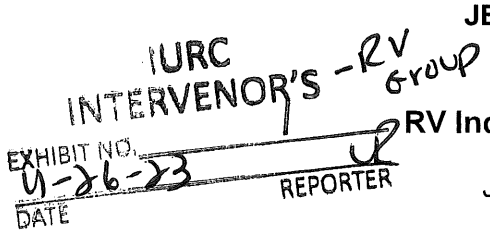
STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 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 A NEW RIDER FOR VARIABLE NONLABOR O&M EXPENSES ASSOCIATED WITH COALFIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POSTRETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.	)	Cause No. 45772

Direct Testimony and Attachments
of
JEFFRY POLLOCK



On Behalf of
RV Industry User's Group

January 20, 2023

OFFICIAL EXHIBITS

J. POLLOCK
INCORPORATED

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 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 A NEW RIDER FOR VARIABLE NONLABOR O&M EXPENSES ASSOCIATED WITH COALFIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POSTRETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.	)	**Cause No. 45772**

TABLE OF CONTENTS

GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
CCOSS	Class Cost-of-Service Study
EEI	Edison Electric Institute
FERC	Federal Energy Regulatory Commission
kW / kWh	Kilowatt / Kilowatt-Hour
NIPSCO	Northern Indiana Public Service Company
ROR	Rate of Return
RROR	Relative Rate of Return
RV Group	RV Industry User's Group

ATTACHMENT LIST

Attachment	Description
JP-1	Summary of NIPSCO's Class Cost-of-Service Study Results at Present and Proposed Rates
JP-2	Proposed Class Revenue Allocation
JP-3	Proposed Increase Measured on Revenues Excluding Fuel Costs
JP-4	Recommended Allocation of NIPSCO's Proposed Increase
JP-5	Summary of NIPSCO's Class Cost-of-Service Study Results at Present Rates and Recommended Allocation
JP-6	Large Commercial and Small Industrial Customer Typical Bill Comparison: Summer 2021/Winter 2022

1

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in electrical engineering and a Master's in Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces, including the Indiana Utility Regulatory Commission. My qualifications are documented in **Appendix A**. A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the RV Industry User's Group (RV Group). The RV Group is an ad hoc group of manufacturing and commercial users of Northern Indiana Public Service Company (NIPSCO). The members operate multiple manufacturing and commercial operations throughout Northern Indiana for which they purchase substantial amounts of electricity. Their electricity purchases from NIPSCO are on Rates 821, 823, 824, and 826.

Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS PROCEEDING CONSTITUTE AN ENDORSEMENT OF NIPSCO'S POSITION ON THESE ISSUES?

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of the proposals in this proceeding.

Q ARE YOU SPONSORING ANY ATTACHMENTS IN CONNECTION WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Attachments JP-1** through **JP-6**. These attachments were prepared by me.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

- NIPSCO's class cost-of-service study (CCOSS) uses the same methodologies approved in the last rate case and is generally consistent with accepted cost-causation principles and industry practice. Hence, it should be used as a primary tool in determining class revenue allocation.
- Despite its purported reliance on the results of its CCOSS to set rates, NIPSCO's proposed class revenue allocation would generally result in moving rates farther from, rather than closer to, cost.
- Large commercial and small industrial customers are paying much more for electricity purchased from NIPSCO than their peers served by investor-owned electric utilities in Indiana, the surrounding states, and nationally.
- The Commission should reduce interclass subsidies in this case by *at least* 25% with the caveats that no rate class would receive an increase that exceeds 1.5 times the system average base rate increase, excluding embedded fuel costs, and, given the magnitude of the proposed increase, no rate class should receive a rate decrease.

2. CLASS COST-OF-SERVICE STUDY

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each customer class's responsibility for the utility's costs. Thus, it determines whether the revenues a class provides cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and class revenue allocation, customers are grouped into relatively homogeneous classes according to their usage patterns and service characteristics. The procedures typically used in a CCOSS are described in more detail in **Appendix C**.

Q IS NIPSCO'S CLASS COST-OF-SERVICE STUDY GENERALLY REASONABLE AND DOES IT COMPORT WITH ACCEPTED PRACTICE?

A Yes. NIPSCO's CCOSS recognizes the different types of costs it incurs, as well as the different ways electricity is delivered to, and used by, its various types of customers. In particular:

- All production and transmission plant costs and related expenses are classified to demand.
- NIPSCO uses the four coincident peak (4CP) method to allocate production demand-related costs and the twelve coincident peak (12CP) method to allocate transmission demand-related costs.[1]

[1] While I do not support the 12CP method to allocate transmission costs (because NIPSCO is a predominantly summer-peaking utility), I am not challenging its use in this case because it is consistent with this Commission's practice.

