equipment			(540,494)		(540,494)	0
395.00	Laboratory Equipment			17,218		17,218	0
397.00	Communication Equipment			(1,134,972)		(1,134,972)	0
398.00	Miscellaneous Equipment			(80,666)		(80,666)	0
	Total Reserve Adjustment for Amortization			**(3,339,636)**		**(3,339,636)**	**0**
	Total Depreciable Common Plant	**157,444,386**	**0.65%**	**1,024,272**	**0.65%**	**1,024,272**	**0**

Northern Indiana Public Service Company
Table 9: Calculation of Depreciation Rates
As of December 31, 2025

Account	Description	12/31/23 Investment	12/31/23 Book Reserve	Percent Reserve	Future Net Salvage Percent	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	G	H	I
	General Plant							
390.00	Structures and Improvements	119,186,170	51,144,956	42.91%	-10%	38.2	1.76%	2,093,189
391.10	Office Furniture and Equipment	6,400,112	3,338,392	52.16%	0%	9.6	4.98%	318,929
391.20	Computers and Perifpheral Equipment	3,435,861	1,777,663	51.74%	0%	3.4	14.19%	487,705
393.00	Stores Equipment	2,740,544	1,654,128	60.36%	0%	11.9	3.33%	91,295
394.00	Tools, Shop, and Garage Equipment	9,143,195	3,238,921	35.42%	0%	16.1	4.01%	366,725
395.00	Laboratory Equipment	2,298,862	678,766	29.53%	0%	14.1	5.00%	114,900
397.00	Communication Equipment	10,512,400	6,576,115	62.56%	0%	5.6	6.69%	702,908
398.00	Miscellaneous Equipment	3,727,242	1,965,820	52.74%	0%	9.5	4.97%	185,413
	Total General Plant	**157,444,386**	**70,374,761**	**44.70%**	**-6%**	**22.0**	**2.77%**	**4,361,066**
	Reserve Adjustment for Amortization							
391.10	Office Furniture and Equipment		6,029,329			3.0		(2,009,776)
391.20	Computers and Perifpheral Equipment		(1,172,489)			3.0		390,830
393.00	Stores Equipment		(54,673)			3.0		18,224
394.00	Tools, Shop, and Garage Equipment		1,621,484			3.0		(540,495)
395.00	Laboratory Equipment		(51,653)			3.0		17,218
397.00	Communication Equipment		3,404,917			3.0		(1,134,972)
398.00	Miscellaneous Equipment		241,998			3.0		(80,666)
	Total Reserve Adjustment for Amortization							**(3,339,637)**
	Total Depreciable Common Plant	**157,444,386**	**80,393,674**	**51.06%**	**35%**	**22.0**	**0.65%**	**1,021,429**

Northern Indiana Public Service Company
Table 10: Current and Proposed Parameters
As of December 31, 2025

Account	Description	Current Approved			NIPSCO Proposed				OUCC Proposed			
		Proj Life	Iowa Curve Shape	Future Net Salvage	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L
	General Plant											
390.00	Structures and Improvements	50	S0	-10%	55	S0	38.2	-10%	55	S0	38.2	-10%
391.10	Office Furniture and Equipment	20	SQ	0%	20	SQ	9.6	0%	20	SQ	9.6	0%
391.20	Computers and Perifpheral Equipment	7	SQ	0%	7	SQ	3.4	0%	7	SQ	3.4	0%
393.00	Stores Equipment	30	SQ	0%	30	SQ	11.9	0%	30	SQ	11.9	0%
394.00	Tools, Shop, and Garage Equipment	25	SQ	0%	25	SQ	16.1	0%	25	SQ	16.1	0%
395.00	Laboratory Equipment	20	SQ	0%	20	SQ	14.1	0%	20	SQ	14.1	0%
397.00	Communication Equipment	15	SQ	0%	15	SQ	5.6	0%	15	SQ	5.6	0%
398.00	Miscellaneous Equipment	20	SQ	0%	20	SQ	9.5	0%	20	SQ	9.5	0%
	Total General Plant											

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Nineteenth Set of Data Requests

OUCC Request 19-001:
Pages 8, 9, and 27 of Attachment 12-C indicate Estimated Retirement Years for Solar Production as follows: Cavalry 2049, Dunns Bridge II 2050, Fairbanks 2050, and Gibson 2050. Pages 66, 72, and 76 of Attachment 12-C indicate Estimated Retirement Years for Solar Production as follows: Cavalry 2054, Dunns Bridge II 2055, Fairbanks 2055, and Gibson 2055. What are the estimated retirement years for those solar production units?
Objections:
Response:
The previous life span for solar facilities was 25 years; however, in this study it was determined that a 30-year life span for this generation of solar farms was most appropriate. Therefore, the probable retirement date for Cavalry is 2054, Dunns Bridge II is 2055, Fairbanks is 2055 and Gibson is 2055 when these facilities are placed in service. Updated Tables 1, 7, 8 and associated depreciation calculations for all solar accounts are set forth in OUCC Request 19-001 Attachment A, OUCC Request 19-001 Attachment B, OUCC Request 19-001 Attachment C, and OUCC Request 19-001 Attachment D, respectively. Correcting the associated weighted net salvage produced an overall increase in depreciation expense of approximately $896,000 from what was filed for solar assets. NIPSCO is not seeking to increase the total revenue requirement for this higher depreciation adjustment but is providing it as responsive information for purposes of this request and the parties' rate case review.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Corrected and Supplemental Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-015:
Please provide the workpaper that supports the Total Decommissioning Cost of Bailly Steam Production shown in column (3) of Table 4 on page 289 of Attachment 12-B.
Objections:
Response:
The decommissioning amount shown for Bailly in Table 4 of Attachment 12-B is from a decommissioning study filed in Cause No. 45772 and escalated as described in the Verified Direct Testimony of John J. Spanos (Petitioner's Exhibit No. 12). Please see OUCC Request 14-015 Attachment A.
Corrected and Supplemental Response:
The decommissioning amount shown for Bailly in Table 4 of Attachment 12-B is from a decommissioning study prepared in anticipation of Cause No. 45772. OUCC Request 14-015 Attachment A is Table 8 from that study, which was not filed with the Commission. OUCC Request 14-015 Attachment B is the excel version of Table 4 of Attachment 12-B in this Cause with formulas intact that shows the escalation calculation of the Total Decommissioning Cost of Steam Production.

VERIFIED DIRECT TESTIMONY OF JEFFREY T. KOPP

Q1. Please state your name, business address and title.

A1. My name is Jeffrey ("Jeff") T. Kopp, P.E. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114. I am a Senior Managing Director of 1898 & Co., which is the consulting group within Burns & McDonnell Engineering Co., Inc. ("BMcD").

Q2. On whose behalf are you submitting this direct testimony?

A2. I am submitting this testimony on behalf of Northern Indiana Public Service Company LLC ("NIPSCO").

Q3. Please describe the business of BMcD.

A3. BMcD is a consulting environmental, engineering, and construction firm working with many industries, including electric utilities. BMcD has been in business since 1898, serving multiple industries, including the electric power industry. In 2022, BMcD was rated No. 8 overall of the Top 500 Design Firms by the Engineering News Record ("ENR"). BMcD was rated

Decommissioning Cost Study

Northern Indiana Public Service Company

NIPSCO Decommissioning Cost Study
Project No. 143405

7/13/2022

Table A-1
Bailly
Decommissioning Cost Summary

		Labor		Material and Equipment		Disposal		Environmental		Total Cost		Scrap Value
Bailly												
Unit 7												
Asbestos Removal	$	-	$	-	$	-	$	3,998,000	$	3,998,000	$	-
Boiler	$	1,273,000	$	1,205,000	$	-	$	-	$	2,478,000	$	-
Steam Turbine & Building	$	958,000	$	907,000	$	-	$	-	$	1,865,000	$	-
Precipitators	$	282,000	$	267,000	$	-	$	-	$	549,000	$	-
Scrubber / FGD	$	477,000	$	452,000	$	-	$	-	$	929,000	$	-
Stacks	$	243,000	$	230,000	$	-	$	-	$	473,000	$	-
Cooling Water Intakes and Circulating Water Pumps	$	9,000	$	9,000	$	-	$	-	$	18,000	$	-
GSU, Foundation & Electrical	$	63,000	$	59,000	$	-	$	-	$	122,000	$	-
On-site Concrete Crushing & Disposal	$	-	$	-	$	72,000	$	-	$	72,000	$	-
Scrap	$	-	$	-	$	-	$	-	$	-	$	(4,512,000)
Subtotal	**$**	**3,305,000**	**$**	**3,129,000**	**$**	**116,000**	**$**	**3,998,000**	**$**	**10,548,000**	**$**	**(4,512,000)**
Unit 8												
Asbestos Removal	$	-	$	-	$	-	$	4,620,000	$	4,620,000	$	-
Boiler	$	1,845,000	$	1,747,000	$	-	$	-	$	3,592,000	$	-
Steam Turbine & Building	$	1,261,000	$	1,194,000	$	-	$	-	$	2,455,000	$	-
Precipitator	$	448,000	$	424,000	$	-	$	-	$	872,000	$	-
SCR	$	301,000	$	285,000	$	-	$	-	$	586,000	$	-
Scrubber / FGD	$	1,119,000	$	1,059,000	$	-	$	-	$	2,178,000	$	-
Stacks	$	528,000	$	500,000	$	-	$	-	$	1,028,000	$	-
Cooling Water Intakes and Circulating Water Pumps	$	14,000	$	13,000	$	-	$	-	$	27,000	$	-
GSU, Foundation & Electrical	$	68,000	$	64,000	$	-	$	-	$	132,000	$	-
On-site Concrete Crushing & Disposal	$	-	$	-	$	88,000	$	-	$	88,000	$	-
Scrap	$	-	$	-	$	-	$	-	$	-	$	(8,500,000)
Subtotal	**$**	**5,584,000**	**$**	**5,286,000**	**$**	**150,000**	**$**	**4,620,000**	**$**	**15,640,000**	**$**	**(8,500,000)**
Unit 10												
Asbestos Removal	$	-	$	-	$	-	$	15,000	$	15,000	$	-
CTGs and HRSGs	$	102,000	$	96,000	$	-	$	-	$	198,000	$	-
Stacks	$	3,000	$	3,000	$	-	$	-	$	6,000	$	-
GSU, Foundation & Electrical	$	56,000	$	53,000	$	-	$	-	$	109,000	$	-
On-site Concrete Crushing & Disposal	$	-	$	-	$	4,000	$	-	$	4,000	$	-
Debris	$	-	$	-	$	7,000	$	-	$	7,000	$	-
Scrap	$	-	$	-	$	-	$	-	$	-	$	(637,000)
Subtotal	**$**	**161,000**	**$**	**152,000**	**$**	**11,000**	**$**	**15,000**	**$**	**339,000**	**$**	**(637,000)**