- A portion of the distribution network (*i.e.,* investments booked to Federal Energy Regulatory Commission (FERC) Account Nos. 364-368) is classified as a customer-related cost.

These specific costing practices were adopted by the Commission in NIPSCO's last rate case. NIPSCO's CCOSS is generally consistent with the principles of cost causation; that is, costs are allocated to customer classes based on the degree to which each class caused NIPSCO to incur each specific cost.

Q WHAT ARE THE RESULTS OF NIPSCO'S CLASS COST-OF-SERVICE STUDY?

A **Attachment JP-1** summarizes the results of NIPSCO's CCOSS at present and proposed rates. The results are expressed in three ways: (1) rate of return (columns 1 and 4), (2) relative rate of return (columns 2 and 5), and the interclass subsidy (columns 3 and 6).

Rate of return (ROR) measures the net operating income (revenues minus operating expenses) expressed as a percentage of the allocated rate base. A class that is earning a ROR above the Indiana retail average rate of return is producing revenues that are above its allocated costs, while a class that is earning a ROR below the Indiana retail average rate of return is producing revenues below its allocated cost.

Relative rate of return (RROR) measures each class's ROR as a percent of the Indiana retail average rate of return. For example, a class with a RROR of 100 is providing revenues equal to its allocated costs. A RROR above 100 indicates that a class is above cost, while a RROR below 100 indicates that a class is below cost.

The interclass subsidy measures the differential between allocated costs and revenues. A negative subsidy indicates that a class is being subsidized by other customer classes, while a positive subsidy indicates that a class is subsidizing other classes.

Therefore, changes in the interclass subsidies determine whether rates are moving closer to, or farther from, cost.

Q SHOULD NIPSCO'S CLASS COST-OF-SERVICE STUDY BE USED TO DETERMINE CLASS REVENUE ALLOCATION AND RATE DESIGN?

A Yes. However, as discussed next, although NIPSCO claims to have used the results of its CCOSS to determine the allocation of the proposed revenue increase among the various rate classes (*i.e.,* class revenue allocation), the proposed rates would move farther from, rather than closer to, cost.

3. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class the utility serves.

Q WHAT CRITERIA DID NIPSCO USE TO DETERMINE THE CLASS REVENUE ALLOCATION?

A NIPSCO witness, Mr. Taylor, states that the following criteria were used in developing the proposed class revenue allocation:

- Cost of service results;
- Class contribution to present revenue levels and the resulting interclass subsidies;
- Customer bill impacts; and
- The Company's belief that while movement toward parity with the system-wide rate of return is the ultimate goal, moderation should be employed in accomplishing that goal.[2]

Applying the latter criterion, no rate class would receive an increase higher than 1.5 times the system average increase, including riders. However, as discussed in more detail later, NIPSCO's proposed class revenue allocation actually results in moving rates *farther* from cost.

Q ARE THE ABOVE LISTED CRITERIA REASONABLE CONSIDERATIONS?

A Yes. However, I disagree with how NIPSCO applied the above criteria. I do agree

[2] Petitioner's Exhibit No. 19, Direct Testimony of John D. Taylor at 38.

that base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. This is consistent with the general concept of cost causation and cost recovery discussed in my attached **Appendix C**. I also recognize that regulators sometimes choose to limit the immediate movement to cost based on principles of gradualism and other factors.

Q PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.

A *Gradualism* is a regulatory concept that is applied to prevent one or more rate classes from receiving an overly-large or disproportionate rate increase. That is, the movement to actual cost of service is made in steps or gradually rather than all at once to avoid rate shock to the affected customers.

Q WHY ARE COST-BASED RATES APPROPRIATE?

A Cost-based rates are equitable because each customer pays what it actually *costs* the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable. Cost-based rates are efficient because when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility. Cost-based rates also encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just *less use*). If rates are not based on a properly conducted CCOSS, then consumption choices are distorted. Further, when rates are

closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in a corresponding or parallel change in revenues and expenses.

Q SHOULD ABILITY TO PAY OVER-RIDE SETTING RATES TO RECOVER ACTUAL COSTS?

A No. In today's marketplace, the forces of supply and demand dominate pricing. Every manufacturer, including the RV Group members, must be cognizant of energy use per unit of production in order to remain competitive. This is because electricity costs can be a significant component of the overall cost of production. Competitive forces limit how much of the increased cost can be passed through. Thus, higher rates erode competitiveness. Manufacturers like the RV Group members who operate in NIPSCO's service area, have no more of an ability to pay than any other NIPSCO rate class customer.

Further, the ability to deduct electricity costs for tax purposes is not an advantage for businesses. Higher electricity costs reduce net profits. A business would have to increase revenues by over $1.21 (at a 21% marginal tax rate) for every $1 of net income lost due to a rate increase just to retain the same profitability that existed prior to the rate increase.

Q HOW IS NIPSCO PROPOSING TO SPREAD THE PROPOSED INCREASE AMONG THE VARIOUS RATE CLASSES?

A NIPSCO's proposed class revenue allocation is shown in **Attachment JP-2**. The increases are measured as a percentage of overall revenue, including riders. As can be seen, the proposed revenue changes range from a 49% *decrease* for Rates 842

and 843 to up to a 29% increase for Rates 820, 844, 850, 860 and Interdepartmental. NIPSCO is only proposing the *system average* increase for Rates 811.

Q DO THE INCREASES SHOWN IN ATTACHMENT JP-2 ACCURATELY MEASURE THE IMPACT OF THE CHANGES IN NIPSCO'S COSTS IN THIS PROCEEDING?

A No. If rates are moving closer to cost, the rate classes for which NIPSCO is currently earning a below system-average ROR should receive above-average increases, while the rate classes for which NIPSCO is currently earning an above system-average ROR should receive below-average increases. However, because the proposed $291.8 million increase has nothing to do whatsoever with changes in fuel costs – either the fuel costs embedded in base rates or the fuel costs recovered in Rider 870, measuring the impact on total revenues provides no information about whether the proposed class revenue allocation would result in moving rates closer to cost.

Q HOW SHOULD THE IMPACT OF THE PROPOSED CLASS REVENUE ALLOCATION BE MEASURED?

A Because the proposed increase is related to increases in non-fuel costs, the impact should be measured relative to current base revenues, excluding the fuel costs embedded in base rates.

Q HAVE YOU MEASURED THE PROPOSED INCREASES RELATIVE TO CURRENT BASE REVENUES EXCLUDING EMBEDDED FUEL COSTS?

A Yes. **Attachment JP-3** shows the proposed increases relative to present base

revenues, excluding the fuel costs that are embedded in base rates.[3] As can be seen, NIPSCO's proposed $291.8 million increase would translate into a 26.2% increase when fuel costs are excluded. Some rate classes (*e.g.,* Rate 820, 833, 844) would experience increases in excess of 39.3%, which is 1.5 times the system average non-fuel increase.

Q IS NIPSCO'S PROPOSED CLASS REVENUE ALLOCATION CONSISTENT WITH ITS STATED CRITERIA?

A No. NIPSCO's proposed class revenue allocation is not consistent with its stated criteria. First, as shown in **Attachment JP-3,** some rate classes would receive base revenue increases that exceed 1.5 times the system average *non-fuel* increase. Second, with a few notable exceptions, rates would move farther from, and not closer to, cost. This runs afoul of the previously discussed concept of gradualism.

Q HOW DID YOU DETERMINE THAT RATES WOULD MOVE FARTHER FROM COST?

A Table 1 below shows the interclass subsidies at present and proposed rates. If rates are moving closer to cost, the subsidy should be reduced. As Table 1 demonstrates:

- Only Rate 831 would move to cost;
- Rates 842, 843, and 860 would move closer to cost;
- Rate 820 would move from below cost to above cost; and
- All other rates would move farther from cost.

[3] Rider 870 recovers estimated fuel, purchased power, fuel-related MISO charge types, and other costs approved by the Commission less $0.026736 per kilowatt-hour (kWh) of costs that are embedded in base rates.

Table 1
Interclass Subsidies at Present and Proposed Rates
($000)

Rate Class	Present Rates	Proposed Rates	Movement to Cost
Rate 811/511	($119,930)	($150,919)	-26%
Rate 820/520	($6)	$100	1734%
Rate 821/521	$47,657	$54,329	-14%
Rate 822/522	$134	$173	-29%
Rate 823/523	$18,381	$25,856	-41%
Rate 824/524	$21,611	$33,808	-56%
Rate 825/525	$1,249	$1,693	-36%
Rate 826/526	$17,744	$29,414	-66%
Rate 831/531	$10,816	$0	100%
Rate 832/532	$1,209	$2,700	-123%
Rate 833/533	$1,356	$4,089	-201%
Rate 841/541	$897	$1,080	-20%
Rate 842/542	$78	$19	76%
Rate 843/543	$1,804	$416	77%
Rate 844/544	$13	$174	-1224%
Rate 850/550	($1,364)	($1,636)	-20%
Rate 855/555	$268	$341	-27%
Rate 860/560	($759)	($538)	29%
Interdepartmental	($1,157)	($1,099)	5%
Total	$0	$0	-22%

Source: **Attachment JP-1**

1

Overall, rates would be 22% farther from cost. Thus, despite its stated objective to move rates gradually to parity (cost), the majority of NIPSCO's non-residential customers would not only continue subsidizing NIPSCO's residential customers, the amount of the subsidies would increase.