Handling												
Coal Handling Facilites	$	336,000	$	318,000	$	-	$	-	$	654,000	$	-
Coal Storage Area Restoration	$	-	$	-	$	-	$	2,252,000	$	2,252,000	$	-
On-site Concrete Crushing & Disposal	$	-	$	-	$	4,000	$	-	$	4,000	$	-
Debris	$	-	$	-	$	111,000	$	-	$	111,000	$	-
Scrap	$	-	$	-	$	-	$	-	$	-	$	(411,000)
Subtotal	**$**	**336,000**	**$**	**318,000**	**$**	**115,000**	**$**	**2,252,000**	**$**	**3,021,000**	**$**	**(411,000)**
Common												
Lagre Pipe Flowable Fill	$	-	$	-	$	-	$	44,000	$	44,000	$	-
BOP Misc.	$	3,000	$	3,000	$	-	$	-	$	6,000	$	-
Roads	$	81,000	$	77,000	$	-	$	-	$	158,000	$	-
All BOP Buildings	$	433,000	$	410,000	$	-	$	-	$	843,000	$	-
Fuel Equipment	$	5,000	$	4,000	$	-	$	-	$	9,000	$	-
All Other Tanks	$	189,000	$	179,000	$	-	$	-	$	368,000	$	-
Transformers & Foundation	$	10,000	$	9,000	$	-	$	317,000	$	336,000	$	-
Mercury & Universal Waste Disposal	$	-	$	-	$	-	$	718,000	$	718,000	$	-
Below Grade Fuel Lines Removal/Remediation	$	-	$	-	$	-	$	145,000	$	145,000	$	-
Non-CCR Pond Closure	$	-	$	-	$	-	$	165,000	$	165,000	$	-
Historic Contamination associated with SWMUs	$	-	$	-	$	-	$	23,539,000	$	23,539,000	$	-
Hazardous Waste Disposal	$	-	$	-	$	-	$	632,000	$	632,000	$	-
Plant Washdown & Materials Disposal	$	-	$	-	$	-	$	70,000	$	70,000	$	-
Concrete Removal, Crushing, & Disposal	$	-	$	-	$	40,000	$	-	$	40,000	$	-
Grading & Seeding	$	-	$	-	$	-	$	3,316,000	$	3,316,000	$	-
Debris	$	-	$	-	$	10,000	$	-	$	10,000	$	-
Scrap	$	-	$	-	$	-	$	-	$	-	$	(352,000)
Subtotal	**$**	**721,000**	**$**	**682,000**	**$**	**50,000**	**$**	**28,946,000**	**$**	**30,399,000**	**$**	**(352,000)**
Bailly Subtotal	**$**	**10,107,000**	**$**	**9,567,000**	**$**	**442,000**	**$**	**39,831,000**	**$**	**59,947,000**	**$**	**(14,412,000)**
TOTAL DECOM COST (CREDIT)									**$**	**59,947,000**	**$**	**(14,412,000)**
PROJECT INDIRECTS (5%)									**$**	**2,997,000**		
CONTINGENGY (20%)									**$**	**11,989,000**		
TOTAL PROJECT COST (CREDIT)									**$**	**74,933,000**	**$**	**(14,412,000)**
TOTAL NET PROJECT COST (CREDIT)									**$**	**60,521,000**		

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-036:
Please provide a description of and documents supporting the 5% "Project Indirects" cost included in the estimated decommissioning cost on pages 13-17 and pages 20-21 of Attachment 12-D.
Objections:
Response:
The 5% "Project Indirect" cost was the level used in prior decommissioning studies. Based on Gannett Fleming's experience, this continues to be reasonable and is consistent with prior studies.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-038:
Please provide a description of and documents supporting the 6.5% "Indirect Costs" cost included in the estimated decommissioning cost on pages 18-19 of Attachment 12-D.
Objections:
Response:
As was the case for other generation assets, the indirect cost was based on levels used for prior decommissioning studies. In this case specifically, the 5% indirect cost level was increased to account for inclusion of project management costs that are unique to hydro facilities given the need to ensure continued operation of the damn and spillways.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