Q WHY WOULD NIPSCO'S PROPOSED CLASS REVENUE ALLOCATION RESULT IN RATES MOVING AWAY FROM, RATHER THAN CLOSER TO, COST?

A First, NIPSCO targeted the increases to specific rate classes. Specifically, it limited the increase to Rate 811 to the system average including riders, despite the fact that this class is highly subsidized. It also proposed a below-system average increase to set Rate 831 to cost. Though the latter is consistent with achieving cost-based rates, a rate class that is currently earning a below system-average return should receive an above-system average (not a system average) increase as NIPSCO is proposing for Rate 811.

Second, contrary to its proposed treatment of Rate 811, NIPSCO proposed the maximum increase (approximately 29%) for most of the other rate classes that also had below-system average rates of return at present rates, regardless of the degree.

Q HOW SHOULD ANY RATE CHANGES RESULTING FROM THIS CASE BE ALLOCATED AMONG THE VARIOUS CLASSES?

A Consistent with good public policy and past Commission practice, rates for each class should be set at a level that will recover the cost of serving that class, as closely as practicable. My recommended class revenue allocation is shown in **Attachment JP-4**. Specifically, I applied the same criteria as NIPSCO, except the increase was spread to reduce the interclass subsidies for all classes. Additionally, no class would receive

more than 1.5 times the system average increase, excluding fuel costs, and no class would receive a decrease.

Q WOULD ALL RATE CLASSES MOVE CLOSER TO COST UNDER YOUR RECOMMENDATION?

A Yes. On average, rates would be moved about 29% closer to cost, as shown in **Attachment JP-5**. However, because of the cap (*i.e.,* increase limited to 1.5 times the system average non-fuel increase) and floor (no decrease), which are consistent with gradualism, the movement was limited for some rate classes (*e.g.,* Rates 842, 843, 850).

Q WHY IS IT ESPECIALLY IMPORTANT TO SET RATES TO COST IN THIS PROCEEDING?

A NIPSCO's current electricity rates for large commercial and small industrial customers are not competitive. This is shown in **Attachment JP-6**.

Q PLEASE EXPLAIN ATTACHMENT JP-6.

A **Attachment JP-6** ranks the monthly bills for specific commercial and industrial customers based on both size (in kW) and energy usage (in kWh). The information was sourced from the Typical Bills and Average Rates Report published by the Edison Electric Institute (EEI), I ranked NIPSCO's typical monthly bills reported by investor-owned electric utilities to the EEI for non-residential customers. The rankings are based on the rates in effect during the summer 2021 and winter 2022 for Indiana, Indiana and the surrounding states, and the national average (excluding Alaska and Hawaii).

As can be seen, NIPSCO has the highest monthly bills for large commercial and small industrial customers of any investor-owned utility in Indiana. Further, its bills are among the highest in Indiana and surrounding states, and in the top 10% to 17% out of 145 investor-owned utilities in the nation. Thus, the proposed increase will make NIPSCO's already non-competitive rates even less competitive. Raising NIPSCO's already high electricity rates even higher would make it even more difficult for manufacturers to compete and make NIPSCO's service territory a much less attractive place for business — with the decline in and volatility of the current economy nation-wide, it is more important than ever for states to be able to not only attract, but retain current businesses.

Q IF THE COMMISSION APPROVES A LOWER INCREASE THAN NIPSCO IS SEEKING, HOW SHOULD THAT LOWER INCREASE BE ALLOCATED TO CUSTOMER CLASSES?

A If the Commission approves a lower revenue increase, it should reduce the base revenues shown in **Attachment JP-4** (column 2) in the same proportion as the reduction in NIPSCO's non-fuel revenue requirement. For example, if the Commission approves 50% of NIPSCO's proposed increase, it would reduce the proposed total non-fuel revenues by approximately 10%. Thus, the amounts shown in **Attachment JP-4**, column 2 should be reduced by approximately 10%.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing

requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022

You may download a complete list from 1976 to present using this link.

APPENDIX C

Procedure for Conducting a Class Cost-of-Service Study

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed Operation and Maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that

a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- operate at higher load factors;
- take service at higher delivery voltages; and
- use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

VERIFICATION

The undersigned verifies and affirms under the penalties of perjury that the that the testimony, statements, and representations contained herein are true and correct to the best of his knowledge, information, and belief.

Jeffry Pollock
J. Pollock, Incorporated