<u>OUCC Request 14-034:</u>
Please provide a description of and documents supporting the 15% "Overhead" cost included in the estimated decommissioning cost on pages 13-17 and pages 20-21 of Attachment 12-D.
<u>Objections:</u>
<u>Response:</u>
Overhead costs, both fixed and variable, will vary given project size. Typically, larger projects will have higher overhead rates, primarily driven by higher variable costs. In this case, 15% is a fairly typical rate for a decommissioning project of this size, based on extensive prior experience by Gannett Fleming's cost estimation team.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-040:
Please provide a description of and documents supporting the 15% "Overhead and Profit" cost included in the estimated decommissioning cost on pages 18-19 of Attachment 12-D.
Objections:
Response:
The 15% Overhead and Profit level represents the expectation of what would be required by the General Contractor given the expected decommissioning scope and any unknown site conditions. The 15% rate is based on Gannett Fleming's experience developing cost estimates as well as the design and construction of large capital projects.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-035:
Please provide a description of and documents supporting the 10% "Profit on Subcontractors" cost included in the estimated decommissioning cost on pages 13-17 and pages 20-21 of Attachment 12-D.
Objections:
Response:
The 10% rate is based on Gannett Fleming's experience developing cost estimates as well as the design and construction of large capital projects. A rate of 10% Profit markup on Subcontractor work is reasonable when estimating a project given the scope and scale of a project. Lower rates, such as 5% would typically only be appropriate when the Contractor specifically knows the Subcontractor that is being utilized and the amount of work to be performed has a significantly high dollar value and the general contractor is trying to reduce their bid. For instance, this could occur because the general contractor is using a known subcontractor that did not provide the lowest available bid.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-037:
Please provide a description of and documents supporting the 20% "Contingency" cost included in the estimated decommissioning cost on pages 13-17 and pages 20-21 of Attachment 12-D.
Objections:
Response:
The 20% "contingency" cost was the level used in the decommissioning study proposed and approved in Cause No. 45772. Based on the scope of the decommissioning cost estimates as well as Gannett Fleming's experience, a contingency of at least 20% would be reasonable. The contingency captures unknown factors that will impact a project's costs, such as weather delays or incremental costs (such as environmental costs) that were not captured in the decommissioning estimates due to the level of precision in the development of these estimates. The use of a contingency factor is common when estimating the cost of construction or demolition projects.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Fourteenth Set of Data Requests

OUCC Request 14-039:
Please provide a description of and documents supporting the 30% "Contingency" cost included in the estimated decommissioning cost on pages 18-19 of Attachment 12-D.
Objections:
Response:
As was the case for other generation assets, the initial contingency cost was based on levels used for prior decommissioning studies. In this case specifically, the contingency cost level was elevated to account for unknown conditions at the site and for unforeseen eventualities. As site conditions are directly observed during the decommissioning process, expected contingency costs will be better understood.

Northern Indiana Public Service Company
Comparison of Actually Incurred Net Salvage and Net Salvage Accruals in Proposed Depreciation Rates
As of December 31, 2023

Account	Description	Five-Year Average Annual Net Salvage Actually Incurred	Net Salvage Recovery Included in NIPSCO Proposed Depr Rates	NIPSCO Proposed / Actually Incurred	Net Salvage Recovery Included in OUCC's Proposed Depr Rates	OUCC's Proposed / Actually Incurred
		A	B	C=B/A	D	E=D/A
	Transmission Plant					
350.20	Land Rights	0	0	0.0	0	0.0
352.00	Structures and Improvements	31,569	235,323	7.5	173,252	5.5
353.00	Station Equipment	1,341,696	2,156,351	1.6	2,156,351	1.6
354.00	Towers and Fixtures	114,021	587,972	5.2	498,082	4.4
355.00	Poles and Fixtures	853,535	2,043,330	2.4	1,772,732	2.1
356.00	Overhead Conductors and Devices	459,297	1,419,167	3.1	1,236,291	2.7
357.00	Underground Conduit	0	95	0.0	95	0.0
358.00	Underground Conductors and Devices	1,317	2,995	2.3	2,995	2.3
359.00	Roads and Trails	0	0	0.0	0	0.0
	Total Transmission Plant	**2,801,436**	**6,445,234**	**2.3**	**5,839,799**	**2.1**
	Distribution Plant					
360.20	Land Rights	0	0	0.0	0	0.0
361.00	Structures and Improvements	27,504	35,165	1.3	35,165	1.3
362.00	Station Equipment	504,401	1,446,646	2.9	952,535	1.9
364.00	Poles, Towers, and Fixtures	3,768,728	7,412,834	2.0	7,417,589	2.0
365.00	Overhead Conductors and Devices	1,148,030	3,528,575	3.1	2,931,361	2.6
366.00	Underground Conduit	0	2,934	0.0	2,934	0.0
367.00	Underground Conductors and Devices	671,244	3,684,207	5.5	3,114,004	4.6
368.00	Line Transformers	537,811	631,658	1.2	631,658	1.2
369.00	Services	846,237	1,633,073	1.9	1,633,911	1.9
370.00	Meters	28,220	125,707	4.5	49,424	1.8
371.00	Installations on Customers' Premises	92,237	108,733	1.2	108,481	1.2
373.00	Street Lighting and Signal Systems	1,480,021	876,868	0.6	878,672	0.6
	Total Distribution Plant	**9,104,433**	**19,486,402**	**2.1**	**17,755,736**	**2.0**

Public Utility

Depreciation Practices

August 1996

Compiled and Edited by

Staff Subcommittee on Depreciation of

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of the

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Costs may also be distributed over production rather than over service life. This method, the unit of production method, distributes the costs as units are produced using a rate per unit developed from the total estimated units to be produced. It is similar to the straight-line method but is a function of production rather than a function of time.

Salvage Considerations

Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between the gross salvage that will be realized when the asset is disposed of and the cost of retiring it. Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage. Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.

This treatment of net salvage is in harmony with generally accepted accounting principles and tends to remove from the income statement any fluctuations caused by erratic, although necessary, abandonment and removal operations. It also has the advantage that current consumers pay or receive a fair share of costs associated with the property devoted to their service, even though the costs may be estimated.

The practical difficulties of estimating, reporting, and accounting for salvage and cost of retirement have raised questions as to whether more satisfactory results might be obtained if net salvage were credited or charged, as appropriate, to current operations at the time of retirement instead of being provided for over the life of the asset. The advocates of such a procedure contend that salvage is not only more difficult to estimate than service life but, for capital intensive public utilities, it is typically a minor factor in the entire depreciation picture. The obvious exception, of course, is the huge retirement cost of decommissioning nuclear power plants. The advocates of recording salvage at the time of retirement further contend that salvage could properly be accounted for on the basis of known happenings at the date of retirement rather than on speculative estimates of factors, such as junk material prices, future labor costs, and environmental remediation costs in effect at the time of retirement.

One of the practical difficulties of estimating net salvage is that reported salvage is a mixture of salvage on items retired and reused internally, salvage on items sold externally as functional equipment, and salvage on items junked and sold as scrap. Because the likelihood of reuse is greater for items that are retired at early ages, the historical salvage is usually higher than the future salvage to be realized when the account begins to decline and there is little opportunity for reuse. Therefore, under these circumstances, book salvage may overstate the average salvage realized over the entire life of the account. This has led to the proposal to redefine net salvage and retirements to eliminate the effect of reused material. Reuse salvage is further discussed in Chapter III.

The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices. In an increasing number of instances, the average net salvage is estimated to be a large negative number when expressed as a percentage of original cost, sometimes in excess of negative 100%. This may look unrealistic but is appropriate and necessary so that the required cost allocation occurs. Nonetheless, a careful analysis of retirements should be made to determine if such large negative net salvage values are due to unusual circumstances. An example is the retirement of old cast iron gas mains in congested metropolitan areas. Due to urban renewal, a utility may have a significant amount of such activity for a few years. Since most of the investment in this account may now be in plastic mains in rural or suburban areas where access is easier, the removal of old cast iron gas mains at today's cost may not be representative of the costs that can be expected for plastic mains.

While this situation should not impose insurmountable difficulties from a depreciation expense or cost allocation perspective, it presents an interesting problem from the standpoint of the rate base. Since rate base is generally the difference between book cost and accumulated depreciation, the provision for negative salvage further decreases the rate base. If the original book cost for old plant is less than the accumulated provision for depreciation, the rate base could be a negative amount.

As the foregoing discussion indicates, gross salvage, in contrast to service life, is usually small in its overall effect on calculating a depreciation rate. Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate.

Group Plan

The group plan of depreciation accounting is particularly adaptable to utility property. Rather than depreciating each item by itself (unit depreciation) or depreciating one single group containing all utility plant, a group contains homogeneous units of plant which are alike in character, used in the same manner throughout the utility's service territory, and operated under the same general conditions.

Of course there will be different lives for individual units within groups. For example, poles are generally combined in a single group. Some poles will be retired because of storms or automobile accidents. Some will decay, some will be displaced due to road relocations and some will be retired because of underground replacements. However, they are combined in the same group because they are homogeneous units. Years ago when some poles were untreated, there was a need for a separate grouping as these poles were more susceptible to decay and termite infestation than treated poles. Likewise, concrete poles have unique characteristics and qualify to be grouped separately from wood poles. Buried, aerial, and underground (in conduit) cables are further examples of the same type of plant receiving different grouping because of superior equipment. For example, the replacement of copper cable with fiber optic cable not only enhances the operational efficiency but also provides the potential for future applications mandated by the changing requirements of customers and market forces.

Growth

Growth in demand for utility service may cause present facilities to become inadequate. The service life of longer life property may be shortened because of the need for capacity to carry a greater load. Growth in demand should be examined for the impact on past retirements and the analyst should consider whether future growth will alter the historical trend of retirements. If growth was present in the past and is expected to be slow in the future, then the analyst might expect service lives in the future to be greater than in the past. The historical period might be filled with replacements that were improvements over the property being retired. On the other hand, if future growth is expected to be greater than past growth, service lives may decrease because present property might not be adequate to handle future demand.

Informed Judgment

A depreciation study is commonly described as having three periods of analysis: the past, present, and future. The past and present can usually be analyzed with great accuracy using many currently available analytical tools. The future still must be predicted and must largely include some subjective analysis. *Informed judgment* is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.

The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance. For example, the following forces of retirement need to be considered: Do the past and current service life dispersions represent the future? Will scrap prices rise or fall? What will be the impact of future technological obsolescence? Will the company be in existence in the future? The analyst must rank the factors and decide the relative weight to apply to each. The final estimate might not resemble any one of the specific factors; however, the result would be a decision based upon a combination of the components.

Judgment is not necessarily limited to forecasting and is used in situations where little current data are available. The analyst gathers what is known about a particular situation and modifies and refines the data to reflect the actual circumstances. The analyst's role in performing the study is to review the results and determine if they represent the mortality characteristics of the property. Using judgment, the analyst considers such things as personal experience, maintenance policies, past company studies, and other company owned equipment to determine if the stub curve represents this class of property.

The use of informed judgment sometimes becomes a point of controversy in the regulatory setting because some of the analyst's opinions cannot be quantified or easily supported. It is sometimes impossible to pinpoint the reasons for making a decision that diverges from a company's historical data or standard reference material. For instance, limited retirement data show that a new transformer design appears to have a significantly shorter service life; this would result in a significantly higher depreciation rate. Since this is a new design, there is no field experience to apply to the estimate, other than the scant data. Should the rate be based solely on the data? In the other extreme, should this preliminary data be given little weight and should the rate be based upon other types of transformers as reasonable indicators of the life of this new design? It is the analyst's responsibility to apply any additional known factors that would produce the best estimate of the service life. The analyst's judgment, comprised of a combination of experience and knowledge, will determine the most reasonable estimate.

In summary, several factors should be considered in estimating property life. Some of these factors are:

1. Observable trends reflected in historical data,
2. Potential changes in the type of property installed,
3. Changes in the physical environment,
4. Changes in management requirements,
5. Changes in government requirements, and
6. Obsolescence due to the introduction of new technologies.

CHAPTER XI

ESTIMATING SALVAGE AND COST OF REMOVAL

General

A general discussion of salvage and cost of removal is presented in Chapter III. Before discussing the process of analyzing and estimating these factors, a review of definitions and discussion of general principles is presented below.

When depreciable plant facilities are retired from service and physically removed, costs may be incurred and/or cash or other value may be realized if they are sold or retained for reuse. The abandonment of utility property in place can also cause costs to be incurred, (e.g., the cost of filling an abandoned gas pipe line with an inert gas). The term gross salvage refers to the amount received for retired property sold or junked, reimbursement received from insurance or other sources, or the amount at which reusable material is charged to a utility's Material and Supplies Account.[1] Cost of removal is the expenditure incurred in connection with retiring, removing, and dispersing of property. Net salvage is the difference between gross salvage and cost of removal.

Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

Some commissions have abandoned the above procedure and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred.

Determining a reasonably accurate estimate of the average or future net salvage is not an easy task; estimates can be the subject of considerable discussion and controversy between regulators and utility personnel. This is one of the reasons advanced in support of current-period accounting for these items. When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process should start by

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[1] Regulatory agencies generally require that reusable material consisting of retirement units be salvaged at original cost, while minor items may be salvaged at current prices new. Some regulatory agencies take into consideration the fact that depreciation has been sustained.

analyzing past salvage and cost of removal data and by using the results of this analysis to project future gross salvage and cost of removal.

When performing an analysis of net salvage data, certain considerations should be kept in mind. Generally, if transfers or sales of plant have contributed significantly to realized salvage, and such transactions are considered to be unrepresentative of the future, these transactions should be eliminated from the data. If the account consists of several categories of plant, such as several radically different types and sizes of buildings, the realized salvage should be analyzed to determine whether the related retirements are a representative cross-section of the account. The age of the retired plant, market conditions prevailing at the time of retirement, company policy regarding reuse in the past, environmental remediation costs, and reimbursements in instances of damage, condemnation or forced relocation resulting from highway construction should all be considered in preparation for projecting future net salvage.

It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current-period accounting for gross salvage and, particularly, cost of removal.

Analysis and Forecast

Data relative to gross salvage and cost of removal associated with past retirement of plant can be obtained from a variety of sources; the depth of the necessary analysis will depend on the particular circumstances surrounding the past retirement of plant from the account under analysis. Generally, a first cut can be obtained from data found in the utility's annual report filed with the state regulatory commission; that data should replicate the data contained in the utility's Depreciation Reserve or Accumulated Depreciation account records. The utility, however, may subdivide primary accounts into two or more classifications for depreciation purposes, while the data contained in its annual report to the regulatory commission may be for the entire primary account.

Frequently it is necessary to go beyond the summary information contained in utility annual reports. Internal utility reports that provide monthly and cumulative data on retirements, gross salvage, and cost of removal by sub-account or depreciation category are usually available. Review of these records, particularly monthly records, can be of great benefit in isolating the circumstances surrounding apparently abnormal data. It may be necessary to review specific work orders or estimates to determine whether particular data is correct and/or representative of the category and future activity. If the utility is using retirement work orders, and is using them properly, the salvage and cost of removal amounts appearing in a utility's Accumulated

Conformance Index (CI)
A measure of closeness of fit between calculated and actual balances in the Simulated Plant-Record Model. The best fits are those with the highest CIs. The CI equals 1,000 divided by the index of variation (IV). See **Simulated Plant-Record Model (SPR).**

Continuing Property Record (CPR)
A perpetual collection of essential records showing the detailed original costs, quantities, and locations of plant in service. These records vary in detail depending upon the kind of plant. CPRs are required by most systems of accounts. Generally, a CPR should contain 1) an inventory of property record units which can be readily checked for proof of physical existence, 2) the association of costs with such property record units to ensure accurate accounting for retirements, and 3) the dates of installation and removal of plant to provide data for use in connection with depreciation studies.

Converted Life Table
A life table with the same basic shape as the Graduated Life Table from which it was developed but having whatever average life was specified by the analyst.

Cost of Removal
The costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place. See **Net Salvage**.

Cradle-to-Grave
An accounting method which treats a unit of plant as being in service from the time it is first purchased until it is finally junked or disposed of. Periods in shop for refurbishing, and in stock awaiting reinstallation are included in the service life. See, in contrast, **Location Life.**

Depletion
The loss of service value incurred in connection with the exhaustion of a natural resource in the course of service.

Depreciable Base
The cost of plant in service which is allocable to expense during the service life of the property through the depreciation process.

Depreciable Plant
Plant in service for which it is proper to allocate the original cost to annual expense through the depreciation process. Items such as land and plant under construction are not considered depreciable.

Gross Additions
Plant additions made during an accounting period. These additions do not include adjustments, transfers, and reclassifications applicable to plant placed in a previous year.

Gross Salvage
The amount recorded for the property retired due to the sale, reimbursement, or reuse of the property.

Group Depreciation
In depreciation accounting, a procedure under which depreciation charges are accrued on the basis of the original cost of all property included in each depreciable group.

h Curves
A system of mathematically-developed, generalized survivor curves based on the truncated normal distribution (curve). The h curves are used by the New York Department of Public Service and most New York utilities.

Half-Year Convention
For calculation purposes, the units installed during an age interval are assumed to have been installed simultaneously at the middle of the interval and thus to have an age dating from the middle of the interval during which they were placed in service. See **Age Interval**.

Harmonic Weighting
See **Reciprocal Weighting**.

Historical Cost
See **Book Cost**.

Index of Variation (IV)
The conformance index divided by 1,000. See **Conformance Index (CI)**.

Indirect Weighting
See **Reciprocal Weighting**.

Installations
See **Gross Additions**.

Installed Cost
The cost of labor, material, engineering and overhead associated with transporting and delivering, attaching, testing, and preparing a piece of equipment for the purpose for which acquired. These outlays are capitalized as part of the cost of the asset. This is also referred to as in-place cost.

Location Life
The period of time during which depreciable plant is in service at one location. See, in contrast, **Cradle-to-Grave Accounting**.

Major Structure
A large, identifiable unit of plant or any assembly of plant, most of which will continue in service until final retirement. See **Interim Retirements**, **Final Retirement**, **Average Year of Final Retirement**.

Mass Property Group or Account
An account consisting of large numbers of similar units, the life of any one of which is not, in general, dependent upon the life of any of the other units. For such classes of plant, the retirement of a group of units occurs gradually until the last unit is retired. The retirements and additions to the account occur more or less continually and systematically.

Mortality Data
See **Aged Data**.

Mortality Rate
See **Retirement Ratio (Rate)**.

Net Book Cost
The recorded cost of an asset or group of assets minus the accumulated depreciation of those assets.

Net Salvage
The gross salvage for the property retired less its cost of removal.

Observed Life Table
A series of percents surviving, by age, reflecting the actual experience recorded in a band of mortality data.

Original Cost
The cost of property when first placed in service. See **Book Cost**.

Placement Year
See **Vintage Year**.

Probable Life
The total expected service life for survivors at a given age. It is the sum of the age of the survivors and their remaining life.

Projection Life
The average life expectancy of new additions to plant. See **Projection Life Table**.

Depreciation Systems

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Contents

and heavy equipment, while the gross salvage is nil or negligible. The result is a net salvage that is often both large and negative. Decommissioning costs of a nuclear generating plant are a contemporary example of an investment with a significant negative net salvage.

Basic salvage concepts must be understood before either the analysis of realized salvage or the forecasting of future salvage can be discussed. Most of these concepts can be applied equally well to either gross salvage or cost of removal, so the term *salvage* is used generically to apply to net salvage, gross salvage, or cost of retiring.

Property placed in service during the same year forms a *vintage group.* The fraction of the vintage group remaining in service is a function of its age and is described by a survivor curve. An underlying functional relationship between the age at retirement and salvage is assumed. A formal development of how salvage changes as property ages is necessary to understand the effect of salvage on depreciation.

A salvage curve is the graph of the salvage ratio versus age. The salvage ratio is the ratio of the salvage to the original cost of the retired unit. The salvage received during any age interval is found by multiplying the salvage ratio for that interval by the dollars retired during that interval. The net salvage ratio is the gross salvage ratio less the cost of retiring salvage ratio.

As one example of a salvage curve, consider property that is easily removed from service and is still functional after retirement. Gross salvage of early retirements will be high if the property is in good condition and the technology is current, because the property will be valuable for sale or reuse. Older retirements would be less valuable because, besides their added wear, they would be competing for use with property that has a more current technology. If the cost of retiring is assumed to be near zero, this model would lead to a net salvage schedule where the salvage ratio is initially near one, but then decreases with age. This example could be expanded to include retirements resulting from damage from an accident or mechanical failure. Because of their physical condition, these units would have a salvage ratio near zero and would lower the overall salvage ratio.

A salvage curve need not decrease with age. The gross salvage of scrap copper, steel, or aluminum typically, because of inflation, increases with age. A cost of retiring that is labor and equipment intensive is another example of a salvage curve that, because of inflation, increases with age. Because this element of salvage is a cost, the term "increases with age" means the salvage becomes more negative with age. Retirement of a utility pole is an example of an activity for which the hours required to remove the pole might remain relatively constant, but the hourly labor rate, and therefore the cost of retirement, would increase as the pole ages.

There are three reasons why it is important to consider salvage as a function of age, rather than simply using an overall average salvage. First, though the average life (AL) procedure uses an accrual rate based on the average net salvage, the equal life group (ELG) procedure uses the net salvage associated with each equal life group (i.e., salvage by age). Second, the calculated accumulated depreciation (CAD) model must reflect the change in salvage with age if it is to approximate the accumulated provision for depreciation. Because the CAD is the feedback measure used to determine the adequacy of the accumulated provision for depreciation, it is important that the model used be as lifelike as possible. When the remaining life method of adjustment is used, the amount to be recovered is found by adjusting for the future salvage. These first two reasons show that regardless of the system of depreciation used, both the average and the future salvage are required. Finally, considering salvage as a function of age results in a more realistic model and therefore enhances understanding of the depreciation process and aids in forecasting.

THE SALVAGE RATIO

One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels. Consider the pattern of installations and retirements illustrated in Figure 4.1 (see end of chapter).

Two replacement cycles are represented. The installation cost of the first unit is B dollars, it lasts K years, and has a net salvage of V dollars. The salvage ratio of the first unit is SR(present) = V/B. If the cost of the replacement when measured in constant dollars is equal to the cost of the first unit, then the replacement cost measured in inflated dollars is $B \times (1 + p)^K$. The factor $(1 + p)^K$ is called the compound amount factor and equals the value of \$1 after K years when the annual rate of inflation is p. Suppose the life of the replacement unit is L years and during its life the annual rate of inflation is f. Then the future salvage of the replacement is $V \times (1 + f)^L$. The salvage ratio of the replacement is SR(future) = $V \times (1 + f)^L/B \times (1 + p)^K$. If the past inflation rate p equals the future inflation rate f, and if the life of the original equals that of the replacement, so that K equals L, then the two inflation factors will be equal. The salvage ratio for the replacement will equal V/B, unchanged from the original ratio.

This simple model illustrates two important characteristics of the salvage ratio when the uninflated original cost and uninflated salvage remain the 1981 vintage, and similar calculations must be made for all other vintages. The vintage group model, which uses observed life and observed salvage data to construct the realized portion of the schedule, is a refinement of the broad group model. It has the advantage of more accurately reflecting the actual world transactions then does the broad group model.

THE SIMULATION OF SALVAGE BY AGE

It is not uncommon to record only the total salvage during the year. The data shown in Table 14.3 are of this type. Estimates of the ASR and an average FSR must be based on the unaged salvage data. When retirements are recorded by age, an alternate method of using this data is available. The alternative requires the depreciation professional to adopt a salvage model and use it to allocate the total annual salvage to each vintage. The result is salvage by age, as shown in Table 14.1, except the data are simulated rather than observed. The simulated data can be used in the manner described earlier in this chapter. However, the simulated data cannot be used to verify the model because to do so would be circular logic.

Table 14.7 (see end of chapter) shows how the $10.42 cost of retiring during 1970 can be allocated to the 1962 through 1970 vintages *if* the cost of retiring model discussed earlier in this chapter is adopted. The depreciation professional must be familiar with the account Utility Devices so that he or she can judge whether the model will result in a reasonable representation of the cost of retiring. Column (a) shows the vintage year and column (b) shows the original cost of the retirements during the 1970 calendar year. Column (c) shows the consumer price index (CPI-U) for July of the vintage year. Column (d) shows the ratio of the CPI-U for the vintage year to the CPI-U for the 1970 calendar year. For 1963, the ratio 61.0/39.0 or 1.56 suggests that a dollar spent in 1963 would purchase 1.56 times as much as a dollar spent in 1970. Column (e) is the product of column (b) times column (d), and represents a restatement of the vintage dollars to 1970 price level dollars. The $14.00 retired in 1963 are restated as $21.90 in the 1970 price level.

Thus, entries in column (e) are proportional to the *units* retired during 1970 *if* the model is applicable *and* the CPI-U is an appropriate index. The entries in column (e) are used as weights to allocate the $10.42 cost of retiring. Column (f) is the entry from column (e) divided by the sum of column (e). The fraction of the $10.42 allocated to the 1963 vintage is 21.90/61.84 or 0.3541. The allocation to the 1962 vintage is 0.3541 × 10.42 or $3.69, as shown in column (g). If this process is repeated for each calendar year, the result is the simulated cost of retiring by age. The simulated data can be used to construct salvage schedules similar to the schedule shown in Table 14.5.

SUMMARY

It is desirable to analyze gross salvage and cost of retiring separately. The two salvage schedules can be combined to find the average net salvage ratio and the future net salvage ratios by age. Data that reflect salvage by age, rather than only the total annual salvage, provide valuable information.

In practice, the procedure for estimating salvage varies widely. The depreciation professional's judgment of whether a procedure is reasonable is based on several variables. These include the magnitude of the salvage ratio, the available data, and the importance of the depreciable group. It is not unusual for a mass property account of a utility to exhibit large negative salvage. In such cases, the depreciation accrual rate may be more sensitive to the salvage estimate than to the life estimate.

If both the realized gross salvage and realized cost of retiring are near zero, extensive analyses may not be productive because the depreciation calculations are not sensitive to salvage ratios near zero. In such cases, the key to forecasting is predicting whether there will be a significant change in future operations that will change the levels of gross salvage or cost of retiring.

Often the only available data are the total annual gross salvage and cost of retiring. An example of this type of data is shown in Table 14.3. When analyzing unaged salvage, remember that realized salvage depends on the age of the retirements. Realized salvage starts at zero and does not reach the average until the final unit in the group is retired. Thus, the average age of the annual retirements and the average life of the group are important variables. Continuous property groups showing growth typically have large differences between the average age of the retirements and the average life of the group.

Salvage ratios are a function of inflation. For long-lived property, the salvage associated with the longest-lived property is affected most. However, this effect may not be reflected in the data for some time. A mathematical model that includes the effect of salvage can be a valuable forecasting tool. Salvage data by age contains information helpful for constructing and verifying a mathematical model.

NOTES

1. Cost of retiring is also called cost of removal.
2. See Chapter 4 for a discussion of inflation and salvage ratios.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Roxie McCullar

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12-16-2024
Date

CERTIFICATE OF SERVICE

This is to certify that a copy of the **Indiana Office of Utility Consumer Counselor Public's Exhibit No. 8 Testimony of OUCC Witness Roxie McCullar** has been served upon the following counsel of record in the captioned proceeding by electronic service on December 19, 2024.

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